Southwest Regional Partnership on Carbon Sequestration

Final Report

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Principal Author*: Brian McPherson

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Submitting Organization: New Mexico Institute of Mining and Technology
801 Leroy Place
Socorro, New Mexico 87801

*Other Contributing Authors:
Rick Allis, Utah Geological Survey, Barry Biediger, Utah Automated Geographical Reference Center, Joel Brown, U.S. Department of Agriculture, Jim Cappa, Colorado Geological Survey, George Guthrie, Los Alamos National Laboratory, Richard Hughes, University of Oklahoma, Eugene Kim, Texas Bureau of Economic Geology, Robert Lee, New Mexico Institute of Mining and Technology, Dennis Leppin, Gas Technology Institute, Charles Mankin, Oklahoma Geological Survey, Peter Kobos, Sandia National Laboratories, Rajesh Pawar, Los Alamos National Laboratory, Tarla Peterson, University of Utah, Steve Rauzi, Arizona Geological Survey, Jerry Stuth, Texas A&M University, Genevieve Young, Colorado Geological Survey, and many other partners in the Southwest Partnership

Disclaimer

Abstract

The Southwest Partnership on Carbon Sequestration completed its Phase I program in December 2005. The main objective of the Southwest Partnership Phase I project was to evaluate and demonstrate the means for achieving an 18% reduction in carbon intensity by 2012. Many other goals were accomplished on the way to this objective, including (1) analysis of CO_2 storage options in the region, including characterization of storage capacities and transportation options, (2) analysis and summary of CO_2 sources, (3) analysis and summary of CO_2 separation and capture technologies employed in the region, (4) evaluation and ranking of the most appropriate sequestration technologies for capture and storage of CO_2 in the Southwest Region, (5) dissemination of existing regulatory/permitting requirements, and (6) assessing and initiating public knowledge and acceptance of possible sequestration approaches.

Results of the Southwest Partnership's Phase I evaluation suggested that the most convenient and practical "first opportunities" for sequestration would lie along existing CO_2 pipelines in the region. Action plans for six Phase II validation tests in the region were developed, with a portfolio that includes four geologic pilot tests distributed among Utah, New Mexico, and Texas. The Partnership will also conduct a regional terrestrial sequestration pilot program focusing on improved terrestrial MMV methods and reporting approaches specific for the Southwest region. The sixth and final validation test consists of a local-scale terrestrial pilot involving restoration of riparian lands for sequestration purposes. The validation test will use desalinated waters produced from one of the geologic pilot tests.

The Southwest Regional Partnership comprises a large, diverse group of expert organizations and individuals specializing in carbon sequestration science and engineering, as well as public policy and outreach. These partners include 21 state government agencies and universities, five major electric utility companies, seven oil, gas and coal companies, three federal agencies, the Navajo Nation, several NGOs, and the Western Governors Association. This group is continuing its work in the Phase II Validation Program, slated to conclude in 2009.

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Executive Summary

The Southwest Regional Partnership on Carbon Sequestration (SWP) region includes Arizona, Colorado, New Mexico, Oklahoma, Utah, and contiguous areas from three adjacent states, including western Texas, southern Wyoming, and western Kansas. This region is a net exporter of electricity, coal, oil and gas, and has some of the largest growth rates in the nation.

The Partnership characterized the region's geologic and terrestrial sequestration attributes and options, including ranges of storage capacities of each option. The Partnership also evaluated and summarized CO2 sources in the region, and associated separation and capture technologies employed in the region. Measurement, mitigation and verification (MMV) options were evaluated, and a suite of most appropriate MMV options for Phase II validation testing was assembled. Outreach and education of the public was initiated, using a range of communication approaches, including websites, townhall meetings and conferences. The resulting data from all SWP analyses were compiled and published in comprehensive databases, with public online access; these data were also propagated to NATCARB.

The southwest region possesses an extensive CO_2 pipeline network that transports over 30 Mt of naturally-sourced CO_2 per year from the central Rockies to the Permian basin for EOR operations. In the Partnership's Phase I project, we concluded that the most convenient and practical opportunities for sequestration would be to supplant the natural CO_2 in these pipelines with power-plant-sourced CO_2. We maintain this idea and suggest that "first options" for the nation may lie along existing pipelines. Furthermore, the SWP's Phase I ranking of sequestration opportunities considered proximity to sources and/or pipeline infrastructure in addition to economic, safety, risk mitigation potential, and other factors. The result of the Phase I ranking process produced plans for a technology validation program that includes four geologic pilot tests located among Utah, New Mexico, and Texas, in addition to a region-wide terrestrial analysis and a local-scale terrestrial pilot test. The Phase I project recommended geologic sequestration test sites to inject a minimum of ~75,000 tons/year CO_2, with a minimum injection duration of one year. Such pilots represent medium-scale validation tests in sinks that may host capacity for possible larger-scale sequestration operations in the future. These validation tests will also demonstrate a broad variety of carbon sink targets and multiple value-added benefits, including testing of deep saline sequestration, enhanced oil recovery and sequestration, enhanced coalbed methane production and a geologic sequestration test combined with a local terrestrial sequestration pilot. The local terrestrial pilot involves restoration of riparian lands for sequestration purposes, using desalinated waters produced from our scheduled enhanced coalbed methane / CO_2 sequestration pilot project. The Partnership's regional terrestrial sequestration pilot program will focus on improved terrestrial MMV methods and reporting approaches specific for the Southwest region. In sum, the SWP's Phase I project produced a field validation testing program that will seek to maximize specific performance, economic, and environmental goals of the DOE Carbon Sequestration Roadmap. This validation-testing will demonstrate efficacy of sequestration technologies to reduce or offset greenhouse gas emissions in the region. Risk mitigation, optimization of MMV protocols, and effective outreach and communication are additional critical goals of these field validation tests.

The SWP comprises a diverse group of expert organizations specializing in carbon sequestration science and engineering, as well as economics, public policy and outreach. These partner organizations are drawn from: 1) industry, 2) State governmental agencies and universities, 3) U.S. Federal government entities, and 4) other specialized partners, including the Western Governors Association. The Southwest Partnership continues a close alliance with the other Regional Partnerships, and the Western Governors' Association has facilitated communication and collaboration. For Phase II, the Southwest Partnership is collaborating with Big Sky Partnership and WESTCARB on two different pilot tests in the region.

This report outlines the general results of the Phase 1 SWP program, which focused on characterization of the region and its sequestration options. Also included is a series of appendices, which are intended as stand-alone documents; these appendices include descriptions of the general regulatory frameworks in the Southwest region (by state), a summary of carbon sources in the region, a summary of the SWP risk factors assessment, a summary of monitoring technologies and gaps in coverage, a summary of activities conducted by the Western Governors Association on behalf of the SWP, and the action plans for the SWP Phase 2 sequestration validation program.

Experimental

No special experimental methods are being employed in this project. Materials and equipment used include only standard communication means and data management tools, including computerized databases, internet websites, etc.

Results and Discussion

Geologic Sinks

Arizona Geologic Sinks

The total carbon dioxide (CO_2) sequestration capacity of geologic sinks in Arizona, excluding mineralization, is estimated to be in excess of 27,520 million metric tons (Table 1). Saline reservoirs on the Colorado Plateau in northern Arizona and the intermountain basins in southern Arizona account for essentially all of this capacity even though they have the greatest uncertainty as to effective reservoir and trap development (Fig. 1). Oil and gas fields on the Navajo Nation in northeastern Arizona account for only 14.1 million metric tons of the total. No CO_2 sequestration capacity was estimated for coal because none of the coal deposits meet the minimum depth requirement for maintaining CO_2 in a critical state. The deepest coal deposits are less than 2,000 ft deep whereas the CO_2 critical state requirements are based on temperature and pressure levels below a minimum depth of 2,600 ft. There is no coalbed methane production in Arizona.

The six major utility point sources in Arizona discharged 41 million metric tons of CO_2 in 2002. The Navajo Generating Station near Page discharged 18 million metric tons of CO_2 in 2002. The Navajo Generating Station is the largest point source of CO_2 emissions in Arizona. All six major utility point sources are located over potential saline reservoirs. None of the major utility point sources are located near oil and gas fields.

Oil and Gas Fields

There are 14 relatively small oil and gas fields in northeastern Arizona (Fig. 1). The total CO_2 sequestration capacity for all of the fields together is estimated to be about 14.1 million metric tons. The oil and gas fields include the (1) Dineh-bi-Keyah, (2) East Boundary Butte, (3) Black Rock, (4) Dry Mesa, (5) Teec Nos Pos, (6) Tohache Wash, (7) Bita Peak, (8) Twin Falls Creek, (9) North Toh Atin, (10) Toh Atin, and (11) Walker Creek fields on the Navajo Nation and the (12) Pinta Dome, (13) Navajo Springs, and (14) East Navajo Springs helium fields in the Holbrook Basin. All have been abandoned except for the Dineh-Bi-Keyah, East Boundary Butte, Black Rock and Dry Mesa fields. All production has come from geologic units of Paleozoic age except for Dineh-bi-Keyah. Dineh-bi-Keyah is unique because the producing reservoir is igneous rock of Tertiary (Oligocene) age that was intruded into carbonate and organic-rich, black shale of Pennsylvanian age.

Field	Location	Productive horizon
Dineh-bi-Keyah	35-36n/29-30e	Tertiary Igneous in Penn. Hermosa Fm
East Boundary Butte	41n/28-29e	Penn. Paradox Fm
Black Rock	40n/29e	Miss. Leadville Ls / Penn. Paradox Fm
Dry Mesa	40n/28e	Miss. Leadville Ls / Penn. Paradox Fm
Teec Nos Pos	41n/30e	Penn. Paradox Fm
Tohache Wash	41n/30e	Devonian Aneth Fm/ Miss. Leadville Ls
Bita Peak	41n/31e	Penn. Paradox Fm
Twin Falls Creek	41n/30e	Penn. Paradox Fm
North Toh Atin	41n/28e	Penn. Paradox Fm
Toh Atin	40n/28e	Penn. Paradox Fm
Walker Creek	41n/25e	Devonian McCracken Ss
Pinta Dome	19-20n/26e	Permian Coconino Ss
Navajo Springs	19-20n/27-28e	Permian Coconino Ss
East Navajo Springs	19-20n/27-28e	Permian Coconino Ss

Only two oil and gas fields in Arizona exceed the cumulative production values of 1 million barrels of oil or 10 billion cubic feet of gas used by the Southwest Partnership to identify preferable geologic sink candidates. These include the Dineh-bi-Keyah field with a cumulative oil production of 18.5 million barrels and the East Boundary Butte field with a cumulative gas production of 10 billion cubic feet. The total estimated sequestration capacity of Dineh-bi-Keyah and East Boundary Butte is 11 million metric tons. None of the fields in Arizona are in close proximity to a major point source of CO_2. The closest point sources are about 45 miles to the east in northwest New Mexico.

Dineh-bi-Keyah Field (AZ-000F02)

Why the site looks good:

- Demonstrated reservoir with effective seal
- Cumulative production of 18.3 million barrels oil, 6.6 million barrels water, and 4.7 billion cubic feet gas
- Existing well bores plus added value from a potential CO_2 flood
- Injection targets range from 2,800 to 3,800 ft
- Potential CO_2 sequestration capacity of 9 million metric tons

Issues needing further evaluation:

- Approximately 45 miles to nearest point sources in northwestern New Mexico
- Located on Navajo Nation and may require special permits and fees

East Boundary Butte Field (AZ-000F01)

Why the site looks good:

- Demonstrated reservoir with effective seal
- Cumulative production of 10 billion cubic feet gas, 5.2 million barrels water, and 0.9 million barrels oil
- Existing well bores plus added value from a potential CO_2 flood
- Injection targets range from 4,700 to 5,000 ft
- Potential CO_2 sequestration capacity of 2 million metric tons

Issues needing further evaluation:

- Approximately 45 miles to nearest point sources in northwestern New Mexico
- Located on Navajo Nation and may require special permits and fees

Deep Saline Reservoirs

The total maximum CO_2 sequestration capacity for the ten deep saline reservoirs identified in Table 1 is estimated to be about 27,500 million metric tons. Three of the saline reservoirs are Paleozoic units located near Page, Holbrook, and St. Johns in northern Arizona. The remaining seven are basin-fill sediments located in the intermountain Tertiary basins in southern Arizona. Six of the saline reservoirs underlie major utility point sources of CO_2 including the Navajo, Cholla, Coronado, and Springerville power plants in northern Arizona and the Apache and Irvington power plants near Willcox and Tucson in southern Arizona (Fig. 1).

Greater uncertainty exists in terms of reservoir extent and trap efficiency in the deep saline reservoirs as opposed to the oil and gas fields. There is very little direct reservoir and trap information such as porosity, permeability, depth, and thickness available for the saline reservoirs, especially in the Tertiary basins, because there are so few deep drill holes and the information that is available from the few deep drill holes is in most cases very sparse and sketchy. As a result, porosity, depth and thickness are based mostly on driller's descriptions and old electrical logs. Reservoir pressures are estimates based mostly on a pressure gradient of 0.433 psi per ft of depth. The estimated area of the saline reservoirs in the Tertiary basins is based on the 3,000 ft depth-to-bedrock contours, which in turn are based on gravity.

Focus Site: Navajo Generating Station

The Navajo Generating Station (NGS) is the largest stationary point source of CO_2 emissions in Arizona. It discharged about 18 million metric tons of CO_2 in 2002. The 2,400 MW coal-fired NGS is approximately five miles southeast of Page on property leased from the Navajo Nation. The Salt River Project (SRP) operates the NGS.

The youngest to oldest potential CO_2 sequestration reservoirs underlying the NGS include the Kaibab Limestone, Coconino Sandstone, and Cedar Mesa Sandstone of Permian age; Redwall Limestone of Mississippian age; and Tapeats Sandstone of Cambrian age. Potential reservoir seals include the Muav Limestone, Bright Angel Shale, Organ Rock Shale, Chinle and Moenkopi Formations. The estimated reservoir and seal depths and thicknesses underlying the NGS are tabulated in Table 2.

There are no deep exploratory wells in the immediate vicinity of the NGS. Formation depths and thickness estimates underlying the NGS are based on projections of formation tops in the Shell Soda Unit #1 in Utah (2-40s-7e) and the Sinclair Oil Navajo Tribal #1 in Arizona (28-37n-14e). The Shell Soda Unit #1 and Sinclair Oil Navajo Tribal #1 are approximately 39 miles northeast and 38 miles southeast of the NGS, respectively. Figure 2 illustrates the relative location of the NGS, wells, orientation of A-A' profile, NGS projection point onto A-A', and a cross section along A-A'.

The NGS is within the Kaibito Plateau physiographic province, which is part of the Kaiparowits Basin. The Kaibab Uplift, White Mesa, and Navajo Mountain bound the basin on the west, south, and east, respectively. The basin extends north into Utah and covers approximately 3,000 square miles in Arizona.

Land surface elevation near the NGS is approximately 4,350 ft above mean sea level and located within a grassland-shrub vegetation zone. Average annual temperature is approximately 58°F. Mean annual precipitation is less than eight inches. Range in annual snowfall exceeds 40 inches. Municipal and industrial water demands in the area are provided from Lake Powell surface-water withdrawals.

Groundwater is present at approximately 1,050 ft below land surface and occurs primarily in the Glen Canyon Group, which is known as the N-aquifer system. The early Jurassic to upper Triassic (180 to 210 Ma) N-aquifer system consists of the Navajo Sandstone, Kayenta Formation, and Wingate Sandstone. The deeper C-aquifer includes the Kaibab Limestone and Coconino Sandstone. The C-aquifer is not a water supply formation in the northern Arizona Colorado Plateau region. Indications are that the Kaibab Limestone and the Coconino Sandstone are dry west of the north-south trending Wahweap syncline, located approximately three miles east of Page. Groundwater in the vicinity of the NGS flows north toward Lake Powell.

Cambrian Tapeats Sandstone

The Grand Canyon Tonto Group of Cambrian age has been differentiated into the Tapeats Sandstone, Bright Angle Shale, and Muav Limestone. The Tapeats Sandstone is the deepest saline reservoir under consideration for CO_2 sequestration with approximately 6,500 ft of overburden. Thickness estimates range between 200 to 350 ft near the confluence of the Little Colorado and Colorado Rivers. It is not considered an aquifer due to its depth and salinity. The Tapeats is very fine to very coarse, subrounded to subangular and is poorly sorted with clear, white, and pink quartz grains. The sandstone is thin- to thick-bedded with planar-tabular cross-bedding that is medium to low angle and medium to large scale. It may contain lenses of conglomerate near the basal contact and is generally well cemented by siliceous quartzite material. Thus, the Tapeats does not readily transmit water rapidly unless fractured. The Hopi have used the seeps near the mouth of the Little Colorado River as a source of salt. The Sinclair Oil Navajo Tribal #1 did not fully penetrate the Tapeats (only 30 ft) so the projected thickness is unknown. The Tapeats thickness in the Shell Soda Unit #1 is 215 ft. The thickness estimate underlying NGS is 330 ft.

Mississippian Redwall

The Mississippian Redwall Limestone in Grand Canyon is equivalent to the Leadville Limestone in the Four Corners region. The Redwall is approximately 500 ft thick in Grand Canyon where it has been differentiated into four members:

- Member-A, the basal Whitmore Wash Member, is a thick-bedded unit 70 to 130 ft thick. Limestone predominates in the western part of the area and dolomite in the eastern part.
- Member-B, Thunder Springs Member, is approximately 65 to 105 ft thick and consists of alternating beds of chert and carbonate rock approximately 1 to 5 inches thick and forms a conspicuous banded cliff.
- Member-C, Mooney Falls Member, is a thick bedded, massive, cliff-forming unit that ranges from 200 to 400 ft thick.
- Member-D, the uppermost Horseshoe Mesa Member, is a 40 to 100 ft thick thin bedded, mostly aphanitic limestone.

The Mississippian rocks thin progressively to the southeast and are no longer present east of Holbrook. The Redwall Limestone appears massive but close inspection indicates it contains numerous solution channels and cavities developed along bedding planes, faults, and joints. Previous thickness estimates near Page are between 600 and 700 ft.

Pennsylvanian and Permian Rocks

The Aubrey Group, named after the Aubrey Cliffs near Seligman, consists of the following units from top to bottom: Kaibab Limestone, Coconino Sandstone, Hermit Shale, and the Supai Formation. The Coconino and the Kaibab are the chief water-bearing units in the southern part of the Colorado Plateau. These units are connected hydraulically and form the C-multiple aquifer system. The Kaibab Limestone is not present in the Sinclair Oil Navajo Tribal #1 and, assuming the unit pinches out at the well, is of negligible thickness beneath the NGS (15 ft). The projected Coconino Sandstone thickness is approximately 550 ft beneath the NGS.

Discussion

The Kaibab Limestone and Coconino Sandstone are above a depth of 2,600 ft in the vicinity of the NGS (Table 2, Fig. 2). Geological sequestration of CO_2 below a depth of 2,600 ft is preferred because formation temperature and pressure conditions below 2,600 ft will maintain CO_2 in a critical state.

The 1,315 ft thick Cedar Mesa Sandstone, which lies deeper than the preferred depth of 2,600 ft, underlies approximately 455 ft of Organ Rock Shale, a potential seal formation. The deeper-lying Redwall Limestone and Tapeats Sandstone merit further evaluation. Exploratory drilling near the NGS is needed to obtain direct and critical information regarding the potential for CO_2 sequestration near the NGS.

Tapeats-Redwall-Cedar Mesa (AZ-000R01)

Why the site looks good:

- Location beneath major point source (Navajo Generating Station)
- Thick sandstone and carbonate rocks with good porosity provide potential reservoirs
- Thick shale units with few mapped faults provide effective seals
- Injection targets range from 5,000 to 10,000 ft

Issues needing further evaluation:

- Insufficient number of boreholes to demonstrate storage capacity of reservoirs
- Environmental concern of potential reservoir rocks beneath national recreation area
- Located on Navajo Nation and may require special permits and fees

Naco Limestone (AZ-000R02)

Why the site looks good:

- Location beneath major point source (Cholla Power Plant)
- Extensive salt deposits to provide effective seal
- Possible permeability and porosity development in carbonate or clastic reservoirs
- Injection targets range from 2,500 to 3,500 ft

Issues needing further evaluation:

- Insufficient number of boreholes to demonstrate storage capacity of reservoirs
- Insufficient number of boreholes to delineate structural and stratigraphic traps

Tertiary Basin Fill (AZ-000R04)

Why the site looks good:

- Location beneath major point source (Apache Power Plant)
- Thick clastic basin-fill deposits as potential injection reservoirs
- Injection targets range from 2,500 to 6,000 ft

Issues needing further evaluation:
- Insufficient number of boreholes to demonstrate the presence of effective seals
- Insufficient number of boreholes to demonstrate storage capacity of reservoirs
- Insufficient number of boreholes to delineate structural and stratigraphic traps

St. Johns – Springerville (AZ-000R03)

Why the site looks good:
- Location beneath major point source (Springerville Power Plant)
- Operator press releases report up to several trillion cubic feet of gas in place

Issues needing further evaluation:
- Relatively shallow injection targets range from 1,500 to 3,000 ft
- Insufficient number of boreholes to demonstrate storage capacity of reservoirs
- Insufficient capacity resulting from the recent start and low volume of production
- Low hydrostatic gradients and reservoir pressures
- Relationship between numerous springs, travertine domes, and effectiveness of seals

Coal

Unminable coal seams were evaluated as potential CO_2 sequestration sinks but none of the coal deposits met the minimum depth requirement for maintaining CO_2 in a critical state. Carbon dioxide critical state requirements are based on temperature and pressure levels below 2,600 ft minimum depth. There is no coal-bed methane production in Arizona.

Coal Deposits in the Black Mesa Basin

Why the site looks good:
- Large reserve containing an estimated 20 billion tons of unminable coal
- Added value from potential enhanced recovery of coal-bed methane from CO_2 flood

Issues needing further evaluation:
- Approximately 65 miles to nearest point source at Page, Arizona
- Very shallow injection targets between 300 and 1,700 ft
- Insufficient number of boreholes to demonstrate storage capacity of reservoirs
- Located on Navajo and Hopi lands and may require special permits and fees

Table 1. Potential Carbon Sequestration Capacity for Arizona (in Million Metric Tons)

CO_2 Emissions in 2002		Geologic			Mineralization		Total Capacity
		Oil & Gas	CBM	Saline Aquifers	Silicates	Produced Waters	
Navajo	18	0	0	24,094	Not studied	Not studied	24,094
Cholla	8	0	0	401	Not studied	Not studied	401
Springerville	6	0	0	18	Not studied	Not studied	18
Coronado	5	0	0	18	Not studied	Not studied	18
Apache	3	0	0	629	Not studied	Not studied	629
Irvington	1	0	0	186	Not studied	Not studied	186
Red Rock	0	0	0	366	Not studied	Not studied	366
Higley	0	0	0	469	Not studied	Not studied	469
Luke	0	0	0	386	Not studied	Not studied	386
Mohawk	0	0	0	688	Not studied	Not studied	688
San Cristobal	0	0	0	252	Not studied	Not studied	252
Oil & gas fields	0	14.1	0	0	Not studied	Not studied	14.1
Total	***41***	***14.1***	***0***	***27,507***	Not studied	Not studied	***27,521***

Table 2. Stratigraphic Units beneath Navajo Generating Station

Formation	Elevation (ft)	Depth (ft)	Thickness (ft)
Chinle-Moenkopi	3825	525	1155
Kaibab Limestone	2670	1680	15*
Coconino Sandstone	2655	1695	555
Organ Rock Shale	2100	2250	455
Cedar Mesa Sandstone	1645	2705	1315
Redwall Limestone	-235	4585	545
Muav Limestone-Bright Angel Shale	-1525	5875	615
Tapeats Sandstone	-2140	6490	330**

* Assumes Kaibab pinches out at the Sinclair Oil Navajo Tribal #1well
** Estimate from R. Allis, Utah Geological Survey

Selected Arizona Data Sources
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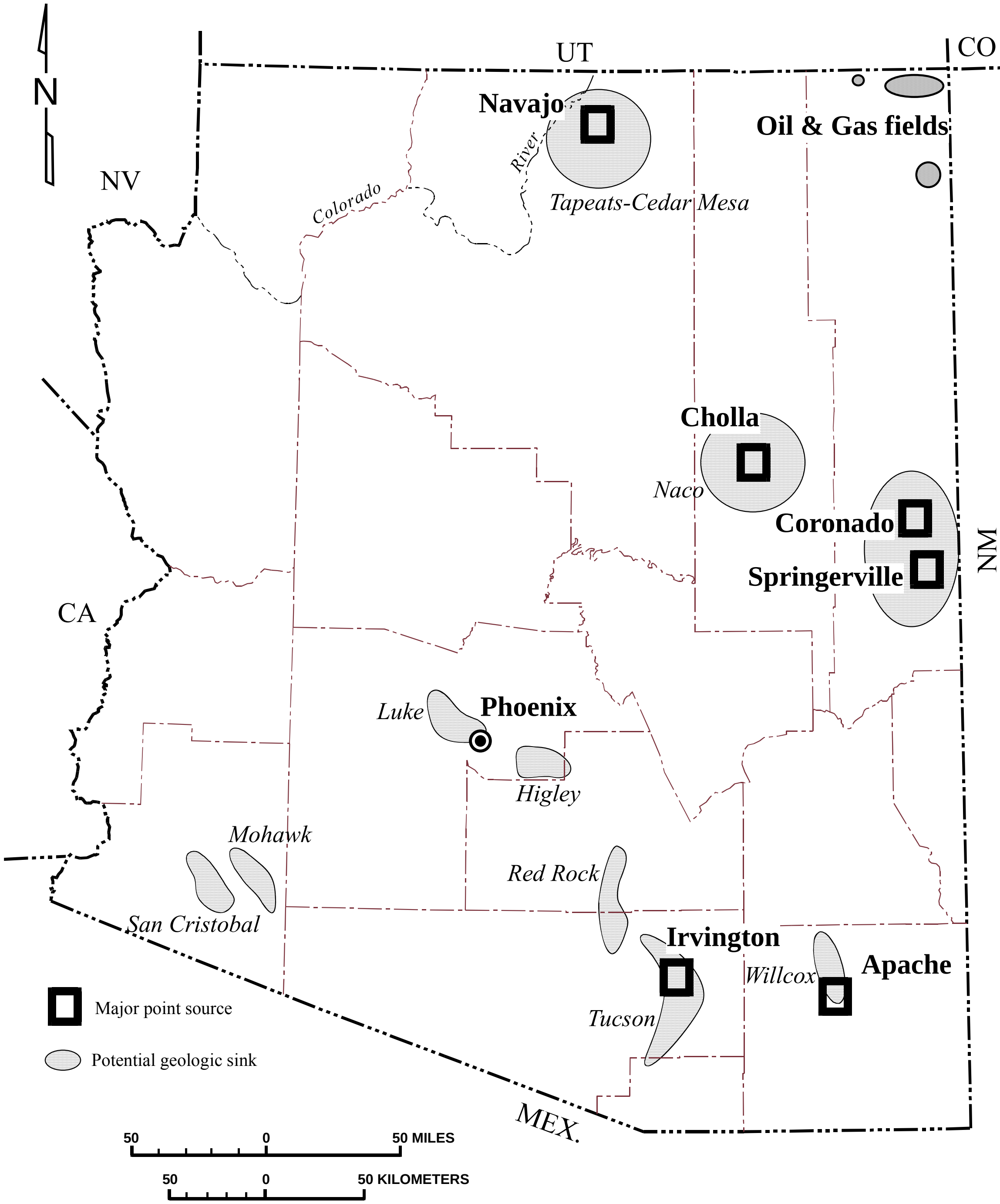

Fig. 1. Major point sources and potential geologic sinks in Arizona.

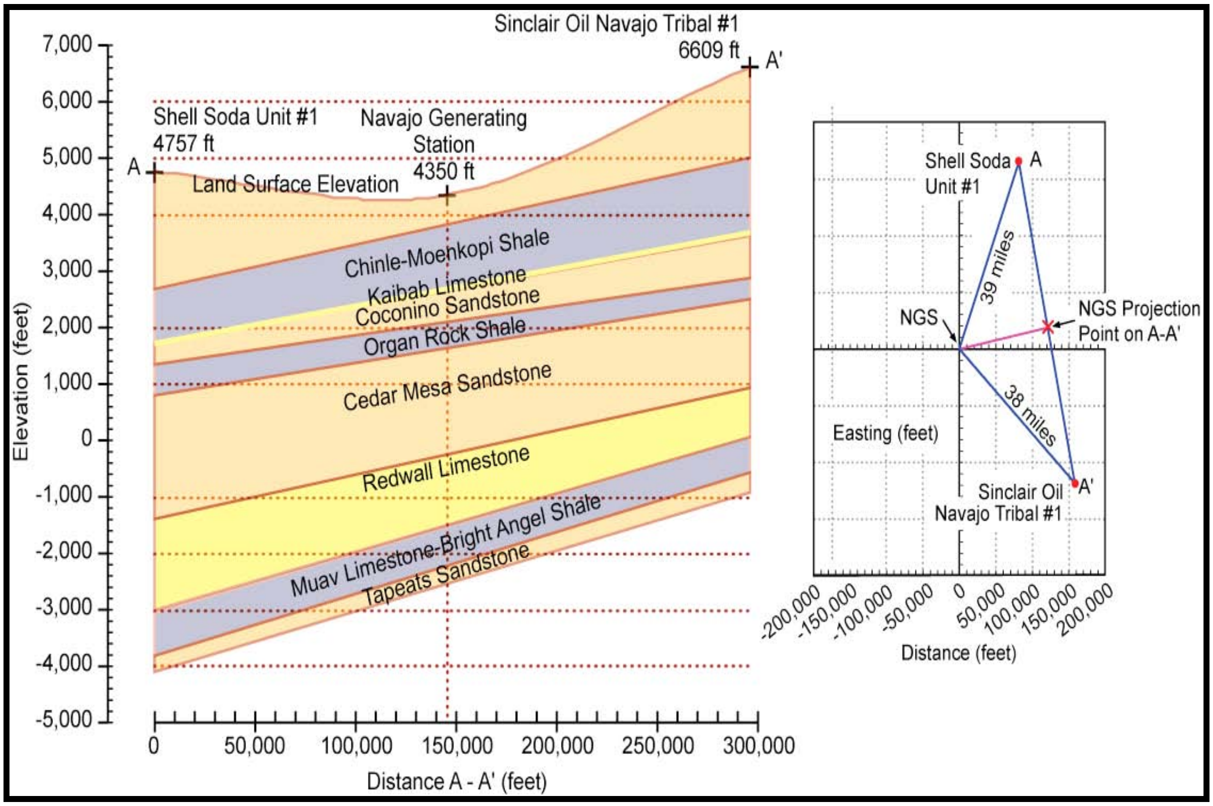

Fig. 2. Potential saline reservoirs beneath Navajo Generating Station.

Colorado Geologic Sinks

The Colorado Geological Survey (CGS) participated in Phase I of the Southwestern Regional Partnership for Carbon Sequestration Project where the primary objective was to characterize the CO_2 environment throughout the southwestern region of the United States. For the State of Colorado, this task consisted of the following three subtasks: (1) assemble CO_2 source data, (2) assemble CO_2 sink data, and (3) estimate carbon storage capacity. These results were incorporated into a geographical information system for public access and region-based analysis. The summary that follows briefly discusses the methodology, data sources, and findings for each of these subtasks**.**

CO2 Source Data

In 2000, CO_2 emissions were more than 68 million metric tonnes (MMt) in Colorado and are projected to increase by 1.5 % per year from 2002 to 2025 (U.S. Environmental Protection Agency, 2004; Energy Information Administration, 2004). Nearly 75 % of these emissions result from activities in the utility and transportation sectors (Fig. 3, Table 3). Power generation in the state relies primarily on coal and as a result, 42% of the total CO_2 emissions in Colorado are emitted from power plants in the utility sector (U.S. Environmental Protection Agency, 2004). These stationary point sources afford the possibility of capture and separation of CO_2 for transport and storage at nearby "sinks". The primary source of the CO_2 emission data for this project was the most comprehensive public database that includes CO_2 data, *Emissions & Generation Resource Integrated Database* (eGRID), which is maintained by the Office of Atmospheric Programs at the U.S. Environmental Protection Agency.

CO2 Sink Potential

Although CO_2 sink potential is widely distributed across the state, data collection focused on seven primary Pilot Study Regions (Fig.3). These study regions were defined based on the maximum diversity in potential sequestration options within close proximity to CO_2 sources; that is, within a 30 to 40 mile radial distance of one or more power plants. The sequestration options evaluated for Colorado included oil and gas reservoirs, underground gas storage facilities, natural CO_2 fields, coalbed reservoirs, deep saline aquifers, and advanced mineralization processes. Table 4 summarizes the potential CO_2 sequestration capacity for each of the sequestration options in each of the pilot study regions.

Utilizing both geologic and mineralization options, the preliminary forecast for CO_2 sequestration within the seven pilot study regions is nearly 157 billion metric tonnes (Gt). These areas have the potential for several hundred years of carbon dioxide storage based on 1999 emission levels. The highest CO_2 sequestration capacity potential for Colorado lies within the Denver Basin and Canyon City Embayment east of the Rocky Mountains, and within the Piceance and Sand Wash basins in northwestern Colorado.

The Denver and Rangely regions provide the greatest potential for carbon dioxide storage in oil and gas reservoirs; their combined carbon dioxide storage is estimated at 1.2 Gt or 70 % of the total oil and gas sink potential for Colorado. The Craig study region is estimated to provide more than 10 Gt of carbon dioxide storage due to the vast coal resources in the area. When combined with the coal resources of the Ignacio and Palisade study regions, the carbon storage potential for these three regions exceeds 14 Gt or nearly 85 % of the total coalbed methane storage potential for Colorado. The Cañon City, Denver, and Palisade study regions have very similar carbon dioxide storage capacities estimated for the deep saline aquifers that occur in these areas. With more than 20 Gt each, the carbon dioxide storage for these three regions represents more than half of the saline aquifer potential for Colorado. The Craig study region provides the greatest mineralization potential through carbonation of silicate minerals. Preliminary estimates are almost 27 Gt if mineralization engineering technology were commercially available.

Oil and Gas Reservoirs

There are approximately 1,400 oil and gas fields in Colorado; about 223 of these fields constitute large-volume producers; that is, cumulative production exceeds 1 million barrels (MMBbls) of oil and / or 10 billion cubic feet (Bcf) of gas. More than half of these large-volume producing fields (122) are located within 30 miles of a large CO_2 point source consisting of one or more coal-burning power plants. All of these 122 large-volume fields produce from oil and gas reservoirs that are deep enough to maintain CO_2 at supercritical conditions; that is, average reservoir depth exceeds 3,000 ft, which is sufficient to maintain CO_2 at a pressure and temperature of 1,000 psi and 90°F, respectively.

A minimum level of data has been compiled on all oil and gas fields in Colorado, consisting primarily of location, geologic age, production, discovery date, and depth. Where data are available in the public domain, additional reservoir properties such as porosity, permeability, gas and oil composition and fluid properties were compiled, particularly for those reservoirs within the seven pilot study regions. Data sources consisted of the Colorado Oil and Gas Conservation Commission, PI/Dwights, U.S. Department of Energy, and state geological survey publications.

The estimate of CO_2 sequestration capacity for oil and gas reservoirs in the seven source areas is 1,710 MMt with nearly 70 % of that capacity contained in the Denver and Rangely source areas (Table 4.). This estimate is based on cumulative production through December 2003. Estimating CO_2 storage capacity for oil and gas reservoirs was accomplished by calculating the equivalent mass of CO_2 that is required to replace the reservoir volume voided by production. This CO_2 capacity calculation for Colorado should be considered conservatively low due to the significant underestimation of water production for the state.

CO_2 sequestration capacity for oil and gas reservoirs in the seven pilot study regions is estimated at nearly 1,710 MMt with about 70 % of that capacity potential associated with the Denver and Rangely regions (Table 4). Recent work by Advanced Resources suggests that 510 to 580 MMBbls of oil may be economically recoverable from potential future enhanced oil recovery projects using CO_2 flooding (CO_2-EOR) in 12 of Colorado's major oil reservoirs (Advanced Resources, 2006). These EOR projects would not only provide suitable longer-term sequestration opportunities but would also result in increased production to offset costs.

Craig Region

The Craig Pilot Study Region is comprised primarily of the eastern two-thirds of the Sand Wash Basin, the extreme northern part of the Piceance Basin, and the Axial Basin Uplift separating the two (Fig. 4). There are 39 oil and gas reservoirs in 12 fields that screened as candidates for CO_2 sequestration. The total carbon dioxide capacity calculated for this region is 112 MMt with an average capacity of 2.9 MMt per field (Table 5). The largest capacity is estimated at 65 MMt for the Wilson Creek field in the northernmost Piceance Basin; nearly all of this capacity is associated with production from the Morrison and Entrada reservoirs. Screened reservoir depth varies 2,300 to 9,400 ft, averaging in excess of 5,000 ft.

The principal reservoirs in the Sand Wash Basin are those within the Upper Cretaceous stratigraphic interval, including the Niobrara Member of the Mancos Shale; Mesaverde Group, Lewis Shale, and Lance Formation (Fig. 5). For these reservoirs, porosity ranges from 10 to 30 % and permeability ranges from 0.1 to 500 millidarcies. Reservoir thickness is highly variable, ranging from 10 to 40 f.t. Cretaceous reservoirs in the deeper part of the basin are low-permeability reservoirs. The trapping mechanism for nearly all accumulations is structural. Existing fields are anticlinal folds that are commonly faulted. Impermeable shales and / or faults provide the seals (U.S. Geological Survey, 2005).

The principal reservoirs in the Axial Basin Uplift and northern Piceance Basin include the Pennsylvanian Minturn Formation; Pennsylvanian-Permian Weber Sandstone; Permian Phosphoria Formation; Triassic Moenkopi Formation and Shinarump Sandstone; Jurassic Entrada Sandstone, Curtis and Morrison Formations; Lower Cretaceous Dakota Group; and Upper Cretaceous Niobrara Formation, and Marapos Sandstone Member of the Mancos Shale (Fig. 5). Porosity ranges from 12 to 20 % and permeability ranges from 0.1 to 300 millidarcies. Reservoir thickness ranges 8 to 65 ft. Most hydrocarbon accumulations are in structural traps although reservoirs such as the Weber, Entrada, Shinarump, Dakota and Frontier have stratigraphic aspects (U.S. Geological Survey, 2005). Seals are provided by shales within the section.

Reservoir lithologies in the Craig Pilot Study Region are primarily sandstones interbedded with shales and reflect deposition in eolian, fluvial deltaic, strand plain, and shallow margin environments. Horizontal and vertical reservoir heterogeneity varies widely due to facies variations, diagenetic effects, and faulting.

Denver Region

The Denver Pilot Study Region coincides with the western third of the Denver Basin and includes the heavily-populated metropolitan areas concentrated along the eastern edge of the Front Range (Fig. 4). There are 82 oil and gas reservoirs in 31 fields that screened as candidates for CO_2 sequestration. The total carbon dioxide capacity calculated for this region is 505 MMt with an average capacity of 6.2 MMt per field (Table 6). The largest capacity is estimated at 352 MMt for the Wattenberg field in the west-central part of the Denver Basin; all of this capacity is associated with production from multiple reservoirs with the Cretaceous stratigraphic interval. Screened reservoir depth varies from 1,800 to 9,200 ft, averaging in excess of 6,400 ft.

The principal reservoirs in the Denver region include the Lower Cretaceous Lytle Formation (Lakota) and Dakota Group (Muddy J Sandstone); the Upper Cretaceous Benton Group (Greenhorn Limestone and Codell Sandstone Member of the Carlile Shale), Fort Hays (Timpas) Member of the Niobrara Formation, and the Pierre Shale (Shannon, Sussex, and Parkman Sandstone Members of the Pierre Shale) (Fig. 5). There is also some production from the Lower Permian Lyons Sandstone. For these reservoirs, porosity ranges from 2 to 26 % and permeability ranges from a very tight 0.05 to 100 millidarcies. Reservoir thickness is highly variable, ranging from 5 to 165 ft. The Cretaceous producing interval is characterized primarily by low-permeability reservoirs. The trapping mechanism for most of the accumulations is stratigraphic; although combination structural / stratigraphic traps are common.

The lithology of most the reservoirs in this region are sandstones and siltstones with some carbonaceous shales and limestones that reflect deposition in shallow shelf, fluvial deltaic, and strand plain environments. Horizontal and vertical reservoir heterogeneity is consistently very high due to depositional and diagenetic effects.

Fort Morgan Region

The Fort Morgan Pilot Study Region is immediately adjacent to the Denver Pilot Study Region and is approximately half its size (Fig. 4). There are 51 oil and gas reservoirs in 48 fields that screened as candidates for CO_2 sequestration. The total carbon capacity calculated for this region is 149 MMt with an average capacity of 2.9 MMt per field (Table 7). The largest capacity is estimated at 37 MMt for the Adena field near the center of the region, where all of this capacity is associated with the Dakota reservoir, which is currently undergoing waterflood operations. Screened reservoir depth varies from 4,400 to 6,500 ft, averaging about 5,300 ft.

The principal reservoirs in the Fort Morgan region include the Lower Cretaceous Dakota Group (Muddy J Sandstone), the Upper Cretaceous Benton Group (D Sandstone, Greenhorn Limestone and Codell Sandstone Member of the Carlile Shale), and the Niobrara Formation (Fig. 5). For these reservoirs, porosity ranges from 7 to 27 % and permeability ranges from 1 to 1,200 millidarcies. Reservoir thickness is highly variable, ranging from 3 to 72 ft. The trapping mechanism for most of the accumulations is stratigraphic; although combination structural / stratigraphic traps are also common.

Reservoir lithology is consistently sandstone with the exception of the Greenhorn Limestone. Depositional environments include fluvial deltaic, shallow shelf, and strand plain environments. Horizontal and vertical reservoir heterogeneity is consistently very high due to abrupt facies variations and post-depositional diagenetic effects.

Ignacio Region

The Ignacio Pilot Study Region is located in the southwestern part of Colorado and includes most of the northern portion of the San Juan Basin and the southeastern part of the Paradox Basin (Fig. 1.4). There are 10 oil and gas reservoirs in four fields that screened as candidates for CO_2 sequestration. The total carbon dioxide capacity calculated for this region is 169 MMt with an average capacity of 17 MMt per field (Table 8). The largest capacity is estimated at 155 MMt for the Ignacio Blanco field in the northern San Juan Basin, where most of this capacity is associated with Cretaceous-age reservoirs. Screened reservoir depth varies from 3,100 to 9,800 ft, averaging about 5,800 ft.

The principal reservoirs in the Paradox Basin are the Pennsylvanian Molas Formation and Hermosa Group; Jurassic Morrison Formation; and the Lower Cretaceous Dakota Sandstone (Fig. 5). For these reservoirs, reported porosity data is consistently very low at less than one % and permeability ranges from 10 to 20 millidarcies. Reservoir thickness is highly variable, ranging from 15 to 100 ft. The trapping mechanism is typically stratigraphic for most accumulations.

Reservoir lithology is dominated by limestones and dolomites in the Paleozoic part of the section where deposition was associated with large reef complexes. Alternatively, reservoir lithology is dominated by sandstones in the Mesozoic part of the section where deposition was associated with fluvial deltaic and non-marine environments. Horizontal and vertical reservoir heterogeneity is very high particularly for carbonate reservoirs that have experienced significant post-depositional diagenetic effects.

The principal reservoirs in the San Juan Basin include the Upper Jurassic Morrison Formation; Lower Cretaceous Dakota Sandstone; and Upper Cretaceous Mesaverde Group (Fig. 5). For these reservoirs, porosity ranges from 5 to 10 % and permeability is generally less than 10 millidarcies. Total reservoir thickness ranges from 100 to 150 ft. The trapping mechanism is usually structural anticlines for most accumulations.

Reservoir lithology is dominated by sandstones and siltstones where deposition was associated with fluvial deltaic and strand plane environments. Horizontal and vertical reservoir heterogeneity is related to depositional effects and is considered moderate for this basin.

Palisade Region

The Palisade Pilot Study Region is located in the southern half of the Piceance Basin, approximately south of Interstate Highway 70 (Fig. 4). There are 26 oil and gas reservoirs in 12 fields that screened as candidates for CO_2 sequestration. The total carbon dioxide capacity calculated for this region is 105 MMt with an average capacity of 4 MMt per field (Table 1.7). The largest capacity is estimated at 29 MMt for the Rulison field in the east-central part of the Piceance Basin; all of this capacity is associated with Mesaverde Group production interval. Screened reservoir depth varies from 400 to 8,000 feet, averaging in excess of 3,700 ft.

The principal reservoirs in the Palisade region include the Middle Jurassic Entrada (Sundance) Sandstone; Upper Jurassic Morrison Formation; Lower Cretaceous Cedar Mountain Formation of the Dakota Group; Upper Cretaceous Frontier Sandstone Member of the Mancos Shale and the Mesaverde Group (Iles and Williams Fork Formations, and Ohio Creek Member); and the Paleocene Wasatch Formation (Fig. 5. For these reservoirs, porosity ranges from 2 to 23 % and permeability ranges from a very tight 0.05 to 0.15 millidarcies. Total reservoir thickness is highly variable, ranging from 10 to 1,500 ft. The Cretaceous producing interval is characterized primarily by low-permeability reservoirs. The trapping mechanisms for most of the accumulations are a combination of structural and stratigraphic; specific types include lateral variations in facies and post-depositional porosity development, anticlinal features and structural noses; fracturing and faulting are common.

The lithologies of most the reservoirs in this region are sandstones and siltstones with interbedded shales. Environments of deposition include shallow shelf, fluvial deltaic, and strand plain environments. Horizontal and vertical reservoir heterogeneity is extremely high due to depositional and diagenetic effects as well as the presence of extensive fracturing and faulting.

Rangely Region

The Rangely Pilot Study Region is located in the northern half of the Piceance Basin, approximately north of Interstate Highway 70 (Fig. 4). There are 39 oil and gas reservoirs in 10 fields that screened as candidates for CO_2 sequestration. The total carbon dioxide capacity calculated for this region is 671 MMt with an average capacity of 1.6 MMt per field when the Rangely field is excluded from the computation (Table 1.8). The largest capacity is estimated at 617 MMt for the Rangely field in the northwestern part of the Piceance Basin; all of this capacity is associated with Weber Sandstone, which is currently undergoing a CO_2 miscible flood. Screened reservoir depth varies from 2,400 to 14,400 ft, averaging nearly 5,600 ft.

The principal reservoirs in the Rangely region include the Pennsylvanian-Lower Permian Weber (Maroon) Sandstone; Upper Triassic Shinarump Sandstone Member of the Chinle Formation; Middle Jurassic Entrada (Sundance) Sandstone; Upper Jurassic Morrison Formation; Lower Cretaceous Cedar Mountain Formation of the Dakota Group; Upper Cretaceous Emery (Mancos B) Sandstone of the Mancos Shale and the Mesaverde Group (Williams Fork Formation and Ohio Creek Member); Paleocene Wasatch Formation; and Eocene Douglas Creek Member of the Green River Formation (Fig. 5). For these reservoirs, porosity ranges from 8 to 17 % and permeability ranges from a low of 0.1 to 25 millidarcies. Total reservoir thickness ranges from 200 to 300 ft. The trapping mechanisms for most of the accumulations are a combination of structural and stratigraphic; specific types include lateral variations in facies and post-depositional porosity development, anticlinal features and structural noses; fracturing and faulting are common.

The lithology of most the reservoirs in this region are sandstones and siltstones with interbedded shales; limestones and conglomerate are less common. Environments of deposition include eolian, lacustrine, and fluvial deltaic environments. Horizontal and vertical reservoir heterogeneity is extremely high due to depositional and diagenetic effects as well as the presence of extensive fracturing and faulting.

Underground Gas Storage

In 2004, Colorado had nine underground gas storage (UGS) facilities in operation, providing a total working gas storage capacity of 45.3 billion cubic feet (Bcf) (American Gas Association, 2004). Most of these are located in the Denver and Piceance basins (Fig. 6). In addition to working gas volumes, UGS facilities require base gas that in Colorado ranges from 17 to 163 % of working gas. Thus, the actual total gas injected into Colorado UGS facilities is nearly 60 Bcf.

Together, gas storage and EOR projects represent the largest industrial experience in gas injection into geologic formations. With the exception of the Leyden Mine, all of Colorado's underground storage facilities are converted from depleted oil and natural gas fields, which is typical for UGS facilities throughout the world. Reservoir types are all sandstone lithology except for the Leyden Mine, which is coal. The Leyden Mine was decommissioned for gas storage in 2005 and is undergoing conversion to water storage for municipal use.

In natural gas storage, the working gas (CH_4) is injected and produced seasonally while a base (or cushion) gas that is not extracted is used to provide pressure support. In the case of depleted gas reservoirs being used for gas storage, the base gas is commonly leftover native gas (CH_4). Another approach is to produce most of the methane from the reservoir since it can be sold for profit, replacing it with a cheaper inert gas for use as the base gas. CO_2 injection associated with carbon sequestration via enhanced gas recovery (CSEGR) can be conducted while simultaneously producing the reservoir's methane. Particularly advantageous is the significant density change CO_2 undergoes near its critical pressure, increasing methane storage about 30 % relative to a native gas base (Oldenburg, 2003). Furthermore, CO_2 injection may in the future be economically favorable through carbon credits or tax advantages offered to encourage carbon sequestration. Limiting the rate of mixing between methane and carbon dioxide through careful reservoir selection and operations will be critical to the use of CO_2 as a base gas (Oldenburg, 2003).

Current underground gas storage facilities in Colorado have nearly 48 Bcf committed in base gas, representing a significant portion of total project investment. Some of these facilities may be suitable to base gas reductions via CO_2 replacement. Up to 4 MMt of CO_2 would be required to offset the current base gas levels in Colorado, assuming complete replacement of existing base gas volumes. If this replacement is linked with a 30 % increase working gas, the current 45.3 Bcf could potentially be increased to 58.9 Bcf.

Natural CO_2 Fields

Large naturally occurring geologic deposits of carbon dioxide are found in three of Colorado's sedimentary basins – the Paradox, Raton, and North Park (Fig. 7). The resources of the Paradox and Raton basins provide low-cost sources of high-pressure CO_2, primarily for EOR projects in the Permian Basin of New Mexico and Texas. In this basin alone, approximately 50 projects produce an incremental 145 MMBbls of oil per day, more than 80 % of the North American enhanced oil produced from CO_2 floods in 2004 (Cappa and others, 2005).

An extensive CO_2 pipeline and re-injection infrastructure system exists throughout the Permian Basin, making it attractive for expanding or starting new projects. High-pressure pipelines supply CO_2 from natural source fields at Bravo Dome in northern New Mexico, and

McElmo Dome and Sheep Mountain in southern Colorado. Shell's completion of the pipeline out of McElmo Dome in 1983 significantly increased the value of the naturally occurring CO_2 reserves in Colorado. In addition to EOR applications, CO_2 is used in welding, the manufacture of dry ice, and the food and beverage industry.

Colorado has some of the largest natural CO_2 reserves in the Rocky Mountain region (Table 11). McElmo Dome field is the largest deposit in Colorado, contains over 17 Tcf of 98 %-pure CO_2 that does not require processing or compression prior to injection (New Mexico Bureau of Geology and Mineral Resources, 2006). Natural CO_2 fields are useful analogs for evaluating the safety and costs of geologic sequestration, both in terms of the long-term physical and chemical interactions of CO_2 with reservoir rocks and fluids, but also in terms of industry's field operational experience in handling and transporting large volumes of CO_2 (Stevens and others, 2001).

Use of CO_2-EOR has resulted in CO_2 becoming a valuable commodity. The total value of carbon dioxide production in Colorado was nearly $130 million in 2004, an increase of nearly 32 % over the value $98 million in 2003 (Cappa and others, 2005). Carbon capture and storage technology is key to extending the availability this valuable natural resource.

Colorado's production of natural CO_2 has averaged 300 Bcf per year since the mid-1980s primarily for use in Permian Basin CO_2-EOR projects. Representing an annual equivalent of 16 MMt, economic sources of anthropogenic CO_2 would have considerable commodity value and would have the potential to offset depletion of existing natural deposits.

Coalbed Reservoirs

Deep unmineable coal for Colorado is defined as coal-bearing formations occurring between 2,000 and 7,500 ft deep. Coal parameters such as rank, gas content, ash and moisture content were compiled from U.S. Bureau of Mines data, Gas Research Institute reports, and state geological survey publications. The vast majority of coals in the state are bituminous in rank, which makes them suitable for enhanced coalbed methane recovery and carbon sequestration. The estimate of CO_2 sequestration capacity for coalbed methane reservoirs in the seven pilot study regions is nearly 17 Gt with nearly 80 % of that capacity associated with the Iles-Williams Fork-Fort Union coals of the Sand Wash Basin and the Fruitland coals of the San Juan Basin (Table 4.). This estimate of capacity was made by applying a carbon dioxide/methane (CO_2/CH_4) replacement ratio based on coal rank and a replacement efficiency of 65 %. In reality, the physics are far more complicated than this and require a reservoir simulator to calculate more accurately.

Cañon City and Denver Regions

The Laramie coalbeds straddle the boundary between the Cañon City and Denver Pilot Study Regions, covering an area in the subsurface in excess of 500,000 acres (Fig. 8). These coals are Upper Cretaceous in age and subbituminous in rank. With an average thickness of 10 ft and gas content approaching 300 standard cubic feet of gas per ton of coal (scf/ton), the coalbed methane in-place is estimated to be 2.7 trillion cubic feet (Tcf). Assuming a CO_2/CH_4 replacement ratio of 10, the CO_2 capacity is estimated at 1.4 Gt. Although there is considerable variability in recovery estimates, recent work by Advanced Resources suggests that the replacement of CH_4 by CO_2 may average 65 % overall (Reeves, 2003). A replacement efficiency of 65 % would reduce the carbon dioxide storage estimate to just under 1 Gt with the potential of about 1.5 Tcf in enhanced coalbed methane recovery (Table 12.). This recovery factor assumes 1.7 Tcf of produced CH_4 per Gt of sequestered CO_2 (Reeves, 2003)

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Craig Region

The Craig Pilot Study region has three stratigraphic intervals characterized by coalbed reservoirs: the Upper Cretaceous Iles and Williams Fork Formations of the Mesaverde Group, and the Upper Cretaceous – Lower Tertiary Fort Union Formation (Figure 1.3). These coal "packages" differ in their subsurface areal extent from approximately 500,000 acres for the Iles to 750,000 acres for the Williams Fork; the Fort Union covers about 700,000 acres (Fig. 8.). Coal rank varies from high-volatile A bituminous (HVA) to high-volatile bituminous (HV). With a total average thickness in excess of 160 ft and gas content approaching 350 scf/ton, the coalbed methane in-place is estimated to be 62 Tcf. Assuming a CO_2/CH_4 replacement ratio of 3 for HV-ranked coals and 6 for HVA-ranked coals, the CO_2 capacity is estimated at 15.4 Gt. A replacement efficiency of 65 % would reduce the carbon storage estimate to 10 Gt with the potential of about 17 Tcf in enhanced coalbed methane recovery (Table 12.).

Ignacio Region

The Ignacio Pilot Study region has active coalbed methane development ongoing in both the Upper Cretaceous Menefee and Fruitland Formations (Fig. 5). These two coal intervals both extend over approximately 550,000 acres each in the subsurface of the northern San Juan Basin (Fig. 1.8). The Menefee coal rank is HVA and the Fruitland coals vary from HVA to medium-volatile bituminous (MV). More than 50 % of the Fruitland coal volume is estimated to be the higher MV coal rank. With a total average thickness of 70 ft and gas content approaching 300 scf/ton, the coalbed methane in-place is estimated to be 23 Tcf. Assuming a CO_2/CH_4 replacement ratio of 1.5 for MV-ranked coals, 3 for HV-ranked coals, and 6 for HVA-ranked coals, the CO_2 capacity is estimated at 4 Gt. A replacement efficiency of 65 % would reduce the carbon storage estimate to 2.5 Gt with the potential of about 4.3 Tcf in enhanced coalbed methane recovery (Table 12).

Palisade and Rangely Regions

The Cameo-Fairfield Coal Group in the Piceance Basin straddles the boundary between the Palisade and Rangely Pilot Study Regions and covers a subsurface area of nearly 1.5 million acres (Fig. 8). This coal group lies within the Upper Cretaceous Iles and Williams Fork Formations of the Mesaverde Group. The Piceance Basin is the only area in Colorado where coal depths actually exceed 7,500 ft. Coal rank ranges from HV to MV with more than 75 % of the coals being MV in rank. With a total average thickness of almost 55 ft and gas content exceeding 200 scf/ton, the coalbed methane in-place is estimated to be 34 Tcf. Assuming a CO_2/CH_4 replacement ratio of 1.5 for MV-ranked coals, 3 for HV-ranked coals, and 6 for HVA-ranked coals, the CO_2 capacity is estimated at 4 Gt. A replacement efficiency of 65 % would reduce the carbon storage estimate to 2.6 Gt with the potential of about 4.4 Tcf in enhanced coalbed methane recovery (Table 12.).

Trinidad Region

Although there is minimal anthropogenic CO_2 available in the Raton Basin, the Trinidad Pilot Study Region was defined only for the purpose of including a carbon storage estimate for the Upper Cretaceous Raton and Vermejo coals (Fig. 5). These HV- to MV-ranked coals cover a subsurface area of nearly 600,000 acres (Fig. 8). The Raton and Vermejo coals are under active coalbed methane development, where gas is produced from very shallow depths particularly adjacent to the Purgatoire River. As such, for this basin only, the depth cutoff was limited to a depth of 500 ft (instead of the 2,000 ft used elsewhere). With a total average thickness of about

60 ft and gas content exceeding 300 scf/ton, the coalbed methane in-place is estimated to be nearly 13 Tcf. Assuming a CO_2/CH_4 replacement ratio of 1.5 for MV-ranked coals and 3 for HV-ranked coals, the CO_2 capacity is estimated at 1 Gt. A replacement efficiency of 65 % would reduce the carbon storage estimate to less than 700 MMt with the potential of about 1 Tcf in enhanced coalbed methane recovery (Table 1.10).

Deep Saline Aquifers

The criteria used to select deep saline aquifers suitable for CO_2 sequestration included lithology consisting primarily of sandstone or other rock types with sufficient porosity and permeability, depth exceeding 3,000 ft (to maintain supercritical conditions for CO_2 and to minimize the possibility that the formation would be developed for future water resources), salinity exceeding 1,000 ppm (again, to minimize the possibility that the formation would be developed for potable water sometime in the future), and the presence of an overlying formation that would function as a top seal to prevent vertical migration of injected CO_2. Most of the formations evaluated have had some associated oil or gas production. This implies the existence of a long-term structural or stratigraphic trapping mechanism that may decrease the possibility of migration of injected CO_2 to the surface. Data sources consisted of Colorado Oil and Gas Conservation Commission, Colorado Division of Water Resources, and publications from the Rocky Mountain Association of Geologists, Texas Bureau of Economic Geology, U.S. Geological Survey, and state geological surveys.

The amount of carbon that a given formation may sequester was calculated using the sequestration calculator available on the Midcontinent Interactive Digital Carbon Atlas and Relational dataBase (MIDCARB) website (Carr and White, 2003). The calculation is based on empirical data for the solution of CO_2 in water under various temperature, pressure, and salinity conditions. The part of the calculator used for this study is that related to CO_2 dissolution only; no consideration was given to the volume of water that may be displaced by injected CO_2. The estimate of CO_2 sequestration capacity for deep saline aquifers in the seven pilot study regions is 109,520 MMt with about 56 % of the capacity contained in the Cañon City, Denver, and Palisade regions (Table 1.11). This capacity estimate is limited to only that portion of these areally extensive aquifers that lie within a 30 mile radius of the primary CO_2 sources. The carbon storage capacity of these vast deep saline aquifers may be greater when not screened for distance. However, further study is required to develop a better understanding of the distribution of trap mechanisms needed to contain injected CO_2. Aquifer characterization data are provided in Table 14 and distribution is shown in Fig. 9.

Cañon City Region

The Jurassic Morrison Formation is one of the most widespread geologic units in the U.S., underlying portions of 13 states, and all of the Denver Basin except for a small area in northwestern Nebraska (Curtis, 1963). The unit is composed mainly of variegated mudstone, claystone, siltstone, and marlstone, but includes dominantly lenticular beds of sandstone, limestone, and conglomerate. The Morrison Formation ranges in thickness from 200 to 400 ft along the east flanks of the Front Range and Sangre de Cristo Mountains and thins irregularly to the east. The Morrison only underlies part of the eastern half of the region, so formation volume is limited, and geologic well logs (Denver Earth Resources Library, 2004) indicate that the unit becomes too shallow for sequestration in its southern parts.

The Lyons Formation is fairly homogeneous, massive, medium-grained sandstone cemented with silica and minor amounts of lime (Shaw, 1956; Mitchell and others, 1956). Locally thin beds of red shale and arkosic sandstone are present within the normally homogeneous sandstone. In the northern part of the Raton Basin, the Lyons thins from the east to the west and pinches out directly east of the Sangre de Cristo Mountains (Shaw, 1956). Shaw (1956) reports that the formation averages 150 ft in thickness, but Mitchell and others (1956) report a thickness of 300–500 ft. The Lyons Formation in the Dome gas field was one of the few producing formations in the area (Clair and Bradish, 1956), and at this site well logs report the thickness of the unit at 270 ft. Geologic well logs (Denver Earth Resources Library, 2004) indicate that the Lyons Formation becomes too shallow for sequestration toward the south side of the region.

The Fountain Formation is correlative with the Maroon Formation of western Colorado and the Sangre de Cristo Formation of southern Colorado (Pearl, 1977), and the names are used interchangeably in some reports. The formation is divided into two members, and research suggests that it may be the thickest sedimentary formation in the area. The strata of the lower member of the formation vary from 2,000 to 4,500 ft of medium- to coarse-grained, micaceous, arkosic sandstones and conglomerates, to up to 6,000 ft of fine-grained, arkosic sandstones, siltstones, shales, and few lenticular limestone and gypsum beds and minor coal (De Voto, 1980). The lower member generally is comprised of large-scale (up to 700 ft thick) cycles of sediment, each cycle grading upward from conglomerates and conglomeratic sandstone to fine-grained sandstones, siltstones, and shales (De Voto, 1980). Thin, occasionally stromatolitic, lime mudstones occur in some localities near the top of some of the cycle units. The lower member strata are overlain unconformably by up to 9,000 ft of coarse-grained, arkosic sandstones and boulder conglomerates of the Permian age upper member (Crestone Conglomerate Member) of the Sangre de Cristo Formation. No oil or gas production records were found for the Fountain Formation in this region. Geologic well logs (Denver Earth Resources Library, 2004) indicate that the Fountain Formation becomes too shallow for sequestration toward the south side of the region.

<u>Craig Region</u>

The Entrada Sandstone in the Sand Wash Basin grades from cross-bedded eolian sandstone in the east to marginal marine, muddy sandstone and siltstone westward (Freethey and Cordy, 1991). The Slick Rock Member, which comprises 50 to 80 % of the total unit thickness, consists of very fine- to fine-grained, cross-bedded and massive, flat-bedded, eolian sandstone. The sandstone is moderately well sorted and generally weakly cemented. The grains are 95 % frosted quartz with siliceous cement with glauconite present in the matrix (Grace and Nelson, 1963). The Entrada is the second largest oil producing formation in northwest Colorado after the Weber Formation (Haun, 1962; Piro, 1962), accounting for 40 % of total production. The unit also produced gas (Brainerd and Carpen, 1962). The Entrada differs from the other units in the area in that it is the only true blanket sandstone, and therefore there is little variation in lithological parameters, which allows uniform completion practices (Polumbus, 1963). On this basis the Entrada would appear to be a highly favorable formation for sequestration. Geologic well logs (Denver Earth Resources Library, 2004) indicate that the Entrada thickens from east to west, locally attaining thicknesses greater than 400 feet on the western edge of the basin. However, the logs indicate that the formation becomes too shallow for sequestration at some locations on the western edge of the basin.

The Weber Formation in the Sand Wash Basin is composed of over a thousand feet of massive white cross-bedded, sandstones that outcrop along the Uinta Mountains and along the Utah-Colorado border (Daniels, 1982). At the type section in Weber Canyon, Utah, the age of this sandstone is Pennsylvanian, but in the Danforth Hills area of Colorado the upper portion is Permian, as determined by fossils in the overlying Park City Formation (Daniels, 1982).

Additional details regarding the characteristics of the Weber Formation can be found in the section devoted to the Palisade and Rangely Pilot Study Regions.

The Weber produces both oil and gas in the Sand Wash Basin, and was one of the largest producers in the basin (Cummings and Pott, 1962), though not nearly to the magnitude as in the Piceance Basin. Geologic well logs (Denver Earth Resources Library, 2004) indicate that the Weber pinches out toward the eastern edge of the area, and becomes too shallow for sequestration at some locations on the west and south sides of the area.

Denver and Fort Morgan Regions

The Denver Basin is a structural basin that contains a large aquifer system in Tertiary and Cretaceous age formations. Underlying the aquifers is up to 7,000 ft of nearly impermeable Pierre Shale, which should function well as a top seal if the deeper formations are developed as sinks for carbon sequestration.

The lithology of the Morrison Formation in eastern Colorado is highly variable (Curtis, 1963), but is very similar to the Brushy Basin Member of the Morrison Formation of southwestern Colorado, consisting of variegated claystones, siltstones, sandstones, and dense limestones characterized by Chara algae and stromatolitic fresh-water algal limestones with some conglomerates (Curtis, 1963; Berman and others, 1980). These sequences have been interpreted as representing lacustrine, lacustrine-deltaic, distributary-channel and floodplain depositional environments (Jackson, 1979). Thickness ranges from 100 to 300 ft beneath the Denver Basin (Curtis, 1963). No record of hydrocarbon production from the Morrison Formation in the Denver Basin was found, although noncommercial shows are reported (Clark and Rold, 1961).

The Morrison in Colorado becomes too shallow for sequestration on the west side of the basin where it outcrops.

The Dockum Group consists mainly of fine- to medium-grained, usually massive sandstone, although locally it can be interbedded with siltstone and shale with rare interbeds of carbonate and anhydrite (Robson and Banta, 1987). Intergranular cement is commonly silica but locally consists of anhydrite, calcite, or clay (Robson and Banta, 1987). The Entrada Sandstone overlies the Dockum Group and consists of cross-bedded, eolian sandstone and planar-bedded, water-lain sandstone (Berman and others, 1980; Robson and Banta, 1987). Toward the central and northeastern parts of the study area, the unit grades into siltstone and shale (Berman and others, 1980; Robson and Banta, 1987). The aggregate sandstone thickness of the group is about 50 ft in the area surrounding the largest carbon dioxide producers in the Denver area, but exceeds 500 ft in the southeastern part of the state (Robson and Banta, 1987). The steepening dip of the formation on the west side of the basin renders it too shallow for sequestration locally. No record of hydrocarbon production from the Entrada-Dockum Group in the Denver Basin was found, although non-commercial shows are reported (Hofstra, 1961; Lavington, 1961).

The Lyons Formation in the Denver Basin consists of fine- to medium-grained, well-sorted, cross-bedded quartzose sandstone with minor siltstone and conglomeratic sandstone (Fenneman, 1905; Maughan and Wilson, 1960; Walker and Harms, 1972). It has been interpreted by at least two workers as an eolian and littoral deposit (Thompson, 1949; Maughan, 1980). The top of the Lyons is generally capped by 2- to 3-ft thick, parallel-bedded to massive, brown sandstone deposited subaqueously above the cross-bedded sequence. Locally, arkosic sandstone intertongues with the Lyons, but this is not common except in the vicinity of the town of Lyons and to the south. The Lyons in the vicinity of Morrison has been shown to include stream-channel and shallow-water deposits as well as eolian sandstones (Weimer and Erickson, 1976).

The Lyons Formation underlies most of the area of Colorado east of the Front Range, although it pinches out in eastern Colorado. Silica, carbonates, and anhydrite are the primary cementing materials in the Lyons Sandstone (Levandowski and others, 1973). The thickness of the Lyons ranges from zero in the northeastern and southwestern parts of the eastern plains to 370 ft at its type locality near the town of Lyons (Thompson, 1949). Limited well log data for the Lyons Formation (Denver Earth Resources Library, 2004) suggest that the unit might be too shallow for sequestration locally on the western edge of the Denver Basin.

The Fountain Formation in the Denver region is dominantly a continental deposit of arkoses, conglomerates, sandstone, siltstones and shales (Hoyt, 1963), consisting primarily of unsorted to poorly sorted arkose and arkosic conglomerate, with an average porosity of about 7 % (Robson and Banta, 1987). Distal from the Front Range uplift, in the eastern parts of the Denver Basin, the lithology grades from sandstone to predominantly shale and carbonates. The Front Range uplift to the west was the source of the arkosic clastic rocks comprising the Fountain Formation (Rascoe, 1978). Eastward from the Front Range, the Fountain Formation interfingers with Permo-Pennsylvanian marine sediments (Hoyt, 1963). The Fountain produced oil from several fields in eastern Colorado, including the Bent's Fort (Brown, 1961), the Colt (Adams, 1961), and the McClave (Carpen, 1961). One of the highly favorable aspects of the Fountain is its great thickness, up to 4,500 ft in the Colorado Springs area (Lovering and Goddard, 1950). In the Denver area, the formation is closer to 2,000 ft thick (Robson and Banta, 1987). The Fountain is exposed along the east flank of the Front Range in northern Colorado (Maughanz and Wilson, 1963), so it is likely too shallow for sequestration in some locations in this area.

<u>Ignacio Region</u>

The Mesaverde Group consists of the Cliff House Sandstone, the Menefee Formation, and the Point Lookout Sandstone. The Cliff House consists of calcareous marine sandstone, very fine- to fine-grained, locally cross-bedded and massive shaly sandstone with local silt and shale beds (Topper and others, 2003; Brogden and Giles, 1976). The maximum thickness of the Cliff House is about 350 ft. The Menefee Formation contains varying proportions of sandstone, siltstones, and shale with interbedded coal seams (Brogden and Giles, 1976), and attains a maximum thickness of 350 ft. The Point Lookout Sandstone is a fine- to very fine-grained well-cemented marine sandstone with laminations of carbonaceous shale (Pritchard, 1973; Fassett, 1983). The unit is generally massive and cliff-forming and has a maximum thickness of 400 ft (Brogden and Giles, 1976). The Mesaverde was the largest gas-producing Cretaceous unit in the San Juan Basin (Irwin, 1983; Thomaidis, 1978). Geologic well logs (Denver Earth Resources Library, 2004) indicate that the Mesaverde becomes too shallow for sequestration along the northern edge of its extent.

The Dakota Sandstone is the basal Cretaceous unit in the basin, and can be divided into continental and marine lithologic sequences (Dane and Bachman, 1957; Grant and Owen, 1974; Ridgley, 1977). The basal sequence generally consists of fluvial sandstone and conglomeratic sandstone, carbonaceous shale and siltstone, and thin coal beds. The upper sequence is primarily medium- to fine-grained sandstone, locally cross-bedded, and represents deposition in coastal and near-shore marine distributary channel environments (Ridgely and others, 1978). Within the central basin, the basal Dakota Sandstone is often conglomeratic and rests unconformably on the Jurassic Morrison Formation (Deischl, 1973). The thickness of the Dakota generally ranges from 200 to 300 ft with a maximum observed thickness of 350 ft (Stone and others, 1983). Geologic well logs (Denver Earth Resources Library, 2004) indicate that the Dakota is too shallow for sequestration on the north and west edges of the area.

The Morrison Formation is a heavily studied unit in the San Juan Basin, where it is the uppermost Jurassic stratum. The Morrison is present throughout the San Juan structural basin (Green and Pierson, 1977), and is unconformably overlain in most of the basin by the Cretaceous Dakota Sandstone (Dam and others, 1990). In the San Juan Basin, the Morrison is generally composed of coarse-grained, arkosic to subarkosic sandstone, with locally conglomeratic sandstone and claystone, representing deposition in a variety of alluvial, fluvial and lacustrine environments (Ridgely and others, 1978; Dam and others, 1990; Condon, 1992; Craig and others, 1955; Turner-Peterson, 1985; Peterson and Turner-Peterson, 1987; Green and Pierson, 1977). Minor limestone beds also appear in the unit (Stone and others, 1983; Green and Pierson, 1977; Woodward and Schumacher, 1973). Thickness of the Morrison ranges from zero at its erosional edge to about 1,100 ft in the northwest part of the basin (Dam and others, 1990; Condon and Peterson, 1986). The low-permeability Brushy Basin Member, a mudstone (Treviño, 2003), could function effectively as a top seal. The lower part of the formation has been mined for uranium in the Four Corners area (Condon, 1992), and is a significant source of both uranium and water in the Grants uranium region of New Mexico (Stone and others, 1983). Oil and gas production data were commingled with the overlying Dakota Sandstone (Irwin, 1983) and reservoir data are sparse. Geologic well logs (Denver Earth Resources Library, 2004) indicate that the Morrison is too shallow for sequestration along the north and west edges of the basin.

The Middle Jurassic Entrada Sandstone is a sugary, friable, cross-bedded sandstone that underlies the entire basin except for the southern margin (Ridgely and others, 1978) across the border in New Mexico. The formation attains a maximum thickness of nearly 400 ft in the center of the basin (Ridgely and others, 1978). It consists of the basal Dewey Bridge Member, which is a very fine-grained, argillaceous sandstone and siltstone, and the overlying Slick Rock Member, which is a very fine-grained to fine-grained, locally medium-grained, sandstone (Wright and others, 1962). The Entrada is a minor oil and gas producer in the San Juan Basin (Halpenny and Harshbarger, 1950; Matheny and Ulrich, 1983). The evaporite minerals in the overlying Todilto Limestone may contribute to the salinity of the Entrada (Lyford, 1979). Geologic well logs (Denver Earth Resources Library, 2004) indicate that the Entrada becomes too shallow for sequestration along the north edge of its extent in the region.

The Hermosa Group consists of, from oldest to youngest, the Pinkerton Trail, Paradox, and Honaker Trail Formations (Huffman and Condon, 1993). The group includes four distinct interbedded facies consisting of poorly sorted conglomeratic arkose, siltstone, fine-grained sandstone, cyclic deposits of dolomite, limestone, and carbonaceous shale, and an evaporite sequence consisting of cyclic deposits of halite and minor shale, dolomite, limestone, and anhydrite (Peterson and Hite, 1969). The evaporite sequence contains as many as 33 separate beds of halite divided by interbeds of limestone, dolomite, anhydrite, and black shale (Hite, 1960; Hite and Buckner, 1981). The Hermosa Group has produced both oil and gas (Thomaidis, 1978), and is an attractive sequestration target due to its great thickness, over 3,000 ft at maximum (Ridgely and others, 1978; Huffman and Condon, 1993).

The Pinkerton Trail and Honaker Trail Formations have lesser amounts of chemical precipitates and greater amounts of clastic rocks (Huffman and Condon, 1993) than the Paradox. The Pinkerton Trail Formation consists of finely to coarsely crystalline, argillaceous to silicified limestone and minor carbonaceous shale (Huffman and Condon, 1993). Amounts of coarse clastic detritus increase north of Durango (Fetzner, 1960). The Pinkerton Trail is thin relative to the other Hermosa units, attaining a maximum thickness of only 225 ft across the border in Utah (Huffman and Condon, 1993). Fassett (1983) reports no fields producing oil or gas from the Pinkerton Trail Formation.

The Paradox Formation consists primarily of thick chemical precipitates (carbonate, anhydrite, halite, or potash) with relatively minor interbedded clastic rocks, but coarser grained clastic rocks are more common on the edges of the basin (Huffman and Condon, 1993). The Desert Creek and Ismay Zones are the primary oil and gas producers of the Paradox Formation.

The Honaker Trail Formation consists of a variable sequence of finely crystalline limestone and dolomite, micaceous siltstone, and arkosic sandstone (Huffman and Condon, 1993). The percentage of carbonate is higher at the base of the unit and at the center of the basin. Clastic rocks increase along the northern margin of the basin and in the upper part of the unit (Wengerd, 1957). The Honaker Trail is at least 1,390 feet thick in the San Juan Trough, and the thickness combined with the favorable lithology suggests it may be the most attractive sequestration target in the group.

Because of the variety of lithologies in the Hermosa Group, reported porosities range from 4 to 22 %, and permeabilities from 0.01 to 114 millidarcies (Bevacqua, 1983; Brown, 1978; Ghazal, 1978; Halverson and Roe, 1978; Hart and Mickel, 1983; Krivanek, 1978; Latch, 1978; Lehman, 1983; Lister, 1983; Mecham, 1978, Mickel, 1978a, 1978b; Miesner, 1978; Roth, 1983a, 1983b, 1983c; Riggs, 1978; Spencer, 1978; Squires, 1978; Wold, 1978; Young, 1978). The average porosities reported for 11 fields producing from the Paradox Formation and an equal number of fields producing from the Honaker Trail are nearly the same at around 11 %, but the average permeability of the Paradox is roughly twice that of the Honaker Tail (27 versus 14 millidarcies).

The Hermosa Group is sufficiently deep for sequestration throughout its extent in the San Juan Basin.

The Leadville Limestone is composed of a thin basal dolomite and a thick, massive upper limestone (Ridgely and others, 1978; Condon, 1992). The lower unit is commonly a sucrosic dolomite to micritic limestone and correlates with the Redwall Limestone of the Grand Canyon (Parker and Roberts, 1963; Stevenson, 1983). The upper unit is predominantly limestone that is commonly oolitic and crinoidal (Stevenson, 1983; Baars, 1966). The unit thickens toward the northern part of the basin (Ridgely and others, 1978: Stevenson, 1983), where it attains a thickness locally of at least 300 ft (Denver Earth Resources Library, 2004). The Leadville Limestone produced both oil and gas (Condon, 1992; Thomaidis, 1978) and has been an important producer of carbon dioxide and helium in the region (Gerling, 1983; Casey, 1983). Geologic well logs (Denver Earth Resources Library, 2004) indicate that the Leadville Limestone is sufficiently deep for sequestration throughout its extent in the San Juan Basin.

Palisade and Rangely Regions

The Dakota Aquifer includes the Dakota Sandstone, the Burro Canyon, Cedar Mountain, and Cloverly Formations, the Gannett Group, and the Bear River, Smith, Thomas Fork, and Cokeville Formations (Freethey and Cordy, 1991). Sandstone and mudstone are the dominant rock types in the Burro Canyon and Cedar Mountain Formations. The Dakota Sandstone consists of a lower conglomeratic sandstone, a middle unit consisting of carbonaceous shale and coal, and an upper massive, fine- to medium-grained sandstone. The Gannett Group consists of a variety of well-cemented fluvial and lacustrine sediments. The Cloverly Formation consists of a lower conglomeratic sandstone and an upper bentonitic shale with siliceous and calcareous zones (Freethey and Cordy, 1991). The thickness of the Dakota ranges from 100 to 300 ft within the Piceance Basin with an average of 130 ft. Geologic well logs (Denver Earth Resources Library, 2004) indicate that the Dakota Formation becomes too shallow for sequestration around the edges of the Piceance basin, but depths exceed 13,000 ft in the center of the basin.

The Morrison Formation in the Piceance Basin includes the Tidwell, Bluff Sandstone, Salt Wash, Recapture, and Westwater Canyon Members. The Cow Springs Sandstone and Junction Creek Sandstone are also considered part of the Morrison Aquifer (Freethey and Cordy, 1991). The lithology of the Morrison in this region consists predominantly of siltstone (Tidwell Member), interbedded fine- to medium-grained sandstone and claystone (Salt Wash, Recapture, and Westwater Canyon Members), and conglomeratic sandstone and sandstone (Bluff Sandstone Member and Junction Creek and Cow Springs Sandstones) (Freethey and Cordy, 1991). The Morrison Formation is thicker on the west sides of both the Palisade and Rangely areas. In the Palisade area, the unit ranges from 100 to 1,055 ft thick, and in Rangely from 100 to over 1,400 ft thick, with an average thickness over both areas of 680 ft (Denver Earth Resources Library, 2004). The Morrison directly underlies the Dakota Sandstone, and in similar fashion becomes too shallow for sequestration around the edges of the Piceance basin (Denver Earth Resources Library, 2004).

The Weber Formation in the Piceance Basin is a clean, fine- to very-fine-grained, well sorted, cross bedded, quartzose sandstone up to 1,300 ft thick, with local, thin carbonate interbeds and varying but generally low permeability (Grace and Nelson, 1963; McMinn and Patton, 1963; Curtis, 1962). Variations in permeability are due to partially compressed and interlocking grains, secondary silica, micro-cross-laminations, and cement (McMinn and Patton, 1963). The unit interfingers to the east and south with conglomeratic and arkosic upper Maroon Formation beds (Haun, 1962; Curtis, 1962). The Weber correlates with the Tensleep Formation of Wyoming and the Wells Formation of Idaho (Grace and Nelson, 1963). There is a large variation of porosity and permeability throughout the entire section of the Weber, and fractures are thought to be of major importance in the reservoir capabilities of these sands (Grace and Nelson, 1963).

Geologic well logs indicate that the Weber becomes too shallow for sequestration on the north edge of the Rangely area and on the east edge of the Palisade area (Denver Earth Resources Library, 2004).

Mineralization

The primary goal of the mineral carbonation process is to sequester large amounts of CO_2 through carbonation of silicate minerals. Although there are numerous naturally occurring silicate minerals in the earth's crust, research for mineral CO_2 sequestration has focused primarily on olivine, serpentine, and wollastonite; silicate minerals that are rich in magnesium or calcium. In Colorado, these minerals are prevalent in mafic and ultramafic rocks such as serpentinite, peridotite, dunite, gabbro, and to a lesser extent, basalt and alkalic igneous rocks. In the industrial sector, waste materials such as coal fly ash or municipal solid waste incinerator bottom ash, asbestos waste, and metal slag are potential alternative feedstocks. Mineral silicates are a promising option for CO_2 sequestration in Colorado. Given current technology, silicate ore contained within the Cañon City, Craig, and Palisade source areas could sequester a total of 28,808 MMt of CO_2 assuming 15 to 20 % efficiency and subtracting CO_2 emitted during the sequestration process (Table 4.). Continued research and technological advances are needed before this process becomes a cost-effective and leading contender in the pool of technologies available for CO_2 sequestration.

Waters produced in association with oil and gas extraction are also a potential source of cations, particularly calcium, for mineral carbonation. However, preliminary calculations indicate that the water needed to sequester CO_2 emissions in a given region far exceeds current produced water volumes, and sequestration via this method is not likely to be practical. Even assuming 100 % efficiency, the volume of water produced in Colorado could only sequester about 23,000 metric tonnes of CO_2 (Table 4).

Three of Colorado's pilot study regions offer mineral carbonation via silicate rocks: Cañon City, Craig, and Palisade. Waters produced coincident with oil and gas extraction are potential candidates for the mineral carbonation process in all but the Cañon City region.

Silicate Rocks

In Colorado, feedstock options for the mineralization process include basalt, gabbro, syenite, and minor pyroxenite, diabase, dunite, and diorite. Although these resources are quite small relative to those in other parts of the country, they may prove adequate to handle local CO_2 emissions. Basalt is the most abundant of the potential feedstocks in Colorado. Outcrops are found primarily throughout the central part of the state along a northwest trend (Fig. 10). There are also basalt flows east of the Front Range in the southern part of the state. The vast majority of these flows are Miocene in age, although some were extruded during Pleistocene time. The combined MgO, CaO, and FeO content for these rocks averages 15 to 20 wt %. This is significantly lower than in the high purity experimental feedstocks (such as olivine), which can have as much as 49 wt % MgO (O'Connor and others, 2004). This does not automatically eliminate basalt as a potential mineralization candidate. Rather, it merely indicates that a greater tonnage of ore must be utilized to sequester the same amount of CO_2 as would be assimilated by a more pure feedstock. Depending on which mineralization process is deemed optimal by future research, this may or may not be economical.

Mafic and ultramafic rocks are of higher quality for CO_2 sequestration than basalt, but in Colorado, are much less widespread (Fig. 10). They crop out as small stocks, plugs, and dikes that are Precambrian or Cambrian in age. Of the larger mafic bodies, gabbro is the dominant rock type, and has a combined MgO, CaO, and FeO content that averages 25 to 30 wt %. While still of lower quality than the experimental feedstocks, gabbro has a greater capacity for CO_2 storage than does basalt. Similarly, syenite has lower Na_2O and K_2O concentrations than do source materials used for the mineralization process in which soda ash (Na_2CO_3) is formed, but still may be practical for local sequestration projects. Syenite crops out at only a handful of locations in south-central Colorado. It should be noted that carbonation with the sodium and potassium ions results in a highly soluble material, such as soda ash, that will require immediate industrial use or ensured long-term dry storage. The mineralization reaction is reversed with the addition of water, and thus, CO_2 will be released back into the atmosphere if the product is not kept dry.

Three Colorado pilot study regions have potential for mineral carbonation using silicate rocks as feedstock (Table 15). Total sequestration potential was calculated for each region on the basis of the following factors and assumptions:

- Ore resources within about 40 miles of the CO_2 point source(s) as shown on 1:250,000-scale geologic maps (Fig. 10)
- Mining depth of 200 ft for basalt; 500 ft for all other rocks
- Average specific gravity of 2.8 for syenite; 3.0 for all other rocks
- Geochemistry extracted from the U.S. Geological Survey PLUTO database (U.S. Geological Survey, 2004a) and averaged for similar rock types

Cañon City Region: Silicate rocks crop out primarily in the western half of the pilot study region and are predominantly gabbro and syenite in composition, although minor basalt and pyroxenite are also present. Mafic and ultramafic rocks represent more than 32 Gt of potential feedstock for the mineralization process. Similarly, syenite bodies in the area could provide about 28 Gt of feedstock. Basaltic rocks would provide a mere 1.6 Gt of material. Ore tonnage requirements per metric tonne of CO_2 sequestered would be 3.7 metric tonnes for mafic and ultramafic rocks, 4.3 metric tonnes for syenite, and 5.9 metric tonnes for basalt. Total theoretical CO_2 sequestration potential for the area is over 13.1 Gt, assuming 100 % efficiency (Table 15).

Experiments conducted by O'Connor and others (2004) suggest that the reaction efficiencies for basalt and gabbro are far below 100 % using current technology. In fact, they are probably as low as 15 to 20 %, respectively, significantly lower than pure olivine feedstock, which yields 60 to 80 % efficiency. Actual CO_2 sequestration potential is therefore greatly reduced. In addition, an energy penalty must be added to account for the CO_2 produced during the mineralization process. Carbon dioxide avoided is the difference between total CO_2 sequestered and CO_2 that is produced during mineralization, which averages about 75 % of total CO_2 sequestered for several mineral feedstocks investigated. This translates to actual sequestration potential of about 2.0 Gt of CO_2 for the Cañon City region (Table 15). The large gap between theoretical potential and potential based on current technology clearly indicates there is a great deal of room for technological advancement.

Craig Region: Bimodal basalt is prevalent in the southern part of the region and represents 1,323 Gt of potential feedstock. To the northeast, mafic and ultramafic rocks (primarily gabbro) could provide 55.2 Gt of material. Assuming 100 % efficiency, these rocks could sequester more than 232 Gt of CO_2. At 15 to 20 % reaction efficiency, estimated sequestration potential would be closer to 26.7 Gt (Table 15). Basalt and (ultra)mafic rocks would be consumed at a rate of 5.4 and 3.7 metric tonnes per metric tonne of CO_2 sequestered, respectively.

Palisade Region: Basalt is the only feedstock option in the Palisade region. Total ore available is estimated at 8.9 Gt, which indicates a maximum sequestration potential of 1.5 Gt of CO_2. Actual sequestration potential is closer to 165 MMt when current reaction efficiencies and CO_2 emissions are taken into account (Table 1.13).

Produced Waters

The majority of produced waters in Colorado are associated with the principal oil and gas producing basins: Denver, Raton, San Juan, and Piceance (Fig. 11). Statewide production of water amounted to nearly 294 million barrels in 2003 (Colorado Oil and Gas Conservation Commission, 2004), more than half of which was from the Purgatoire River, Rangely, and Ignacio Blanco oil and gas fields. An evaluation of all produced water in the state reveals that calcium concentrations are highly variable, ranging from trace amounts to as much as 62,000 ppm. Magnesium is similarly variable and may reach over 7,000 ppm. Nearly all of the produced waters contain more than 1,000 ppm total dissolved solids (TDS). Maximum TDS is over 340,000 ppm; mean TDS for 2,001 samples is 25,319. Average geochemistry may be calculated for various fields or basins, but the high degree of variability, even within a single well, suggests that other factors will need to be considered. If all the water produced from all the various formations in a given region is combined for use at a single mineralization plant, then a simple average, weighted by volume per producing horizon, may suffice. If, however, it is deemed more practical to collect high-calcium water only from selected horizons then several permutations may be necessary and acceptable collection methods will need to be developed.

Six Colorado pilot study regions have potential for mineral carbonation using produced waters as a cation source (Table 16). Total sequestration potential was calculated for each region on the basis of the following factors and assumptions:

- Includes water resources from all fields within about 40 miles of the region's CO_2 point source(s) (Fig. 11)
- Assumes 100 % mineralization with the Ca and Mg cations, energy requirements are not considered
- Water geochemistry extracted from the U.S. Geological Survey produced waters database (U.S. Geological Survey, 2004b) and averaged by principal producing formations and by pilot study region

Craig Region: About 50 fields produce oil and gas from the Sand Wash Basin located in this region. Three fields also produce coalbed methane. Cumulative water production for the past five years is well over 111 million barrels. Two of Colorado's 2003 top 10 water-producing fields are located in the Craig region: Iles and Maudlin Gulch fields. Waters with the highest calcium content originate from the Cretaceous Mancos Shale, Triassic Chinle Formation, and Pennsylvanian-Permian Weber Formation (Fig. 5).

Denver Region: Wattenberg field is the largest in the region and is a source of oil, natural gas, and CO_2 gas. Nearly all other fields in the area produce only oil and natural gas. Production of water is predominantly from the Cretaceous Dakota and Pierre Formations and the Permian Lyons and Ingleside Formations (Fig. 5). Total water production in the region amounted to 44.2 million barrels from 1999 to 2003. Calcium content in waters from the Denver region is relatively low, averaging 264 ppm, regardless of producing formation.

Fort Morgan Region: There are several hundred small oil and gas fields in this region, which is situated in the central part of the Denver Basin in northeastern Colorado. Nearly all production is from the D Sand and the Muddy J Sand of the Cretaceous Dakota Group (Fig. 5). Cumulative water production since 1999 is over 70.2 million barrels, but average calcium concentration in these waters is very low, which renders this region lowest on the list of proposed pilot study areas for produced water mineralization.

Ignacio Region: The largest Colorado field in the area is Ignacio Blanco, which has produced significant volumes of oil, gas, and coalbed methane from several different stratigraphic horizons. Water has been produced from many of these same horizons, but has been most prolific from the Cretaceous Dakota, Mancos, and Mesaverde Formations and the Pennsylvanian Hermosa Group (Fig. 5). Colorado water production in this region has totaled 122.5 million barrels from 1999 through 2003. Water chemistry indicates that the Hermosa Formation tends to have the highest calcium content, whereas the Mancos Shale is relatively low in calcium.

Palisade Region: The majority of the 50-plus fields in this region produce oil and/or natural gas. Roughly a dozen of these fields also produce coalbed methane. Water production from 1999 through 2003 exceeded 7.4 million barrels. Geochemical analyses indicate that the Cretaceous Dakota and Mesaverde Formations and the Jurassic San Rafael Formation produce waters high in calcium (Fig. 5).

Rangely Region: There are over 50 oil and gas fields in this region; four of the fields also produce coalbed methane. The Rangely field is the top water producer and is also an important oil and gas reservoir. There are numerous producing horizons in the Piceance Basin and water chemistry is highly variable. The Jurassic San Rafael Group and the Pennsylvanian-Permian Weber Sandstone have the highest calcium concentrations (Fig. 5). The Mancos Shale, as in the Ignacio region, tends to produce waters that are very low in calcium. Produced waters have exceeded 400 million barrels over the course of the last five years.

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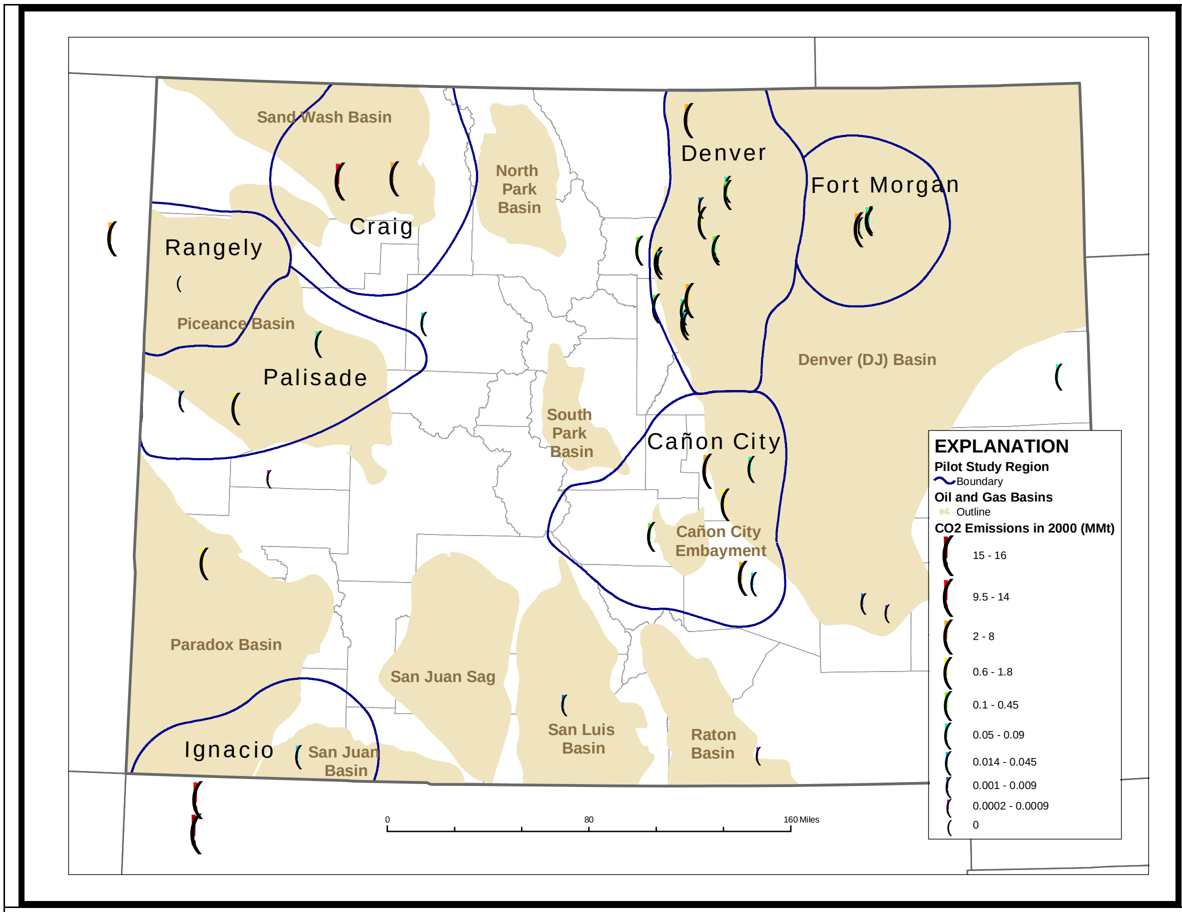

Fig. 3. Pilot study regions and CO_2 emissions for Colorado in 2000 (MMt = Million Metric Tonnes).

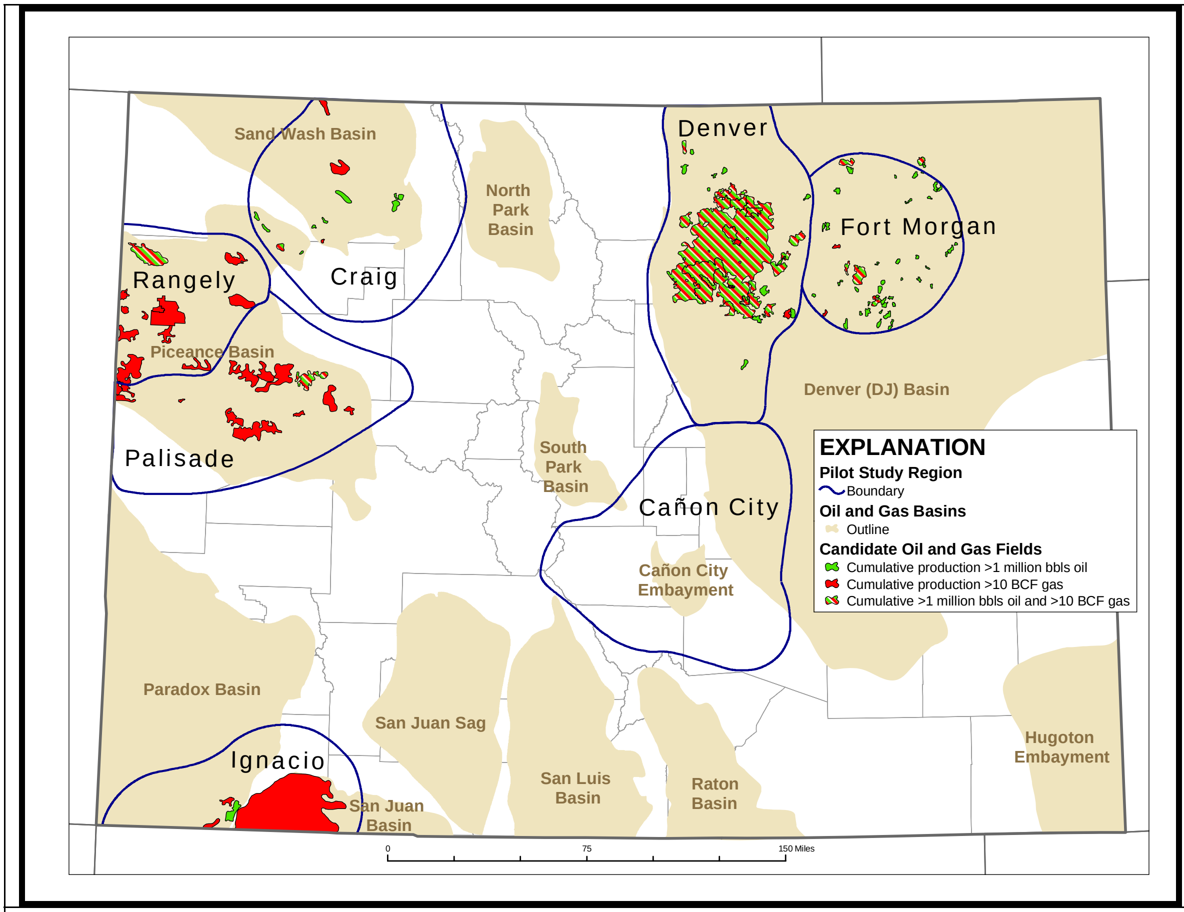

Fig. 4. Oil and gas reservoirs included in carbon storage estimates for Colorado (bbls = barrels; BCF = Billion Cubic Feet).

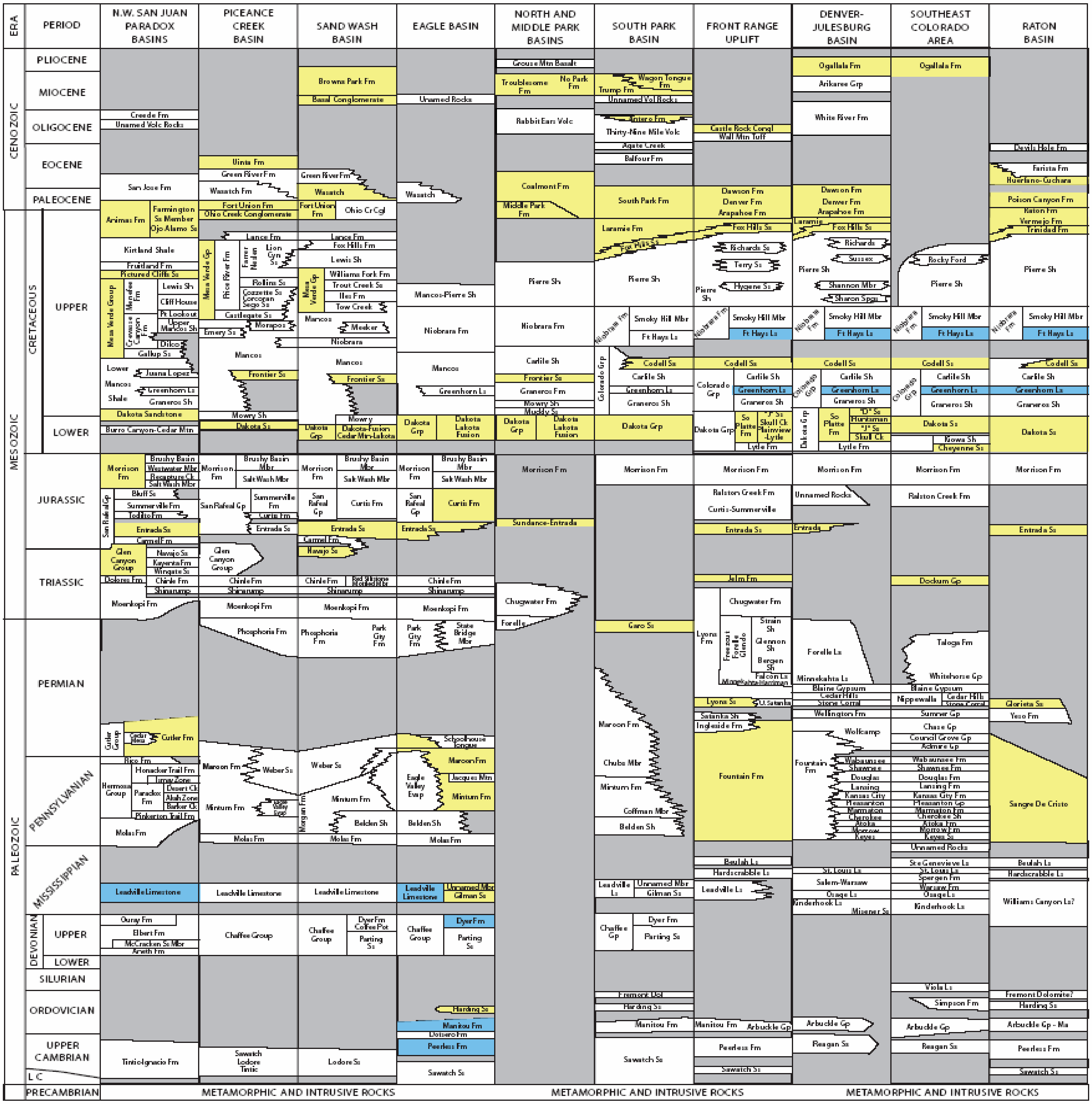

Fig. 5. Stratigraphic nomenclature for Colorado (Pearl, 1977).

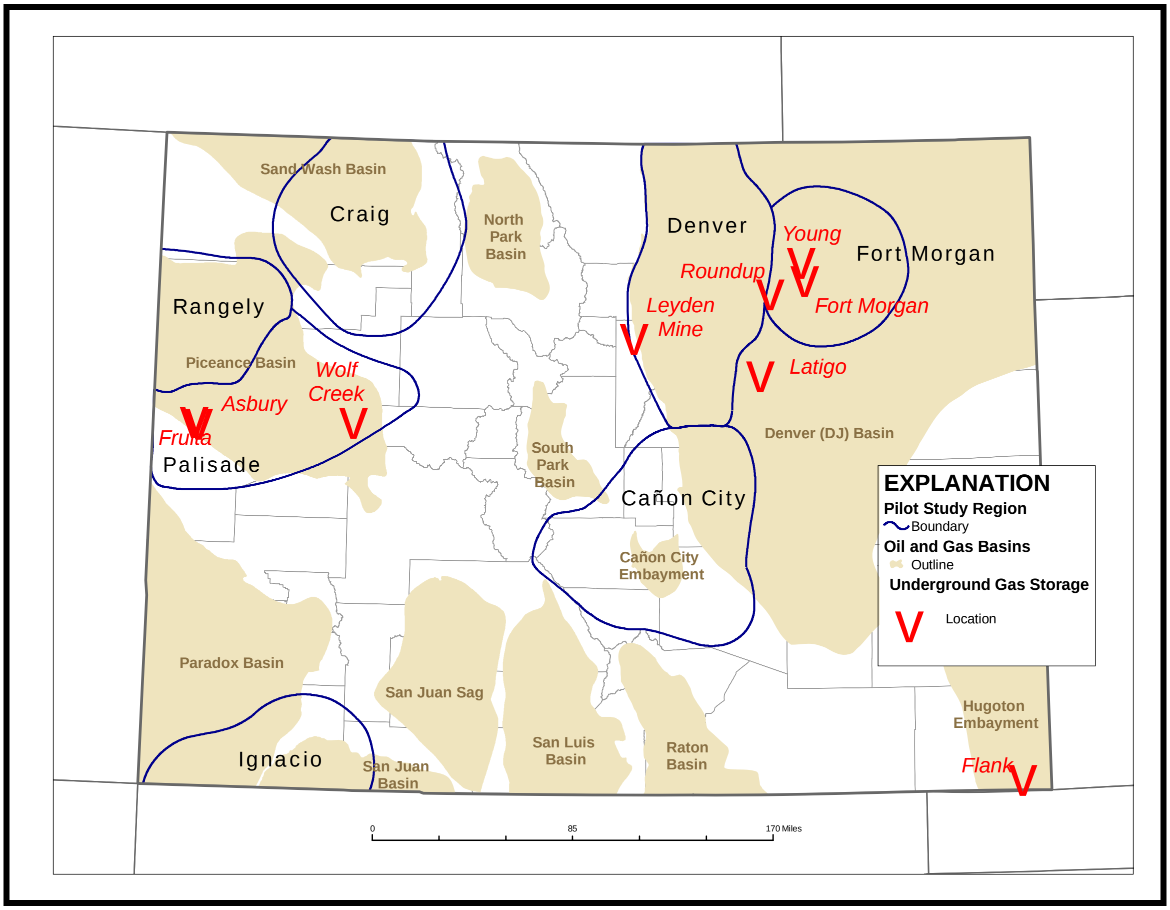

Fig. 6. Underground gas storage facilities in Colorado.

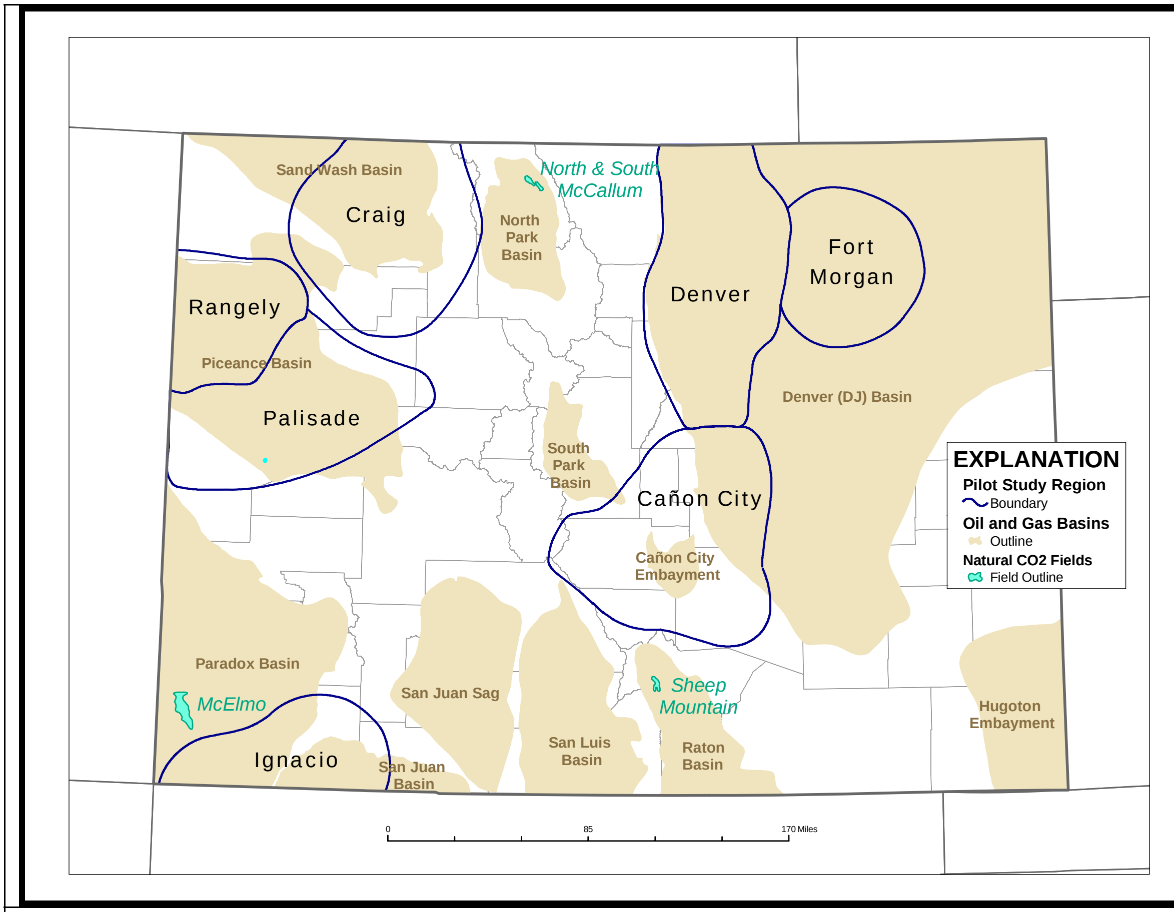

Fig. 7. Natural CO_2 fields in Colorado.

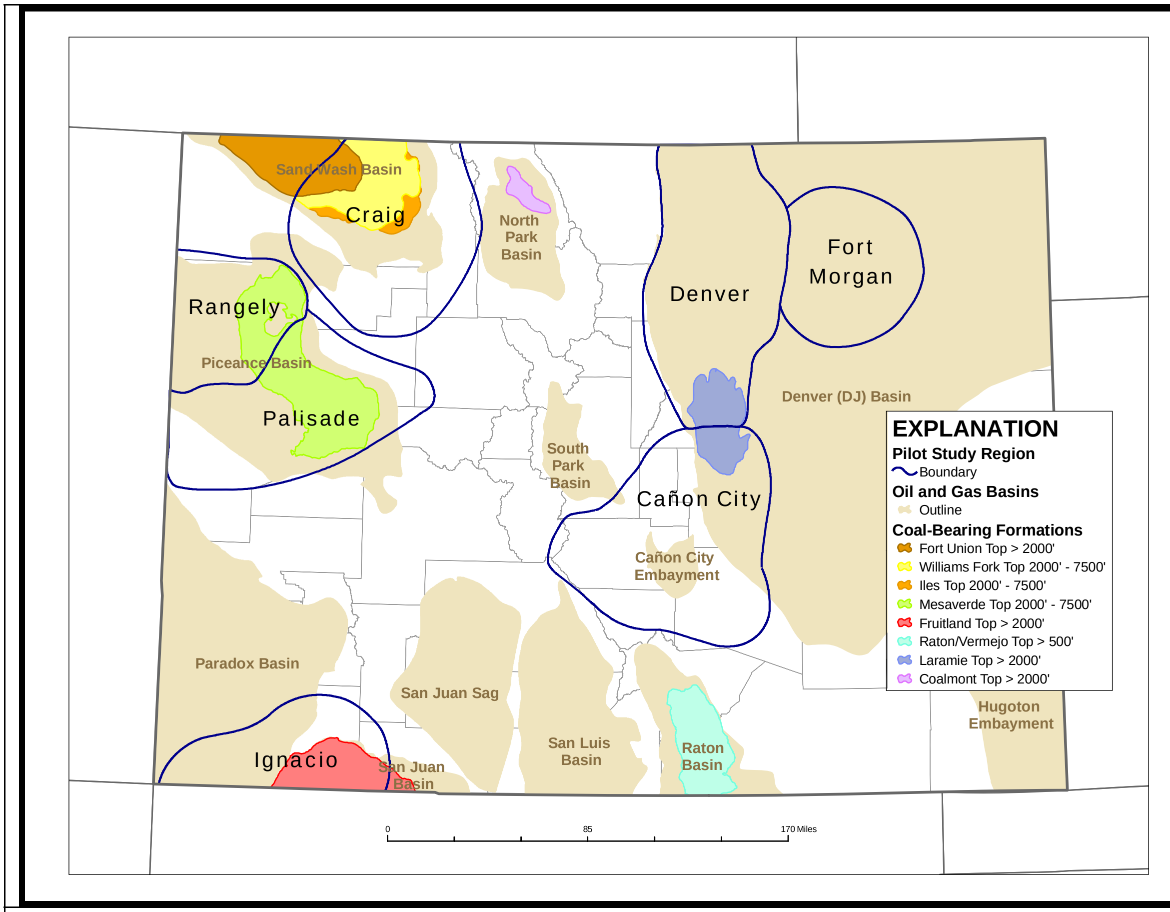

Fig. 8. Coalbed reservoirs included in carbon storage estimates for Colorado. Color-coded areas are screened for depths greater than 2,000 ft and less than 7,500 ft except in the Raton Basin.

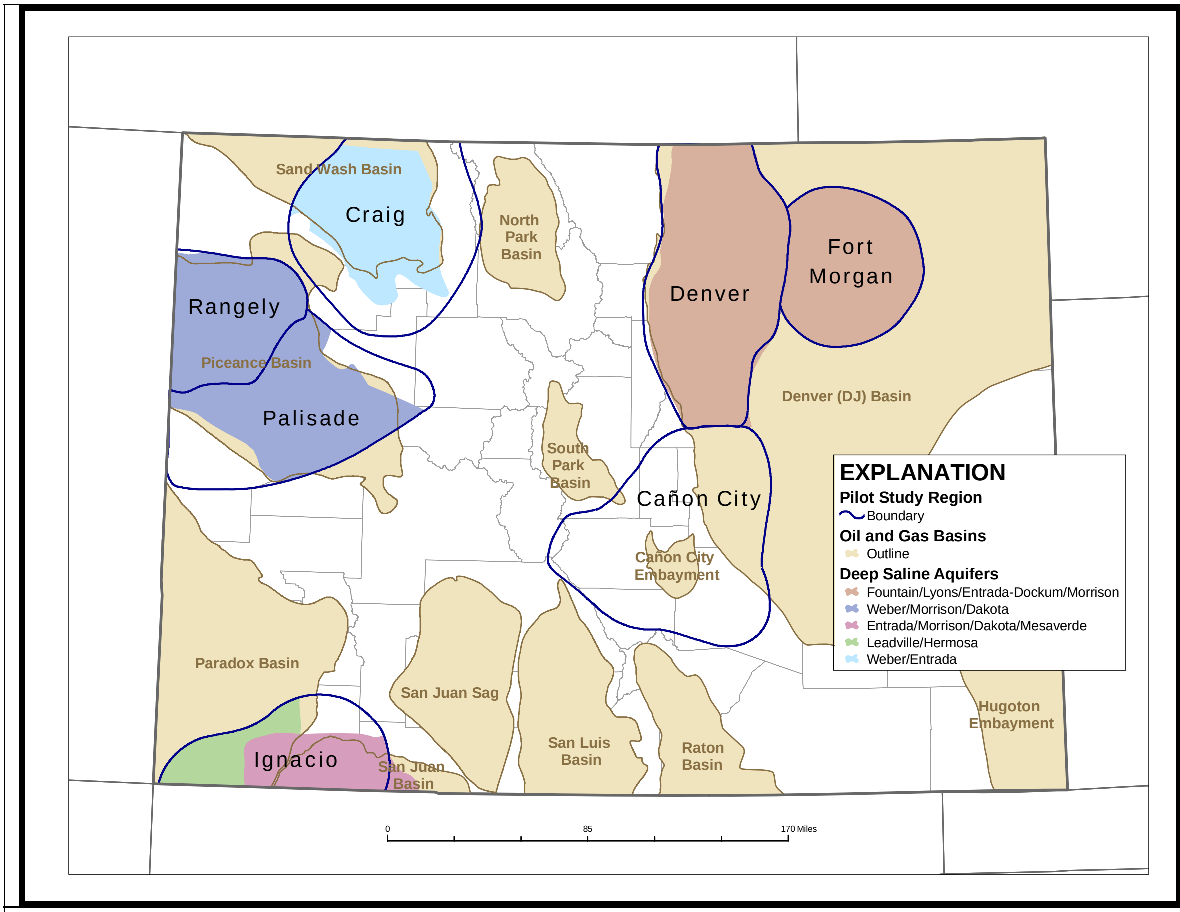

Fig. 9. Deep saline aquifers included in carbon storage estimates for Colorado.

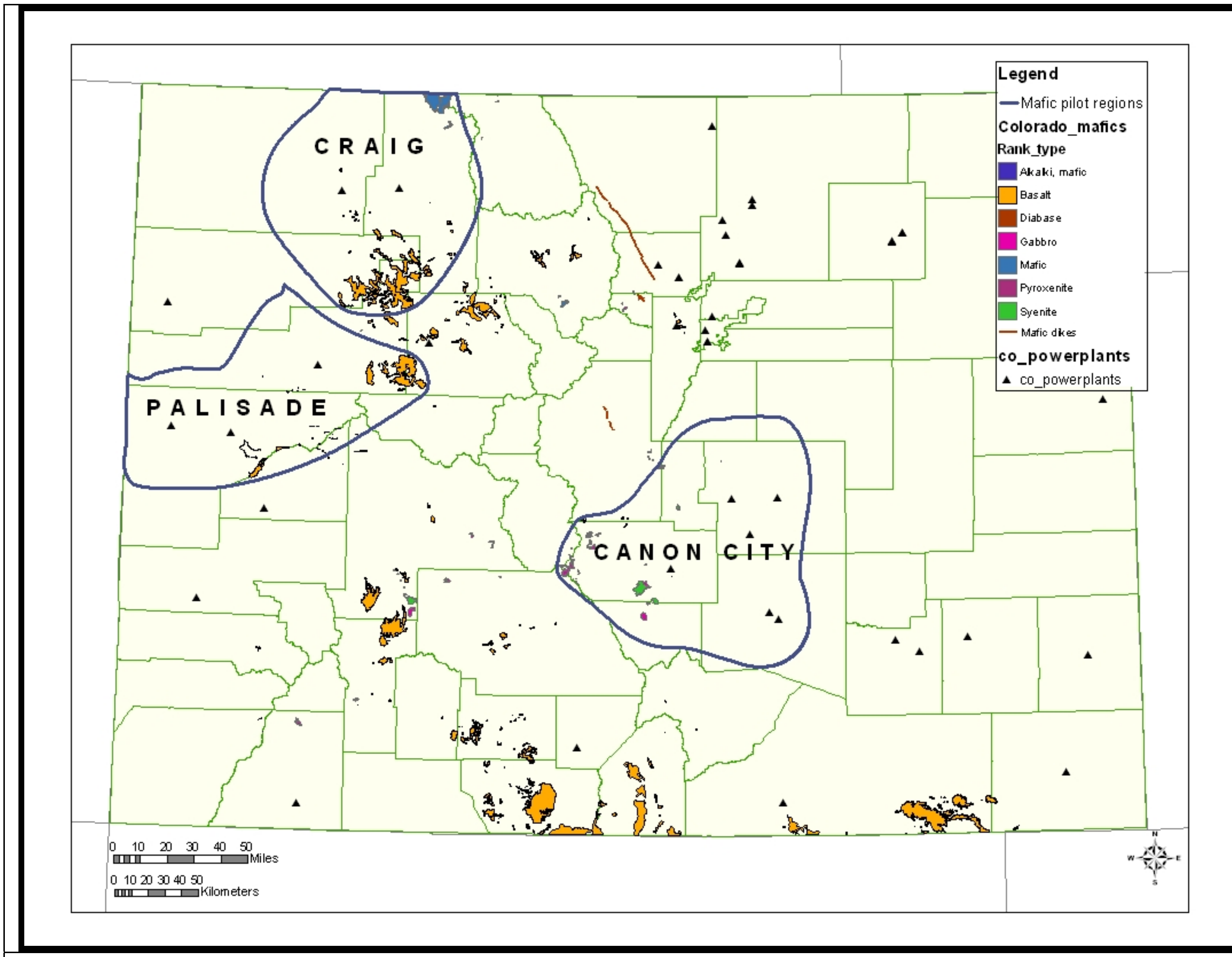

Fig. 10. Silicate mineralization pilot study regions and distribution of mafic and ultramafic rocks, basalt, and alkalic igneous rocks in Colorado.

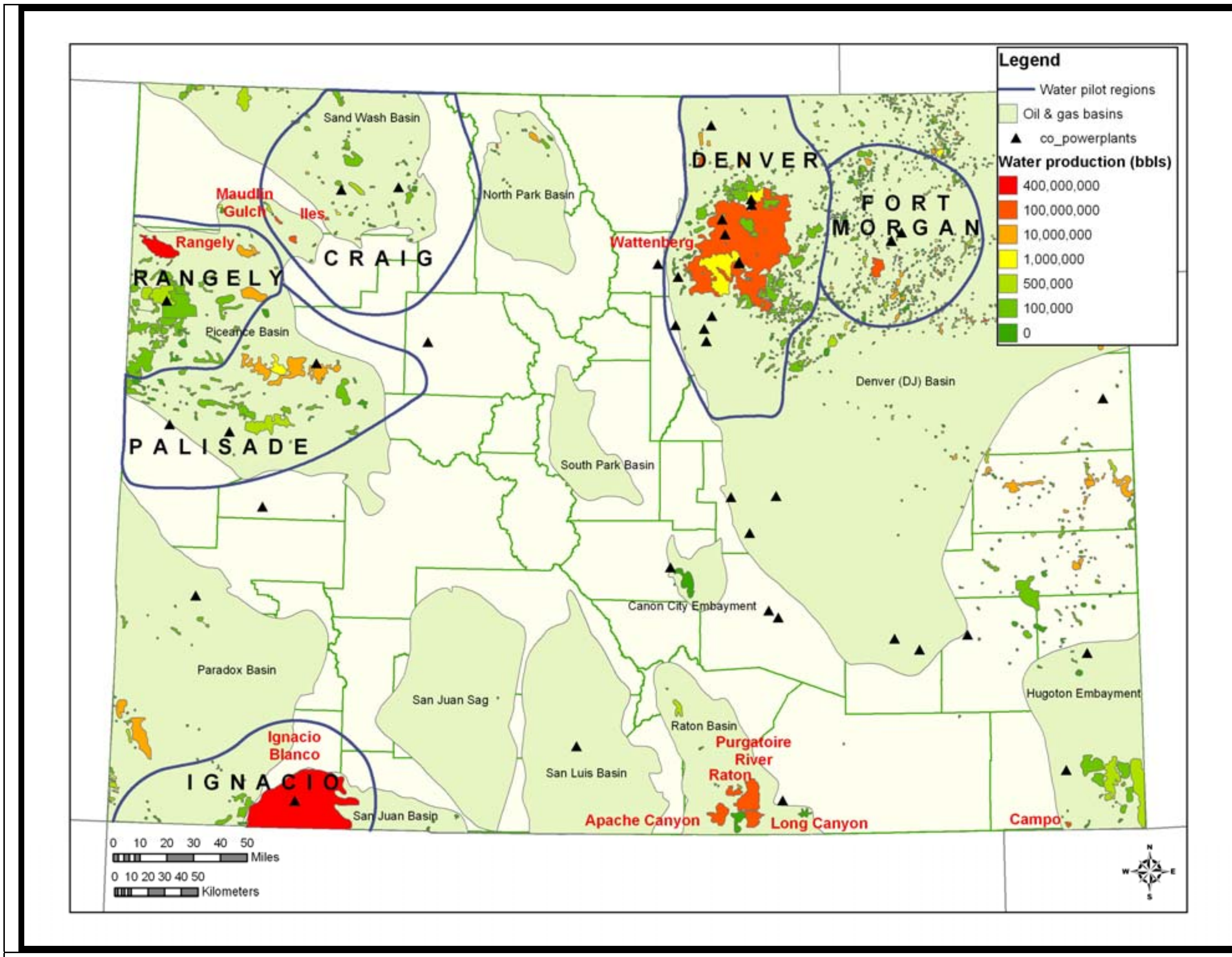

Fig. 11. Oil and gas fields in Colorado, ranked on the basis of water production from 1999 through 2003. The top 10 water producing fields for 2003 are labeled in red.

Table 3. Annual CO_2 Emissions for Colorado in 2000

		Facility Name	Annual CO_2 Emissions (Metric Tonnes)
PILOT STUDY REGION	IGNACIO	Four Corners (New Mexico)	15,367,449
		San Juan (New Mexico)	13,165,444
		Ignacio Gasoline Plant	21,624
		Region Total	**28,554,517**
	CRAIG	Craig	9,495,198
		Hayden	3,562,043
		Region Total	**13,057,241**
	DENVER	Arapahoe	1,773,354
		Arapahoe Combustion Turbine Project	17,510
		Cherokee	4,921,185
		Fort Lupton	49,472
		Fort St Vrain	1,238,994
		Rawhide	2,205,279
		TCP 122	263,690
		TCP 150	330,694
		Thermo Greeley Inc	67,932
		Thermo Power Electric Inc	258,211
		Valmont	1,237,033
		Valmont Combustion Turbine Project	17,080
		Zuni	60,628
		Trigen Colorado Energy Corp	250,546
		Johnstown Cogeneration	1,081
		University of Colorado	105,295
		Region Total	**12,797,986**
	CAÑON CITY	Comanche	4,438,134
		George Birdsall	84,817
		Martin Drake	1,980,499
		Pueblo	38,197
		Ray D Nixon	1,627,135
		W N Clark	339,238
		Region Total	**8,508,019**
	FORT MORGAN	Manchief Electric Generating Station	1,679
		Brush Cogen Project Phase 2 BCP	104,445
		Brush Iv	37,871
		Brush Power Project Phase 1 CPP	47,106
		Pawnee	4,256,150
		Region Total	**4,447,253**
	RANGELY	Bonanza (Utah)	3,059,113
		Dragon Trail Gas Processing Plant	0
		Region Total	**3,059,113**
	PALISADE	Cameo	633,994
		American Atlas 1 Cogeneration Plant	75,450
		Fruita	3,729
		Region Total	**713,172**

Table 4. CO_2 Sequestration Capacities Estimated for Colorado (in Million Metric Tonnes)

Pilot Study Regions	Geologic			Mineralization		Total CO_2 Capacity
	Oil & Gas	CBM	Saline Aquifers	Silicates	Produced Waters	
Cañon City	0	447	20,300	1,950	---	22,697
Craig	112	10,033	8,350	26,693	0.001	45,188
Denver	505	546	20,500	---	<0.001	21,551
Fort Morgan	149	0	7,900	---	<0.001	8,049
Ignacio	169	2,548	14,270	---	0.008	16,987
Palisade	105	1,631	20,700	165	<0.001	22,601
Rangely	671	941	17,500	---	0.014	19,112
Trinidad	0	674	NA	---	---	674
Total Capacity	**1,710**	**16,820**	**109,520**	**28,808**	**0.023**	**156,858**
Number of sink types	**247**	**19**	**25**	**---**	**---**	**291**
Average per sink type	**7**	**885**	**4,381**	**---**	**---**	**539**
Maximum capacity per sink type	**616**	**4,485**	**17,400**	**---**	**---**	**22,501**

e 5. CO_2 Sequestration Capacities for Oil and Gas Fields in the Craig Pilot Study Region, Northwestern Colorado

n	Field Name	Number of Reservoirs	Play Code[1]	Reservoir Name	Average Depth (Feet)	Total CO_2 Capacity (MMt)[2]		Avg CO_2 Capacity (MMt)[2]	Max CO_2 Capacity (MMt)[2]
						Reservoir	Field		
	Bear River	1	RMKU-3	Niobrara	4,302	0.9	0.9	0.9	0.9
	Buck Peak	3	RMKU-3	Mancos Shale	3,288	0.9	3.5	1.2	2.6
			RMKU-3	Niobrara	6,822	2.6			
			RMFS-4	Shinarump	9,402	0.0			
	Craig North	2	RMKU-2 / RMKU-3	Lewis Shale, Mesaverde	2,821	3.0	3.0	1.5	3.0
	Grassy Creek	1	RMKU-3	Niobrara	5,134	0.7	0.7	0.7	0.7
	Iles	3	RMFS-4	Morrison	2,953	0.7	17.7	5.9	17.0
			RMFS-4	Entrada (Sundance)	3,243	17.0			
			RMFS-4	Curtis	3,310	0.0			
	Thornburg	4	RMFS-4	Dakota	2,301	0.6	3.1	0.8	1.7
			RMFS-4	Entrada Sandstone	2,902	0.7			
			RMFS-4	Shinarump, Weber	3,485	1.7			
	Tow Creek	1	RMKU-3	Niobrara	3,201	1.7	1.7	1.7	1.7
	West Side Canal	3	RMKU-1	Lance	2,709	0.3	3.8	1.3	3.4
			RMKU-2	Lewis Shale	3,769	3.4			
			RMKU-3	Mesaverde	5,830	0.1			
	Danforth Hills	7	RMPC-4	Dakota, Morrison	5,659	0.8	2.6	0.4	1
			RMPC-5	Entrada (Sundance)	6,525	1.0			
			RMPC-6	Shinarump, Moenkopi, Minturn, Weber	7,175	0.8			
	Maudlin Gulch	8	RMPC-4 / RMPC-5	Dakota, Morrison, Entrada (Sundance)	6,012	6.2	9.4	1.2	6.2
			RMPC-6	Shinarump, Moenkopi, Phosphoria, Weber, Minturn	7,476	3.3			
	Nine Mile	1	RMPC-4	Dakota	7,215	0.6	0.6	0.6	0.6
	Wilson Creek	5	RMPC-3	Niobrara	4,163	0.1	64.5	12.9	41.9
			RMPC-4	Morrison	6,486	41.9			
			RMPC-5	Entrada (Sundance)	6,731	21.6			
			RMPC-6	Shinarump, Minturn	8,025	1.0			
TOTALS		**39**			**5,036**	**111.6**	**111.6**	**2.9**	**80.7**

DOE assigns a play code to a group of reservoirs in a geographic area that have similar geologic parameters (Whitehead and others, 1993). [2] MMt = Million Metric Tonnes

Table 6. CO_2 Sequestration Capacities for Oil and Gas Fields in the Denver Pilot Study Region, Northeastern Colorado

Basin	Field Name	Number of Reservoirs	Play Code[1]	Reservoir Name	Average Depth (Feet)	Total CO_2 Capacity (MMt)[2] Reservoir	Total CO_2 Capacity (MMt)[2] Field	Avg CO_2 Capacity (MMt)[2]	Max CO_2 Capacity (MMt)[2]
Denver	Aristocrat	5	RMDB-1 / RMDB-2 / RMDB-5	Niobrara, Codell Ss, Sussex, Shannon, Dakota	4,436	3.2	3.23	0.6	0.6
	Banner Lakes	1	RMDB-4 / RMDB-5	Dakota	7,666	1.5	1.46	1.5	1.5
	Base Line	2	RMDB-2	Codell Sandstone	7,026	0.0	1.00	0.5	1.0
			RMDB-4 / RMDB-5	Dakota	7,429	1.0			
	Black Hollow	1	RMEC-2	Lyons Sandstone	8,965	7.0	7.05	7.0	7.0
	Bracewell	5	RMDB-1	Sussex, Shannon	4,344	0.0	3.60	0.7	3.6
			RMDB-2 / RMDB-5	Niobrara, Codell Sandstone, Dakota	6,845	3.6			
	Chieftain	1	RMDB-4 / RMDB-5	Dakota	7,492	2.2	2.21	2.2	2.2
	Clarks Lake	1	RMDB-4 / RMDB-5	Dakota	6,162	1.6	1.56	1.6	1.6
	Eaton	2	RMDB-2	Niobrara, Codell Sandstone	6,910	2.5	2.50	1.3	2.5
	Fort Collins	3	RMDB-2	Niobrara	3,892	0.0	4.90	1.6	4.7
			RMDB-5	Dakota	4,969	4.7			
			RMEC-2	Lyons Sandstone	6,190	0.2			
	Greasewood	1	RMDB-4	Dakota	6,714	0.8	0.80	0.8	0.8
	Greeley	4	RMDB-1	Parkman	3,607	0.1	2.60	0.7	2.5
			RMDB-2	Niobrara, Fort Hays, Codell Sandstone	6,728	2.5			
	Hambert	3	RMDB-1	Sussex	4,389	6.0	6.20	2.1	6.0
			RMDB-2	Niobrara, Codell Sandstone	6,822	0.2			
	Irondale	1	RMDB-4 / RMDB-5	Dakota	7,045	1.7	1.70	1.7	1.7
	Jamboree	1	RMDB-4 / RMDB-5	Dakota	7,781	2.9	2.87	2.9	2.9
	Kersey	3	RMDB-2	Niobrara, Fort Hays, Codell Sandstone	6,512	3.0	2.98	1.0	3.0

Table 6. CO_2 Sequestration Capacities for Oil and Gas Fields in the Denver Pilot Study Region (Cont'd.)

Basin	Field Name	Number of Reservoirs	Play Code[1]	Reservoir Name	Average Depth (Feet)	Total CO_2 Capacity (MMt)[2]		Avg CO_2 Capacity (MMt)[2]	Max CO_2 Capacity (MMt)[2]
						Reservoir	Field		
Denver	Lanyard	2	RMDB-2	Codell Sandstone	6,467	0.0	2.60	1.3	2.6
			RMDB-4 / RMDB-5	Dakota	6,920	2.6			
	Longbranch	1	RMDB-4 / RMDB-5	Dakota	7,043	3.0	3.00	3.0	3.0
	Lost Creek	2	RMDB-2	Niobrara	6,093	0.0	2.00	1.0	2.0
			RMDB-4 / RMDB-5	Dakota	6,778	2.0			
	Loveland	8	RMDB-1	Sussex, Shannon	1,804	0.0	3.30	0.4	3.3
			RMDB-2 / RMDB-4 / RMDB-5	Niobrara, Codell Ss, Timpas, Dakota, Lakota	4,734	3.3			
			RMEC-2	Lyons Sandstone	6,896	0.0			
	Lowry	2	RMDB-2	Niobrara	7,794	0.0	1.30	0.7	1.3
			RMDB-4 / RMDB-5	Dakota	8,493	1.3			
	New Windsor	3	RMDB-1	Sussex	4,254	0.2	0.70	0.2	0.5
			RMDB-2	Codell Sandstone	6,877	0.0			
			RMEC-2	Lyons Sandstone	8,993	0.5			
	Pierce	1	RMEC-2	Lyons Sandstone	9,221	7.3	7.31	7.3	7.3
	Radar	1	RMDB-4 / RMDB-5	Dakota	7,850	1.4	1.43	1.4	1.4
	Roggen	2	RMDB-2	Niobrara	6,260	0.0	3.90	2.0	3.9
			RMDB-4 / RMDB-5	Dakota	6,970	3.9			
	Space City	1	RMDB-4 / RMDB-5	Dakota	7,907	2.2	2.20	2.2	2.2
	Spindle	7	RMDB-1 / RMDB-2 / RMDB-4 / RMDB-5	Sussex, Shannon, Niobrara, Fort Hays, Codell Ss, Timpas, Dakota	4,695	64.1	64.05	9.2	64.1
	Third Creek	1	RMDB-5	Dakota	8,303	5.5	5.55	5.5	5.5
	Trapper	1	RMDB-4 / RMDB-5	Dakota	7,890	2.3	2.28	2.3	2.3

Table 6. CO_2 Sequestration Capacities for Oil and Gas Fields in the Denver Pilot Study Region (Cont'd.)

Basin	Field Name	Number of Reservoirs	Play Code[1]	Reservoir Name	Average Depth (Feet)	Total CO_2 Capacity (MMt)[2] Reservoir	Total CO_2 Capacity (MMt)[2] Field	Avg CO_2 Capacity (MMt)[2]	Max CO_2 Capacity (MMt)[2]
Denver	Waite Lake	4	RMDB-2	Niobrara	5,865	0.0	1.70	0.4	1.7
			RMDB-2	Codell Sandstone	6,152	0.0			
			RMDB-2	Greenhorn Limestone	6,179	0.0			
			RMDB-4 / RMDB-5	Dakota	6,525	1.7			
	Wattenberg	11	RMDB-1	Parkman	3,651	0.0	352.00	32.0	352.0
			RMDB-2 / RMDB-4 / RMDB-5	Sussex, Shannon, Niobrara, Fort Hays, Codell Ss, Greenhorn, Graneros, Dakota, Lakota, Timpas	4,367	352.0			
	Wellington	1	RMDB-5	Muddy (J) Sandstone	4,494	7.3	7.32	7.3	7.3
TOTALS		**82**			**6,355**	**505.4**	**505.4**	**6.2**	**502.1**

[1] U.S. DOE assigns a play code to a group of reservoirs in a geographic area that have similar geologic parameters (Whitehead and others, 1993).

[2] MMt = Million Metric Tonnes

Table 7. CO_2 Sequestration Capacities for Oil and Gas Fields in the Fort Morgan Pilot Study Region, Northeastern Colorado

Basin	Field Name	Number of Reservoirs	Play Code[1]	Reservoir Name	Average Depth (Feet)	Total CO_2 Capacity (MMt)[2]		Avg CO_2 Capacity (MMt)[2]	Max CO_2 Capacity (MMt)[2]
						Reservoir	Field		
Denver	Adena	1	RMDB-4/RMDB-5	Dakota	5,561	36.5	36.5	36.5	36.5
	Akron East	1	RMDB-4	D Sandstone	4,580	1.6	1.6	1.6	1.6
	Arroyo	1	RMDB-4/RMDB-5	Dakota	5,977	0.9	0.9	0.9	0.9
	Atwood East	1	RMDB-4/RMDB-5	Dakota	4,412	1.8	1.8	1.8	1.8
	Badger Creek	1	RMDB-4/RMDB-5	Dakota	5,296	3.0	3.0	3.0	3.0
	Beacon	1	RMDB-4/RMDB-5	Dakota	5,767	1.2	1.2	1.2	1.2
	Belle	1	RMDB-5	Dakota	4,841	0.6	0.6	0.6	0.6
	Big Beaver	1	RMDB-5	Muddy (J) Sandstone	5,015	7.9	7.9	7.9	7.9
	Bijou	2		Greenhorn Limestone	5,819	0.0	1.5	0.8	1.5
			RMDB-4	D Sandstone	6,095	1.5			
	Bijou West	1	RMDB-4	D Sandstone	6,158	1.0	1.0	1.0	1.0
	Bobcat	1	RMDB-4/RMDB-5	Dakota	5,142	5.0	5.0	5.0	5.0
	Boxer	1	RMDB-4/RMDB-5	Dakota	5,839	3.4	3.4	3.4	3.4
	Deer Trail	1	RMDB-4/RMDB-5	Dakota	6,220	1.3	1.3	1.3	1.3
	Dune Ridge	1	RMDB-4/RMDB-5	Dakota	4,443	1.2	1.2	1.2	1.2
	Elm Grove	1	RMDB-4/RMDB-5	Dakota	4,604	1.6	1.6	1.6	1.6
	Frasco	1	RMDB-4/RMDB-5	Dakota	5,410	1.0	1.0	1.0	1.0
	Graylin Northwest	1	RMDB-4/RMDB-5	Dakota	4,910	8.5	8.5	8.5	8.5
	Hardway	1	RMDB-4	D Sandstone	4,438	0.6	0.6	0.6	0.6
	Jackpot	1	RMDB-4	D Sandstone	6,461	1.1	1.1	1.1	1.1
	Kejr	1	RMDB-4/RMDB-5	Dakota	4,986	1.9	1.9	1.9	1.9
	Lilli	2	RMDB-2	Codell Sandstone	5,930	0.0	4.8	2.4	4.8
			RMDB-4	D Sandstone	6,381	4.8			
	Little Beaver	1	RMDB-4/RMDB-5	Dakota	5,201	12.1	12.1	12.1	12.1
	Little Beaver East	1	RMDB-4/RMDB-5	Dakota	5,064	2.6	2.6	2.6	2.6
	Luft	1	RMDB-4/RMDB-5	Dakota	4,868	1.8	1.8	1.8	1.8
	McRea	1	RMDB-5	Muddy (J) Sandstone	4,933	0.8	0.8	0.8	0.8
	Merino	1	RMDB-5	Muddy (J) Sandstone	4,980	2.9	2.9	2.9	2.9
	Middlemist	1	RMDB-5	Muddy (J) Sandstone	5,508	1.3	1.3	1.3	1.3
	Moccasin	1	RMDB-5	Muddy (J) Sandstone	5,417	0.7	0.7	0.7	0.7

Table 7. CO_2 Sequestration Capacities for Oil and Gas Fields in the Fort Morgan Pilot Study Region (Cont'd.)

Basin	Field Name	Number of Reservoirs	Play Code[1]	Reservoir Name	Average Depth (Feet)	Total CO_2 Capacity (MMt)[2]		Avg CO_2 Capacity (MMt)[2]	Max CO_2 Capacity (MMt)[2]
						Reservoir	Field		
Denver	Nile	1	RMDB-4/RMDB-5	Dakota	6,360	2.4	2.4	2.4	2.4
	Nugget	1	RMDB-4	D Sandstone	5,216	1.5	1.5	1.5	1.5
	Park	2	RMDB-2	Niobrara	5,232	0.0	0.9	0.5	0.9
			RMDB-4/RMDB-5	Dakota	6,098	0.9			
	Pawnee Creek	1	RMDB-5	Muddy (J) Sandstone	5,035	1.4	1.4	1.4	1.4
	Peterson	1	RMDB-4	D Sandstone	5,173	0.8	0.8	0.8	0.8
	Phegley	1	RMDB-4	D Sandstone	4,856	1.4	1.4	1.4	1.4
	Plumb Bush Crk	1	RMDB-5	Muddy (J) Sandstone	4,969	10.3	10.3	10.3	10.3
	Rago North	1	RMDB-4/RMDB-5	Dakota	4,876	3.1	3.1	3.1	3.1
	Ramp	1	RMDB-5	Muddy (J) Sandstone	4,915	0.6	0.6	0.6	0.6
	Ranchero	1	RMDB-4/RMDB-5	Dakota	4,746	0.9	0.9	0.9	0.9
	Redwing	1	RMDB-4	D Sandstone	4,555	1.3	1.3	1.3	1.3
	Sand River	1	RMDB-4	D Sandstone	5,124	2.9	2.9	2.9	2.9
	Shield	1	RMDB-4/RMDB-5	Dakota	4,845	0.9	0.9	0.9	0.9
	Sooner	1	RMDB-4/RMDB-5	Dakota	6,279	2.2	2.2	2.2	2.2
	Swan	1	RMDB-4/RMDB-5	Dakota	5,036	1.9	1.9	1.9	1.9
	Vallery	1	RMDB-4/RMDB-5	Dakota	5,904	1.2	1.2	1.2	1.2
	Vortex	1	RMDB-5	Muddy (J) Sandstone	4,936	0.7	0.7	0.7	0.7
	Westfork	1	RMDB-5	Muddy (J) Sandstone	4,924	2.1	2.1	2.1	2.1
	Xenia West	1	RMDB-4/RMDB-5	Dakota	4,710	1.9	1.9	1.9	1.9
	Zorichak	1	RMDB-4/RMDB-5	Dakota	4,945	1.6	1.6	1.6	1.6
TOTALS		**51**			**5,274**	**148.5**	**148.5**	**2.9**	**148.4**

[1] U.S. DOE assigns a play code to a group of reservoirs in a geographic area that have similar geologic parameters (Whitehead and others, 1993).

[2] MMt = Million Metric Tonnes

Table 8. CO_2 Sequestration Capacities for Oil and Gas Fields in the Ignacio Pilot Study Region, Southwestern Colorado

Basin	Field Name	Number of Reservoirs	Play Code[1]	Reservoir Name	Average Depth (Feet)	Total CO_2 Capacity (MMt)[2]		Avg CO_2 Capacity (MMt)[2]	Max CO_2 Capacity (MMt)[2]
						Reservoir	Field		
Paradox	Alkali Gulch	3	RMSJ-6	Dakota	3,074	0.0	2.6	0.9	2.0
			RMSJ-6	Hermosa Group	8,192	2.0			
			RMSJ-6	Molas	9,752	0.6			
	Barker Dome	2	RMSJ-5	Dakota	3,178	0.0	9.9	5.0	9.9
			RMSJ-6	Hermosa Group	7,683	9.9			
	Red Mesa	2	RMSJ-3 / RMSJ-5 / RMSJ-6	Dakota, Morrison	3,396	1.4	1.4	0.7	1.4
San Juan	Ignacio Blanco	3	RMSJ-1 / RMSJ-2 / RMSJ-3 / RMSJ-5	Mesaverde Group, Dakota, Morrison	4,963	154.6	154.6	51.5	154.6
TOTALS		**10**			**5,748**	**168.5**	**168.5**	**16.8**	**167.9**

[1] U.S. DOE assigns a play code to a group of reservoirs in a geographic area that have similar geologic parameters (Whitehead and others, 1993).

[2] MMt = Million Metric Tonnes

Table 9. CO_2 Sequestration Capacities for Oil and Gas Fields in the Palisade Pilot Study Region, West-Central Colorado

Basin	Field Name	Number of Reservoirs	Play Code[1]	Reservoir Name	Average Depth (Feet)	Total CO_2 Capacity (MMt)[2]		Avg CO_2 Capacity (MMt)[2]	Max CO_2 Capacity (MMt)[2]
						Reservoir	Field		
Piceance	Bar X	3	RMPC-4	Dakota, Morrison	2,496	0.8	1.6	0.5	0.8
			RMPC-5	Entrada Sandstone	3,035	0.8			
	Bridle	3	RMPC-4	Dakota, Morrison	3,118	2.4	2.4	0.8	2.4
			RMPC-5	Entrada Sandstone	3,700	0.0			
	Buzzard Creek	2	RMPC-1	Wasatch	396	0.0	1.5	0.8	1.5
			RMPC-2	Mesaverde Group	4,503	1.5			
	Divide Creek	1	RMPC-2	Mesaverde Group	3,009	7.3	7.3	7.3	7.3
	Grand Valley	1	RMPC-2	Mesaverde Group	3,619	24.2	24.2	24.2	24.2
	Hunters Canyon	2	RMPC-4	Dakota, Morrison	6,161	0.4	0.4	0.2	0.4
	Mamm Creek	1	RMPC-2	Mesaverde Group	3,845	23.7	23.7	23.7	23.7
	Parachute	1	RMPC-2	Mesaverde Group	3,810	9.6	9.6	9.6	9.6
	Plateau	3	RMPC-2	Mesaverde Group	3,734	0.7	0.9	0.3	0.7
			RMPC-4	Dakota, Morrison	7,360	0.2			
	Rulison	2	RMPC-2	Mesaverde Group	4,153	29.2	29.3	14.7	29.2
			RMPC-3	Mancos Shale	8,004	0.0			
	Shire Gulch	6	RMPC-2/RMPC-3/ RMPC-4	Mesaverde Group, Dakota, Frontier, Cedar Mtn, Mancos, Morrison	775	2.9	2.9	0.5	2.9
	Wolf Creek	1	RMPC-2	Mesaverde Group	1,643	1.3	1.3	1.3	1.3
TOTALS		**26**			**3,727**	**105.1**	**105.1**	**4.0**	**104.1**

[1] U.S. DOE assigns a play code to a group of reservoirs in a geographic area that have similar geologic parameters (Whitehead and others, 1993).

[2] MMt = Million Metric Tonnes

Table 10. CO_2 Sequestration Capacities for Oil and Gas Fields in the Rangely Pilot Study Region, West-Central Colorado

Basin	Field Name	Number of Reservoirs	Play Code[1]	Reservoir Name	Average Depth (Feet)	Total CO_2 Capacity (MMt)[2]		Avg CO_2 Capacity (MMt)[2]	Max CO_2 Capacity (MMt)[2]
						Reservoir	Field		
Paradox	Alkali Gulch	3	RMSJ-6	Dakota	3,074	0.0	2.6	0.9	2.0
			RMSJ-6	Hermosa Group	8,192	2.0			
			RMSJ-6	Molas	9,752	0.6			
	Barker Dome	2	RMSJ-5	Dakota	3,178	0.0	9.9	5.0	9.9
			RMSJ-6	Hermosa Group	7,683	9.9			
	Red Mesa	2	RMSJ-3 / RMSJ-5 / RMSJ-6	Dakota, Morrison	3,396	1.4	1.4	0.7	1.4
San Juan	Ignacio Blanco	3	RMSJ-1 / RMSJ-2 / RMSJ-3 / RMSJ-5	Mesaverde Group, Dakota, Morrison	4,963	154.6	154.6	51.5	154.6
TOTALS		**10**			**5,748**	**168.5**	**168.5**	**16.8**	**167.9**

[1] U.S. DOE assigns a play code to a group of reservoirs in a geographic area that have similar geologic parameters (Whitehead and others, 1993).

[2] MMt = Million Metric Tonnes

Table 11. Natural CO_2 Reserves in the Rocky Mountain Region

State	Basin	Field	Recoverable Reserves (Tcf)
Wyoming	Greater Green River	LaBarge-Big Piney	55
New Mexico	Northeastern NM	Bravo Dome	16
Colorado	Paradox	McElmo Dome	17
Colorado	Raton	Sheep Mountain	2.5
Colorado	North Park	North and South McCallum	<0.1

Source: New Mexico Bureau of Geology and Mineral Resources, 2006; De Bruin, 2001; Carpen, 1957

Table 12. CO_2 Sequestration Capacities for Coalbed Reservoirs in Colorado

Pilot Study Region	Basin	Formation	Coal Rank[1]	Average Depth (Feet)	Total CO_2 Capacity (MMt)[2]		Avg CO_2 Capacity (MMt)[2]	Max CO_2 Capacity (MMt)[2]
					Coal Rank	Pilot Region		
Cañon City	Cañon City	Laramie	Sub	1,703	446.8	446.8	446.8	446.8
Craig	Sand Wash	Fort Union	HV	4,545	468.6	10,032.7	1,672.1	4,485.0
			HVA	3,828	1,159.3			
		Williams Fork	HV	2,863	1,565.7			
			HVA	5,453	4,485.0			
		Iles	HV	3,839	594.2			
			HVA	6,134	1,760.0			
Denver	Denver	Laramie	Sub	1,703	546.0	546.0	546.0	546.0
Ignacio	San Juan	Fruitland	HV	2,246	110.5	2,548.1	637.0	1,287.3
			HVA	2,676	1,287.3			
			MV	2,845	663.4			
		Menefee	HVA	5,495	486.9			
Palisade	Piceance	Cameo-Fairfield Coal Group	HV	3,090	121.8	1,631.3	543.8	995.4
			HVA	3,777	514.1			
			MV	4,057	995.4			
Rangely	Piceance	Cameo-Fairfield Coal Group	HVA	3,777	514.1	940.7	313.6	514.1
			MV	4,057	426.6			
Trinidad	Raton	Raton - Vermejo	HV	2,339	53.8	674.4	337.2	620.6
			MV	1,767	620.6			
TOTALS				**1,991**	**16,820.0**	**16,820.0**	**885.3**	**8,895.2**

[1] Coal Rank: Sub-Bituminous (Sub); High-Volatile Bituminous (HV); High-Volatile A Bituminous (HVA); Medium-Volatile Bituminous (MV)
[2] MMt = Million Metric Tonnes

Table 13. CO_2 Sequestration Capacities for Deep Saline Aquifers in Colorado

Pilot Study Region	Basin	Formation	Average Depth (Feet)	Total CO_2 Capacity (MMt)[1]		Avg CO_2 Capacity (MMt)[1]	Max CO_2 Capacity (MMt)[1]
				Formation	Pilot Region		
Cañon City	Cañon City	Morrison	2,884	2,200	20,300	6,767	17,400
		Lyons	2,922	700			
		Fountain	3,068	17,400			
Craig	Sand Wash	Entrada	2,560	3,950	8,350	4,175	4,400
		Weber Sandstone	2,512	4,400			
Denver	Denver	Morrison	2,353	6,500	20,500	5,125	9,700
		Entrada-Dockum Ss	2,290	2,000			
		Lyons	3,106	2,300			
		Fountain	4,083	9,700			
Fort Morgan		Morrison	2,353	3,900	7,900	1,975	3,900
		Entrada-Dockum Ss	2,290	1,200			
		Lyons	3,106	1,400			
		Fountain	4,083	1,400			
Ignacio	San Juan	Mesaverde Group	2,866	1,800	14,270	2,378	5,900
		Dakota	2,700	700			
		Morrison	3,016	4,900			
		Entrada	2,737	200			
		Hermosa Group	3,866	5,900			
		Leadville Limestone	6,756	770			
Palisade	Piceance	Dakota	2,530	1,600	20,700	6,900	9,600
		Morrison	2,483	9,600			
		Weber Sandstone	3,008	9,500			
Rangely		Dakota	2,530	1,400	17,500	5,833	8,500
		Morrison	2,483	7,600			
		Weber Sandstone	3,008	8,500			
TOTALS			**3,024**	**109,520**	**109,520**	**4,381**	**59,400**

[1] MMt = Million Metric Tonnes

Table 14. Reservoir Properties for Deep Saline Aquifers in Colorado

Pilot Study Region	Formation	Minimum Depth to Top of Formation (ft)	Average Formation Thickness (ft)	Porosity (%)	Permeability (millidarcies)	Salinity (ppm)	Reservoir Temperature (^oF)	Reservoir Pressure (psig)	Reservoir Area (sq mi)	Potential Seal Formation
Denver	Morrison	2,353	250	15.7	31	2,300 - 96,000	199	3,156	5,400	Graneros
	Entrada-Dockum	2,290	60	15.7	31	4,800 - 18,000	199	3,039	5,445	Graneros
	Lyons	3,106	100	12	88	32,000	187	3,525	5,500	Lynkis
	Fountain	4,083	1,220	10 - 12	1 - 1.5	180,000	241	4,130	5,200	Sundance
Fort Morgan	Morrison	2,353	250	15.7	31	2,300 - 96,000	199	3,156	3,300	Graneros
	Entrada-Dockum	2,290	60	15.7	31	4,800 - 18,000	199	3,039	3,269	Graneros
	Lyons	3,106	100	12	88	32,000	187	3,525	3,300	Lynkis
	Fountain	4,083	1,220	10 - 12	1 - 1.5	180,000	241	4,130	757	Sundance
Palisade	Dakota	2,530	130	14	0 - 1,500	35,000	158	2,216	2,900	Mowry
	Morrison	2,483	680	16	21	2,300 - 96,000	156	2,360	3,200	Mowry
	Weber	3,008	880	12.5	10	109,000	152	4,311	2,700	Moenkopi
Rangely	Dakota	2,530	130	14	0 - 1,500	35,000	158	1,987	2,600	Mowry
	Morrison	2,483	680	16	21	2,300 - 96,000	156	2,204	2,600	Mowry
	Weber	3,008	880	12.5	10	109,000	152	2,919	2,600	Moenkopi
Ignacio	Mesaverde	2,866	560	11 - 13	0.02 - 0.5	26,000	116	2,286	755	Lewis
	Dakota	2,700	190	7.5	0.02 - 0.7	1,170 - 24,616	203	2,769	1,300	Mancos
	Morrison	3,016	660	13.5	10 - 20	0 - 4,000	195	2,750	1,400	Brushy Basin
	Entrada	2,737	150	22 - 26	150 - 450	>10,000	186	2,423	1,500	Wanakah
	Hermosa	3,866	1,880	8	10	76,000-149,000	178	3,475	1,600	Rico
	Leadville	6,756	180	8	10	72,000	159	3,996	1,600	Molas
Craig	Entrada	2,560	170	20	400	1,513 - 15,483	133	2,362	2,900	Curtis
	Weber	2,512	330	11	2	29,430	139	2,844	3,400	Moenkopi
Cañon City	Morrison	2,884	320	15.7	31	56,500	144	2,691	1,300	Graneros
	Lyons	2,922	240	4.4	0.9	6,293	123	2,644	1,600	Lynkis
	Fountain	3,068	3,460	16	2	22,000	102	3,984	1,600	Sundance

Table 15. CO_2 Sequestration Capacities for Silicate Rocks in Colorado

Pilot Study Region	Feedstock	Ore Available (MMt)[3]	Ore Demand/Year[4] (MMt)[3]	CO_2 Capacity at 100% Efficiency (MMt)[3]	CO_2 Capacity at 15-20% Efficiency[5] (MMt)[3]
Cañon City	Mafics[1]	32,078	302	7,757	1,164
	Basalt	1,610	634	248	28
	Alkalic Igneous[2]	28,043	406	5,053	758
Craig	Mafics[1]	55,235	247	13,444	2,017
	Basalt	1,323,421	484	219,347	24,676
Palisade	Basalt	8,869	20	1,470	165
TOTALS			**84**	**247,319**	**28,809**

[1] Primarily gabbro, also diabase, pyroxenite, diorite, and dunite

[2] Primarily syenite

[3] MMt = Million Metric Tonnes

[4] Ore required to sequester total 2003 CO_2 emissions

[5] Estimated potential assuming 15% efficiency for basalt, 20% efficiency for mafics, and accounting for CO_2 produced during mineralization

Table 16. CO_2 Sequestration Potential Utilizing Produced Waters as Cation Source for Mineral Carbonation

Rank	Pilot Study Region	Avg Annual Production (Mbbls)[1]	Avg Ca (mg/L)	Avg Mg (mg/L)	CO_2 Sequestration Potential[2] (metric tonnes)
1.	Rangely	80.2	979	199	13,689
2.	Ignacio	24.5	1,752	488	8,182
3.	Craig	22.2	246	41	910
4.	Denver	8.8	264	70	438
5.	Palisade	1.5	1,295	352	364
6.	Fort Morgan	14.0	36	13	106
				TOTAL	**23,689**

[1] Average annual production calculated using production from 1999 through 2003; Mbbls = Thousand Barrels.

[2] Theoretical potential assuming 100 percent efficiency.

New Mexico Geologic Sinks

The total carbon dioxide (CO_2) sequestration capacity of geologic sinks in New Mexico, excluding mineralization, is estimated to be in excess of 278,000 million metric tons (Table 17). This total sequestration capacity is so large that it requires knowledge of the output from the two largest power plants in New Mexico to be put in perspective. The San Juan and Four Corners power plants, located about 10 mi apart and about 15 mi west of Farmington, NM, released about 31 mmt of CO_2 into the atmosphere during 2001 (Allis et al., 2003). The 278,000 mmt of estimated sequestration capacity is equivalent to about 9,000 years of storage for 100% of the CO_2 released from those two power plants in 2001.

The total sequestration capacity is spread unequally across New Mexico in three basins and three sink types (Fig. 12). The San Juan Basin in northwest quarter of the state has about 65% of the estimated total; the Raton Basin in the northeast, has less than 1%; and the Permian Basin in the southeast, has about 35% of the total capacity. Oil and gas pools account for 3% of the total, coal-bed-methane sinks for about 4%; and deep saline aquifers for about 93%.

Oil and gas pools and coal-bed-methane sinks have approximately the same total capacity, but there are only two coal-bed-methane sinks in contrast to the 468 oil and gas pools. The average sequestration capacity for an oil and gas pool is 19 mmt, that for a coal-bed-methane sink is 5,500 mmt, and that of a deep saline aquifer is 36,897 mmt (Table 17).

However, averages do not tell the whole sequestration story. Oil and gas pools are much better characterized geologically than either of the other two sink types, although there is overlap among the sink types in that hydrocarbon production occurs in the same stratigraphic units that serve as both the coal–bed-methane and deep-saline-aquifer sinks. The Southwest Partnership's interactive database reflects this economic reality and contains much more geologic and engineering data on oil and gas pools.

In addition, saline aquifers and coal-bed-methane sinks tend to be basin size in area. Oil and gas pools are structure to trap size in area and are generally more than an order of magnitude smaller than a basin. Note, however, that the largest of the oil and gas pools has an estimated capacity of 867 mmt, more than 20 times the average capacity and equal to approximately 29 years of the annual CO_2 emissions from the two large San Juan Basin power plants in 2001 (Table 17).

Each of the three sink types will be discussed in detail in the sections of this report that follow. The information presented below is designed to give the interested user enough detail to be able to select particular sinks for further evaluation using the Southwest Partnership's interactive, online database. Many of the figures illustrating these sections came directly from the Partnership's database and were prepared by the Utah Automated Geolographic Reference Center (AGRC), the Partnership's database manager.

The three sink types will be discussed in descending order of geological characterization, beginning with oil and gas pools and finishing with deep saline aquifers. An in-depth discussion will be presented of the Southwest Partnership's San Juan Basin Enhanced Coal Bed Methane (ECBM) Pilot Test that was selected for Phase 2 work.

Oil and Gas Pools

The New Mexico Oil Conservation Division (OCD) uses the term "pool" in the same sense that the other states in the Partnership use the term "reservoir." A pool is single, discrete hydrocarbon accumulation within a single trap." Pools are areally continuous and can lie in vertical succession or side by side, or overlap laterally. The pool name has two parts: 1) a field name, usually a geographic location, and 2) a stratigraphic name based on the producing (reservoir) unit. An example of a pool is the Blanco Mesaverde. This pool of the Blanco Field produces hydrocarbons from the Upper Cretaceous Mesaverde Group. See Broadhead (1993a) for details.

The OCD assigns a unique number of three to five digits to each pool. For example, the Blanco Mesaverde pool has been assigned the number 72319; the stratigraphically higher pool, the Blanco Pictured Cliffs pool, has been assigned the number 72400. In the Southwest Partnership's database these pools have been assigned the unique codes of NM-072319 and NM-072400, respectively, so that the attributes in different databases or data tables can be assigned to the proper, legally defined pool.

Hydrocarbon production in New Mexico is reported by pool, not by field, providing an accurate record of the volume of hydrocarbons that have come from each reservoir. This fact is extremely important in estimating the sequestration capacity of a reservoir. If production statistics from two or more reservoirs in the same field were commingled, there would be no way to get an accurate estimate of how much came from each reservoir, nor how much carbon dioxide could be injected into a reservoir to replace the volume of produced hydrocarbons.

Of the more than 3,000 recognized hydrocarbon pools in New Mexico, only 468 are included in the Southwest Partnership's database because they had cumulative productions of more than 1 million barrels of oil (mmbo) and/or 10 billion cubic feet of gas (BCF). These 468 pools have an estimated sequestration capacity of almost 9 billion tons (Table 17). There are 66 pools (14% of the total) in the San Juan Basin that account for 2,742 mmt (31%) of the estimated sequestration capacity (Table 2) and 402 pools (86%) in the Permian Basin with 6,162 mmt (69%) of the estimated sequestration capacity (Table 3).

Figure 13 shows the areal distribution of the 468 largest pools by cumulative production in New Mexico. A circle whose diameter is proportional to the pool's sequestration capacity is shown at the centroid of each pool's area. Estimated capacities range from less than 1 mmt to more than 800 mmt. Most of the pools in both basins are in close proximity to the Cortez Pipeline, the major CO_2 pipeline that transports CO_2 from Colorado to west Texas for enhanced oil recovery projects. A few pools with small to mid-size capacities are closer to the Sheep Mountain Pipeline, which also transports CO_2 from Colorado to west Texas for enhanced oil recovery projects.

Table 17 indicates that the Permian Basin oil and gas pools possess more than twice the total estimated sequestration capacity of those in the San Juan Basin (6,162 mmt to 2,740 mmt), but have that capacity spread over six times as many pools (402 pools to 66 pools). As a result, the average sequestration capacity per pool in the San Juan Basin is about three times that in the Permian Basin (42 mmt to 15 mmt).

There is also a greater percentage of large capacity pools in the San Juan Basin. However, the largest pools, those with capacities greater than 400 mmt, are equally distributed between the two basins. Of the six pools in New Mexico with estimated sequestration capacities greater than 400 mmt, three are in the San Juan Basin–Blanco Mesaverde (867 mmt), Basin Fruitland Coal (739 mmt), and Basin Dakota (484 mmt)—and three are in the Permian Basin—Hobbs Grayburg–San Andres (533 mmt), Eunice Monument Grayburg–San Andres (484 mmt), and Vacuum Grayburg–San Andres (413 mmt). Although these large capacity pools could provide many more years of storage capacity than their smaller counterparts, the smaller pools could provide additional injection opportunities in the same injector well or leak-protection for a deeper target. In addition the smaller capacity pools may be attractive pilot sites.

The major assumptions made in calculating the CO_2 sequestration capacities for oil and gas pools (and that are built into the Partnership's interactive sequestration capacity calculator) are 1) that the storage capacity volume is created in the reservoir by the production of oil and gas and 2) that CO_2 at reservoir temperature and pressure will fill 100% of the volume originally occupied by the hydrocarbons. Minor amounts of CO_2 will also be dissolved completely in the oil and water remaining in the trap.

The San Juan Basin

The San Juan Basin is a 26,000 square mile, bowl-shaped depression primarily in northwest New Mexico, but also in southwest Colorado. This structural basin, formed during the early Tertiary Laramide Orogeny, contains more than 14,000 feet of sedimentary rocks ranging in age from Paleozoic to Recent. It is a major producer of gas in the United States, with cumulative production of more than 17 trillion cubic feet from 21,000+ wells. The first commercial oil well in New Mexico was drilled in the San Juan Basin near Farmington in 1922. Most of the hydrocarbon production is from fluvial, deltaic, and shallow-marine and near-shore rocks and coals associated with the Late Cretaceous Seaway. Hydrocarbons are also produced from carbonate buildups in the Pennsylvanian Paradox Formation. (See Allis et al. (2003) and Brister and Hoffman (2002) for recent summaries.)

For ease of comparison, the hydrocarbon pools in the San Juan Basin have been grouped into seven "plays" based on the stratigraphic unit that produces the hydrocarbons (Table 18). They have been arranged stratigraphically and numbered one through seven. Each has been given the prefix SJ on Table 2 and in the Partnership's database. These play numbers are similar to those assigned to the San Juan Basin Gas Plays by Whitehead (1993, p.118) in the Atlas of Major Rocky Mountain Gas Reservoirs. The Entrada Sandstone Play (SJ-6), an oil play, has been inserted into the original Atlas list to complete the plays in the San Juan Basin.

Table 20 is a simplified stratigraphic column of Pennsylvanian through Cretaceous rocks in the San Juan Basin showing where the seven plays fit relative to the overall stratigraphic framework. Fig.14 is a simplified cross section across the San Juan Basin.

The greatest oil and gas sequestration capacity in the San Juan Basin, and in New Mexico, lies within the rocks of the Mesaverde Group Play (SJ-3), where four pools have a total capacity of 889 mmt and an average capacity of 222 mmt (Table 18). This play contains the Blanco Mesaverde pool, which has the largest estimated sequestration capacity of any oil and gas sink in New Mexico. This pool will be discussed in detail below. The average depth for these Mesaverde Group pools is 3,788 ft, which puts them below the depth threshold of ~3,000 ft for supercritical CO_2 injection.

Seven hundred feet above the Mesaverde Group is another 339 mmt of total sequestration capacity in the Pictured Cliffs Formation (SJ-2), still below the supercritical depth-threshold. Above that, the Fruitland Formation (SJ-1) provides another 751 mmt of total capacity primarily in coals that are often above the depth threshold. The possibility of utilizing a single injector well that penetrates two or more horizons with high sequestration capacities at relatively shallow depths (less than 5,000 ft) is high in the San Juan Basin because of favorable geological conditions. This possibility can be investigated using the Partnership's interactive database.

The search engine in the Southwest Partnership's Database can be used to find pools that meet or exceed 50 key criteria; e.g. specified distance from power plants to the pool's centroid, thickness, porosity, cumulative production, estimated sequestration capacity, and depth. The following discussion illustrates the kind of data that can be found in the interactive database, using the Blanco Mesaverde pool as an example (Fig. 15). This pool was chosen because it has the largest estimated sequestration of any oil and gas sink in New Mexico and it extends into Colorado, where it is known as the Ignacio Blanco Mesaverde field, and, thus, involves two state-regulatory agencies.

Blanco Mesaverde Pool (NM-072319)

Advantages as a CO_2 sequestration target:

- Majority of production (>90%) is from the regressive Point Lookout Sandstone, a continuous marine sandstone reservoir.
- Several hundred feet of shale and coal seal the main reservoir.
- Cumulative production through Dec. 31, 2003 of more than 41million barrels of oil, 12 million barrels of water, and 10 trillion cubic feet of gas.
- Reservoir is at an average depth of more than 4,500 ft, well below the supercritical depth threshold.
- The discovery well was drilled in 1927. Since then, more than 2,400 wells have been drilled in the pool.
- Average reservoir is thickness is 140 ft; porosity range is 10–16%.
- Calculated storage capacity of CO_2 is more than 867 mmt.
- The Blanco Pictured Cliffs pool, which has produced 728 bcfg, is 1,700 feet above. If CO_2 were to leak out of the Mesaverde reservoirs, it could be trapped here (calculated storage capacity of about 113 mmt).
- The region is sparsely populated with few nearby population centers (e.g., Farmington, Bloomfield, and Aztec).
- Large areal extent (more than 1 million acres) means that sequestered CO_2 could be injected at wide spacing.

Issues needing further evaluation:

- The Pictured Cliffs pool (NM-072400), which is 1700 feet above, is near the depth cutoff for supercritical CO_2 (800 m = ~ 3,000 ft) and could possibility provide additional CO_2 storage from the same injector well.
- There will be regulatory issues related to pool's extension in two states.
- The pool is located on private, state, BLM, and tribal lands.
- The location, age, and status of every one of the 2,400+ wells in the pool need to be determined.

Figure 15 illustrates how some of the stored data on the Blanco Mesaverde pool can be visualized along with putting various aspects of that data into spatial context. Farmington, the largest city in the area, and Broomfield lie west of the pool's boundary. Aztec, on the other hand, lies just inside the western boundary of the pool. Surface ownership within the Blanco Mesaverde pool is a complex checkerboard of private, state, federal, and tribal lands. Negotiating the right of way for a CO_2 pipeline, for example, could involve many parties.

The centroid of the Blanco Mesaverde pool, which is the point location stored for the pool in the database, is shown with respect to its boundary to help put the capacity illustrations (Fig. 13) into perspective. The surface areas of the pools often overlap, creating possibilities for multiple targets from a single injector well. Pipeline distances for the Partnership's Integrated Assessment Model were measured from a power plant to the centroid of a pool. In some cases the power plant lies within the boundary of a pool; in other cases the power plant is closer to the edge of a pool than it is to the centroid, which is the case for the Blanco Mesaverde pool and either the San Juan or Four Corners power plants (Fig. 15). In either case, pipeline costs will be less than modeled.

Two other very large pools in the San Juan Basin are also appealing CO_2 sequestration targets: the Basin Dakota pool (NM-071599) with 484 mmt of estimated sequestration capacity, and the Basin Fruitland Coal (NM-071629) with 739 mmt of estimated sequestration capacity. Both pools cover almost the entire San Juan Basin, hence the field name, and are the result of OCD orders combining several smaller pools producing from either the Dakota Sandstone or the Fruitland Formation coals. The Dakota Sandstone is a more or less continuous near-shore marine sandstone body containing discrete traps; the Fruitland consists of a series of discontinuous, often vertically separated coal beds. The Southwest Partnership has chosen an Enhanced Coalbed Methane (ECBM) project in a Fruitland coal reservoir as one of the its three pilot tests for Phase 2. This project will be discussed in the section on coal-bed-methane sinks.

Data Sources

The following major sources of data were used to obtain the information on the San Juan Basin Oil and Gas pools in the Southwest Partnership's Database:

- The Four Corners Geological Society Oil and Gas Fields of the Four Corners Area (Fasset, J. E. (ed.), 1978a, 1978b, and 1983);
- The Atlas of Major Rocky Mountain Gas Reservoirs (Hjellming, C. A. (ed.), 1993);
- State of New Mexico, Energy, Minerals, and Natural Resources Department, Oil Conservation Division Orders;
- New Mexico Oil and Gas Engineering Committee, 2003, Annual report of the New Mexico Oil and Gas Engineering Committee: v. 1A , Southeast New Mexico and v. 2A, Northwest New Mexico; and
- The detailed well and pool data housed at the New Mexico Bureau of Geology and Mineral Resource's Petroleum Records Section in Socorro, NM.

The Permian Basin

The Permian Basin of southeastern New Mexico is part of a larger, petroleum basin that extends into west Texas (Figs. 16 and 17). The greater Permian Basin is the third largest petroleum-producing area in the United States, accounting for 17% of the total United States oil production in 2002 (Dutton et al., 2005). It is primarily an oil-producing region, as opposed to the San Juan Basin, which is primarily a gas–producing region. The Permian Basin produces primarily from Paleozoic carbonate rocks; the San Juan Basin produces primarily from Mesozoic clastic rocks and coal.

Dutton et al. (2004 and 2005)) developed a new oil-play portfolio of the Permian Basin as part of the U.S. Department of Energy's Preferred Upstream Management Practices Program (PUMP) that defines 32 oil plays, numbered from 101 to 132, from oldest to youngest producing reservoir. Seventeen of those plays contain pools in the New Mexico portion of the basin that met the production cutoffs (Table 19). Dutton et al.'s (2004) play numbers have been assigned the prefix "PB" on Table 19. Their Mississippian Platform Carbonate oil-play (108) was expanded to include the primarily gas prone Lower Pennsylvanian Atoka–Morrow sequence on Table 19 so as not to change the play-number sequence that was provided prior to publication by R. F. Broadhead, NMBGMR, (personal communication, 2004).

Table 19 shows these 17 New Mexico plays arranged numerically, with the oldest reservoirs on the bottom and the youngest on the top. The largest number of qualifying pools

(100) occurs in the Lower Pennsylvanian Atoka-Morrow gas play (PB-108). However, the greatest capacities occur higher in the section in three plays in the Upper Permian that include the San Andres-Grayburg and Artesia Platform Sandstone reservoirs (PB-124, 125, and 132). The San Andres-Grayburg plays include three of the top six largest sequestration capacity pools in New Mexico: Hobbs Grayburg-San Andres (533 mmt), Eunice Monument Grayburg-San Andres (484 mmt), and Vacuum Grayburg-San Andres (413 mmt).

Unlike the San Juan Basin plays (Table 18), which, when arranged numerically by play code, deepen progressively downward, the depths of the Permian Basin plays show no systematic trend. This depth-trend loss is because of a more complex structural geology in the older Permian Basin and because the Permian Basin is subdivided into several sub-basins or bathymetric elements, each with a different geologic history and stratigraphic sequence (Figs. 16 and 17).

The New Mexico portion of the Permian Basin has been divided into the Northwest Shelf and the Delaware Basin (Figs. 16 and 17). The Delaware Basin is one of the deepest basins in North America with more than 24,000 ft of sedimentary rocks. A thinner section extends northwest of the basin margin across the Northwest Shelf. Rocks dip southeast from the Northwest Shelf into the deeper Delaware Basin. The Permian Capitan Reef Trend separates the Northwest Shelf from the Delaware Basin (Fig. 17).

The PUMP play names and numbers were applied in stratigraphic order, beginning with the oldest producing reservoirs in the Delaware Basin, then proceeding to same age reservoirs the Northwest Shelf. If the producing units were the same in both sub-basins, they received the same Play Code (number); if not, they received different, but sequential numbers. Then it was back to the Delaware Basin for the next youngest reservoir, and so forth. Thus, the play code numbers jump back and forth by age and depth from one sub-basin to the other (Tables 21 and 22).

Dutton et al. (2005, p. 568–570) note that four of these play reservoirs in the Texas portion of the basin have been subjected to CO_2 flooding, essentially being used to sequester CO_2 while enhancing oil production. The four reservoirs that have been flooded in Texas are equivalent to: PB-132 (Artesia Platform Sandstone); PB-130 (Delaware Mountain Group Basinal Sandstone); and PB-125 and PB-125 (Upper San Andres and Grayburg Platform). The CO_2 pipelines shown crossing New Mexico are carrying CO_2 to west Texas fields for enhanced recovery, not to southeast New Mexico pools.

The Partnership's database contains the same kinds of information on Permian Basin pools that it does for San Juan Basin pools. Thus, searches for and analyses of Permian Basin pools will be similar to those of the Blanco Mesaverde pool from the San Juan Basin that were discussed above. In addition, the database also contains data on the West Pearl Queen pool (PB-132), that was the subject of a CO_2 pilot test (Zhang et al., 2003).

Data Sources

The following major sources of data were used to obtain the detailed information on the Permian Basin Oil and Gas pools in the Southwest Partnership's Database:

- Roswell Geological Society (1956, 1960, 1967, 1977, and 1988) Symposia of oil and gas fields of southeastern New Mexico;
- The Atlas of Major Rocky Mountain Gas Reservoirs (Hjellming, C. A. (ed.), 1993);
- State of New Mexico, Energy, Minerals, and Natural Resources Department, Oil Conservation Division Orders; and

- The detailed well and pool data housed at the New Mexico Bureau of Geology and Mineral Resource's Petroleum Records Section in Socorro, NM.

Natural CO_2 Accumulations

There are four fields in New Mexico that produce or have produced CO_2 from naturally occurring sources (Fig. 18). Two of these fields are abandoned; one is under development; and one supplies CO_2 to the Permian Basin for enhanced oil recovery. Two of the fields are in northeast New Mexico, one is in west-central New Mexico, and one is in western New Mexico on the Arizona border. All of the fields are located outside the major hydrocarbon-producing or coal-bearing basins.

The Bravo Dome Carbon Dioxide Gas Field (NM-096010 and NM-096387) is a naturally occurring CO_2 accumulation in Union and Harding County of northeast New Mexico. The field was discovered in 1916 by a petroleum exploration well that encountered CO_2 in the Permian Tubb Sandstone member of the Yeso Formation (see Table 21 for equivalent stratigraphic position in the Permian Basin) at a depth of 2,506 ft. The CO_2 is sealed in the Tubb sandstones by the stratigraphically higher Permian Cimarron anhydrite. The CO_2 is thought to be derived from a magmatic source in the mantle (Broadhead, 1993, p.7).

At Bravo Dome the Tubb sits on Precambrian basement, is up to 400 feet thick, and has an average porosity of 20%. It has produced more than 873 BCF of CO_2 from an average depth of 1,900 ft. Estimated reserves are in excess of 10 TCF. CO_2 from the field was used entirely for making dry ice and carbonation of soft drinks until the mid-1980s, when production was increased because of demand for CO_2 in enhanced oil recovery. The CO_2 is compressed into liquid form and fed into a pipeline that transports it to west Texas for enhanced oil recovery projects. See Broadhead (1993b) for details.

The two abandoned fields are the Des Moines CO_2 field in Union County and the Estancia CO_2 fields, Torrance County. The Des Moines field, discovered in 1935, was abandoned in 1966. The Estancia fields, discovered in 1928, were abandoned in 1942. Both fields were primarily involved in making dry ice.

The fourth accumulation, the Springerville-St. Johns CO_2 field, was discovered in 1959 and is presently under development. In 1998 by Ridgeway Arizona Oil Corporation leased 400,000 acres around Springerville, AZ, in connection with its CO_2 project. A small portion of the field is in Catron County, New Mexico. The gas-producing intervals are sealed by anhydrite and occur as discontinuous zones in the Permian Supai Formation, which sits on Precambrian granite. Drilling depths for Ridgeway's six New Mexico wells, which are shut-in, range from 2,540 ft to 3,211 ft. Rauzi (1999, p. 12) suggests a primarily juvenile source for the CO_2. This non-producing field could provide insight into the effects of CO_2 leakage into groundwater and the atmosphere from relatively shallow reservoirs. See Rauzi (1999) and Moore et al. (2005) for details. WESTCARB is considering the Springerville-St. Johns CO_2 field as a Phase 2 project.

Data Sources

The following major sources of data were used to obtain the information on the naturally occurring CO_2:

- Rauzi's (1999) open file report on the Springerville-St. Johns CO_2 field;
- Broadhead's (1993b) paper on carbon dioxide in northeast New Mexico; and
- Moore et al.'s (2005) paper on the consequences of the long-term presence of CO_2 in natural reservoirs.

Lesson Learned

The data used for this report took more than one person-year to compile, with most of the compilation effort focused on oil and gas pools. Data were entered into a Partnership modified GASIS (U.S. Department of Energy, 1999) database, which contained 321 datafields for each site. Not all of these datafields pertained to every pool.

The GASIS database was designed for gas, not oil, pools. Unfortunately, most of the information required to populate these 321 datafields turned out to be unimportant for the purposes of regional characterization of oil and gas pools for CO_2 sequestration. The Partnership selected the 50 most important datafields for its online, interactive database. Not every pool has a complete set of data because certain information was not available in the published literature.

However, the Partnership's oil and gas database, coupled with its GIS database, is the only publicly available, digital source of key information on the 468 largest producing oil and gas pools in New Mexico. (The same is undoubtedly true for the other states in the Partnership.) Otherwise, these data are scattered primarily in published (paper) reports of the Four Corners Geological Society, the Roswell Geological Society, and the American Association of Petroleum Geologists and in the Atlas of Major Rocky Mountain Gas Reservoirs. As such, the Partnership's complete databases could be invaluable resources for the oil and gas industry or for subsurface work associated with academic research.

The key lesson learned from Phase 1 is to design the database from the ground up for the problem at hand and not to rely on an already established model that can be made to work, but at a cost of decreased productivity.

<u>*Coalbed Methane Sinks*</u>

The total CO_2 sequestration capacity for coalbed methane sinks in New Mexico has been estimated by Reeves (2003) to be about 11 billion tonnes (Table 17), with about 95% of that capacity residing in the San Juan Basin and about 5%, in the Raton Basin (Fig. 19). The coalbed methane reservoirs are in the Upper Cretaceous Fruitland Formation in the San Juan Basin (Fig. 15) and in the Upper Cretaceous Vermejo Formation in the Raton Basin. Figure 19 shows all the coal-bearing areas of New Mexico; only the San Juan Basin and Raton Basin had sufficient methane content to warrant CO_2 capacity calculations.

The first CO_2-enhanced coalbed methane production occurred in the San Juan Basin in 1995. At Burlington Resources' Allison Unit near the New Mexico-Colorado border more than 100,000 tons of CO_2 were injected into the Upper Cretaceous Fruitland Formation over a three-year period to enhance production of coal-bed methane (Reeves, 2002). The CO_2 was injected by four injector wells and is now sequestered in the coal at depths in excess of 3,000 ft. Critical factors for sequestration include coal seam continuity, cleat permeability, coal shrinkage/swelling, gas adsorption/desorption, and seal integrity.

The San Juan Basin is one of the top ranked basins in the world for CO_2 coalbed sequestration because it has: 1) advantageous geology including coal beds with high methane contents; 2) abundant anthropogenic CO_2 from nearby power plants; 3) low capital and operating costs; 4) well developed natural gas and CO_2 pipeline systems; and 4) local companies with coal-bed methane (CBM) and enhanced coal-bed-methane (ECBM) expertise. Selection of a potential coal-bed methane CO_2 sequestration site in the San Juan Basin requires the more detailed reservoir studies of local operators than those that are available in the literature because: 1) the coal seams on a regional scale are discontinuous and 2) all coalbed methane production from the

Fruitland Formation in the San Juan Basin is now reported together, making it difficult to know how much methane has been produced from a single coalbed reservoir.

The Partnership's Phase I ranking of sequestration opportunities factored proximity to sources and/or pipeline infrastructure in addition to economic, safety, and risk mitigation potential. The result of the Phase I ranking process resulted in the selection of three geologic pilot tests within the Southwest Partnership that are located on the CO_2 pipeline infrastructure. One of those selections is an enhanced coalbed methane test with Burlington Resources as the operator in the San Juan Basin that will be discussed in detail in the next section.

San Juan Basin Enhanced Coal Bed Methane (ECBM) Pilot Test

The San Juan Basin ECBM/CO_2 sequestration field test site is located in San Juan County, New Mexico, in the heart of the San Juan Basin coalbed methane (CBM) fairway. This location is favorable for an ECBM/sequestration demonstration for several reasons. For example, the San Juan Basin has been assessed previously by Advanced Resources International (ARI) under the DOE-sponsored Coal-Seq project as one of the nation's top coal basins for sequestration (Reeves, 2003). The San Juan Basin has a potential storage capacity of 12 Gt of CO_2 (12% of the U.S. total), an ECBM potential of 16 TCF (10% of the U.S. total), and potential cost of storage at a predicted net profit of $4–8/ton of CO_2. The results of the Southwest Partnership's demonstration will be scalable directly to a large portion of the San Juan Basin.

The San Juan Basin is a mature CBM play, and thus much of the infrastructure and services required to implement large-scale sequestration are already in place (e.g., wellbores, gathering and distribution systems, and processing facilities). In addition, a well-established, reasonably priced service capability to maintain and expand that infrastructure exists. Finally, and perhaps most importantly, the infrastructure to deliver CO_2 to the region exists—the Cortez pipeline that delivers (natural) CO_2 from McElmo Dome to west Texas passes directly through the San Juan Basin (Fig. 20). If/when that pipeline begins transporting anthropogenic CO_2, the San Juan Basin will become a premier national sequestration site.

The coals in the San Juan Basin fairway area have exceptionally high permeabilities of 100s of millidarcies. Due to the tendency of coal to swell when in contact with CO_2, high initial coal-permeability is required to maintain high CO_2 injection rates over time. Maintaining high injectivity is an important requirement for large-scale, low-cost CO_2 sequestration in coal, and demonstrating this is an important DOE carbon sequestration program goal (as stated in DOE's 2004 Technology Roadmap and Program Plan). This demonstration represents an ideal opportunity to achieve that goal.

The San Juan Basin ECBM pilot site lies entirely on BLM land (Fig. 20), just west of the BLM's Simon Canyon Area of Critical Environmental Concern (ACEC). This 4,000 acre ACEC, which is managed for semi-primitive forms of recreation including fishing, hiking, and backpacking, was established in 1950 and is the oldest ACEC in New Mexico. The Partnership will be working closely with the BLM's Farmington Office to ensure that the entire project is done in an environmentally friendly manner and that all federal regulations concerning safety and environment are strictly followed. As part of a terrestrial sequestration pilot, we are proposing to desalinate produced water so that it can be used in nearby riparian areas within the ACEC.

The exact pilot site location is Section 33, T. 31 N., R. 8 W. in northeastern San Juan County, New Mexico (Fig. 20). The site will consist of four CBM producing wells drilled on 80-acre spacing and a CO_2 injector well to be drilled by Burlington Resources for the Partnership. The primary gas-producing horizons in this area are coal beds in the Upper Cretaceous Fruitland

Formation. The coals, which occur at depths of approximately 3,000 feet, are about 75 feet thick and are split among three seams over a 175-foot gross interval. This area of the fairway has undergone significant CBM production, and reservoir pressures at the test site are less than100 psi. Coal matrix shrinkage is significant at these low pressures, contributing to the high coal permeabilities that exist here. In addition, CO_2 injection pressures will be low, eliminating any potential CO_2 compression needs for the pilot project. The site is operated by Burlington Resources, San Juan Division, operator of more than 1,200 CBM wells in the San Juan Basin, more than any other company, and a pioneer in CO_2-ECBM technology. Burlington was the operator of the Allison Unit CO_2-ECBM pilot located in San Juan County, NM, north of the proposed test site near the New Mexico-Colorado border (Fig. 20). To date, the Allison Pilot is the largest and longest-running CO_2 injection project in coal for the purposes of ECBM. That project, analyzed by ARI as part of the DOE's Coal-Seq project (Reeves, 2002), has provided most of industry's experience and technical foundation regarding CO_2-ECBM. Burlington is the single most experienced and knowledgeable operator in the world regarding CO_2 injection in coal.

Data Source

The major data source for coal-bed-methane sinks is Scott's (2003) report on CO_2 sequestration and ECBM potential of U.S. coal beds.

Deep Saline Aquifers

The total maximum CO_2 sequestration capacity for the seven aquifers listed in Table 17 is conservatively estimated to be about 258,000 mmt, enough capacity to store more than 8,000 years of the annual 2001 CO_2 emissions from the San Juan and Four Corners power plants. The Cortez pipeline crosses all seven of the deep saline aquifers and the Sheep Mountain pipeline crosses the northeast portion of the San Andres aquifer, making access to these sinks cost effective should the pipelines ever transport anthropogenic CO_2 (Fig. 21).

In order to qualify as a deep saline aquifer, a saline-water-bearing rock-unit had to be at least 3,000 ft deep and have a total dissolved solids (tds) concentration of at least 10,000 ppm. Ground water with a salinity less than 10,000 ppm is protected by state law (W. J. Ford, OCD, personal communication, 2005).

Almost two-thirds of the 258 billion tons of sequestration capacity in deep saline aquifers in New Mexico is in the four deep saline aquifers in the San Juan Basin (Table 23 and Fig. 21). The remaining one-third is in the four aquifers in the Permian Basin. All seven of the formations produce hydrocarbons in New Mexico. This means that there is a considerable amount of well data available at least in the vicinity of the producing traps. In fact, well control was used to estimate the area within the 3,000 or 10,000 ft contour for each sink. All of the seven deep-saline-aquifer formations are important hydrocarbon-producers in New Mexico, setting up the possibility of CO_2 sequestration along with enhanced hydrocarbon recovery.

The capacity estimate for each sink is conservative estimate because it is based on a minimum thickness for the aquifer, a minimum area, and reservoir conditions at the top of the aquifer. Nonetheless, the total estimated sequestration capacity of saline aquifers in New Mexico dwarfs the combined total capacity for oil and gas pools and coal-bed-methane sinks by more than an order of magnitude, 258 to 20 billion tons (Table 17.)

Sequestration capacity was estimated using two methods: one assumed that the CO_2 would displace completely the saline water; the other, that the CO_2 would dissolve completely in the saline water. The first method relied on the Partnership's interactive capacity calculator to compute the density of carbon dioxide at reservoir pressure and temperature. The second method relied on the MIDCARB calculator to compute the solubility of CO_2 in the brine at reservoir pressure and temperature. The capacities shown on Table 1 are from the first method, which yielded the larger capacity estimates.

The total displacement estimate for saline aquifers in New Mexico is about an order of magnitude larger than that of the total solubility estimate, 258 to 26 billion metric tons (Table 23). Even so, the solubility estimate is about 40% larger than the combined total capacity for oil and gas pools and coalbed methane sinks, 26 to 20 billion metric tons. However, the oil and gas pools and coalbed methane sinks are much better characterized geologically than the deep saline aquifers. Much of the data used to characterize the deep saline aquifers comes from oil and gas wells.

The average thickness of the aquifer (Table 23) is the average thickness of the water-producing interval reported by the USGS in its Produced Waters Database, rather than the thickness of the potentially porous and permeable interval(s) in the formation. The area of each saline aquifer is that area within the 3,000 ft or 10,000 ft contour. Those contours were determined from the well data in the Produced Waters Database, supplemented by well picks from the literature.

Reservoir pressure and temperature for each aquifer were estimated for the top of each aquifer, either at the 3,000 ft or 10,000 ft depth. Hydrostatic pressure gradients were assumed for the both basins to estimate pressure. A geothermal gradient of 1.96 F°/100 ft was used to determine temperature in the San Juan Basin and a geothermal gradient of 1.00 F°/100 ft was used to determine temperature in the Permian Basin. These geothermal gradients were derived from data in the Partnership's database.

Reservoir pressures were estimated to be 1,410 psi at 3,000 ft and 4,665 psi at 10,000 ft. Reservoir temperatures were estimated to be 114° F at 3,000 ft in the San Juan Basin and 90°F and 160°F at 3,000 ft and 10,000 ft, respectively, in the Permian Basin. Porosity data are averages from the Partnership's oil and gas database. Salinity data are averages from the Produced Waters Database.

San Juan Basin

The four deep saline aquifers in the San Juan Basin have a maximum estimated CO_2 sequestration capacity of 168,454 mmt about two-thirds of the estimated deep-saline-aquifer capacity in New Mexico (Table 23 and Fig. 21). The Mesaverde, Dakota, and Entrada have estimated capacities between 40,000 and 70,000 mmt; the capacity of the Morrison is an order of magnitude less at approximately 6,000 mmt. All four formations produce hydrocarbons in the basin and all are Mesozoic in age. They will be discussed in descending stratigraphic order, youngest to oldest, beginning with the Mesaverde Group. The NE-SW cross section of the San Juan Basin (Fig. 14) highlights the basin's major aquifers in blue.

Two of the four aquifers shown in blue on Fig. 14, along with the Dakota Sandstone, are discussed below. Of the other two aquifers, the Gallup Sandstone is too restricted areally and the San Andres Limestone/Glorieta Sandstone lacks data. Stone et al. (1981, p 41) remark that "…Although there has been extensive drilling for petroleum in the San Juan Basin, most of these wells bottom in the Cretaceous section, and thus little is known of the deeper deposits of the area. The pre-Jurassic rocks are generally too deep to play a significant part in the energy-resource development or to be used extensively for water supply."

(1) The Upper Cretaceous Mesaverde Group has an estimated maximum sequestration capacity of 50,194 mmt. It consists of the following three formations listed in descending stratigraphic order: Cliff House Sandstone, Menefee Formation, and Point Lookout Sandstone. The Cliff House Sandstone forms the top (eastern) flank of the topographically prominent Hogback Monocline west of Farmington, but the Point Lookout Sandstone accounts for the majority of the hydrocarbon and water production and is the aquifer unit generally picked as "Mesaverde" on well logs.

The Point Lookout Sandstone is a coastal marine sandstone that ranges from 40 to 415 ft thick, has a maximum depth of 6,400 ft, and is not widely used as a source of potable water (Stone et al., 1983). The sand is sealed by shales and coals in the overlying Menefee Formation that can be a few hundred feet thick.

The estimated sequestration capacity for the Mesaverde was determined using a thickness of 319 ft, a depth of 3,000 ft, a pressure of 1410 psi, a temperature of 114°F, a porosity of 14%, and a salinity of 20,000 ppm (Table 23).

(2) The Upper Cretaceous Dakota Sandstone has an estimated maximum sequestration capacity of 43,837 mmt. It is generally a marine to marginally non-marine sandstone that ranges from 200 to 350 ft thick, has a maximum depth of 8,500 ft, and is not widely used as a source of water although there are a few scattered stock and domestic wells (Stone et al., 1983). The sand is sealed by shales in the overlying Mancos Shale that can be a several hundred feet thick.

The estimated sequestration capacity for the Dakota Sandstone was determined using a thickness of 82 ft, a depth of 3,000 ft, a pressure of 1410 psi, a temperature of 114°F, a porosity of 17%, and a salinity of 10,000 ppm (Table 23).

(3) The Upper Jurassic Morrison Formation has an estimated maximum sequestration capacity of 6,370 mmt, the smallest of the seven aquifers. It consists of a sequence of non-marine sandstones, mudstones, and minor limestone that ranges from 330 to 915 ft thick, has a maximum depth of 9,000 ft, and is a major source of ground water, including being the sole source of the public drinking water for Crownpoint and a major source for Gallup (Stone et al., 1983). The Morrison ground water has "some of the lowest specific conductances in the San Juan Basin…Values of less than 1,000 umhos [approximately equal to 1,000 ppm] occur in the Crownpoint-Church Rock area." (Stone et al., 1983, p.39-40) The Morrison Formation, as a result, may not meet the salinity requirement to be a viable CO_2 deep-saline-aquifer-sink.

The Morrison consists of the following four members in descending order: Bushy Basin Shale Member, Westwater Canyon Sandstone Member, Recapture Shale Member, and Salt Wash Sandstone Member. The Westwater Canyon Sandstone Member is the principal aquifer. Shales in the Bushy Basin Shale Member seal the unit.

The estimated sequestration capacity for the Morrison Formation was determined using a thickness of 28 ft, a depth of 3,000 ft, a pressure of 1410 psi, a temperature of 114°F, a porosity of 8%, and a salinity of 10,000 ppm (Table 23).

(4) The Upper Jurassic Entrada Sandstone is an aeolian unit that has an estimated maximum sequestration capacity of 68,052 mmt, the greatest capacity of any aquifer in New Mexico. It consists of three informal members (an upper sandstone, a middle siltstone, and a lower sandstone) that range from 175 to 600 ft thick, has a maximum depth of 9,310 ft, and is the source of domestic and stock water between Smith Lake and Mariano Lake, although generally Entrada water is not suitable for drinking Stone et al., 1983). The Entrada is sealed by the overlying Summerville Formation and Todilto Limestone, which contains evaporites.

The estimated sequestration capacity for the Entrada Sandstone was determined using a thickness of 131 ft, a depth of 3,000 ft, a pressure of 1410 psi, a temperature of 114°F, a porosity of 24%, and a salinity of 10,000 ppm (Table 23).

Permian Basin

The three deep saline aquifers in the Permian Basin have a total maximum estimated CO_2 sequestration capacity of 89,828 mmt (Table 23), about one-third of the estimated deep-saline-aquifer capacity in New Mexico. The San Andres Limestone, Glorieta Sandstone, and the Devonian have estimated capacities between 19,000 and 39,000 mmt with the estimated capacity increasing stratigraphically upward. All three formations produce hydrocarbons in the basin and all are Paleozoic in age. The average dissolved solids of these three aquifers are considerably greater than their younger counterparts in the San Juan Basin, increasing stratigraphically downward from 70,000 to 100,000 ppm. These aquifers will be discussed in descending stratigraphic order, youngest to oldest, beginning with the San Andres Limestone.

(1) The Upper Permian San Andres Limestone has an estimated maximum sequestration capacity of 38,676 mmt, the greatest estimated capacity of any aquifer in Permian Basin. The outcrop area of the San Andres extends for hundreds of square miles across eastern New Mexico, dominating the southeast quarter of the Geologic Map of New Mexico (Scholle, 2003).

Stratigraphic nomenclature problems make it difficult to pin down basic facts about the San Andres, such as its thickness and lithologies. In the older literature, the unit is referred to as the San Andres Formation and contains a sandstone member at its base that was later raised to formation status as the Glorieta Sandstone. Kelly (1971), using the older concept, measured sections that indicate that the thickness range of the (restricted) San Andres Limestone is 250 ft to more than 1,000 ft. He included three members in the San Andres Formation. The upper member includes dolomite and gypsum and is up to 700 ft thick. The middle member is dolomite and limestone and is up to 300 ft thick. The lower member includes limestone, dolomite, and sandstone (the Glorieta). The aquifer unit is probably in Kelley's middle member, which is sealed by gypsum in the upper member. Two facts about the San Andres are not in dispute: it is "…the major aquifer in the Roswell artesian basin and a major oil producer in the Northwest Shelf" (Johnson et al., 2003, p. 148).

The estimated sequestration capacity for the San Andres Limestone was determined using a thickness of 89 ft, a depth of 3,000 ft, a pressure of 1410 psi, a temperature of 90°F, a porosity of 9%, and a salinity of 70,000 ppm (Table 23).

2) The Upper Permian Glorieta Sandstone has an estimated maximum sequestration capacity of 32,094 mmt, the second greatest estimated capacity of the three aquifers in Permian Basin. It ranges in thickness from 100 to 220 ft (Kelly, 1971). The Glorieta Sandstone underlies the San Andres Limestone and is sealed by tight carbonate beds at the base of the San Andres.

The estimated sequestration capacity for the San Andres Limestone was determined using a thickness of 75 ft, a depth of 3,000 ft, a pressure of 1410 psi, a temperature of 90°F, a porosity of 12%, and a salinity of 80,000 ppm (Table 23).

3) The Devonian aquifer has an estimated maximum sequestration capacity of 19,059 mmt, the smallest estimated capacity of any aquifer in Permian Basin, and its deepest aquifer at 10,000 ft. The extreme depth of this aquifer may make it economically unfavorable, although it is a major salt-water disposal unit (W. J. Ford, OCD, personal communication, 2005).

Davidson (2003, p. 116) noted that the Silurian and Devonian formations are often impossible to separate or distinguish on geophysical logs. The use of the generic assignment "Devonian" in the Produced Water's Database is probably to the Lower Devonian Thirtyone

Formation, which often infills an erosion surface on the Silurian Wristen Group (Dutton et al., 2005). The Thirtyone Formation is a deepwater, cherty carbonate that can be up to 1,000 ft thick. The Devonian aquifer is sealed by mudstones in the overlying Woodford Shale, which is also Devonian in age.

The estimated sequestration capacity for the Devonian aquifer was determined using a thickness of 100 ft, a depth of 10,000 ft, a pressure of 4,665 psi, a temperature of 160°F, a porosity of 6%, and a salinity of 100,000 ppm (Table 23).

Data Sources

Publicly available information on deep saline aquifers in New Mexico is scattered in the geologic and hydrologic literature. The Texas Bureau of Economic Geology (BEG) compiled most of the data in the Southwest Partnership's database on the Morrison Formation of the San Juan Basin (Hovorka et al., 2003). Data for the other six deep saline aquifers came from a variety of sources:

- The USGS's Produced Waters database;
- Stone et al.'s (1983) study of the hydrogeology of the San Juan Basin;
- Davidson's (2003) study of the water quality in the Permian Basin of southeast New Mexico;
- Kelly's (1971) study of the geology of the Pecos Country; and
- Statistics compiled in the Partnership's oil and gas database.

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Table 17. Estimated CO_2 Sequestration Capacities for New Mexico's Geologic Sinks in Millions of Metric Tons (mmt)

New Mexico Basins	Sink Type: 468 Oil & Gas Pools	Sink Type: Two Coal Bed Methane Sinks	Sink Type: Seven Deep Saline Aquifers	Sink Type: Mineralization: Silicates	Sink Type: Mineralization: Produced Waters	TOTAL CAPACITY
San Juan	2,742	10,400	168,454	na	na	**181,596**
Permian	6,162	0	89,828	na	na	**95,990**
Raton	0	600	0	na	na	**600**
TOTAL CAPACITY	**8,904**	**11,000**	**258,282**	na	na	**278,186**
Average per sink type	19	5,500	36,897	na	na	580
Maximum capacity per sink type	867	10,400	68,052	na	na	na

Table 18. Estimated CO_2 Sequestration Capacities for San Juan Basin Oil and Gas Pools in millions of metric tons (mmt).

Play Code	Play Name	No. of Pools	Av. Depth (ft)	Total Capacity (mmt)	Av. Capacity (mmt)	Max. Capacity (mmt)
SJ- 1	Fruitland Fm.	8	1,912	751	94	739
SJ- 2	Pictured Cliffs Fm.	12	3,057	339	28	113
SJ- 3	Mesaverde Gp.	4	3,788	889	222	867
SJ- 4	Gallup, Tocito, and Mancos Fms.	29	4,896	174	6	33
SJ- 5	Dakota, Dakota-Morrison Fms.	7	4,930	541	77	484
SJ- 6	Entrada Sandstone	3	5,368	15	5	7
SJ- 7	Pennsylvanian Four Corners Platform	3	7,587	31	10	11
TOTALS		**66**	**4,505**	**2,740**	**42**	**322**

Table 19. Estimated CO_2 Sequestration Capacities for Permian Basin Oil and Gas Pools in millions of metric tons (mmt).

PB-110	NW Shelf Upper Pennsylvanian Carbonate	29	9,243	555	19	178
PB-109	NW Shelf Strawn Patch Reef	17	10,583	63	4	13
PB-108	Atoka-Morrow	100	11,382	381	4	18
PB-105	Wristen Buildups and Platform Carbonate	30	11,942	367	12	90
PB-104	Fusselman Shallow Carbonate	10	8,390	73	7	27
PB-103	Simpson Cratonic Sandstone	4	9,025	26	7	17
PB-102	Ellenberger Karst-Modified Restricted Ramp Carbonate	8	9,913	27	3	9
TOTALS		**402**	**7,874**	**6,162**	**15**	**113**

Table 20. Simplified stratigraphy for Pennsylvania through Cretaceous rocks in the San Juan Basin showing the distribution of hydrocarbon plays in the basin. (Modified from Whitehead, 1993.)

Age	Strata	Play code	Play name
Cretacous	Kirkland Shale		
	Fruitland Formation	SJ-1	Fruitland Fm.
	Pictured Cliffs Sandstone	SJ-2	Pictured Cliffs Fm.
	Lewis Shale		
	Mesaverde Group	SJ-3	Mesaverde Gp.
	Mancos Shale	SJ-4	Gallup, Tocito, and Mancos Fms.
	Crevasse Canyon Formation		
	Gallup Sandstone		
	Mancos Shale		
	Dakota Sandstone	SJ-5	Dakota, Dakota-Morrison Fms.
Jurassic	Morrison Formation		
	Bluff Sandstone		
	Summerville Shale		
	Todilto Limestone		
	Entrada Sandstone	SJ-6	Entrada Sandstone
Triassic	Chinle Group		
Permian	San Andres Limestone		
	Glorieta Sandstone		
Pennsylvanian	Paradox Formation	SJ-7	Pennsylvanian Four Corners Platform

Table 21. Simplified Stratigraphy for Ordovician through Triassic Rocks in the Permian Basin Showing the Distribution of Hydrocarbon Plays in the Northwest Shelf. (Modified from original provided by R F. Broadhead, NMBGMR, 2004.)

<table>
<tr><th colspan="2">Age</th><th colspan="2">Rock Unit</th><th>Play code</th><th>Play name</th></tr>
<tr><td colspan="2" rowspan="2">Triassic</td><td colspan="2">Chinle</td><td colspan="2" rowspan="2"></td></tr>
<tr><td colspan="2">Santa Rosa</td></tr>
<tr><td rowspan="9">Permian</td><td rowspan="4">Ochoan</td><td colspan="2">Dewey Lake</td><td colspan="2" rowspan="4"></td></tr>
<tr><td colspan="2">Rustler</td></tr>
<tr><td colspan="2">Salado</td></tr>
<tr><td colspan="2">Castile</td></tr>
<tr><td rowspan="2">Guadalupian</td><td rowspan="3">Delaware Mountain Group</td><td>Bell canyon</td><td rowspan="3">PB-130</td><td rowspan="3">Delaware Mountain Group Basinal Sandstone</td></tr>
<tr><td>Cherry Canyon</td></tr>
<tr><td>Guadalupian / Leonardian</td><td>Brushy canyon</td></tr>
<tr><td>Leonardian / Wolfcampian</td><td colspan="2">BoneSpring</td><td>PB-118</td><td>Bone Spring Basinal Sandstone and Carbonate</td></tr>
<tr><td>Wolfcampian</td><td colspan="2">Hueco("Wolfcamp")</td><td>PB-115</td><td>Wolfcamp/Leonard slope and basinal carbonate</td></tr>
<tr><td rowspan="5">Pennsylvanian</td><td>Virgilian</td><td colspan="2">Cisco</td><td colspan="2" rowspan="2"></td></tr>
<tr><td>Missourian</td><td colspan="2">Canyon</td></tr>
<tr><td>Des Moinesian</td><td colspan="2">Strawn</td><td colspan="2"></td></tr>
<tr><td>Atokan</td><td colspan="2">Atoka</td><td rowspan="2">PB-108</td><td rowspan="2">Atoka-Morrow</td></tr>
<tr><td>Morrowan</td><td colspan="2">Morrow</td></tr>
<tr><td rowspan="2">Miss.</td><td rowspan="2"></td><td colspan="2">Barnett</td><td colspan="2" rowspan="4"></td></tr>
<tr><td colspan="2">Undivided limestones</td></tr>
<tr><td rowspan="3">Dev.</td><td>Upper</td><td colspan="2">Woodford</td></tr>
<tr><td>Middle</td><td colspan="2"></td></tr>
<tr><td>Lower</td><td colspan="2">Thirtyone</td><td>PB-106</td><td>Devonian Thirtyone Deepwater Chert</td></tr>
<tr><td rowspan="3">Sil.</td><td>Upper</td><td colspan="2">Wristen</td><td>PB-105</td><td>Wristen Buildups and Platform Carbonate</td></tr>
<tr><td>Middle</td><td colspan="2"></td><td colspan="2"></td></tr>
<tr><td>Lower</td><td colspan="2" rowspan="2">Fusselman</td><td rowspan="2">PB-104</td><td rowspan="2">Fusselman Shallow Platform Carbonate</td></tr>
<tr><td rowspan="6">Ord.</td><td rowspan="3">Upper</td></tr>
<tr><td colspan="2">Montoya</td><td colspan="2"></td></tr>
<tr><td colspan="2" rowspan="2">Simpson</td><td rowspan="2">PB-103</td><td rowspan="2">Simpson Cratonic Sandstone</td></tr>
<tr><td>Middle</td></tr>
<tr><td rowspan="2">Lower</td><td colspan="2">Ellenburger</td><td>PB-102</td><td>Ellenburger Karst-Modified Restricted Ramp Carbonate</td></tr>
<tr><td colspan="2">Bliss</td><td colspan="2"></td></tr>
<tr><td colspan="2">Cambrian</td><td colspan="2"></td><td colspan="2"></td></tr>
<tr><td colspan="2">Precambrian</td><td colspan="2">Igneous, Metamorphic, Volcanics</td><td colspan="2"></td></tr>
</table>

Table 22. Simplified Stratigraphy for Ordovician through Triassic Rocks in the Permian Basin: Distribution of Hydrocarbon Plays in the Northwest Shelf. (after Broadhead, 2004.)

Age		Rock Unit		Play code	Play name
Triassic		Chinle			
		Santa Rosa			
Permian	Ochoan	Dewey Lake			
		Rustler			
		Salado			
	Guadalupian	Artesia Group	Tansil	PB-132	Artesia Platform Sandstone
			Yates		
			Seven Rivers		
			Queen		
			Grayburg	PB-125	Upper San Andres and Grayburg Platform-Central Basin Platform Trend
				PB-124	Upper San Andres and Grayburg Platform-Artesia Vaccum Trend
	Guadalupian / Leonardian	San Andres		PB-120	NW Shelf San Andres Platform Carbonate
	Leonardian	Glorieta		PB-117	Leonardian Restricted Platform Carbonate
		Yeso	Paddock		
			Bllnebry		
			Tubb		
			Drinkard		
	Leonardian / Wolfcampian	Abo		PB-116	Abo Platform Carbonate
	Wolfcampian	Hueco ("Wolfcamp")		PB-114	Wolfcamp Platform Carbonate
Pennsylvanian	Virgilian	Cisco		PB-110	Northwest Shelf Upper Pennsylvanian Carbonate
	Missourian	Canyon			
	Des Moinesian	Strawn		PB-109	Northwest Shelf Strawn Patch Reef
	Atokan	Atoka		PB-108	Atoka-Morrow
	Morrowan	Morrow			
Miss.		Undivided			
Dev.	Upper	Woodford			
	Middle				
	Lower	Thirtyone		PB-106	Devonian Thirtyone Deepwater Chert
Sil.	Upper	Wristen		PB-105	Wristen Buildups and Platform Carbonate
	Middle				
	Lower	Fusselman		PB-104	Fusselman Shallow Platform Carbonate
Ord.	Upper				
		Montoya			
		Simpson		PB-103	Simpson Cratonic Sandstone
	Middle				
	Lower	Ellenburger		PB-102	Ellenburger Karst-Modified Restricted Ramp Carbonate
		Bliss			
Cambrian					
Precambrian		Igneous, Metarmorphic, Volcanics			

Table 23. Estimated CO_2 Sequestration Capacity for New Mexico's Deep Saline Aquifers in Millions of Metric Tons (mmt)

Aquifer	Basin	Area (acres)	Thickness (ft)	Porosity	Salinity (TDS)	Solubility (mmt)	Displacement (mmt)
Mesaverde Formation	San Juan	2,463,660	319	0.14	20,000	6,089	50,194
Dakota Sandstone	San Juan	6,897,975	82	0.17	10,000	5,654	43,837
Morrison Formation	San Juan	6,237,580	28	0.08	20,000	773	6,370
Entrada Sandstone	San Juan	4,747,864	131	0.24	10,000	8,777	68,052
Subtotal						21,293	168,454
San Andres Formation	Permian	5,182,069	89	0.09	70,000	2,213	38,676
Glorieta Sandstone	Permian	3,813,896	75	0.12	80,000	1,809	32,094
Devonian strata	Permian	3,171,985	100	0.06	100,000	969	19,059
Subtotal						4,991	89,828
TOTAL						**26,283**	**258,282**

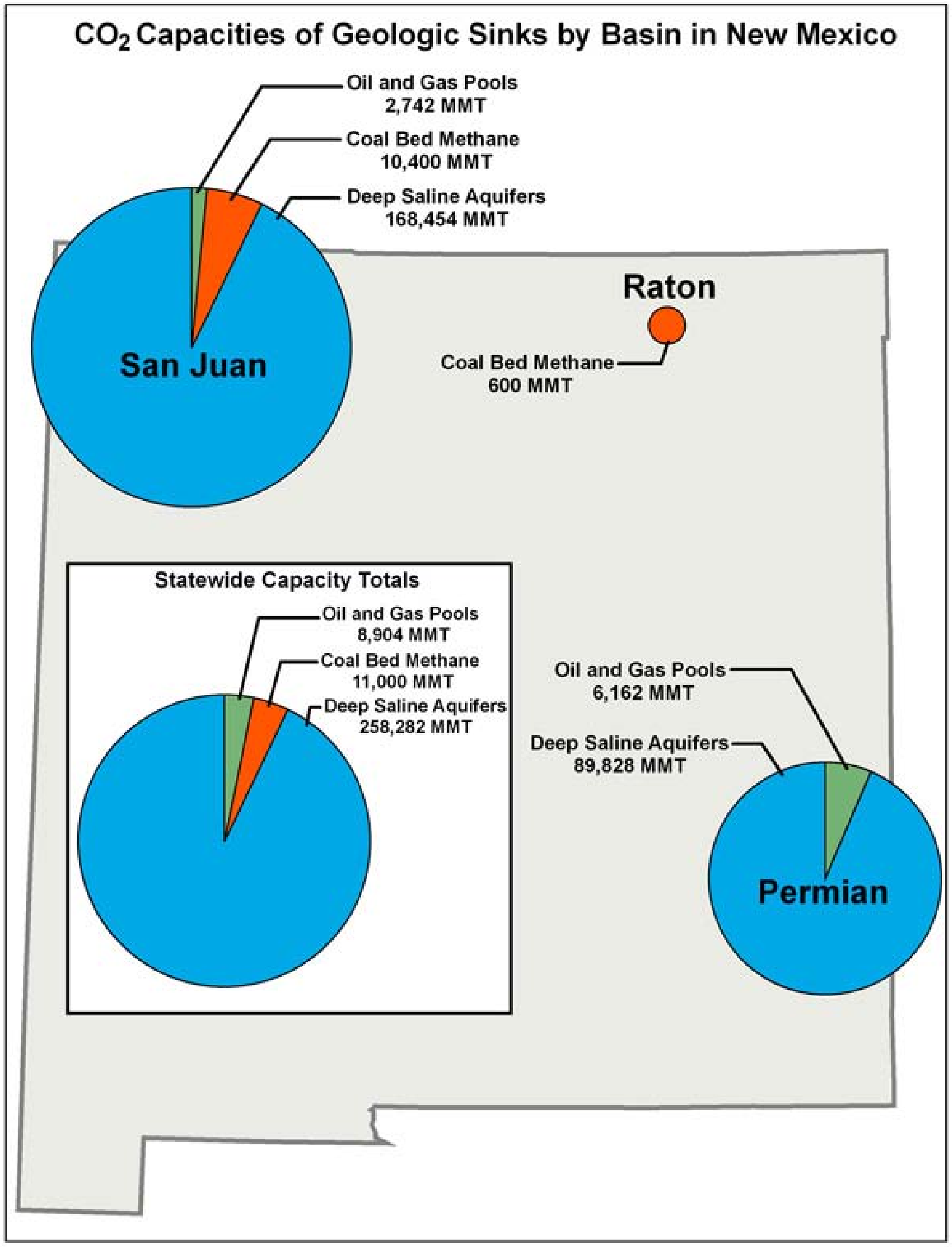

Fig. 12. Map of New Mexico summarizing the estimated CO_2 sequestration capacities of geologic sinks on a state-wide and basin-wide basis. Capacities are in millions of metric tons (mmt). Illustration provided by Utah AGRC.

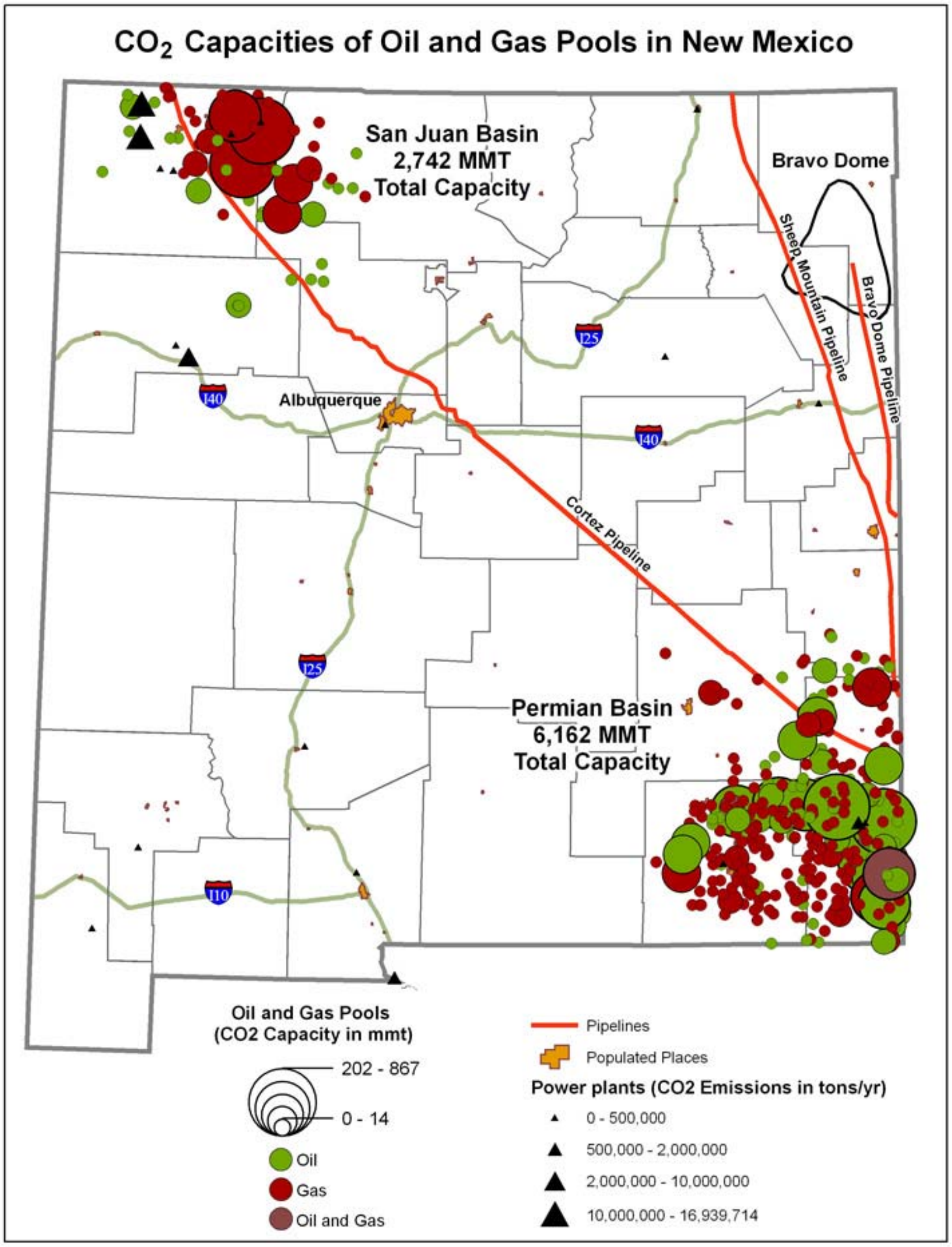

Fig. 13. Map of New Mexico showing the distribution and size of oil and gas sinks and summarizing the total estimated CO_2 sequestration capacity per basin. Capacities are in millions of metric tons (mmt). Illustration provided by Utah AGRC.

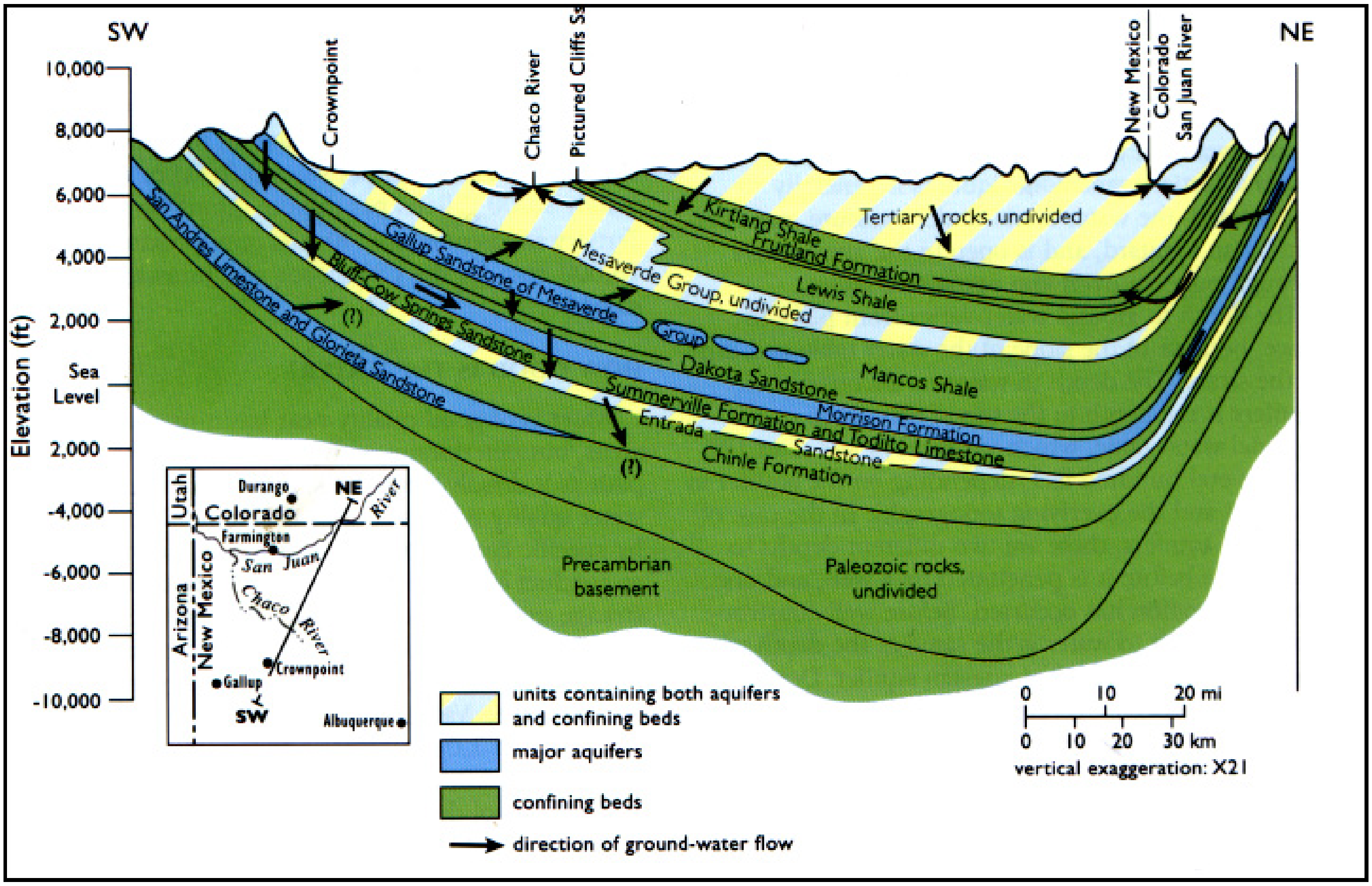

Fig. 14. Northeast-southwest schematic cross section of the San Juan Basin showing the major Mesozoic formations in the basin. (Figure from Stone, 2002.)

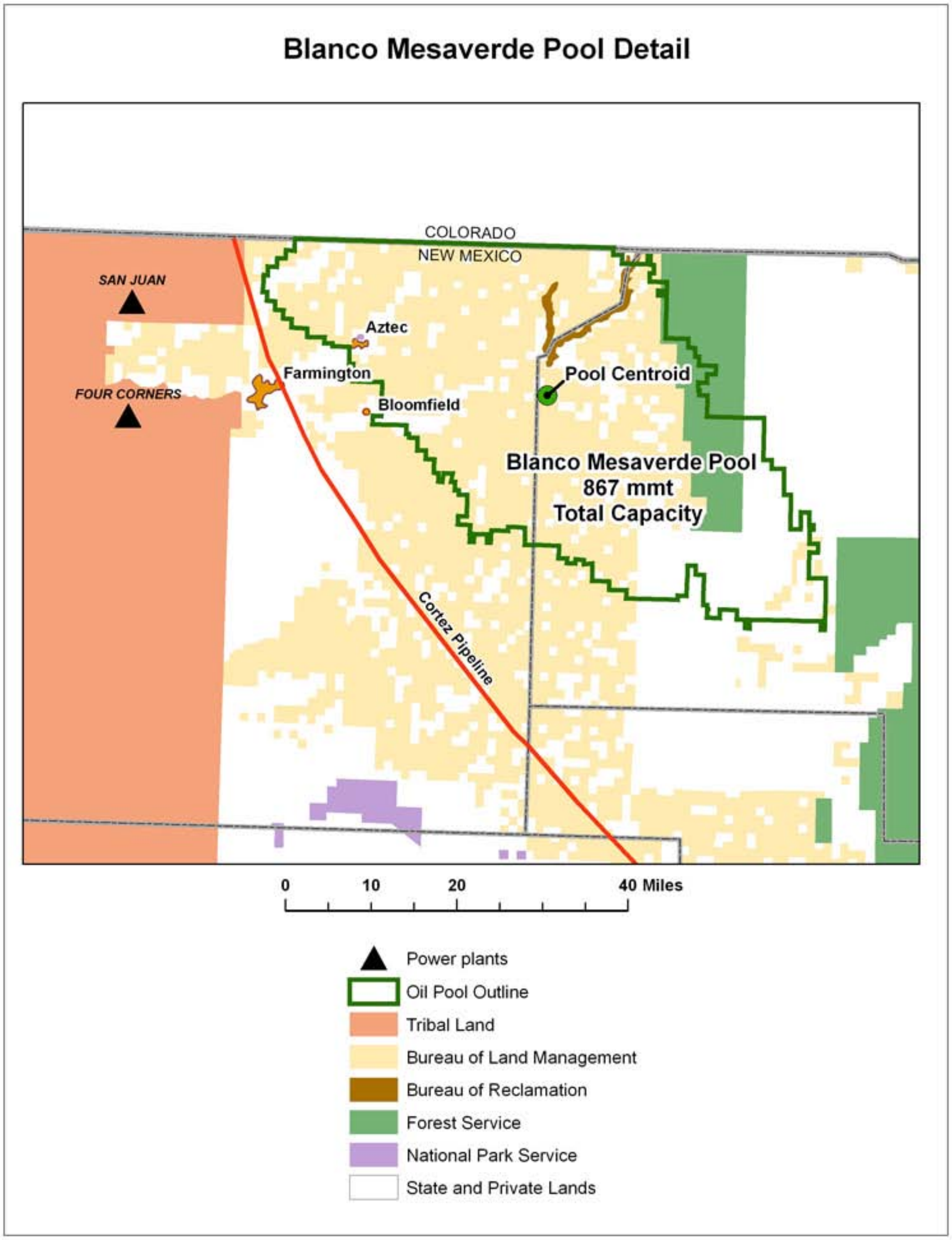

Fig. 15. Map of the northwest portion of the San Juan Basin showing the areal extent of and land ownership within the Blanco Mesaverde pool. Illustration provided by Utah AGRC.

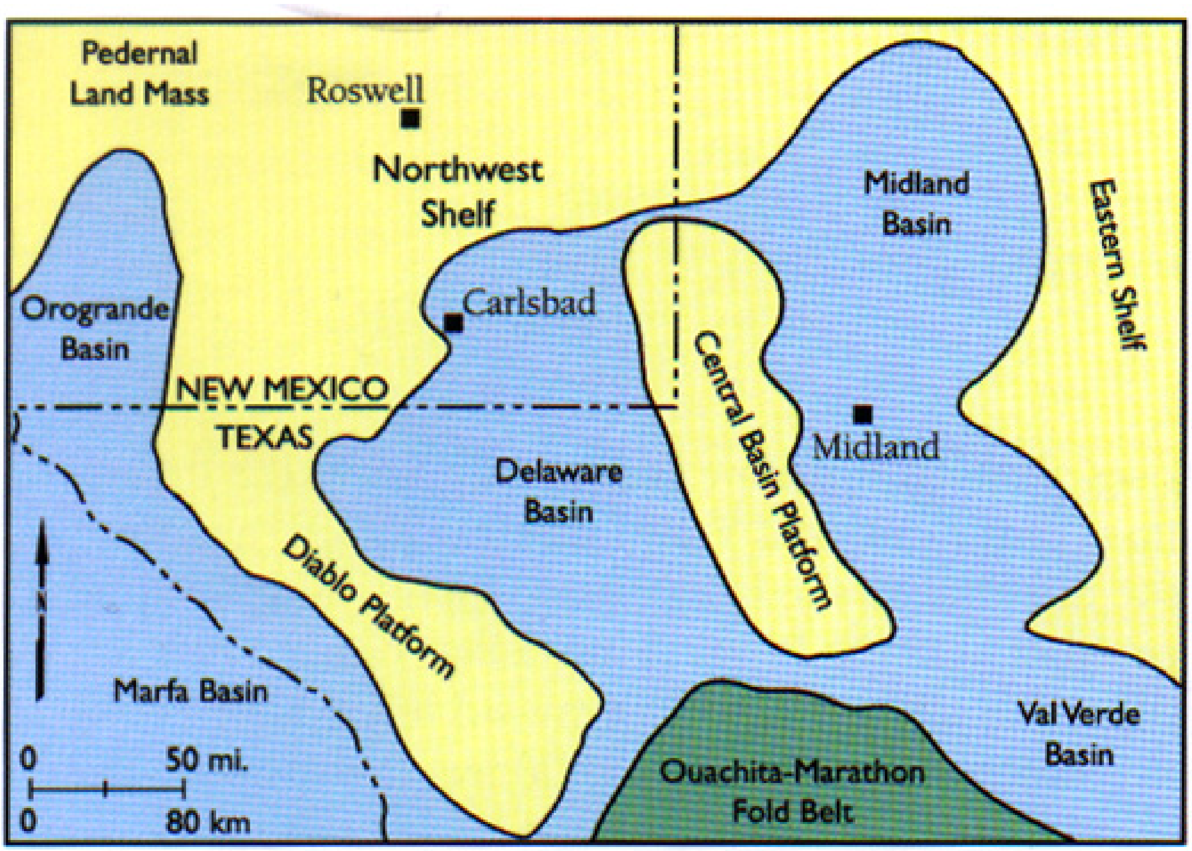

Fig. 16. Map of southeast New Mexico and adjacent west Texas showing the paleogeographic elements of the Permian Basin. (Figure from Land, 2003.)

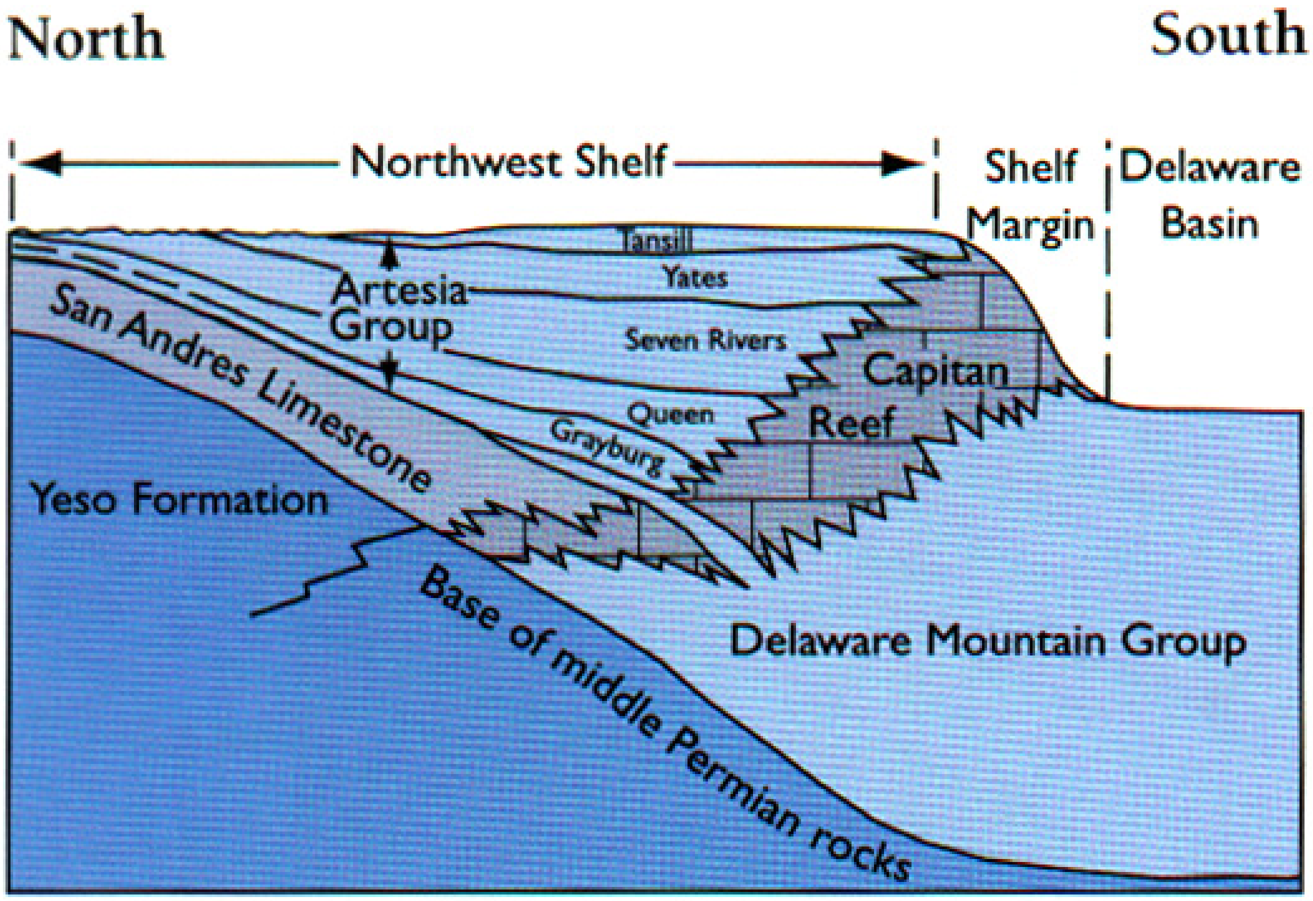

Fig. 17. North-south schematic cross section of the Permian Basin showing the relationship of middle Permian strata of the Delaware Basin to those of the Northwest shelf. The section extends roughly from Roswell, NM to Orla, TX. (Figure from Land, 2003.)

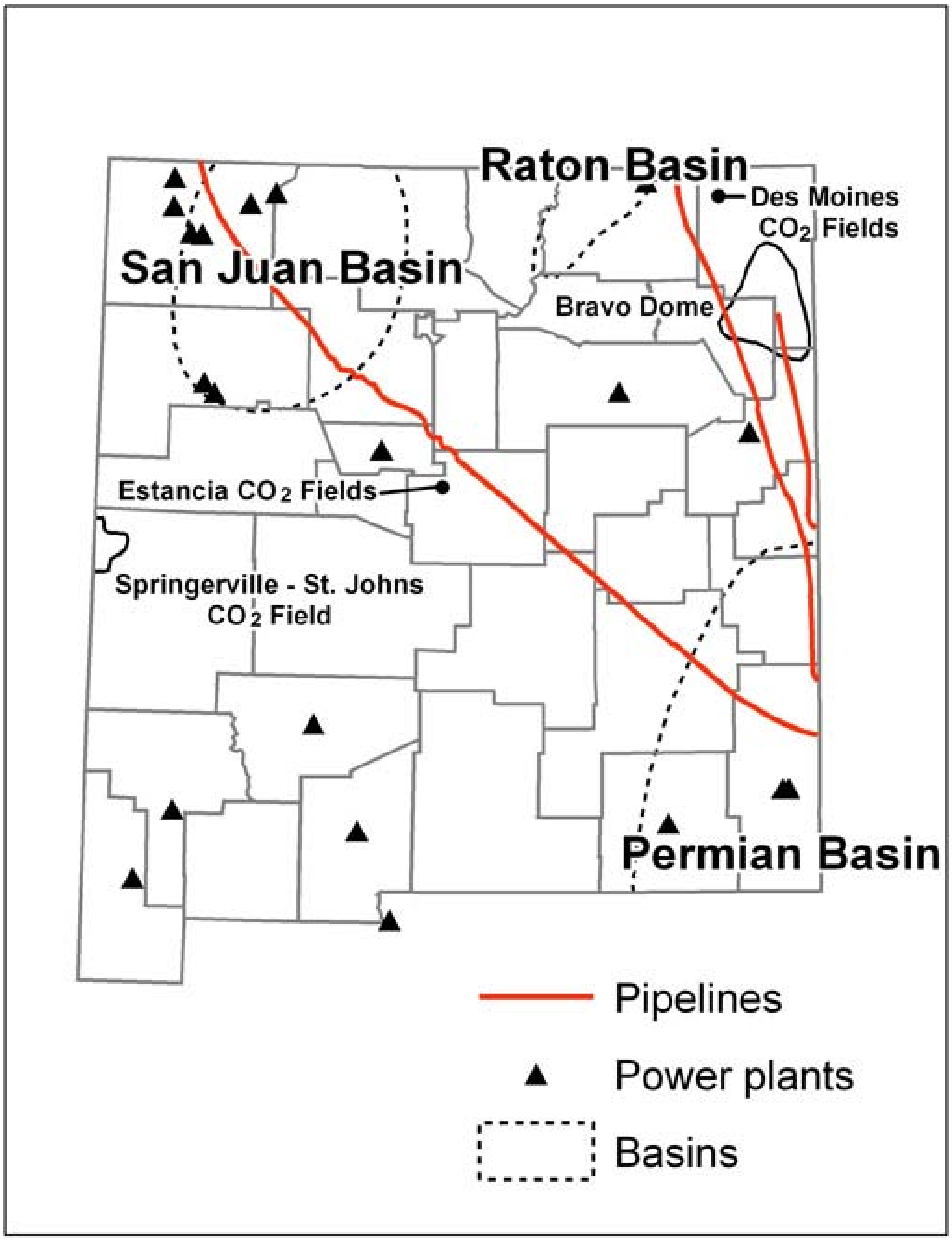

Fig. 18. Map of New Mexico showing the distribution of naturally occurring CO_2 fields. Illustration provided by Utah AGRC.

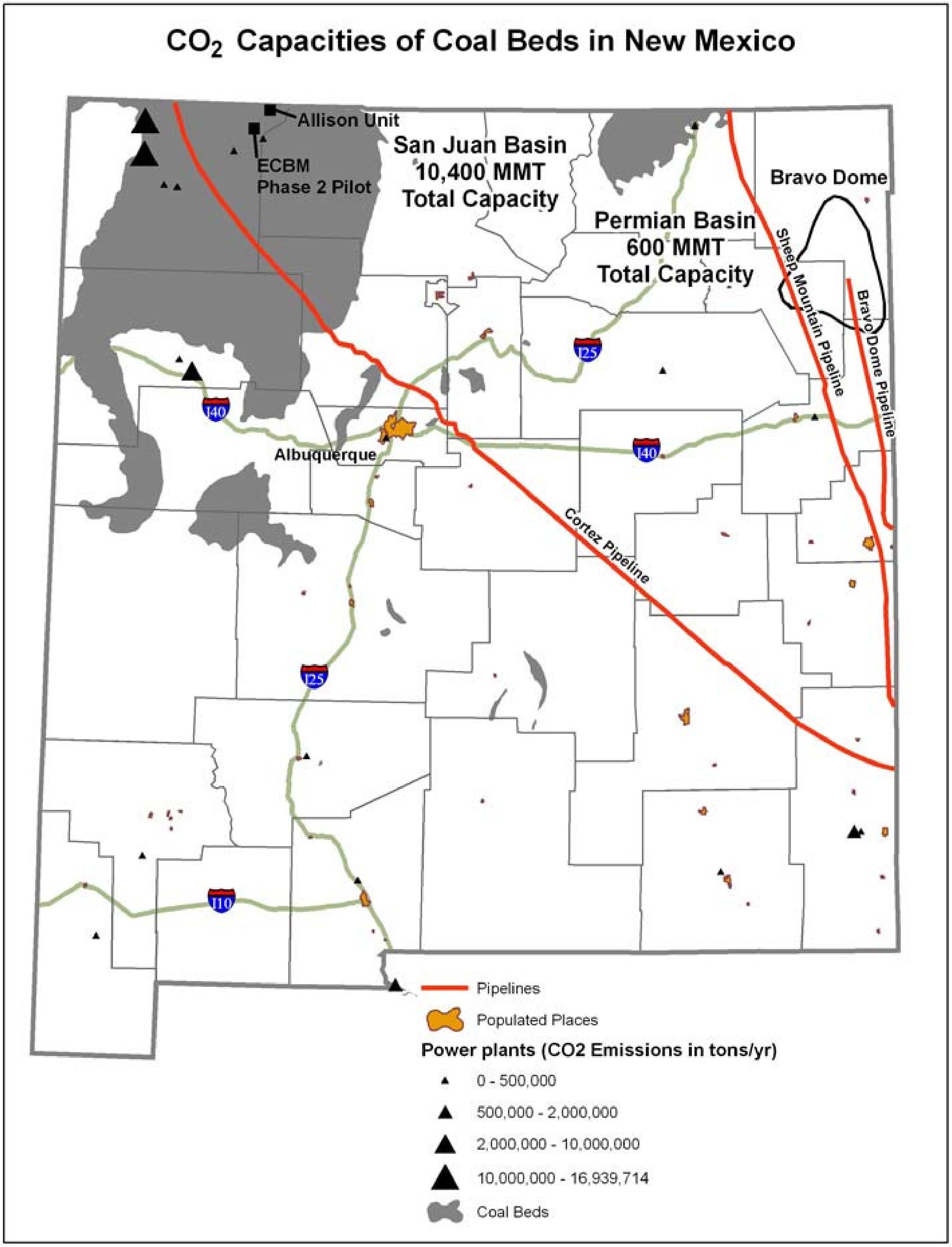

Fig. 19. Map of New Mexico showing the distribution of coal-bearing rocks and the estimated CO_2 sequestration capacity of the coal-bed-methane sinks in the San Juan and Raton Basins. Capacities are in millions of metric tons (mmt). Illustration provided by Utah AGRC.

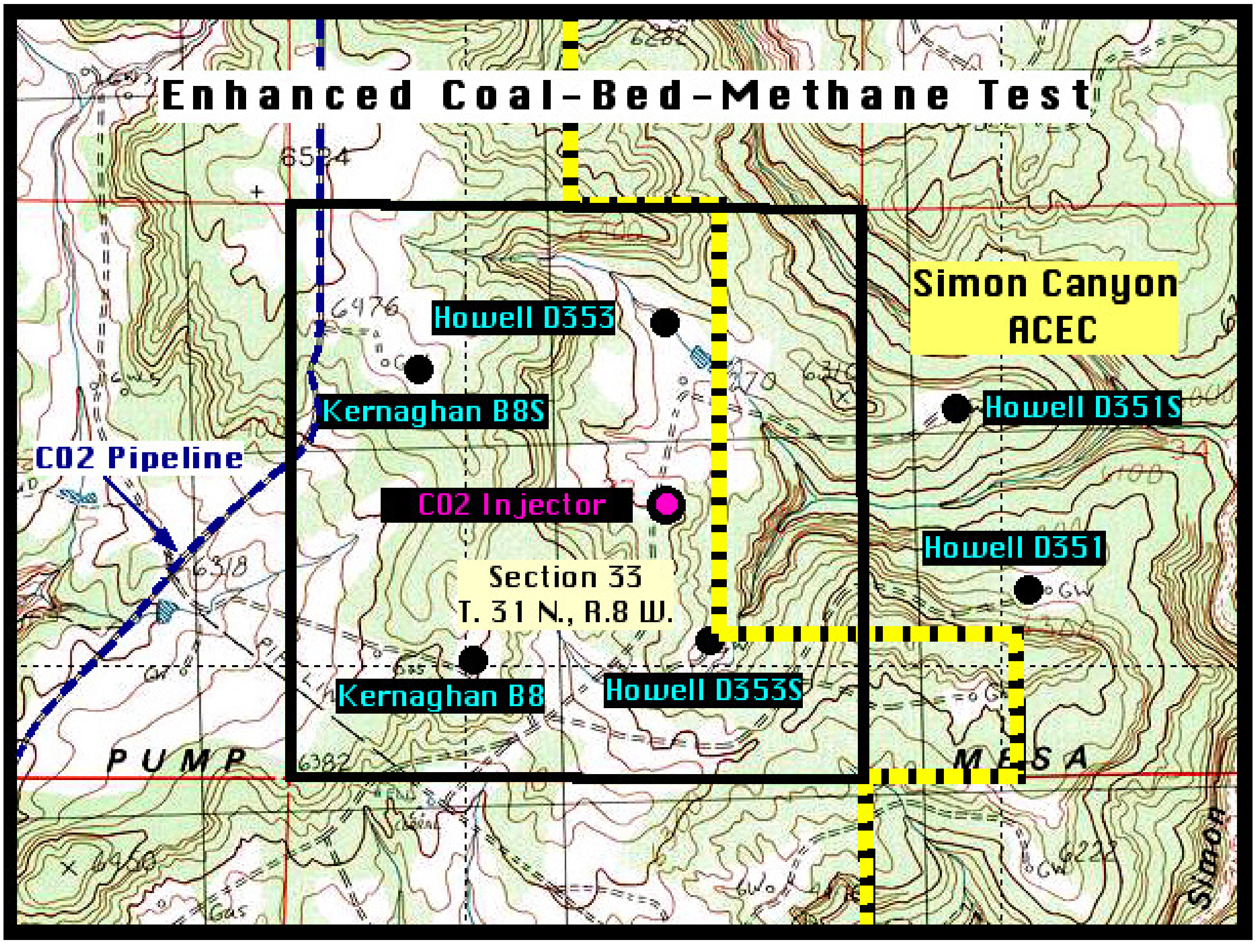

Fig. 20. Topographic map showing the locations of injector and monitoring wells in the area around the Southwest Partnership's Pump Canyon enhanced coal-bed-methane test. Each side of section 33 is one mile long.

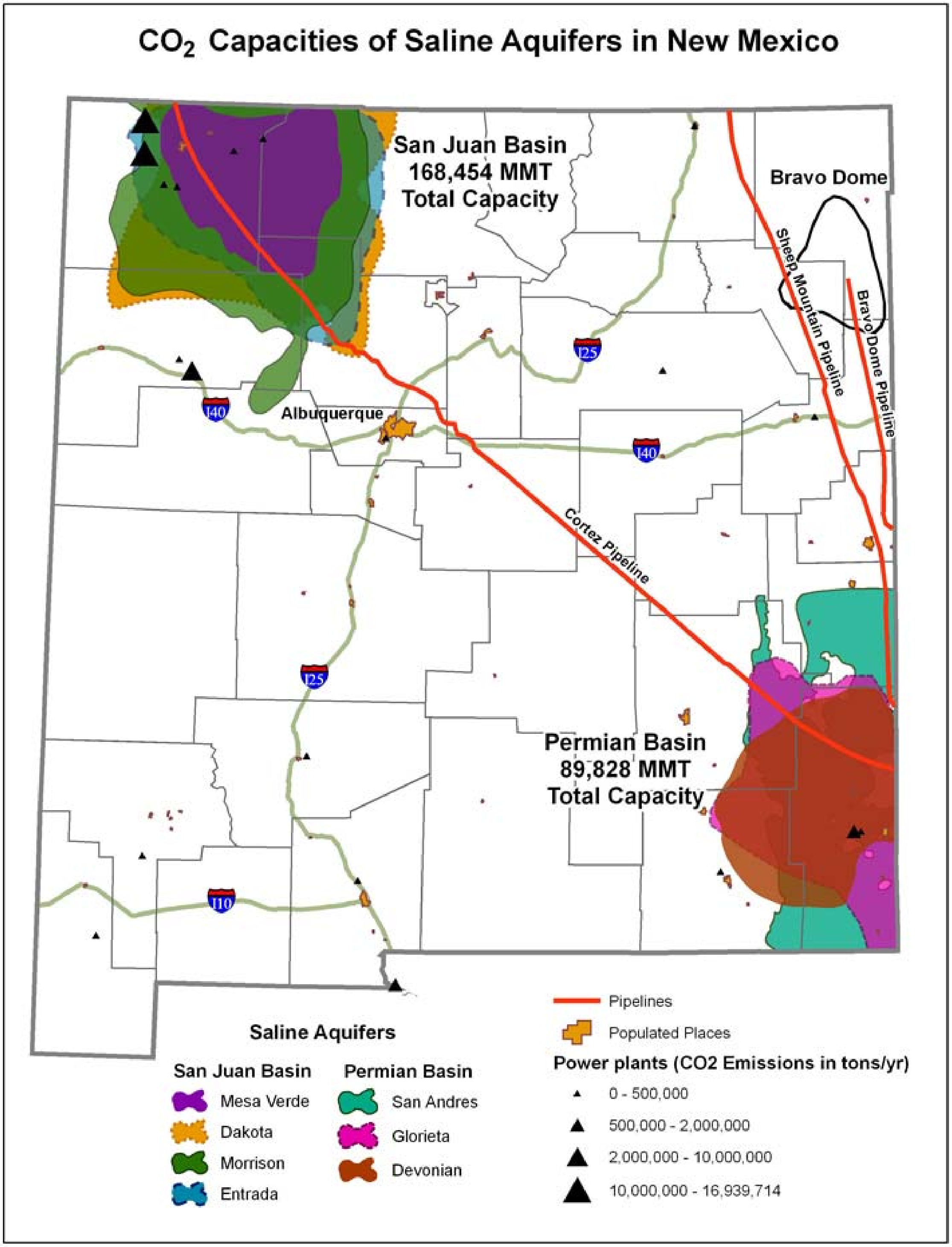

Fig. 21. Map of New Mexico showing the distribution of the seven potential saline aquifer sinks and a summary of the total estimated CO_2 sequestration capacities of saline aquifers by basin. Capacities are in millions of metric tons (mmt). Illustration provided by Utah AGRC.

Oklahoma Geologic Sinks

The total carbon dioxide (CO_2) sequestration capacity of geologic sinks in Oklahoma, excluding mineralization, is very conservatively estimated to be in excess of 340,000 million metric tons (340 gigatonnes or 340 Gt – see Table 24). Since the total CO_2 emissions from power plants in the State is approximately 47 million tonnes (year 2000 data from the EPA EGRID database), the capacity of the State is about 7200 years worth of storage. The Upper Cambrian/Lower Ordovician age Arbuckle formation is the most far-reaching saline aquifer in the State and is the bulk of the sequestrable capacity (roughly 97%) with one smaller saline formation and the oil and gas reservoirs in the State accounting for the remaining 3%. Oil and gas systems form the bulk of the effort by the Oklahoma contingent and account for some 9 Gt of capacity or 191 years worth of storage.

Because of the Arbuckle aquifer and due to the widespread oil and gas production throughout the State, the total sequestration capacity is spread relatively evenly across Oklahoma with the exception of the eastern portion of the state where the depths to formations that would be suitable for sequestration are too shallow or the formations of interest have little oil and gas productive capacity and are therefore more poorly characterized. For the eastern portions of the State, other relatively thin saline formations may be the only option for sequestration.

Oil and Gas Systems

The total sequestrable capacity overwhelms the amount of anthropogenic CO_2 emitted in the State as it does in other states in the Partnership, The difference between Oklahoma and the other Partnership states is that there are some 500,000 holes that have been drilled exploring for oil and gas. This number is an estimate based on the wells that have been reported to the Oklahoma Corporation Commission since regulation of oil and gas wells began in 1914 and estimates of the number of wells completed between 1897 and 1914. Approximately 85,000 wells are currently producing in the State (Boyd, 2002a). It is fairly safe to say that not all of the 500,000 holes have been properly abandoned and are potential leak points for sequestration. Fortunately, a large percentage of the unregulated wells are in the eastern portions of the State where sequestration options are limited. In addition, a significant portion of the sequestration capacity is likely to be uneconomic for sequestration because of the current natural gas prices and/or geologic considerations. Several of the largest capacity sites in the State are the major gas fields (fields with greater 1 Tcf production). These are the Guymon-Hugoton, Mocane-Laverne, Watonga-Chickasha Trend, Putnam, Kinta, Wilburton and Red Oak-Norris gas reservoirs which are still producing significant quantities of natural gas. The Guymon-Hugoton and Mocane-Laverne areas are part of a much larger sequence of gas reservoirs in the southeastern part of Kansas and panhandles of both Oklahoma and Texas that are known as the Guymon-Hugoton-Panhandle gas fields and are some of the largest accumulations of natural gas in the world. If current natural gas prices continue, these reservoirs are likely to be economic for a considerable length of time and are not likely to be true sequestration candidates despite their size and ability to trap light hydrocarbons.

The majority of oil produced in the State is in the central portion along a geologic trend (Fig. 22) called the Cherokee Platform or Shelf along what is called the Nemaha Uplift. Additional significant accumulations are adjacent to the Cherokee Platform in an area called the Northern Shelf (sometimes called the Anadarko Shelf) and in the shallow portions of the Anadarko Basin prior to the basin dropping off to more of a gas province. The Anadarko Basin runs roughly from just northwest of the city of Ardmore in a northwesterly direction towards the Texas Panhandle. There are three other smaller basins in the State. The Arkoma Basin is in the eastern part of the state running from near an area called the Arbuckle Mountain Uplift eastwardly to the Arkansas state line. The Marietta Basin and the Ardmore Basin are south of Ardmore and often get lumped into one designation, typically called the Ardmore Basin. The Marietta Basin includes the supergiant (fields that have produced in excess of 100 million barrels) Healdton and Hewitt fields while the Ardmore Basin includes the supergiant Eola-Robberson field. The Anadarko Shelf region includes the Oklahoma City, Sooner Trend, Edmond West, Crescent-Lovell, Ringwood and Postle supergiant fields. The remaining supergiants are on the Cherokee Platform and include the Tonkawa, Burbank, Cushing, Avant, Bartlesville-Dewey, Glenn Pool, Stroud, Earlsboro, Seminole, St. Louis, Bowlegs, Holdenville, Little River, Fitts and Allen fields.

The primary focus for the evaluation of sequestration capacity in Oklahoma was to obtain data related to the oil and gas formations in the State. Very little public digital data exists for wells and fields in Oklahoma. The GASIS and TORIS database systems available from the Department of Energy formed the starting point for much of the collection with the GASIS system providing data on 725 fields in the State and the TORIS system providing data on 72 fields. This data was supplemented by searching through reports and field descriptions from the United States Geological Survey, the Oklahoma Geological Survey, the International Oil Scouts, the National Oil Scouts and Landmen's Association and a variety of Master’s theses and PhD Dissertations in the University of Oklahoma library system. Production data in the State is reported to the Oklahoma Corporation Commission (OCC) and to the Oklahoma Tax commission by lease. On-line data by lease is available from the OCC from 1998 on and is also available commercially from IHS Energy and Oil/Law Records (which markets the Natural Resource Information System (NRIS) database). Both the IHS Energy and the NRIS system allow searching and aggregation on designations other than lease. Utilizing these data systems would require a license and a fee to be paid to either IHS Energy or to Oil/Law Records. One of the predecessor companies acquired by IHS Energy was Dwights EnergyData and the Youngblood Library at the University of Oklahoma has the annual production report published by Dwights for 1999. It was this report that was used for most of the production data in the Partnership database for Oklahoma.

Data was collected on more than 5,500 hydrocarbon pools in Oklahoma. These 5500 pools were then aggregated by a field designation which provided 700 that had cumulative production amounts greater than 1 million barrels of oil (mmbo) and/or 10 billion cubic feet of gas (BCF). The number is further limited to pools that were at depths greater than 3000 feet. Taking the 3000 foot depth limitation into account reduced the number of fields to 590 which were included in the sequestration capacity calculation. These 590 fields have an estimated sequestration capacity of approximately 9 Gt. The distribution of the capacity is fairly ubiquitous across the State with at least one field that meets the criteria in 74% of the counties in the State. Figure 23 shows the counties in the State, while Table 25 lists the counties which have more than 50 mmt of sequestration capacity. Limiting the depth to 3000 feet also excluded from consideration seven of the 26 supergiant oil fields in the state (Bartlesville-Dewey, Burbank, Cushing, Glenn Pool, Allen, Fitts and Avant fields).

Table 25 shows that two of the top three most prolific counties are in the panhandle region of the State. This is primarily due to the two huge gas fields – the Guymon-Hugoton (Texas County) and Mocane-Laverne fields (Beaver County). Texas County also includes the Postle field and Beaver County includes the Camrick field. These two fields have both been highly responsive CO_2 floods. Much of the remaining capacity for both counties is tied up in gas fields. Carter County has three supergiant oil fields (Sho-Vel-Tum, Healdton and Hewitt) and Seminole has four (Seminole, Bowlegs, Earlsboro and Holdenville) which explains part of why those two counties are listed second and fourth respectively. The Oklahoma City field dominates the capacity in Oklahoma County and Garvin County includes both the Golden Trend field and the Eola-Roberrson field.

From Table 25 you can also see that there are essentially five counties listed that are considered to be in the eastern part of the State. Osage and Creek Counties are at the edge of the Cherokee Platform. Osage County has several other potential large targets if the 3000 foot depth limit for supercritical CO_2 were not strictly adhered to. Two supergiant fields, Burbank and Cushing are excluded due to this restriction. The Burbank field probably should be included as the average depth for that field is 2931 feet while the Cushing field would be a stretch to include as the depth there is around 2600 feet. These areas may still be highly prospective targets for immiscible, subcritical CO_2 flooding, but that possibility was not investigated in this study.

Latimer, Haskell and Pittsburg Counties are the other eastern counties in this list. All three are on the list due to gas fields. Latimer County has the Wilburton and Red Oak-Norris gas fields, Haskell County is on the list almost exclusively due to the Kinta gas field and Pittsburg County is a gas region with a number of moderately large gas fields.

To develop the estimates for the oil and gas fields shown in Table 25, a temperature gradient of 1.2°F per 100 feet of depth with a 60°F surface condition was used. In addition, an estimate for the pressure in the reservoirs used a 0.4 psi/ft gradient. The oil formation volume factor was assumed to be a constant 1.2 reservoir volumes to stock tank volumes for all reservoirs. The CO_2 density varied with the calculated temperature and pressure and used a correlation developed for this project at New Mexico Tech.

The oil recovery factor was assumed to be a constant value of 25% for all reservoirs. Actual recovery factors are sparsely available. Many of the larger reservoirs in the State have undergone waterflooding and hence have somewhat higher recovery factors. This is offset by two things for the calculation of sequestration capacity. First, the Oklahoma database has no water production values. Consequently any additional sequestration capacity that might be attributable to water production has been neglected. Secondly, most of the larger reservoirs in the State were discovered prior to the establishment of solid reservoir engineering practices. Conservation of reservoir energy was not a practice in place during the discovery of the early fields and as a result, excessive gas flaring caused the depletion of reservoir pressure and the lost of production.

In addition, waterflooding many of the larger reservoirs began very early in the development of the waterflooding process. Many of the fields have fairly complex reservoir architecture and, flood efficiencies are generally poor.

The 25% recovery factor was felt to be a reasonable compromise to prevent the time-consuming effort of evaluating the recovery factor of individual reservoirs. The 25% value was also used by Advanced Resources International in their recent study on the evaluation of "stranded oil" in Oklahoma (Advanced Resources International, Inc.). Variations in the recovery factors were evaluated. Using a 20% value rather than the 25% resulted in an increase in the sequestration capacity of about 8% while a similar increase in recovery factor to 30% resulted in a decrease in the estimated capacity of just less than 6%. Increasing the estimated recovery factor to 50% (an unreasonably high value) still resulted in a sequestrable capacity of more than 7 Gt. A more significant change in the sequestration capacity in the State occurs when you exclude the large gas reservoirs. Eliminating the largest 14 gas fields (2.3% of the total number of fields in the data set) reduces the capacity by about 40% (from 9 Gt to 5.5 Gt).

Evaluating areas of the State where sequestration and enhanced oil recovery would be most prospective shows that there are several areas with high potential. The area around Carter and Stephens Counties in south-central Oklahoma where there is current CO_2 flood activity is dominated by the Sho-Vel-Tum, Healdton and Hewitt fields. But as the existing CO_2 flood in the West Velma field shows, fields with 10 to 20 mmstb production are highly prospective as well both for enhanced oil recovery and for sequestration potential. If Garvin County is included, then the Golden Trend and Eola-Robberson fields could be included and 6 other fields that have recovered between 10 and 30 mmstb would come into play as well. Many of these fields are currently undergoing waterflooding and would be viable candidates for carbon dioxide flooding. Expansion of the floods in the Sho-Vel-Tum and the Golden Trend fields would provide the highest potential for sequestration and may also be economically viable as these fields are still producing at reasonable rates. This area is currently served by a CO_2 line from an ammonium nitrate (fertilizer) plant in Enid, OK and any expansion of CO_2 utilization would require additional (likely) anthropogenic sources. Any expansion of this pipeline to other fields in the area will depend primarily on the delivered cost of the CO_2. Flow rates in most of the States oil fields are generally low so project economics are going to be dominated by delivered CO_2 costs either through pipeline costs or through transportation costs in addition to the capital costs associated with CO_2 recycle facilities. At the time of the writing of this report, it is believed that the ammonium nitrate plant has suspended operations. This plant depends on natural gas and shuts down when natural gas prices reach a certain level. Thus, the operators of the pipeline as well as the CO_2 floods are currently investigating other opportunities to develop more stable supplies of CO_2.

Another interesting area would be Seminole, Pottawatomie, Oklahoma and possibly Lincoln Counties in central Oklahoma. Oklahoma County is dominated by the Oklahoma City field but there are other smaller fields in the area that are candidates for CO_2 flooding. Flooding of the Oklahoma City field will likely be limited to the southern and eastern portions of the field to avoid significant population centers. The southern portion of the field is near the open area around the Will Rogers Oklahoma City International Airport which is currently an active waterflood and shifting to a CO_2 flood in that area probably would not be too difficult. The possibility of injecting CO_2 in the northern portions of the field would seem fairly remote as those are under more populated areas and the potential risks would be significantly higher.

Pottawatomie and Seminole Counties are characterized by having supergiant oil fields providing a smaller percentage of the sequestrable capacity than many other counties in the State. In Seminole County, Seminole, Earlsboro, Bowlegs and Holdenville fields account for about 63% of the capacity in the county, leaving 37% in 18 other oil fields and one 22 Bcf gas field. In Pottawatomie County, the supergiant St. Louis field accounts for around 66% of the capacity in the county. There are 30 other oil fields and one 98 Bcf gas field that accounts for the remaining 34%. Oklahoma, Seminole and Pottawatomie Counties are primarily oil provinces while Lincoln County has both oil and gas accumulations. The reservoir depths and the light oils in these areas would make high quality candidates for CO_2 floods. The large numbers of high quality potential sites make this an interesting area for development of an infrastructure for enhanced recovery with CO_2. Again, an anthropogenic source would be the most likely source for the CO_2.

Another prospective area is based mainly on proximity to the Oklahoma Gas and Electric Sooner Power Plant in Noble County. This area would be Noble, Garfield, Kingfisher and possibly Major, Payne and/or Logan Counties. Kingfisher County is dominated by the Sooner Trend set of fields and Major County includes the Ringwood supergiant field. Garfield, Noble, Payne and Logan Counties again have a fairly large number of modest sized fields. Situating enhanced oil recovery infrastructure close to the power plant would be conducive to both the existing power grid as well as being near the CO_2 pipeline and ammonium nitrate plant, as well as being near the Sooner, Ringwood and Oakdale fields.

Extending the pipeline running from Enid to the Sho-Vel-Tum field to some of the oil fields that are on the shelf of the Anadarko Basin would also appear to be prospective. A number of these fields have high cumulative recoveries with secondary recovery and would likely be solid candidates for CO_2 recovery and storage. These fields include the Cement and Apache fields. Establishing an anthropogenic CO_2 source to service all of these areas is necessary.

As previously mentioned, the Panhandle region has a number of possible targets that depend on how serious the nation gets at developing sequestration as a business. However, if these gas fields did become serious sequestration targets, then note that the Sheep Mountain pipeline that terminates at the Postle field runs basically right over the Guymon-Hugoton field. There would be a fairly short extension that could be built to get to the Mocane-Laverne Gas Area. In addition, the pipeline from Borger, TX to the Camrick field could also supply the Camrick gas area should that be an opportunity. Thus, a reasonable infrastructure exists in this area to allow access to these sites.

Data Sources

The following major sources of data were used to obtain the information for the Oklahoma Oil and Gas pools in the Southwest Partnership's Database:

- Boyd's Oklahoma Oil: Past, Present and Future, *Oklahoma Geology Notes*, v. 62, no. 3, Fall 2002
- Boyd's Oklahoma Natural Gas: Past, Present and Future, *Oklahoma Geology Notes*, v. 62, no. 4, Winter 2002
- Oil and Gas Fields of Oklahoma Volume-I, 1963;
- Anadarko Basin, Arkoma Basin Supplement 1 - 1974, Oil and Gas Fields of Oklahoma;
- Oil and Gas Fields of Oklahoma Supplement-II, 1980;
- Oil and Gas Fields of Oklahoma Volume-II, 1994;
- PI/Dwights Production Reports. Crude and Casinghead Quarterly – Annual Report through December, 1999;
- International Oil and Gas Development, Intern. Oil Scouts Assoc. Yearbook-1978;
- DOE GASIS database – modified version obtained from the Utah Geological Survey;
- National Petroleum Council Public Database (TORIS) – available from http://www.netl.doe.gov/technologies/oil-gas/Software/database.html;
- National Oil Scouts and Landmen's Association Yearbook 1946, and
- OGS Special Publication 1981 - Reservoir and Fluid Characteristics of Selected Oil Fields in Oklahoma.

Natural CO_2 Accumulations

There are no natural CO_2 accumulations in Oklahoma.

Coalbed Methane Sinks

Coal seams in the State are in the eastern third of the State and are both thin-bedded coal seams and shallow. There is currently active development of the coalbed methane in these coal seams. However due to their low net thickness and shallow depth to the coal seam, sequestration in Oklahoma coal seams was not considered in this study. Further evidence of lack of sequestration potential in Eastern Oklahoma coal seams is the fact that of the nearly 4000 wells completed in the coal seams in the State, approximately 100 of the wells have depths greater than the Partnership mandated 3000 feet (2.5%). The deepest coalbed methane well in the State is at 4400 feet. There has been a bit more exploration recently for deeper targets, but evaluation of the coal seams was deemed less important that the evaluation of oil and gas systems and saline aquifers.

Deep Saline Aquifers

The primary saline aquifer in the State is the Arbuckle group of formations that are carbonate sequences that reside just above basement rocks nearly everywhere in Oklahoma. The Arbuckle group is absent in the southeastern part of the State where the Ouachita Mountain Uplift pushes the basement rocks to the surface. The zone is also missing in the southwestern part of the State where the Wichita Mountain Uplift also pushes basement rocks to the surface. The Arbuckle on the southwest side of the Wichita Mountain Uplift is a groundwater source for Cotton and Tillman Counties. In the Arbuckle Mountain Uplift, the zone outcrops along the Arbuckle Anticline, the Tishomingo Anticline and the Hunton Anticline. Mineral springs around Davis and Sulphur have their origins in the Arbuckle formation. It is this area that has generated the most interest and study in the State on the Arbuckle formation as there are ongoing studies of the Arbuckle-Simpson Aquifer with support from the United States Geological Survey and the Oklahoma Water Resources Board.

To develop the estimate for the sequestrable capacity for the Arbuckle Formation, maps from the Texas Bureau of Economic Geology were utilized to find areas in Oklahoma where the formation was below 3000 feet (about 1000 m), well away from the formation outcrops. It was also assumed that where the formation drops in the Anadarko Basin, the porosity and permeability of the formation would be too tight to be of interest. These assumptions leave a region that roughly parallels the line on Fig. 22 for the northeastern edge of the Anadarko Basin slightly inside the basin and extending on to the Northern Shelf area. This area was estimated to be roughly 100 km by 275 km and had an average thickness of about 750 m. The area actually could have been opened up slightly to include more of the Cherokee Platform area and some of the deep Anadarko Basin may be prospective as well. However, to develop a conservative estimate of the capacity, these areas were excluded. Salt water disposal wells completed in the Arbuckle formation in the State have an average thickness of 572 feet based on data from the Oklahoma Corporation Commission (Daneshfar, 2006). Using an average 150,000 ppm salinity value, an average depth to the formation of 6562 feet (2000 m), an estimated temperature of the formation of 139°F, an average pressure of 2640 psi and an average porosity of 10%, the capacity of this area was calculated to be 344,277 mmt. The Arbuckle group projects north from the Oklahoma state line and runs almost completely throughout Kansas as well. The Kansas Geological Survey (KGS) has estimated the Kansas portion of the Arbuckle to have a capacity of 894,000 mmt. Thus, the value estimated for Oklahoma is within the order of magnitude of the value computed by KGS and is felt to be a very conservative estimate given the uncertainty in the data.

Other formations in the State also have potential for sequestration. Unfortunately, there are few public regional maps of the formations in question which makes estimating capacity almost impossible. Based on the data from the Oklahoma Corporation Commission (Table 26), the Arbuckle is certainly the largest disposal zone in the State. However, there are a number of other formations that are accepting significant amounts of salt water. The top 20 formations are shown in Table 26. Somewhat hidden in this table is that there again are few sites available in the eastern portions of Oklahoma and even fewer that would be suitable for sequestration. The depths to most of the saline formations are above the 3000 foot Partnership cutoff. Disposal sites that are below the cutoff include the Tonkawa and Osage in Lincoln County, the Cromwell and Booch zones in Hughes County, the Spiro formation in LeFlore County, the Cromwell, Hunton and Wilcox zones in Okfuskee County and the Arbuckle and Wilcox zones in Okmulgee County. Data from the Corporation Commission for disposal sites in the other counties are above the 3000 foot cutoff. Unfortunately, the eastern portion of Oklahoma is also home to most of the larger coal-fired power plants in the State.

In addition to the analysis of the Arbuckle, one additional area of interest was developed through this program. During the program an operator of four wells near Freedom, OK (Fig. 24) approached the Partnership to see whether there was interest in using the wells for a test site. The wells were originally drilled to extract iodine from the salt water. The wells are in a formation called the Woodward Trench which is a 1–2 mile wide by 70 mile incised valley fill of sand and shale of Pennsylvanian (Morrow) age. The channel is isolated from the surrounding (much tighter) Chester limestone with an approximate depth of 6,700 feet. The four wells have been cemented to surface and could likely receive EPA Class I status if tested, and it was proposed that they could be used to inject CO_2 into the trench. The wells have good porosity (published reports put the porosity values for the trench at approximately 14%) and permeability (published values are around 20-40 mD) in the zone of interest. Rates for both production and injection were in excess of 2000 barrels per day so reasonable rates of CO_2 injection should be expected. This site was withdrawn from consideration for a Phase II pilot by the operator about the time that proposals were being generated due to the high cost of CO_2 that would be necessary to obtain for the pilot. The operator sold to a consortium that is trying to redevelop the iodine extraction, but at least one of the consortium members is familiar with sequestration through some work he does with terrestrial sequestration at the US Department of Agriculture test sites near Woodward.

Assuming a 2 mile by 52.5 mile areal extent of the trench, a net thickness of the Morrow of 150 feet, a depth of 8000 feet, a pressure of 3735 psi, a temperature of 212°F, a porosity of 14% and a salinity of 16,000 ppm, this area has a sequestrable capacity of 1,022 mmt (nearly 22 years).

<u>Data Sources</u>

- Daneshfar, J., Oklahoma Corporation Commission, personal communication (2006)
- Johnson, K.S. and Gerber, W.R.: “Iodine Geology and Extraction in Northwestern Oklahoma”, Oklahoma Geological Survey Circular 102, 1999.
- Kansas Geological Survey Open-file Report 2003-33
- Kansas Geological Survey Midcarb Calculators, Solubility of CO2 and Volumetrics
- Texas Bureau of Economic Geology, Carbon Dioxide Disposal in Brine Formations, Arbuckle Group, Oklahoma

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Boyd, D.T.: "Oklahoma Natural Gas: Past, Present and Future", *Oklahoma Geology Notes*, Vol. 62, No. 4, Winter, 2002, pp. 143 – 155.

Cardott, B.J.: personal communication on Coalbed Methane activity in Oklahoma, 2005

Daneshfar, J.: personal communication on Oklahoma Corporation Commission UIC wells, 2006

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Oklahoma Water Resources Board (last accessed 04/15/2006): http://www.owrb.state.ok.us/studies/groundwater/arbuckle_simpson/arbuckle_study.php

Texas Bureau of Economic Geology, Carbon Dioxide Disposal in Brine Formations, Arbuckle Group, Oklahoma (last accessed 04/15/2006): http://www.beg.utexas.edu/environqlty/co2seq/0arbuckle.htm

Kansas Geological Survey Midcarb Calculators, Solubility of CO2 and Volumetrics (last accessed 04/15/2006): http://www.kgs.ku.edu/Magellan/Midcarb/aquifer.html

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Table 24. Estimated CO_2 Sequestration Capacity for Oklahoma's Geologic Sinks (mmt)

	Sink Type					
	590 Oil & Gas Fields	Coal Bed Methane Sinks	2 Deep Saline Aquifers	Mineralization: Silicates	Mineralization: Produced Waters	**TOTAL CAPACITY**
TOTAL CAPACITY	**9,035**	**na**	**331,568**	na	na	**340,603**
Average per sink type	15	na	165,784	na	na	710
Maximum capacity per sink type	1,294	na	330,546	na	na	na

Table 25. Sequestration Capacity by County

County	O&G Sequestrable Capacity (mm tonnes)	Number of Sites	Avg Capacity/site
Texas	1558	14	111.3
Carter	1013	18	56.3
Beaver	760	14	54.3
Seminole	531	23	23.1
Oklahoma	521	16	32.6
Garvin	457	19	24.0
Canadian	449	9	49.9
Latimer	325	5	65.0
Kingfisher	299	5	59.9
Roger Mills	227	10	22.7
Pottawatomie	212	32	6.6
Lincoln	206	31	6.7
Dewey	188	10	18.8
Haskell	182	2	90.8
Caddo	159	14	11.3
Major	153	8	19.1
Beckham	146	5	29.2
McClain	113	14	8.1
Custer	110	19	5.8
Kay	99	17	5.9
Garfield	95	10	9.5
Pittsburg	92	11	8.4
Cimarron	90	5	17.9
Grady	72	14	5.1
Logan	69	17	4.1
Noble	67	18	3.7
Osage	62	24	2.6
Cleveland	61	14	4.4
Creek	60	19	3.2
Woods	58	6	9.7
Woodward	56	10	5.6
Stephens	54	17	3.2
Grant	51	14	3.6

Table 26. UIC Disposal Data by Formation (data from Daneshfar, 2006)

Formation	2005 volume (stb)
Arbuckle	3078446
Brown Dolomite	2483167
Pennsylvanian	2270164
Cottage Grove	2049203
Mississississippian	1607474
Pontotoc	1547551
Wilcox	1356185
Booch	1314023
Tonkawa	1275647
Hunton	1237457
Wolfcamp	1013287
Cisco	996847
Layton	996274
Permian	900349
Simpson	855000
Hoover	846973
Endicott	754180
Hox bar	689000
Cromwell	500009
Hartshorne	497756

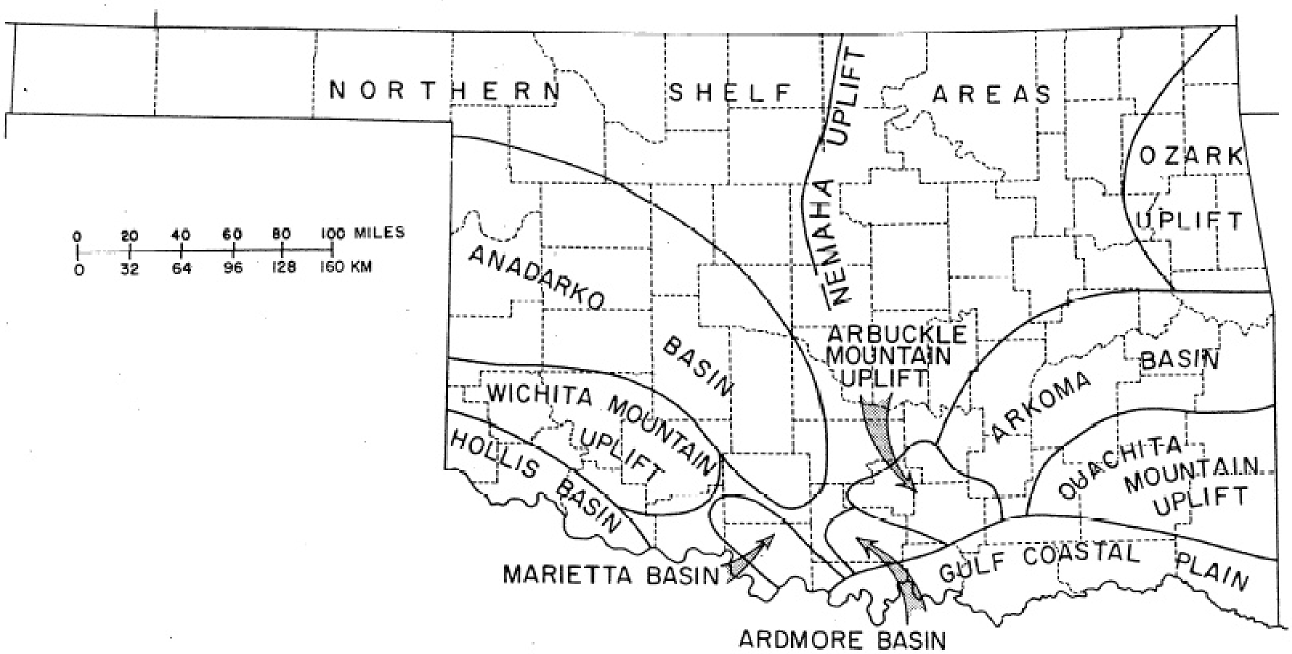

Fig. 22. Major geologic provinces of Oklahoma (from Johnson, 1999).

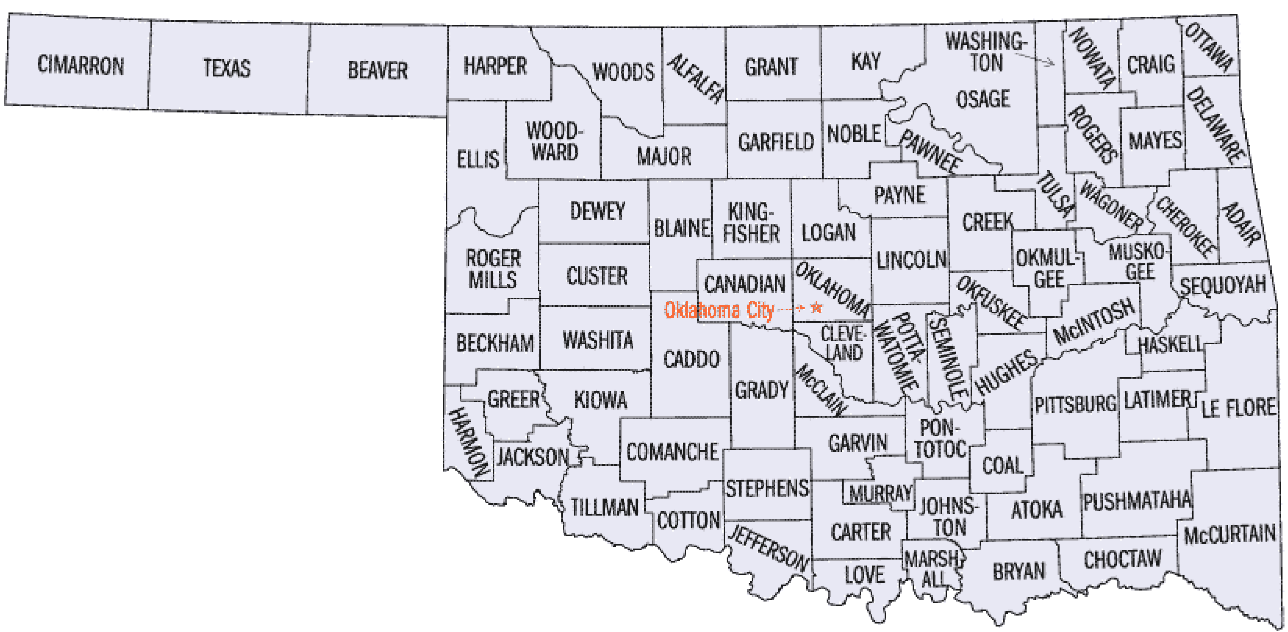

Fig. 23. Oklahoma Counties (from www.censusfinder.com/mapok.htm).

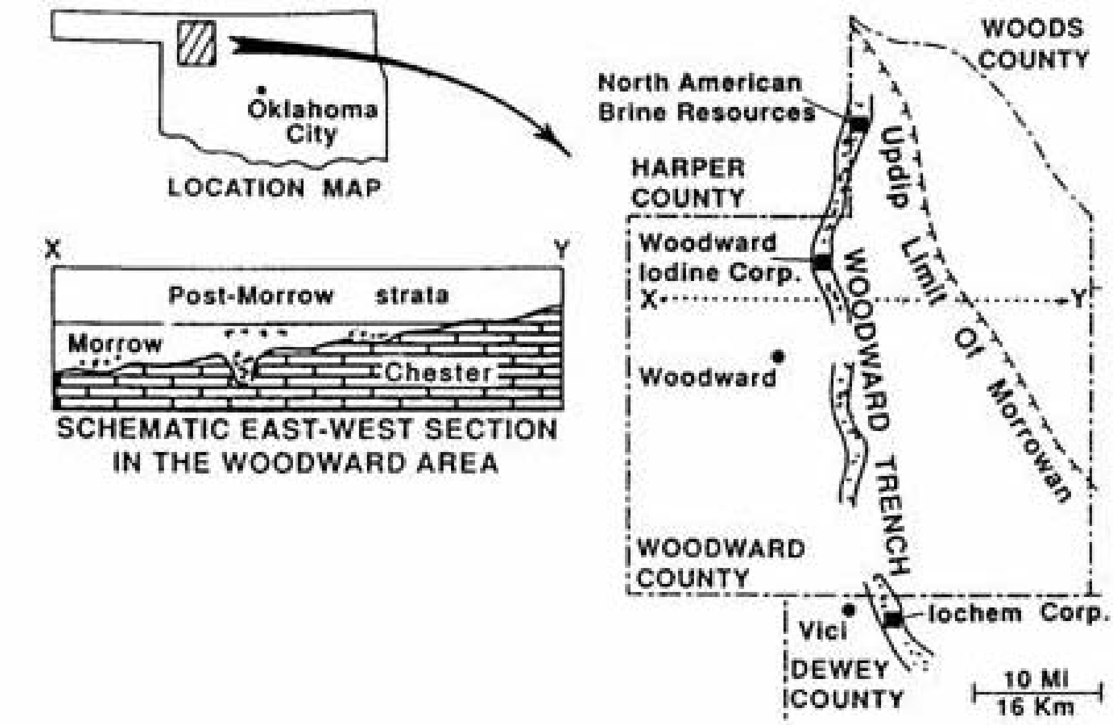

Fig. 24. Woodward Trench area (from Johnson and Gerber, 1999).

Utah Geologic Sinks

The total carbon dioxide (CO_2) sequestration capacity of geologic sinks in Utah, excluding mineralization, is estimated to be in excess of 2,100 million metric tons (mmt; see Table 27). To put this total sequestration capacity in perspective, we can compare to Utah's annual greenhouse gas emissions from fossil fuels for 2002, which totaled about 17.6 mmt of CO_2 (Allis et al., 2003). The 2,100 mmt of estimated sequestration capacity is equivalent to about 119 years of storage for the CO_2 released from fossil fuels burned in Utah in 2002.

The total sequestration capacity is spread unequally across Utah in four basins and three sink types. Figure 25 shows the distribution of the various oil and gas and coal-bed-methane reservoirs studied in Utah. The Uinta Basin in northeast quarter of the state has about 85% of the estimated total; the Paradox Basin in the southeast, has less than 9%; the Northern Thrust Belt in north central Utah has about 5% of the total capacity, and the Utah's small portion of the Green River Basin has less than 1% of the total capacity. Coal-bed-methane sinks, which only occur in the Uinta Basin, are the largest sink and account for about 42% of the total, while oil and gas reservoirs account for 30% of the total, and deep saline aquifers for the remaining 28%. Within Utah, four potential deep-saline-aquifer sinks have been identified in the Uinta Basin, and one in the Paradox Basin. Thus, the majority of the identified geologic sinks occur in the Uinta Basin.

In this study, 90 oil and gas reservoirs, 5 saline aquifers, and 3 coal-bed-methane sinks have been studied (Table 27). The oil and gas reservoirs and saline aquifers have approximately the same total capacity, but the coal-bed-methane sinks, while fewest in number have the greatest CO_2 storage capacity. Within Utah, the average sequestration capacity for a coal-bed-methane sink is 297 mmt, 107 mmt for a deep saline aquifer, and 7 mmt for an oil and gas reservoir (Table 27).

However, averages do not tell the whole sequestration story. Oil and gas reservoirs are much better characterized geologically than either of the other two sink types, although there is overlap among the sink types in that hydrocarbon production occurs in some of the same stratigraphic units that serve as both the coal–bed-methane and deep-saline-aquifer sinks. The Southwest Partnership's interactive database reflects this economic reality and contains much more geologic and engineering data on oil and gas reservoirs. Data on the average reservoir depth, temperature, and pressure for oil and gas, as well as coal-bed-methane sinks are archived in the SWP's geologic sinks database.

In addition, deep-saline-aquifer and coal-bed-methane sinks tend to be larger in area than oil and gas reservoirs. Oil and gas reservoirs are generally a size that is more than an order of magnitude smaller than the other two sink types. It is noteworthy that Utah's largest coal-bed-methane sink has an estimated sequestration capacity of 339 mmt, equal to approximately 19 years of the State's annual fossil-fuel based CO_2 emissions for the year 2002.

Each of the three sink types will be discussed in detail in the sections of this report that follow. The information presented below is designed to give the interested user enough detail to be able to select particular sinks for further evaluation using the Southwest Partnership's interactive, online database. The Partnership's database is managed and maintained by the Utah Automated Geological Reference Center (AGRC).

The three sink types will be discussed in descending order of geological characterization, beginning with oil and gas reservoirs and finishing with deep saline aquifers. A brief discussion is also included for the Southwest Partnership's Paradox Basin Enhanced Oil Recovery (EOR) Pilot Test at the Aneth unit that has been selected for Phase 2 field demonstration work.

Oil and Gas Reservoirs

The Utah Geological Survey (UGS) uses the term "reservoir" in the same sense that the New Mexico Oil Conservation Division uses the term "pool." A reservoir is a single discrete hydrocarbon accumulation within a single stratigraphic trap horizon. Reservoirs are areally continuous and can lie in vertical succession or side by side, or overlap laterally. The reservoir name in the Southwest Partnership's database has two parts: 1) a field name, usually a geographic location, and 2) a stratigraphic name based on the producing (reservoir) unit. An example of a reservoir is the Anschutz Ranch Twin Creek. This reservoir of the Anschutz Ranch field produces hydrocarbons from the Middle Jurassic Twin Creek Limestone. See Sprinkel and Chidsey (1993, Gas Atlas) for details.

The Utah Division of Oil, Gas and Mining (DOGM) assigns a unique number of three digits to each Utah field, regardless of whether it produces from one or more reservoirs. For example, while DOGM has assigned a single number, 500, for the Anschutz Ranch field, the Southwest Partnership's database recognizes the stratigraphically higher Twin Creek reservoir as the number 500A, while the deeper Nugget Sandstone reservoir has the number 500B. In the Southwest Partnership's database these reservoirs have been assigned the unique codes of UT-00500A and UT-00500B, respectively, so that the attributes in different databases or data tables can be assigned to the proper, legally defined field.

The DOGM reports some hydrocarbon production in Utah by reservoir, but those records only extend back as far as 1984. Also, since DOGM's records of Utah commercial hydrocarbon production only began to be compiled in 1948, we lack accurate pre-1948 production data for each individual reservoir for a number of the older fields in the state. In addition, some operators co-mingle production from several reservoir intervals and this also complicates anyone's ability to obtain an accurate record of the volume of hydrocarbons that have come from each individual reservoir. These factors are extremely important in estimating the sequestration capacity of a reservoir. Where possible, we used our best geologic judgment to divide co-mingled or older production statistics from two or more reservoirs in the same field in order to try to get an estimate of how much came from each reservoir, and thus, an estimate of how much carbon dioxide could be injected into each reservoir to replace the volume of produced hydrocarbons. However, such divisions of co-mingled production to each individual reservoir was not always possible, and in such instances all production from multiple reservoirs was simply assigned to the predominant producing reservoir.

Of the approximately 150 recognized hydrocarbon fields in Utah, only 66 are included in the Southwest Partnership's database because they had cumulative production of more than 1 million barrels of oil (mmbo) and/or 10 billion cubic feet of gas (BCF). These 66 fields have an estimated sequestration capacity of 629 mmt (Table 27). The 66 oil and gas fields can be further broken down into 90 reservoirs where some fields produce from more than one reservoir. There are 51 reservoirs in the Uinta Basin that account for 372 mmt (59%) of the estimated oil and gas field sequestration capacity, 26 reservoirs in the Paradox Basin that account for 138 mmt of capacity (22%), 10 reservoirs in the Northern Thrust Belt that account for 110 mmt of capacity (18%) and 3 reservoirs in the Green River Basin that account for 8 mmt of capacity (1%) in Utah (Table 27).

Figure 25 shows the areal distribution of the 66 largest conventional oil and gas fields in Utah (also included coal-bed-methane fields). Estimated individual field sequestration capacities range from less than 0.1 mmt to more than 170 mmt. Only the pools in the Paradox Basin are located near the ExxonMobil pipeline, an 8-inch pipeline that transports CO_2 from McElmo field in southwest Colorado to southeast Utah for EOR projects in the Aneth field. Table 27 indicates that the Uinta Basin oil and gas reservoirs possess more than twice the total estimated sequestration capacity of those in the Paradox Basin and Northern Thrust Belt (372 mmt compared to 138 and 110 mmt), and over 45 times the sequestration capacity of the reservoirs in the Green River Basin. However, the Uinta Basin also has the greatest number of reservoirs of all the areas characterized in Utah. As a result, the average sequestration capacity per reservoir in Utah is fairly consistent in magnitude for all areas studied, ranging from a low of 2.8 mmt in the Green River Basin to a high of 11.0 mmt in the Northern Thrust Belt, with an overall average of 7 mmt.

The percentage of large capacity reservoirs is greatest in the Paradox Basin at 15%. However, the percentage of the largest reservoirs, those with capacities greater than 10 mmt, is consistent at 10% in both the Uinta Basin and Northern Thrust Belt. The Green River Basin, with only three reservoirs, probably has no large reservoirs because there are too few reservoirs in the Utah portion of the basin to have encountered a large reservoir. Of the 10 Utah reservoirs with estimated sequestration capacities greater than 10 mmt, five are in the Uinta Basin, Ashley Valley Weber (172.0 mmt), Altamont Green River-Wasatch (84.4 mmt), Red Wash Green River (35.5 mmt), Bluebell Green River-Wasatch (22.6 mmt), and Wonsits Valley Green River (22.2 mmt); four are in the Paradox Basin, Greater Aneth Desert Creek (51.7 mmt), Upper Valley Kaibab (29.8 mmt), Lisbon Mississippian (29.1 mmt), and Greater Aneth Paradox (10.1 mmt); and one is in the Northern Thrust Belt, Anschutz Ranch East Nugget (96.7 mmt). Although these 10 large-capacity reservoirs provide 88% of the oil and gas field CO_2 storage capacity, the other 80 smaller reservoirs provide additional injection opportunities in the same injector well or up-section leak-protection for deeper reservoir targets.

The major assumptions made in calculating the CO_2 sequestration capacities for oil and gas reservoirs (and that are built into the Partnership's interactive sequestration capacity calculator) are 1) that the storage capacity volume is created in the reservoir by the production of oil and gas and 2) that CO_2 at reservoir temperature and pressure will fill 100% of the volume originally occupied by the hydrocarbons. Minor amounts of CO_2 will also be dissolved completely in the oil and water remaining in the trap.

The Uinta Basin

The Uinta Basin is a 26,000 square mile, bowl-shaped depression primarily in northeast Utah, but also extending slightly into northwest Colorado. This structural basin, formed during the early Tertiary Laramide Orogeny, contains more than 24,000 feet of sedimentary rocks ranging in age from Cambrian to Recent. It is a major oil- and gas-producing region in the United States, and through 2000 had cumulative production of more than 486 million barrels of oil and 1.9 trillion cubic feet from 10,000+ wells. The first commercial petroleum well in the Uinta Basin was a gas well drilled in the Ashley Valley field near Vernal in 1925. Most of the past hydrocarbon production has been from fluvial, deltaic, and lacustrine rocks of the Tertiary Wasatch and Green River Formations, but increasingly drilling has been testing deeper Mesozoic and Paleozoic reservoirs, and the U.S. Geological Survey's Uinta-Piceance Assessment Team (2002) identified substantial undiscovered resources in these deeper reservoirs.

For comparison purposes with reservoirs in other basins in Utah and other states, the hydrocarbon reservoirs in the Uinta Basin have been grouped into six "plays" based on the reservoir stratigraphic unit(s) that produces the hydrocarbons. They have been arranged stratigraphically from top to bottom and numbered one through six. These first three plays are similar to the Uinta Basin Gas Plays discussed in the Atlas of Major Rocky Mountain Gas Reservoirs (Chidsey, 1993, p.83). In addition, three deeper plays, the Ferron Sandstone Member of the Mancos Shale, the Dakota - Morrison Formations, and the Weber Sandstone plays have been added to the original Gas Atlas list to complete the plays in the Uinta Basin.

The oil and gas reservoir with the greatest sequestration capacity in the Uinta Basin is the Green River-Wasatch Formations Play (UN-2), where 21 reservoirs have a total capacity of 185.6 mmt and an average capacity of 8.8 mmt. This play includes the Altamont Green River-Wasatch reservoir, which alone has an estimated sequestration capacity of 84.4 mmt.

Seven thousand feet below the Green River-Wasatch Formations Play (UN-2) is the Weber Sandstone Play (UN-6), another major sink with 172.5 mmt of total sequestration capacity. Together these two play account for 96% of the oil and gas sink sequestration capacity in the Uinta Basin. Other small sinks in the Uinta Basin are found in the Uinta Formation (UN-1), the Wasatch-Mesaverde Formations (UN-3), the Ferron Sandstone Member of the Mancos Shale (UN-4), and the Dakota-Morrison Formations (UN-5). The possibility of utilizing a single injector well that penetrates two or more horizons with high sequestration capacity at relatively shallow depths (less than 5,000 ft) is slim in the Uinta Basin because the shallow portion of each reservoir occurs in ring-shaped areas that extend progressively farther from the center of the basin. The areas where these rings may overlap can be investigated using the Southwest Partnership's interactive database.

The Southwest Partnership's database can be used to find reservoirs that meet key criteria; e.g. specified distance from power plants to the pool's centroid, thickness, porosity, cumulative production, estimated sequestration capacity, and depth. The following discussion illustrates the kind of data that can be found in the interactive database, using the Red Wash Green River reservoir (UT-00665A) as an example. This reservoir was chosen because it is one of the largest estimated sequestration sinks in the Green River-Wasatch Formations Play in Utah.

Red Wash Green River Reservoir (UT-00665A)

Advantages as a CO_2 sequestration target:

- Majority of production is from the fluvial-deltaic sandstones of the Douglas Creek Member of the lower Green River Formation, a more continuous sandstone reservoir.
- Several hundred feet of shale and marlstone of the Parachute Creek Member of the Green River Formation seal the reservoir.
- Cumulative production through 12/31/2003 of more than 81million barrels of oil, 313 million barrels of water, and 343 billion cubic feet of gas.
- Reservoir is at an average depth of more than 5,100 feet, well below the supercritical depth threshold.
- The discovery well was drilled in 1951. Since then, more than 195 wells have been drilled in the pool.
- Average reservoir is thickness is 170 feet; porosity ranges from 10-22%.
- Calculated storage capacity of CO_2 is more than 35.5 mmt.
- The shallower Uinta Formation reservoir lies about 1,000 feet above the primary Green River reservoir. If CO_2 were to leak out of the Green River reservoir, it could be trapped here (uncalculated storage capacity).

- The region is sparsely populated with few nearby population centers (e.g., Myton, Roosevelt, Vernal).
- Reasonably large areal extent (more than 30 thousand acres) means that sequestered CO_2 could be injected at wide spacing.

Issues needing further evaluation:

- The shallower Uinta Formation reservoir, which is about 1,000 feet above, has not produced and is not well understood in this area. It could possibly provide backup protection for any CO_2 leakage from the primary Green River reservoir below.
- The pool is located on private, state, and BLM lands.
- The location, condition, and status of every one of the 195+ wells in the pool need to be investigated and verified.

Four other large reservoirs in the Uinta Basin are also appealing CO_2 sequestration targets: the Ashley Valley Weber (UT-00545C) with 172.0 mmt, the Altamont Green River-Wasatch (UT-00055B) with 84.4 mmt, the Bluebell Green River-Wasatch (UT-00065B) with 22.6 mmt, and the Wonsits Valley Green River (UT-00710A) with 22.2 mmt of estimated sequestration capacity. All of these reservoirs, except for the Ashley Valley Weber, cover at least 12,000 acres within the Uinta Basin, and some reservoirs are the result of DOGM orders combining several smaller reservoirs together. Various Green River Formation fields produce from a fairly continuous alluvial and near-shore marine sandstone trend containing discrete traps. The Southwest Partnership has not chosen a CO_2 sequestration demonstration project in the Uinta Basin as one of its pilot tests for Phase 2.

Data Sources

The following major sources of data were used to obtain the information on the Uinta Basin Oil and Gas pools in the Southwest Partnership's database:

- Four Corners Geological Society Oil and Gas Fields of the Four Corners Area (Fassett, J. E., editor, 1978a, 1978b, and 1983);
- Atlas of Major Rocky Mountain Gas Reservoirs (Hjellming, C. A., editor, 1993);
- 1995 National Assessment of United States Oil and Gas Resources (Gautier, D. L. et al., DDS-30, 1996; Beeman, W. R. et al., DDS-35, 1996: Charpentier, R. R. et al., DDS-36, 1996);
- Petroleum Systems and Geologic Assessment of Oil and Gas in the Uinta-Piceance Province, Utah and Colorado (USGS Uinta-Piceance Assessment Team, DDS-69-B, 2003);
- U.S. Geological Survey Produced Waters Database, provisional release (Breit, G. N., compiler, 2002) available at Web site: http://energy.cr.usgs.gov/prov/prodwat/uses.htm;
- State of Utah Division of Oil, Gas and Mining, Oil and Gas Program Web site at: http://www.ogm.utah.gov/oilgas/default.HTM;
- Utah Geological Association Publication 22, Oil and Gas fields of Utah (Hill, B. G., and Bereskin, S. R., editors, 1993, 1996); and
- U.S. Department of Energy GASIS – Gas Information System release 2 (NETL version, 1999), CD or at Web site: www.netl.doe.gov/scng

The Paradox Basin

The Paradox Basin of southeastern Utah is part of a larger, petroleum basin that extends into western Colorado and a small part of northern Arizona. The Paradox Basin is one of the largest petroleum-producing areas in Utah, accounting for 30% of the total Utah oil and 6% of the gas production in 2004 (DOGM, 2005). It is primarily an oil-producing region, as opposed to the Uinta Basin, which is primarily a gas–producing region. The Paradox Basin produces primarily from Mississippian and Pennsylvanian carbonate rocks; the Uinta Basin produces primarily from Cretaceous and Tertiary clastic rocks and coal.

Morgan (1993) developed a portfolio of three Paradox Basin plays as part of the Atlas of Major Rocky Mountain Gas Reservoirs (Hjellming, 1993), numbered from PX-1 through PX-3, from oldest to youngest producing reservoir. Two of those plays, the Leadville and Paradox Formations, contain reservoirs in the Utah portion of the basin that met the production cutoffs. In addition, two other plays, the Aneth and Kaibab Formations, have sufficiently large sinks to meet the Southwest Partnership guidelines and have been added to the current study.

The Aneth Formation play (PX-4) covers the oldest producing unit in the Utah portion of the Paradox Basin, and oil has been produced from a few deeper wells in the Greater Aneth field.

The Mississippian Leadville Formation play (PX-3) includes four reservoirs that produce from buried-fault-block, carbonate reservoirs in the Paradox fold and fault belt of the northern Paradox Basin. Although most of these reservoirs comprise small sinks, one of the four fields in this play, Lisbon (UT-00385A), is among the ten largest CO_2 sinks in Utah at 29.1 mmt.

The next younger Paradox Formation play (PX-2) is primarily oil prone, and produces from 20 discrete porous carbonate buildup reservoirs from 18 fields in the southern part of the Paradox Basin. Two fields, Bluff and Greater Aneth, produce from two different zones of the Paradox Formation. At the Greater Aneth field, both the Desert Creek (UT-00365A) and Paradox (UT-00365C) reservoirs are included among the top ten largest CO_2 sinks in Utah at 51.7 mmt and 10.1 mmt, respectively. The giant Greater Aneth field, discovered in 1956, includes four production units that cover about 47,000 acres.

The youngest reservoir in the Paradox Basin is the Kaibab reservoir (PX-1), which produces mainly oil from a structural and combination trap found in association with the Permo-Triassic unconformity in the Kaiparowits sub-basin outside of the main Paradox Basin. Only one reservoir is productive in this play at Upper Valley field (UT-00155A), but this field is one of the top ten largest CO_2 sinks in Utah at 29.8 mmt. The largest number of qualifying reservoirs are in the Pennsylvanian Paradox Formation, and the greatest sequestration capacities also occur in this play. Only the Aneth and Paradox plays occur together in the same area at Greater Aneth field; each of the other plays occurs in separate geographic areas of the Paradox Basin.

The reservoirs of the Paradox Basin have the narrowest range of depths for all the Utah basins, and have the second shallowest average depths after the Uinta Basin plays.

Since the Paradox Basin plays area occur mostly in separate areas and are not superimposed on each other, when arranged numerically by play code, they do not deepen progressively downward in a systematic trend. This lack of a depth-trend for older reservoirs is the result of a greater structural complexity for the geologic history of the Paradox Basin.

The Greater Aneth field production unit run by ExxonMobil has already been subjected to CO_2 flooding, essentially being used to sequester CO_2 while enhancing oil production. The

CO_2 used in this enhanced oil recovery project is transported via an 8-inch pipeline from McElmo Dome in southwest Colorado. The Southwest Partnership has selected another production unit of the Greater Aneth field for a Phase 2 sequestration demonstration project. The lack of previous CO_2 injection in this area of the field allows the partnership to collect baseline information before CO_2 injection begins and provides a better opportunity to accurately monitor and verify the Paradox reservoir sequestration capability and capacity. In addition to the pipeline that transports CO_2 from Colorado to Utah, another natural source of CO_2 occurs in the Bluff field several miles to the northwest of the Greater Aneth field (Chidsey et al., 2005).

The Partnership's database contains the same kinds of information on Paradox Basin reservoirs that it does for Uinta Basin reservoirs. Thus, searches for and analyses of Paradox Basin reservoirs will be similar to those of the Red Wash Green River reservoir from the Uinta Basin that were discussed above. In addition, the database also contains data on the Greater Aneth Desert Creek reservoir (PB-132), that is the subject of ExxonMobil's enhanced oil recovery project in the northeastern part of the field.

Data Sources

The following major sources of data were used to obtain the detailed information on the Paradox Basin Oil and Gas pools in the Southwest Partnership's Database:

- Four Corners Geological Society Oil and Gas Fields of the Four Corners Area (Fassett, J. E., editor, 1978a, 1978b, and 1983);
- Utah Geological Association Publication 22, Oil and Gas fields of Utah (Hill, B. G., and Bereskin, S. R., editors, 1993, 1996);
- Atlas of Major Rocky Mountain Gas Reservoirs (Hjellming, C. A., editor, 1993);
- 1995 National Assessment of United States Oil and Gas Resources (Gautier, D. L. et al., DDS-30, 1996; Beeman, W. R. et al., DDS-35, 1996: Charpentier, R. R. et al., DDS-36, 1996);
- Oil and Gas Fields Map of Utah (Chidsey and others, 2005);
- U. S. Department of Energy GASIS – Gas Information System release 2 (NETL version, 1999), CD or at Web site: www.netl.doe.gov/scng
- State of Utah Department of Natural Resources, Division of Oil, Gas and Mining completion files, Division Orders and well data Web site (http://www.ogm.utah.gov/oilgas/DATA_SEARCH/well_data_search.htm); and
- The well and reservoir data housed at the Utah Geological Survey's Petroleum Section in Salt Lake City, UT.

The Northern Thrust Belt

The Northern Thrust Belt of northeastern Utah is part of a larger, petroleum basin that extends into southwestern Wyoming (Figure 25). The Northern Thrust Belt is a smaller but significant producing area in Utah, accounting for nearly 4% of the total Utah oil and 8% of the gas production in 2004 (DOGM, 2005). It is primarily a gas-producing region, like the Uinta Basin. The Northern Thrust Belt produces primarily from Triassic and Jurassic clastic and carbonate rocks; the Uinta Basin produces primarily from Cretaceous and Tertiary clastic rocks and coal.

Doelger et al. (1993a) developed a portfolio of seven Thrust Basin plays as part of the Atlas of Major Rocky Mountain Gas Reservoirs (Hjellming, 1993), numbered from TB-1 through TB-7, from youngest to oldest producing reservoir. The youngest two of those plays, the Jurassic Twin Creek Limestone and Nugget Sandstone, contain reservoirs in the Utah portion of the Thrust Belt province that met the production cutoffs. A third play, the Triassic Phosphoria Formation, was included in the TB-5 (Weber Sandstone play) of Doelger et al (1993a), and has a sufficiently large sink to meet the Southwest Partnership guidelines. This play has been renumbered TB-3 for this study and is included in the current study.

The Jurassic Twin Creek Limestone play (TB-1) includes five reservoirs that produce from thrusted anticlinal carbonate reservoirs in the thrust belt of northeastern Utah. All of these reservoirs comprise small sinks, and none of the five fields in this play are among the ten largest CO_2 sinks in Utah.

The next older Nugget Sandstone play (TB-2) is primarily gas prone, and produces from eolian sandstone reservoirs in thrusted anticlinal traps from four fields in this play. Two fields, Lodgepole and Pineview, produce from both the Twin Creek and Nugget plays. At the Anschutz Ranch East field, the Nugget (UT-00505A) reservoir is included among the top ten largest CO_2 sinks in Utah at 96.7 mmt. The Anschutz Ranch East field was discovered in 1979, and covers between 1,900 and 5,000 acres.

The oldest reservoir in the Northern Thrust Belt is the Phosphoria Formation (TB-3), which produces mainly gas from interbedded shallow water clastics, carbonates, and phosphorites. The sour gas in this reservoir is trapped in thrusted anticlinal structures, and has been productive from only the Cave Creek field (UT-00515B) of the Northern Thrust Belt. The Jurassic Twin Creek play (TB-1) has the most qualifying reservoirs, and the greatest capacity is in the Jurassic Nugget Sandstone play (TB-2). The Phosphoria and Twin Creek plays are both productive at Cave Creek field, while the Nugget and Twin Creek plays are productive at Lodgepole and Pineview fields. The Nugget play is productive by itself at Anschutz Ranch East and Pineview North fields, and the Twin Creek play is productive by itself in Anschutz Ranch and Elkhorn fields.

The reservoirs of the Northern Thrust Belt have the deepest average and minimum depths of all the Utah basins, and also the highest reservoir temperatures. Since the Northern Thrust Belt plays occur mostly in the same area and are generally superimposed on each other, when arranged numerically by play code they deepen progressively downward in a systematic trend. This super-position of younger over older reservoirs provides additional injection opportunities in the same injector well or up-section leak-protection for deeper reservoir targets in the Northern Thrust Belt.

The Southwest Partnership has not selected a field from the Northern Thrust Belt for a Phase 2 sequestration demonstration project. However, the Partnership's database contains the same kinds of information on Northern Thrust Belt reservoirs that it does for the other Utah basin reservoirs. Thus, searches for and analyses of Northern Thrust Belt reservoirs will be similar to those of the Red Wash Green River reservoir from the Uinta Basin that were discussed above.

Data Sources

The following major sources of data were used to obtain the detailed information on the Northern Thrust Belt oil and gas reservoirs in the Southwest Partnership's Database:

- Utah Geological Association Publication 22, Oil and Gas fields of Utah (Hill, B. G., and Bereskin, S. R., editors, 1993, 1996);
- Atlas of Major Rocky Mountain Gas Reservoirs (Hjellming, C. A., editor, 1993);
- Oil and Gas Fields Map of Utah (Chidsey and others, 2005);

- 1995 National Assessment of United States Oil and Gas Resources (Gautier, D. L. et al., DDS-30, 1996; Beeman, W. R. et al., DDS-35, 1996: Charpentier, R. R. et al., DDS-36, 1996);
- U. S. Department of Energy GASIS – Gas Information System release 2 (NETL version, 1999), CD or at Web site: www.netl.doe.gov/scng
- State of Utah Department of Natural Resources, Division of Oil, Gas and Mining completion files, Division Orders and well data Web site (http://www.ogm.utah.gov/oilgas/DATA_SEARCH/well_data_search.htm); and
- The well and reservoir data housed at the Utah Geological Survey's Petroleum Section in Salt Lake City, UT.

The Green River Basin

The Green River Basin of northeastern Utah is part of a larger, petroleum basin that extends into southwestern Wyoming (Figure 25). The Green River Basin is a very small producing area in Utah, accounting for less than 1% of the total Utah oil and gas production in 2004 (DOGM, 2005). It is primarily a gas-producing region, like the Uinta Basin. The Green River Basin also produces primarily from Cretaceous clastic rocks like the Uinta Basin.

Doelger et al. (1993b and c) developed two plays found in the Utah portion of the Green River Basin, an Upper Cretaceous play and a Lower Cretaceous play, as part of the Atlas of Major Rocky Mountain Gas Reservoirs (Hjellming, 1993). The Upper Cretaceous play (GB-1 in this study) covers the Frontier Formation reservoir, while the Lower Cretaceous play (GB-2 in this study) covers the Dakota Sandstone reservoir of the Green River Basin. The Frontier Formation play contains one reservoir in the Utah portion of the Green River Basin that met the production cutoffs. The Dakota Sandstone play contains two reservoirs that had production sufficiently large to meet the Southwest Partnership guidelines. This play has been renumbered TB-3 for this study and is included in the current study.

The Frontier Formation play (GB-1) includes one reservoir that produces from fluvial and near-shore marine sandstone reservoirs in anticlinal traps to the north of the Uinta Mountains in Utah. This play contains one small sink, and is not among the ten largest CO_2 sinks in Utah.

The older Dakota Sandstone play (GB-2) is primarily gas prone, and produces from near-shore deltaic sandstone reservoirs in anticlinal traps from two fields in this play. Again, these reservoirs are small sinks, and are not among the ten largest CO_2 sinks in Utah. The largest number of qualifying reservoirs (2) occurs in the Dakota Sandstone play, which also has the greatest sequestration capacity in this basin.

The reservoirs of the Green River Basin have the second deepest average reservoir depth among all the Utah basins, and have the highest average reservoir pressure. Since the Green River Basin plays occur mostly in the same area and are generally superimposed on each other, when arranged numerically by play code they deepen progressively downward in a systematic trend. This super-position of younger over older reservoirs provides additional injection opportunities in the same injector well or up-section leak-protection for deeper reservoir targets in the Green River Basin.

The Southwest Partnership has not selected a field from the Green River Basin for a Phase 2 sequestration demonstration project. However, the Partnership's database contains the same kinds of information on Green River Basin reservoirs that it does for the other Utah basin reservoirs. Thus, searches for and analyses of Green River Basin reservoirs will be similar to those of the Red Wash Green River reservoir from the Uinta Basin that were discussed above.

Data Sources

The following major sources of data were used to obtain the detailed information on the Green River Basin oil and gas reservoirs in the Southwest Partnership's Database:

- Utah Geological Association Publication 22, Oil and Gas fields of Utah (Hill, B. G., and Bereskin, S. R., editors, 1993, 1996);
- Atlas of Major Rocky Mountain Gas Reservoirs (Hjellming, C. A., editor, 1993);
- Oil and Gas Fields Map of Utah (Chidsey and others, 2005);
- 1995 National Assessment of United States Oil and Gas Resources (Gautier, D. L. et al., DDS-30, 1996; Beeman, W. R. et al., DDS-35, 1996: Charpentier, R. R. et al., DDS-36, 1996);
- U. S. Department of Energy GASIS – Gas Information System release 2 (NETL version, 1999), CD or at Web site: www.netl.doe.gov/scng
- State of Utah Department of Natural Resources, Division of Oil, Gas and Mining completion files, Division Orders and well data Web site (http://www.ogm.utah.gov/oilgas/DATA_SEARCH/well_data_search.htm); and
- The well and reservoir data housed at the Utah Geological Survey's Petroleum Section in Salt Lake City, UT.

Natural CO_2 Accumulations

Chidsey and Morgan (1993) describe seven reservoirs in the Utah portion of the Paradox Basin that produce, or have produced, CO_2-rich (greater than 57 mol%) gas from naturally occurring sources. Three of these reservoirs are older Mississippian and Devonian units that occur below the currently producing Pennsylvanian reservoirs the Bluff, Boundary Butte, and Desert Creek fields. The presence of these deeper naturally occurring CO_2 reservoirs indicates there is relatively good integrity to the seals in the Paradox Basin for sequestration or enhanced oil recovery purposes. Chidsey and Morgan (1993) also discuss the Farnham Dome field, in central Utah near the southwestern margin of the Uinta Basin, which contains substantial resources of CO_2-rich gas (greater than 97 mol %) in the eolian Jurassic Navajo Sandstone. This field, which produced CO_2 from 1931 through 1979 according to Chidsey and Morgan (1991), is located within 50 miles of some of the major oil-producing fields in the southwestern Uinta Basin Green River reservoir play.

Data Sources

The following major sources of data were used to obtain the information on the naturally occurring CO_2:

- Moore and Sigler's (1987) compilation of analyses of natural gas for the U.S. Bureau of Mines;
- Morgan and Chidsey's (1991) paper on Farnham Dome field in the Utah Geological Association's Guidebook 19 on the Geology of east-central Utah; and
- Chidsey and Morgan's (1993) paper on low-Btu gas in Utah.

Coalbed Methane Sinks

The total CO_2 sequestration capacity for coal-bed-methane sinks in Utah was estimated by Reeves (2003) to be about 1.9 billion tonnes, with all of that capacity residing in the Uinta Basin. Subsequent more detailed work in Utah for this study using a sequestration calculator developed for the Southwest Partnership by Advanced Resources International (Reeves, unpublished data) found that Utah coal-bed-gas reservoirs in the Uinta Basin could more conservatively sequester 0.9 billion tonnes of CO_2. The coal-bed-gas reservoirs are found in the Upper Cretaceous Ferron Sandstone Member of the Mancos Shale, the Blackhawk Formation, and the Neslen Formation in the Uinta Basin.

No CO_2-enhanced coal-bed-methane production has occurred in Utah. The closest such project is Burlington Resources' Allison Unit test near the New Mexico-Colorado border, where more than 100,000 tons of CO_2 were injected into the Upper Cretaceous Fruitland Formation over a three-year period to enhance production of coal-bed methane (Reeves, 2002). Four injector wells were used to sequester CO_2 in the coal at depths in excess of 3,000 ft. Critical factors controlling sequestration in coal beds include coal bed continuity, cleat permeability, coal shrinkage/swelling, gas adsorption/desorption capacity, and seal integrity.

The Uinta Basin is not one of the top ranked basins in the United States for CO_2 coal-bed sequestration. However, factors favoring sequestration of CO_2 in Utah coal beds are: 1) advantageous geology including coal beds with high methane contents; 2) abundant anthropogenic CO_2 from nearby power plants; 3) well developed natural gas and CO_2 pipeline systems; 4) potentially low capital and operating costs; and 4) local companies with coal-bed methane (CBM) experience. Selection of a potential coal-bed methane CO_2 sequestration site in the Uinta Basin requires more detailed reservoir studies of local operations than those that are available in the literature because: 1) the coal seams on a regional scale are lenticular discontinuous and 2) all coal-bed methane production from the Uinta Basin is now reported by well, which provides little information about the characteristics of the various individual coal-bed reservoirs.

The Southwest Partnership's Phase I ranked sequestration opportunities based on proximity to sources and/or pipeline infrastructure, as well as economic, safety, and risk mitigation potential. The result of the Phase I ranking process resulted in the selection of three geologic pilot tests within the Southwest Partnership that are located on the CO_2 pipeline infrastructure. No Utah site was selected as an enhanced coal-bed-methane test; such a site was selected in the San Juan Basin with Burlington Resources as the operator (see New Mexico section for detailed discussion).

Data Sources

- Utah Geological Association Publication 22, Oil and Gas fields of Utah (Hill, B. G., and Bereskin, S. R., editors, 1993, 1996);
- 1995 National Assessment of United States Oil and Gas Resources (Gautier, D. L. et al., DDS-30, 1996; Beeman, W. R. et al., DDS-35, 1996: Charpentier, R. R. et al., DDS-36, 1996);
- Petroleum Systems and Geologic Assessment of Oil and Gas in the Uinta-Piceance Province, Utah and Colorado (USGS Uinta-Piceance Assessment Team, DDS-69-B, 2003);
- Atlas of Major Rocky Mountain Gas Reservoirs (Hjellming, C. A., editor, 1993);
- Oil and Gas Fields Map of Utah (Chidsey and others, 2005); and

- An Assessment of CO_2 Sequestration and ECBM Potential of U.S. Coalbeds (Reeves, 2003).

Deep Saline Aquifers

The total maximum CO_2 sequestration capacity for the five aquifers listed on Table 27 is conservatively estimated to be about 587 mmt, enough capacity to store more than 28 years of the annual 2002 CO_2 emissions from all of Utah's power plants. An 8-inch pipeline from McElmo Dome in southwest Colorado crosses only one of the deep saline aquifers, the Paradox Formation aquifer in the Paradox Basin of southeast Utah. None of the other four deep saline aquifers in Utah is served by an existing CO_2 pipeline, however the Uinta Basin deep saline aquifers are situated near existing power plants making access to these sinks cost effective should the pipelines ever transport anthropogenic CO_2 (Figure 25).

In order to qualify as a deep saline aquifer, a saline-water-bearing rock-unit had to be at least 3,000 ft deep. The aquifer also had to contain water with a total dissolved solids (TDS) concentration of at least 10,000 ppm since state laws generally protect groundwater with salinity less than 10,000 ppm.

Over 90% of the 587 million tons of sequestration capacity in deep saline aquifers in Utah is in the four deep saline aquifers in the Uinta Basin. The remaining 8% is in the one aquifer in the Paradox Basin. All five of the formations produce hydrocarbons in Utah and analyses of the water produced with the hydrocarbons were the source of available water chemistry data. This means that there is a considerable amount of well data available at least in the vicinity of the producing traps. In fact, petroleum play information was used to estimate the area underlain by each Utah aquifer sink. All of the five deep-saline-aquifer formations are important hydrocarbon-producers in Utah Mexico, setting up the possibility of CO_2 sequestration along with enhanced hydrocarbon recovery.

The capacity estimate for each sink is conservative estimate because it is based on a minimum thickness for the aquifer, a minimum area, and reservoir conditions noted for the associated petroleum reservoirs. Nonetheless, the total estimated sequestration capacity of saline aquifers in Utah provides a significant additional CO_2 sequestration capacity that is about the same order of magnitude for the total capacity for oil and gas reservoirs (Table 27).

Sequestration capacity in Utah was estimated using the MIDCARB calculator (Kansas Geological Survey, 2004) to compute the solubility of CO_2 in the brine at reservoir pressure and temperature, and the capacities shown in Table 27 rely on this method. This method assumed that the CO_2 would dissolve completely in the saline water. Another method, not calculated for Utah's aquifers, assumed that the CO_2 would displace completely the saline water; this second method could be calculated using the Partnership's interactive capacity calculator to compute the density of carbon dioxide at reservoir pressure and temperature (Zhang et al., 2003). The MIDCARB-based capacities are smaller than the capacities that could be estimated from the Partnership's interactive capacity calculator, which yields capacity estimates about an order of magnitude larger than the MIDCARB calculator (Kansas Geological Survey, 2004). Even so, the solubility estimate is about the same order of magnitude as the total capacity for either the oil and gas reservoirs or the coal-bed-methane sinks, several hundred million metric tons. However, the areas underlain by deep saline aquifers are typically not as well characterized geologically as the full areas of oil and gas pools and coal-bed-methane sinks. Much of the data used to characterize the deep saline aquifers comes from a fraction of the oil and gas wells in the two basins.

The average thickness of the five Utah aquifers ranges from 25 to 70 feet as reported by the USGS in its Produced Waters Database (Breit, 2002), and this thickness may not reflect the total thickness of the potentially porous and permeable intervals in the formations. The area of each saline aquifer is generally between the 3,000 ft and 10,000 ft depth contours, although the Dakota aquifer capacity was calculated to a depth of 20,000 ft. Those contours were determined from the well data in the U.S. Geological Survey's Produced Waters Database (Breit, 2002) or the USGS National Assessment of Oil and Gas projects (Beeman et al., 1996; Charpentier et al., 1996; Gautier et al., 1996; and USGS Uinta-Piceance assessment team, 2003)

Reservoir pressure for each aquifer was estimated for the top of each aquifer, assuming that normal hydrostatic conditions existed in both basins. Reservoir pressures were estimated to be 1,410 psi at 3,000 ft and 4,665 psi at 10,000 ft. Reservoir temperature data was gleaned from the bottom hole temperature data collected for the oil and gas reservoirs in the same formations in the Partnership's database. Average reservoir temperatures were estimated to range from be 123° to 180°F in the Uinta Basin and averaged 125°F in the Paradox Basin. Porosity data are averages from the Partnership's oil and gas database showed the five aquifers ranged from 6 to 12% porosity. Salinity data are averages from the U.S. Geological Survey's Produced Waters Database (Breit, 2002).

Uinta Basin

The four deep saline aquifers in the Uinta Basin have a combined estimated CO_2 sequestration capacity of about 537 mmt, over 90% of the estimated deep-saline-aquifer capacity in Utah (Table 27). The Green River, Wasatch, Mesaverde, and Dakota formation aquifers have estimated capacities between 16 and 312 mmt. All four formations produce hydrocarbons in the basin and the first two are Tertiary in age, while the second two are Mesozoic in age. They will be discussed in descending stratigraphic order, youngest to oldest, beginning with the Green River Formation.

The Green River Formation has an estimated sequestration capacity of 128.2 mmt. This formation consists marginal to open lacustrine sediments deposited in the center of a paleo-lake basin, and it overlies, and intertongues with the upper part of the fluvial to alluvial fan deposits of the Wasatch/Colton Formations that were deposited farther from the lake. Within the Uinta Basin, the total Green River Formation ranges in thickness from 2,000 to 6,000 feet, while the porous saline aquifer was estimated to comprise an interval only 25 feet thick because of the overall fine grained nature of the unit. While the Green River is thickest in the center of the basin, the best aquifer is likely to occur closer to the margins of the basin where there was a greater amount of coarser clastic deposition. The aquifer was estimated to lie between 3,000 and 8,500 feet deep, contain 12% porosity, and could potentially sequester 128.2 MMt of carbon dioxide.

The Wasatch (Colton) Formation was deposited as alluvial fans around the margins of paleo-Lake Uinta. This unit is up to 3,000 feet thick near the margin of the basin and thins to 300 feet thick, or less, near the center of the basin. The average thickness of the saline aquifer within this unit was estimated at 40 feet. The Wasatch aquifer was estimated to exist at depths from 3,000 to 11,000 feet, have an average porosity of 6%, an average salinity of 10,000 TDS, and could potentially sequester 16.4 mmt of CO_2.

The sequestration capacity of a 70-foot-thick Mesaverde Formation aquifer was estimated at 80.5 mmt. It was calculated for a unit at depths from 5,000 to 11,500 feet, containing 8% porosity, an average salinity of 30,000 TDS, and an average temperature of 180°F.
The Mesaverde Formation consist of non-marine shoreline, coastal plain, and palludal deposits

ranging in thickness from 3,000 to 1,200 feet that tend to thin to the east across the Uinta Basin. It consists of the following three formations listed in descending stratigraphic order: Price River Formation (equivalent to the Farrer and Neslen Formations and Sego Sandstone of the eastern Uinta Basin), Castlegate Sandstone, and Blackhawk Formation. The majority of the hydrocarbon and water production in the Uinta Basin comes from the Price River Formation and equivalent units.

The Upper Cretaceous Dakota Sandstone aquifer includes the Cedar Mountain Formation, and they have a combined estimated maximum sequestration capacity of 311.8 mmt. These units are generally non-marine to marginally marine sandstone that ranges from 200 to 500 feet thick, occur at depths from 3,000 to 20,000 feet, have an average temperature of 123° F, and have an average porosity of 12%. The 40-foot-thick Dakota aquifer unit is sealed by several thousand feet of the overlying Mancos Shale.

Paradox Basin

The single deep saline aquifers in the Paradox Basin has a total maximum estimated CO_2 sequestration capacity of 49.6 mmt (Table 27), less than 10% of the estimated deep-saline-aquifer capacity in Utah. The Pennsylvanian Paradox Formation has the highest average total dissolved solids (TDS) content of all the aquifers in Utah at 100,000 TDS. This is no doubt a fact because this unit consists of interbedded evaporites, black shale, and carbonates mounds formed in a shallow sea. The total thickness of the Paradox Formation ranges from 500 to 3,500 feet thick, and it generally thickens to the north in the Paradox Basin. The 30-foot-thick deep saline aquifer is confined to the Ismay and Desert Creek carbonate zones of the Paradox Formation, and is likely to be somewhat discontinuous. The aquifer occurs at depths from 4,000 to 6,500 feet, has an average temperature of 125°F, and has an average porosity of 12%.

Data Sources

Publicly available information on the five deep saline aquifers in Utah came from a variety of sources:

- The USGS's Produced Waters database;
- The Texas Bureau of Economic Geology's study of sequestration in brine (Hovorka et al., 2003)
- Gwynn's (1992; 1995; 1996) studies of the oil-well saline waters of the Utah; and
- Statistics compiled in the Partnership's oil and gas database.

Lessons Learned

The data used for this report took more than one person-year to compile, with most of the compilation effort focused on oil and gas reservoirs. Data were entered into a Partnership modified GASIS (U.S. Department of Energy, 1999) database, which contained 321 data fields for each site. Not all of these data fields pertained to every reservoir/sink type.

The GASIS database was originally designed for gas reservoirs, not oil. Unfortunately, while information in many of the 321 data fields may be useful in detailed sequestration pilot projects, a more restricted data set turned out to be all that was necessary for the purposes of regional characterization of oil and gas reservoir's CO_2 sequestration potential. The Southwest Partnership eventually selected 50 of the 321 data fields that were found to be most important to a regional screening effort for its online, interactive database. Not every pool has a complete set of data because certain information was not always available in the published literature.

However, the Partnership's oil and gas database, coupled with its GIS database, provide the only publicly available, digital source of key regional information on the 90 largest producing oil and gas reservoirs in Utah. As such, the Partnership's complete database could be invaluable resources for the oil and gas industry or for subsurface work associated with pilot project modeling and academic research.

The Partnership members learned from Phase 1 that the more comprehensive data set thought to be necessary for sequestration modeling turned out to be more data than was necessary for a regional screening effort to select Phase 2 pilot sequestration project sites. Extensive detailed reservoir data is only required to model and design site-specific sequestration projects, and the expanded Partnership database will be useful for the few pilot project selected from the region.

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Table 27. Utah Saline Aquifers' Carbon Dioxide Sequestration Capacities

Aquifer	Formation	Basin	Average Depth (ft)	Average Porosity (%)	Average Salinity (TDS)	Temperature (degrees F)	Total Capacity (mmt)
1	Green River Fm.	Uinta	5,750	12	9,880	138	128.2
2	Wasatch Fm.	Uinta	7,000	6	14,060	139	16.4
3	Mesaverde Fm.	Uinta	8,200	8	35,134	180	80.5
4	Dakota Ss. - Cedar Mtn. Fm.	Uinta	11,500	12	23,007	123	311.8
5	Paradox Fm.	Paradox	5,250	12	135,598	125	49.6
ALL POOLS			**7,540**	**10**	**43,536**	**141**	**586.5**

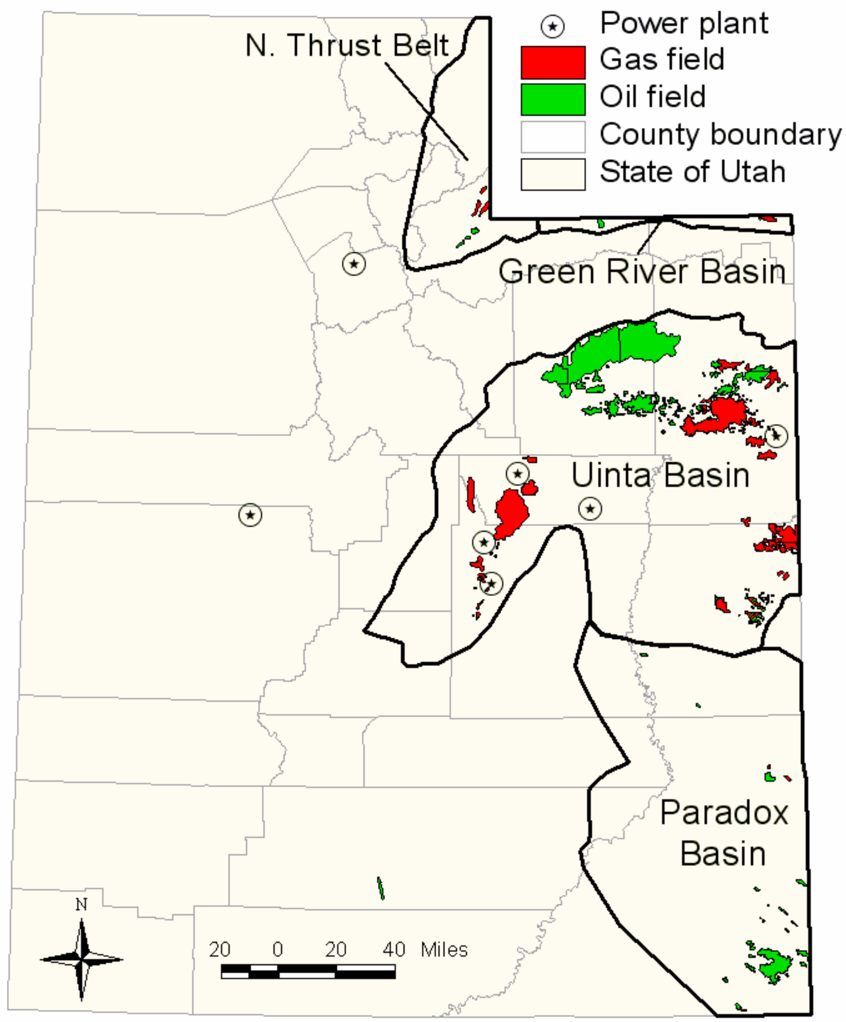

Fig. 25. Distribution of reservoirs studied in Utah.

Terrestrial Sinks

Terrestrial carbon sequestration is an important component of a comprehensive greenhouse gas (GHG) management strategy in the southwest. The ability to transfer and store atmospheric C in soils and vegetation by manipulating the rate and magnitude of naturally occurring processes, such as photosynthesis, humification and aggregation by changing land management is an attractive alternative to reduce GHG levels because 1) results can be achieved quickly 2) technologies for enhanced sequestration can be implemented without major economic impact and are generally associated with improved management of resources and more efficient production systems and 3) delivery infrastructure (land management programs in extension and federal agencies) is in place, proven and relatively well-funded. However, the design and implementation of policies and programs to accelerate and realize the potential of terrestrial sequestration requires analyses that examine regional land use patterns, human activity systems and economic development objectives and how they affect ecological processes.

Within the Southwest Regional Partnership area, the range in ownership and land management patterns require that outreach and education activities must be broad-based, flexible and integrated with a wide variety of federal, state and local programs. Land cover varies considerably within the partnership region, ranging from deciduous forests at the easternmost extreme to desert shrublands in the lower elevation west and coniferous forests in higher elevations. Each soil/vegetation/land management combination has a unique potential to capture and store carbon that can only be assessed within an economic and social, as well as biophysical context.

The complex combination of land use, land management and natural conditions in the Southwest Regional Partnership area offers an opportunity to examine policy, program and operational alternatives to optimize terrestrial sequestration against a background of competing land use objectives. Meeting the challenge of integrating sequestration as another land management objective into agriculture and forestry production systems will require an analytical approach that draws upon existing expertise and information as well as a combination of analytical tools.

Methods

The Southwest Regional Partnership encompasses the states of Arizona, Colorado, Oklahoma, New Mexico, Utah, and portions of Kansas, Nebraska, Texas, and Wyoming (Fig. 26). To assess the regional sequestration potential of land areas within the partnership, a framework was developed that had two distinct phases (Fig. 27). The first phase involved the use of climate, soil, land tenure, land cover, and major land resource area spatial coverages that could be incorporated into a geographic information system (GIS) in order to define areas having greatest potential for implementing carbon sequestration programs in the region. Once these areas were identified, a second phase was initiated that used the COMET VR model to assess the amount of carbon that would be sequestered under land management and conservation programs available for the region (Fig. 27).

GIS Phase

For these analyses, the various data layers were acquired from online data sources and the datasets were classified into categories of potential to allow for spatial indexing. The data layers acquired included: 1) long-term precipitation, 2) land tenure; 3) soils, 4) land Cover, 5) major land resource areas, and 5) administrative boundaries. Long-term precipitation was used to define climatic potential and was defined as precipitation amounts that would be of sufficient quantity to allow for suitable plant growth or success in revegetation. To assess climate potential, the long term average precipitation (1971-2000; Spatial Climate Analysis Service, Oregon State University, http://www.ocs.oregonstate.edu/prism/) was classified as follows: No Potential (0 to13 cm), Low Potential (13 to 23 cm), Moderate Potential (23 to 46 cm) and High Potential (>46 cm) (Fig. 28).

Land tenure was used to delineate private/non-federal, federal, and Indian reservation lands (Fig. 29). This spatial coverage was acquired from the national atlas website (www.nationalatlas.gov). This allowed separation of land areas where carbon sequestration programs could be targeted for private/non-federal land and Indian reservations, since incentive programs will not be implemented on Federal Lands.

Soils data were classified based on three characteristics that influence soil carbon. These were Soil Organic Carbon (SOC), Calcium Carbonate ($CaCO_3$), and the Wind Erodibility Index (WEI). The data layers used were acquired from the Natural Resources Conservation Services (NRCS) Soil Survey Geographic (SSURGO) and State Soil Geographic (STATSGO) soil databases. The SSURGO data (higher resolution) were used where available. STATSGO was used to fill in areas not covered by SSURGO. SOC was classified for indexing as follows: Low (0 to 0.75%), Moderate (0.75 to 1.75%), High (1.76 to 10%) and Very High (>10%) (Fig. 30). CaCO3 content was classified as follows: Low (0 to 15%), Moderate (15 to 30%) and High (>30%) (Fig. 31). The WEI was indexed as follows: Low (0 to 100 t/ha/yr), Moderate (100 to 200 t/ha/yr) and High (> 200 t/ha/yr) (Fig. 32).

The climate, land tenure, and soil data layers were intersected in the GIS to create a coverage that would allow spatial queries based on these attributes. Boundaries of interest—major land resource areas (MLRA), and counties—were also included in the GIS to allow aggregation. We identified sites where management could reliably increase soil carbon by first identifying locations with high or moderate baseline levels and then focusing on sites that have lost, through tillage practices or land conversion, a portion of that carbon. It is unlikely that we can increase soil carbon beyond that identified by soil and climate limitations, but changes in land use or management can restore soil carbon to baseline levels. The land areas identified through this query were designated as target areas for carbon sequestration programs/interventions (Fig. 33). These target areas were then cross indexed with the National Land Cover Data (NLCD, http://landcover.usgs.gov) to determine land cover. NLCD is a 21-class land cover classification scheme applied consistently over the US. The data were reclassified into four major classes to reflect land cover types where government programs could be implemented: Grazinglands, Row Crops, Small Grains, and Forests. Spatial queries were then conducted to acquire the data needed by the COMET-VR model. These included acreages of each land cover category, soil textures, county, and MLRA.

COMET VR Phase

COMET-VR, an on-line interface to the Century model, was used to assess baseline carbon and management induced carbon changes in areas identified as having high to moderate potential for carbon sequestration. The COMET-VR interface allows a user to select a location (state and county), soil texture, landuse history, and a proposed 10-year future management alternative. Based on these choices, COMET-VR accesses information on climate and landuse from database sources and runs the Century model. The results are calculated and presented as ten year annual averages of soil carbon sequestration or emissions with associated statistical uncertainty values.

Areas identified during the GIS Phase that had sufficient acreage in either grazinglands, small grains, or row crops were modeled. For grazinglands, three practices were compared: continuous grazing (heavy or moderate), seasonal reduced grazing, and CRP (Conservation Reserve Program; a cropland retirement program)-grass-legume mixture (no grazing). For row crops and small grains five practices were compared: intensive tillage, reduced tillage, no-till tillage, CRP-100% grass, and CRP-grass-legume mixture. Weighted averages for carbon capture were calculated for each MLRA in order to identify MLRAs with higher sequestration potentials that could be targeted for government incentive programs.

Results

The results will be presented on a state by state basis and are aggregations of Major Land Resource Area (MLRA) and County level information. MLRAs are geographic associations of land based on climate, topography, land use, water, soils and potential natural vegetation (http://soils.usda.gov/survey/geography/mlra/mlra_definitions.html).
Because of the unique nature of many land management decisions and their interactions with government programs, activities at the county level may restrict the amount of incentive funding that can be used influence land owners decisions. Whenever county level limits on land use change or management are important in determining the potential for state level carbon sequestration activities, it will be noted.

Arizona
There were 2, 197, 869 hectares subjected to analysis for the potential to increase carbon storage. No county level constraints on land use change under federal programs were identified, so results will be presented at the MLRA level. The spatial distribution of MLRA is shown in Fig. 34.

MLRA 30, Sonoran Basin and Range (15559 ha)
The primary limitation on the potential to sequester carbon in this area is low rainfall. The dominant land use is livestock grazing at light stocking rates, and maintaining that land use will result in stable carbon fluxes within the area. Improving species composition and net primary productivity by adding legumes to existing rangeland offers the potential to increase soil carbon storage by about 0.10 T C/ha/y over a 10 year period. However, the uncertainty associated with the model applications of this land management practice is extremely high.

MLRA 35, Colorado and Green River Plateaus (965, 035 ha)
Adding a legume to existing rangeland has the potential to increase carbon storage from 0.10 to 0.25 T C/ha/y. Sandy loam soils were identified as the soils with highest potential (0.17 to 0.25) while heavier textured soils (clays) were typically below 0.10 T C/ha/y. Silty soils and clay loam soils were intermediate.

MLRA 36, New Mexico and Arizona Plateaus and Mesas (21, 093 ha)
Legume addition to existing rangelands can increase carbon storage between 0.15 and 0.24 T C/ha/y depending on soil texture. Sandy loam soils have greater potential than heavier textured clay soils. The uncertainty associated with these potential gains is extremely high.

MLRA 38, Arizona Interior Chaparral (356, 987 ha)

Legume addition to existing rangeland has the potential to increase carbon storage between 0.10 and 0.65 T C/ha/y depending on soil texture. The range in potential is similar to other MLRAs (sandy loam>loam>clay>silt). The uncertainty associated with these estimates is extremely high.

MLRA 39, Arizona and New Mexico Mountains (171, 151 ha)
Legume addition to existing good condition or degraded rangeland should increase carbon storage from 0.13 to 0.64 T C/ha/y depending on soil texture (clay loam>loam>sandy loam). However, the uncertainty associated with model outputs for this practice in these areas is extremely high.

MLRA 40, Central Arizona Basin and Range (105, 417 ha)
Potential for increased carbon sequestration in soils ranged from negligible on arid loam soils to 0.60 T C/ha/y on sandy loam soils in more mesic areas. These areas are spatially limited in extent (< 9000 ha). The model results were associated with very high uncertainty.

MLRA 41 Southeastern Arizona Basin and Range (521, 091 ha)
Adding a legume to heavily and moderately grazed rangeland would result in an increase in soil carbon storage of up to 0.34 T C/ha/y in loamy textured soils in the wetter portions this area (Cochise and Graham Counties). Again, model results had a high level of uncertainty associated with this practice.

There are very limited possibilities for increasing carbon sequestration in Arizona soils. This analysis identified only those rangelands having a favorable climate, soils and land use change, yet the vast majority of these areas were estimated to have the potential to sequester less than 0.10 T C/ha/y. Although there were some areas with relatively fertile soils and favorable rainfall, the practices required to achieve these estimates are unreliable and not yet proven. In addition, the uncertainty associated with the model estimates that exceeded 0.2 T C/ha/y were very high.

Colorado
There were 3, 871, 478 ha subjected to the analysis described in the methods to identify areas with high potential for carbon sequestration. The results are reported by MLRA (Fig. 35).

MLRA 34 Central Desertic Basins, Mountains and Plateaus (152, 250 ha)
In general, the potential for sequestration is low throughout MLRA 34. Loamy soils in Rio Blanco and Moffat counties (108, 513 ha) have potential to sequester between 0.16 and 0.48 T C/ha/y when legumes are added to existing grazed rangelands.

MLRA 39 Arizona and New Mexico Mountains (15, 748 ha)
Sequestration potential is limited in this MLRA. Addition of legumes to existing rangelands has the potential to increase soil carbon storage 0.29 T C/ha/y on loam soils.

MLRA 48A Southern Rocky Mountains (498, 927 ha)
Rangelands on loam soils in San Miguel (23, 127 ha) and Rio Blanco (11, 112 ha) counties have the potential to increase carbon storage by 0.16 to 0.24 T C/ha/y with the addition of legumes to

existing grazed rangelands. However, the uncertainty associated with these estimates is extremely high.

MLRA 48B Southern Rocky Mountain Parks (225, 868 ha)
Sequestration potential is very limited in this MLRA, typically less than 0.10 T C/ha/y. Sandy loam soils with rangeland cover in Jackson county (23843 ha) can increase carbon storage by up to 0.24 T C/ha/y with the addition of legumes to existing plant communities. This estimate of sequestration potential is highly uncertain.

MLRA 49 Southern Rocky Mountain Foothills (629, 804 ha)
There is substantial potential to increase soil carbon sequestration in MLRA 49, primarily due to the large proportion of the area in small grains. Converting small grain to perennial vegetative cover in Weld (7599 ha) and Elbert (4036 ha) counties can increase carbon storage between 1.30 and 1.60 T C/ha/y. Alternatively, adopting no till tillage on those areas currently under conventional tillage could increase soil carbon between 0.23 and 0.66 T C/ha/y. Adopting reduced tillage would have little impact on soil carbon levels. The uncertainty associated with these estimates is relatively low (<15%). Adding legumes to currently grazed rangelands has the potential to increase soil carbon on much of the area in this MLRA by up to 0.25 T C/ha/y, but the uncertainty is extremely high.

MLRA 51 High Intermountain Valleys (32, 633 ha)
The potential for carbon sequestration is very limited in this MLRA, primarily due to the high elevation and short growing season. Addition of legumes to rangelands with loam soils could increase soil carbon levels by up to 0.14 T C/ha/y, but uncertainty is extremely high.

MLRA 67 Central High Plains (1, 568, 188 ha)
The 437, 110 ha of small grains in the area offer substantial opportunity to increase carbon storage. Converting cropland to perennial cover (including legumes) in this area will increase soil carbon storage an average of 1.3 T C/ha/y. Converting to perennial grass cover without a legume would increase soil carbon uptake an average of 0.6 T C/ha/y. The uncertainty associated with this practices on these soils is relatively high, especially on silty and clay soils. Adopting no till tillage on these acres would only slightly increase soil carbon uptake (generally <0.05 T C/ha/y). Adopting reduced tillage would not affect the soil carbon levels in this MLRA. Counties included in this MLRA are Adams, Arapahoe, Baca, Cheyenne, Elber, Kiowa, Kit Carson, Lincoln, Morgan, Prowers, Washington and Weld.

MLRA 69 Upper Arkansas Valley Rolling Plains (125, 887 ha)
Carbon sequestration potential is very limited in this area because of low annual precipitation. The greatest opportunity is in converting small grains in Lincoln County (1660 ha) to perennial cover with legumes (1.3 T C/ha/y). Adopting no till tillage gains very little increase in carbon storage (<0.05 T C/ha/y)

MLRA 70 Pecos Canadian Plains and Valleys (19, 562 ha)
This is a relatively small area entirely within Las Animas county. Potential to increase carbon storage is limited by low annual precipitation and current land use patterns (current use is rangeland).

MLRA 72 Central High Tableland (659, 581 ha)
Converting small grain croplands to perennial vegetation cover with legumes offers the greatest potential to increase carbon storage in this area (1.1 to 1.35 T C/ha/y). There are currently 248, 149 ha of small grain cropland in Cheyenne, Kiowa, Kit Carson, Logan, Phillips, Sedgewick, Washington and Yuma counties included in this MLRA. Adopting no till tillage offers only slight potential (<0.05 T C/ha/y). Adding legumes to existing rangelands (328, 806 ha) can increase soil carbon storage an average of 0.03 T C/ha/y, but the uncertainty is extremely high.

Many Colorado counties are near or fully subscribed under existing USDA land conversion programs (Conservation Reserve Program). In the program regulations, 25% of existing cropland enrolled in CRP was established as an upper limit. Realizing the potential carbon sequestration associated with cropland conversion to perennial cover in counties that are currently over the limit would require a change in program rules. Those counties are: Baca, Bent, Cheyenne, Crowley, Dolores, Kiowa, Las Animas, Lincoln, Moffat, Morgan, Prowers, Pueblo, Washington and Weld.

Kansas
The procedure described in the Methods section identified 9, 922, 433 ha as having high potential for carbon sequestration in Kansas. The results are reported by MLRA (Fig. 36).

MRLA 72 Central High Tableland (7, 422, 668 ha)
Throughout this MLRA, there is substantial potential for increasing soil carbon by converting small grain cropland (2, 913, 518 ha; 1.1 to 1.3 T C/ha/y), continuous cotton cropland (128, 897 ha; 0.9 to 1.1 T C/ha/y) and irrigated corn cropland (1,318,874 ha; 0.9 to 1.1 T C/ha/y) to perennial grass cover with a legume. Converting these areas to perennial grass cover without a legume reduces the potential per ha by approximately one-half. The uncertainty associated with these practices is relatively low (<15%). Adopting either no till or reduced till tillage offers minimal opportunity to sequester increased amounts of carbon (<0.05 T C/ha/y).

The remaining area of grazing land (3.06 m ha) can increase carbon uptake an average of approximately 0.20 T C/ha/y with the addition of legumes to existing grazing lands. However, the uncertainty associated with this practice is very high.

MLRA 73 Rolling Plains and Breaks (1,726,252 ha)
Converting small grain cropland (679, 744 ha) to perennial cover with legumes has the potential to increase soil carbon storage from 1.1 T C/ha/y (wheat:milo rotation) to 1.4 T C/ha/y (wheat:fallow rotation). Converting these areas to perennial grass cover without legumes will reduce the potential by approximately one-half. Converting irrigated corn cropland (284, 990 ha) to perennial vegetation cover has the potential to increase soil carbon by an average of 1.1 T C/ha/y throughout the region. Adopting no till tillage on this corn cropland could increase the soil carbon storage an average of 0.45 T C/ha/y. There is little advantage to adopting reduced tillage on irrigated corn cropland. Similarly, adopting no till or reduced till tillage on small grain offers little potential to increase soil carbon.

Adding legumes to existing rangelands has the potential to increase soil carbon storage an average of 0.15 T C/ha/y, but the uncertainty associated with this practice is very high.

Improved management of grazing on existing rangelands also offered very little potential to increase soil carbon (<0.05 T C/ha/y).

MLRA 77 Southern High Plains (249, 689 ha)
Converting winter wheat:milo rotations (90,504 ha) to perennial vegetation with legumes has the potential to increase soil carbon an average of 1.0 T C/ha/y. Adopting no till tillage on these lands will increase soil carbon by 0.13 T C/ha/y. Reduced till tillage will not increase soil carbon significantly. Converting continuous cotton cropland (33, 645 ha) to perennial vegetation with legumes has the potential to increase soil carbon by an average of 1.0 T C/ha/y. Adopting no till tillage on these lands offer little improvement to soil carbon levels.

Changes to species composition (adding legumes) on rangelands (125, 240 ha) offer limited potential to increase soil carbon (<0.15 T C/ha/y), although the uncertainty associated with this practice is very high. There is little potential to increase soil carbon by improving grazing management.

MLRA 78 Central Rolling Red Plains (459, 764 ha)
Converting small grain cropland (118, 543 ha; wheat:milo rotation) to perennial vegetation cover with legumes in this area has the potential to increase soil carbon by an average of 1.1 T C/ha/y. Conversion to perennial vegetation without legumes has the potential to increase soil carbon an average of 0.5 T C/ha/y. Adopting no till tillage on these areas will increase soil carbon storage an average of 0.10 T C/ha/y. There is no carbon benefit to adopting reduced till tillage.

Adding legumes to existing rangelands (341, 221 ha) will only slightly increase soil carbon levels (<0.10 T C/ha/y). Improved grazing management offers no opportunity to increase soil carbon levels.

MLRA 79 Great Bend Sand Plains (48172 ha)
This MLRA is dominated by sandy soils under perennial vegetation cover and used primarily for livestock grazing. There is little opportunity to improve soil carbon by altering species composition or managing livestock.

Clark, Comanche, Hamilton, Hodgeman, Kiowa, Morton, Ness, Stanton and Wallace counties are at or near the limit for Conservation Reserve Program participation. All are in MLRA 72.

<u>*Nebraska*</u>
There were 637, 932 ha subjected to analysis in MLRAs 71, 72 and 73 (Fig. 37).

MLRA 71 Central Nebraska Loess Hills (13, 211 ha)
Livestock grazing on native rangeland occupies 8778ha within this area. There is little opportunity to increase soil carbon sequestration through manipulating species composition or managing grazing. The 4433 ha of irrigated corn for silage also have limited potential to increase soil carbon storage (no till tillage < 0.03 T C/ha/y).

MLRA 72 Central High Tableland (532, 948 ha)

Livestock grazing on native rangeland occupies 208, 238 ha in this area and has some opportunities to increase soil carbon storage. The addition of a legume to existing native plant communities can increase sequestration between 0.20 and 0.35 T C/ha/y, but the uncertainty is very high. Improved grazing management offers little opportunity to improve soil carbon.

Row crops on 175, 817 ha offer a wide variety of options and substantial potential to increase soil carbon. Converting to perennial grass cover with or without legume offers the potential to increase soil carbon levels between 1.0 and 1.2 T C/ha/y on sandy, loamy and clay soils. Silty textured soils have slightly less potential (0.5 to 0.6 T C/ha/y). Adopting no till tillage on these lands will increase soil carbon storage between 0.4 and 0.5 T C/ha/y. About 35, 700 ha of this land category are currently in corn silage:alfalfa rotations and would not benefit from reduced tillage practices.

Small grain cropland (148, 893 ha) in this area is typically farmed as a small grain:fallow rotation. Converting these croplands to perennial grass cover could increase soil carbon between 1.3 and 1.5 T C/ha/y if legumes are added. Conversion without legumes would increase soil carbon by about half that amount. There is little soil carbon benefit to adopting any form of reduced tillage in these wheat:fallow rotations.

MLRA 73 Rolling Plains and Breaks (91, 803 ha)
Livestock grazing is the dominant land use in the area and has limited potential to increase soil carbon through species additions or grazing management. Converting row crops (8536 ha) or small grains (2712 ha) to perennial cover could increase soil carbon between 1.0 and 1.4 T C/ha/y.

<u>New Mexico</u>
In New Mexico, 3, 120, 965 ha were subjected to the analysis described in the Methods section. The land was located in MLRAs 36, 39, 70 and 77D (Fig. 38). Curry, Harding, Lee, Quay and Roosevelt counties are near the limit

MLRA 36 New Mexico and Arizona Plateaus and Mesas (182, 799 ha)
Land use in this area is dominated by grazing on native rangeland. The opportunities for increasing soil carbon storage are limited. Adding legumes to existing rangeland plant communities may increase net primary productivity and soil carbon, but uncertainty is extremely high.

MLRA 39 Arizona and New Mexico Mountains (24, 140 ha)
Rangeland grazing is the dominant land use in this area and there is little potential to increase soil carbon because of the low annual precipitation.

MLRA 70 Pecos Canadian Plains and Valleys (2, 250, 308 ha)
Livestock grazing on native rangeland is the dominant land use in this area (2, 238, 157 ha) and there is little potential for increasing soil carbon due to low precipitation. Cropland with row crops, primarily irrigated corn (8677 ha) offers some potential to increase soil carbon by converting to perennial cover, but the majority of this land use is currently in corn:alfalfa rotations and only moderate increases in soil carbon (0.6 T C/ha/y) could be expected from the conversion. In addition, the majority of this land is in Quay county, which is already exceeding

program limits within the Conservation Reserve Program. Adoption of reduced tillage offers little opportunity for increasing soil carbon.
Cropland with dryland small grains (3474 ha) also offers moderate potential to increase soil carbon. Converting to perennial grass cover with a legume would increase soil carbon 1.1 T C/ha/y; without legumes about half that. However, this option is currently limited because all of this land category is within Quay country, which is currently over the program limit for CRP. Because the crop rotation is primarily wheat:fallow, there is little opportunity to increase soil carbon by adoption of no till tillage.

MLRA 77D Southern High Plains (663,718 ha)
Livestock grazing on rangeland is the dominant land use in this MLRA (599, 877 ha). The only land management option that consistently exceeded 0.10 T C/ha/y, although with very high uncertainty, was the addition of legumes to existing rangeland plant communities. Grazing management offered little opportunity to increase soil carbon storage.

Row crops (42, 019 ha) offer some opportunity to increase soil carbon storage, but will require changes in land use that is limited under current federal programs. Irrigated corn:alfalfa rotations (5446 ha) could be converted to perennial grass cover and increase soil carbon between 0.4 and 0.65 T C/ha/y depending on the use of legumes. Dryland cotton makes up the remainder of the row crop category (36, 573 ha). Increasing soil carbon on this land use can be achieved by conversion to perennial grass with or without legume (0.65 vs 0.4 T C/ha/y). The adoption of reduced tillage offers little opportunity to increase soil carbon on row crops in this area.

Small grain cropland (21, 823 ha), either wheat:fallow or wheat:grain sorghum rotations, have substantial potential to increase soil carbon, either through land use change or changes in tillage practices. Converting wheat:fallow rotations (10, 636 ha) to perennial grass cover with legumes could increase soil carbon by 1.1 T C/ha/y. Converting wheat:milo rotations would sequester about half that amount. Adopting no till tillage on wheat:milo rotations could sequester 0.14 T C/ha/y, while no till tillage on wheat:fallow rotations could increase soil carbon by 0.05 T C/ha/y.

A substantial barrier exists to achieving high rates of sequestration in the MLRA. All of the row crop and small grain cropland is located in Lea, Roosevelt and Quay counties. All of these counties are already at or near participation limits in the Conservation Reserve Program. A more effective strategy to reduce emissions might be to increase incentives to keep land with expiring CRP contracts (10 years in length) enrolled in the program. There are currently more than 3500 ha of land enrolled in CRP on which contracts will expire in 2005 or 2006.

Oklahoma
The methodology previously described identified 2, 086, 517 ha in Oklahoma that had high potential for increasing carbon sequestration. This land was located in MLRAs 70, 77, 78 and 80 (Fig. 39).

MLRA 70 (67, 339 ha)
Land use in this area is dominated by livestock grazing on rangeland within Cimarron county. Adding legumes to existing rangeland plant communities has the potential to increase soil carbon between 0.16 and 0.23 T C/ha/y depending on soil texture (loamy sand>sandy loam>loam).

MLRA 77 (796, 597 ha)
In this area, livestock grazing on rangeland dominates land use (540, 140 ha). The only practice identified to consistently increase soil carbon was the addition of legumes to existing rangeland plant communities (0.10 to 0.20 T C/ha/y). However, the uncertainty associated with this practice is extremely high.

Converting row crops, primarily continuous cotton (26, 392 ha), to perennial grass cover with legumes could increase soil carbon storage by 1.0 to 1.2 T C/ha/y. However, all of this land use in this MLRA is within Cimarron county and that county currently exceeds the level of participation allowed for federal program incentives to convert cropland to perennial cover.

There are 231, 920 ha of small grains in this MLRA, dominated primarily by wheat:grain sorghum rotations. Conversion to perennial grass cover with legumes could increase soil carbon by an average of 1.0 T C/ha/y, about half that without legumes. However, the uncertainty associated with these practices is very high. Also, all of these lands are located in Beaver, Cimarron, Ellis, Harmon, Harper and Texas counties, which already exceed program limits for incentives to convert cropland to perennial cover. A more viable option might be the adoption of no till tillage, which could increase soil carbon levels from 0.10 to 0.15 T C/ha/y.

MLRA 80 Central Rolling Red Prairies (54, 545 ha)
There were no options identified to increase soil carbon on rangelands (18914 ha) in this area. The conversion of small grain cropland (35631 ha) to perennial cover could increase soil carbon by 1.1 to 1.2 T C/ha/y with legumes; about half that without legumes. Adopting no till tillage on these lands could increase soil carbon by 0.10 T C/ha/y.

Texas
Within MLRAs 42, 77, 78 and 81 there were 4, 889, 184 ha identified as having high potential for carbon sequestration (Fig. 40).

MLRA 42 Southern Desertic Basin, Plains and Mountains (34, 927 ha)
The dominant land use in this area is livestock grazing on rangeland. The area is entirely within Brewster County. Very low annual precipitation limits the impact of any land use or management change to increase soil carbon levels. There were no practices identified that could consistently increase soil carbon.

MLRA 77 Southern High Plains (2, 840, 164 ha)
A widespread land use in the area is livestock grazing on rangelands (635, 522 ha). Restoring heavily grazed rangelands with grazing management and the addition of legumes could increase soil carbon storage by an average of 0.10 T C/ha/y. However, the uncertainty associated with this practice is very high.

The dominant land use in the area is cropland with row crops, primarily continuous cotton (1, 338, 038 ha). Converting this land to perennial grass cover with legume could increase soil carbon by 1.0 T C/ha/y throughout the area; without legumes, conversion could increase soil carbon by 0.50 to 0.60 T C/ha/y. However, many of the counties in this area currently exceed or are near the program limits for Conservation Reserve Program participation (Armstrong, Briscoe, Deaf Smith, Floyd, Garza, Hockley, Howard, Lamb, Randall, Sherman and Swisher). Together the amount of land in these counties within this analysis total 222, 315 ha. Other counties within the MLRA are not restricted by program limits. Adopting no till tillage offers little opportunity to increase soil carbon (<0.05 T C/ha/y).

Converting small grain cropland (866, 605 ha), primarily wheat:milo rotation, offers substantial opportunity to increase soil carbon. Establishing perennial vegetation with legume can increase soil carbon by an average of 1.0 T C/ha/y; half that without legumes. Again, participation in federal land retirement programs, such as CRP is high in this area and there is limited potential to increase participation. Armstrong (15, 918 ha), Briscoe (7937 ha), Deaf Smith (41, 366 ha), Floyd (13, 872 ha), Oldham (10, 731 ha), Randall (17, 112 ha), Sherman (14, 160 ha) and Swisher (30, 262 ha) counties currently exceed or are near limits on program participation, limiting the impact of land conversion as a means to increase soil carbon in this area. Adopting no till tillage offers the potential to increase soil carbon storage an average of 0.12 T C/ha/y across the area.

MLRA 81 Edwards Plateau (336, 900 ha)
Grazing is the only land use in this MLRA that was extensive enough to be analyzed for carbon sequestration potential. There is very limited potential to increase soil carbon on grazed rangelands in this area. Only clay loam soils (51, 563 ha)within the area would respond to additions of legumes with an increase of more than 0.10 T C/ha/y. The uncertainty associated with this practice is very high.

<u>*Utah*</u>
Major Land Resource Areas within Utah (Fig. 41) that were identified has having land with high carbon sequestration potential were:

- 25 Owyhee High Plateau (84, 123 ha)
- 28 Great Salt Lake Area (982, 805 ha)
- 34 Central Desertic Mountains, Basins and Plateaus (119, 357 ha)
- 35 Colorado and Green River Plateaus (28, 135 ha)
- 39 Arizona and New Mexico Mountains (64, 887 ha)
- 47 Wasatch and Uinta Mountians (423, 406 ha)
- 48 Southern Rocky Mountains (43, 609 ha).

Regardless of soil and land form classification, the low annual precipitation was the overriding factor limiting response to management in all of the MLRAs. Only the addition of legumes to existing rangeland livestock grazing systems were identified has having a positive effect on soil carbon storage (generally 0.10 to 0.20 T C/ha/y). However, this practice is associated with very high uncertainty.

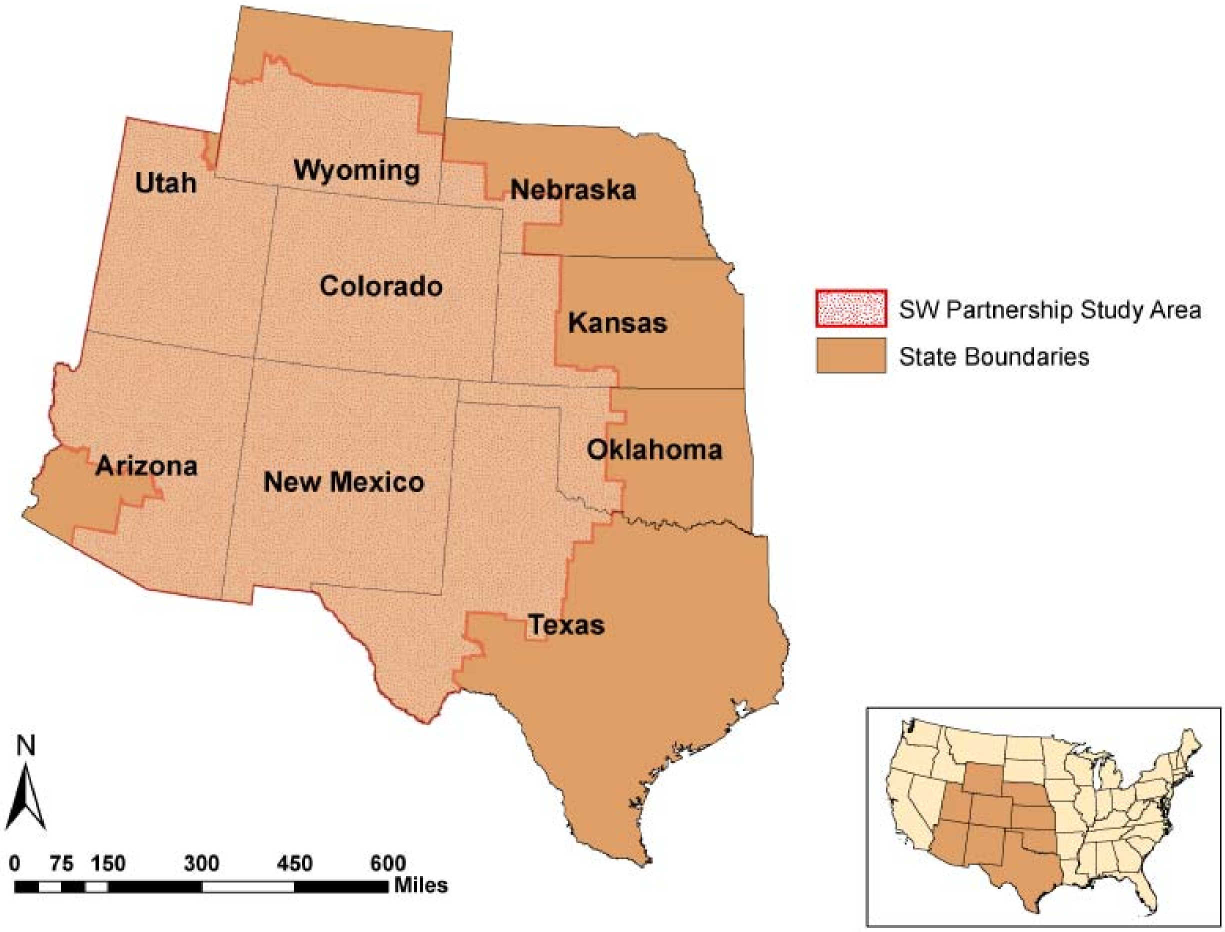

Fig. 26. Study area for assessing carbon sequestration potential in the Southwest Carbon Sequestration Partnership region.

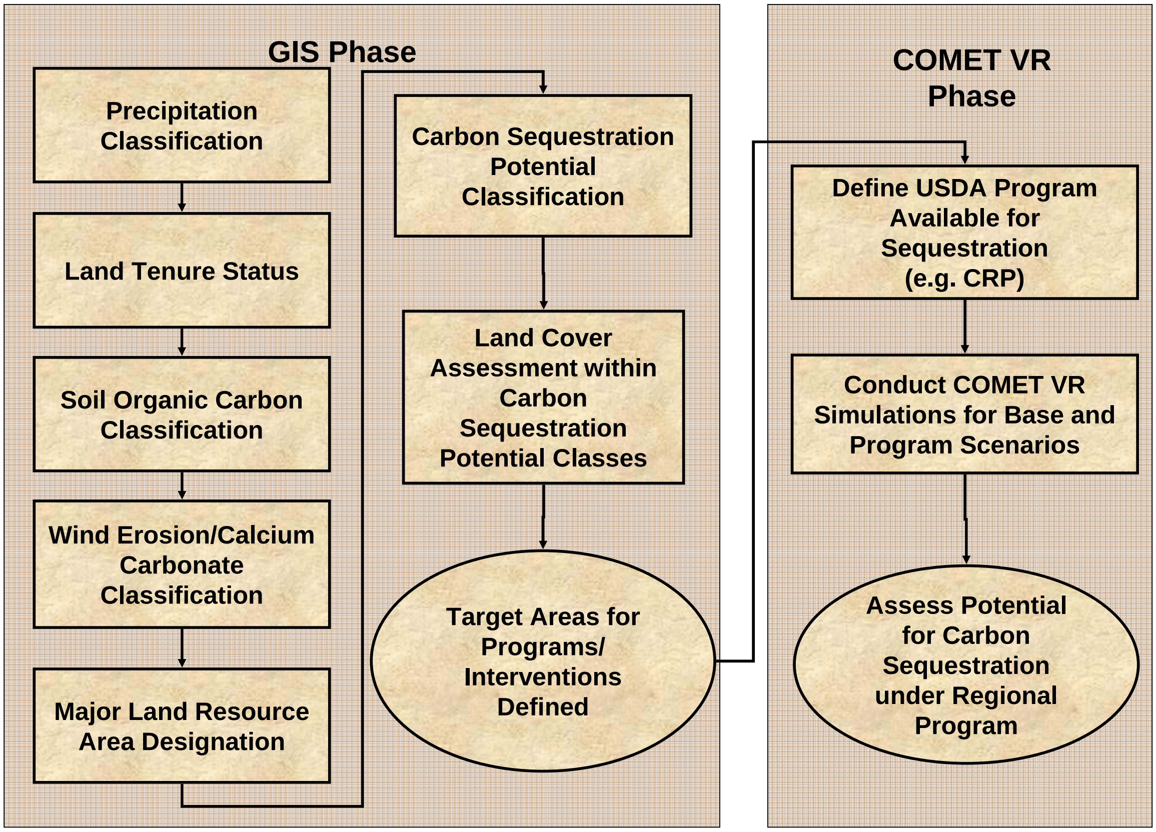

Fig. 27. General framework for assessing carbon sequestration potential in the Southwest Carbon Sequestration Partnership region.

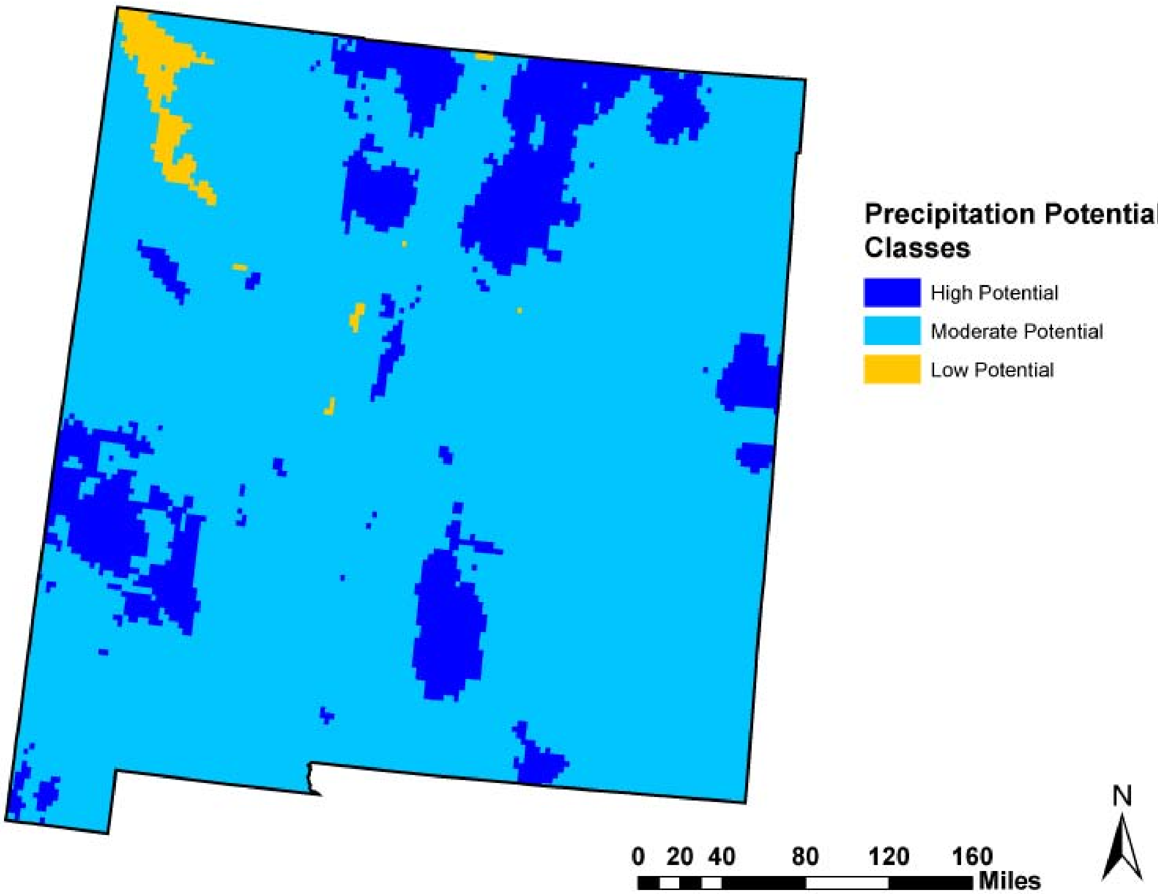

Fig. 28. An example of precipitation potential classification for New Mexico. Potential classes were based on the long term average precipitation (Spatial Climate Analysis Service, Oregon State University, http://www.ocs.oregonstate.edu/prism/) and was classified as follows: No Potential (0 to13 cm), Low Potential (13 to 23 cm), Moderate Potential (23 to 46 cm) and High Potential (>46 cm).

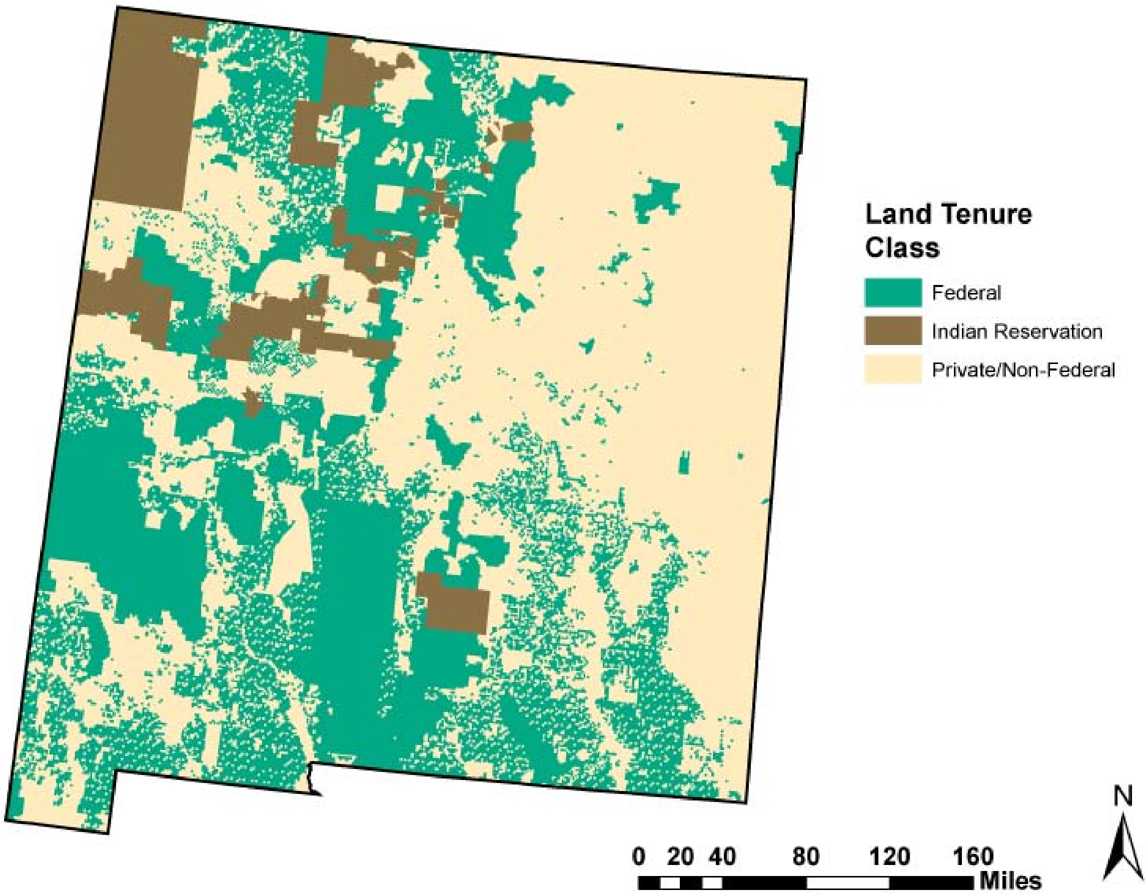

Fig. 29. An example of the land tenure classification for New Mexico using the federal and Indian lands spatial coverage from the National Atlas (www.nationalatlas.gov).

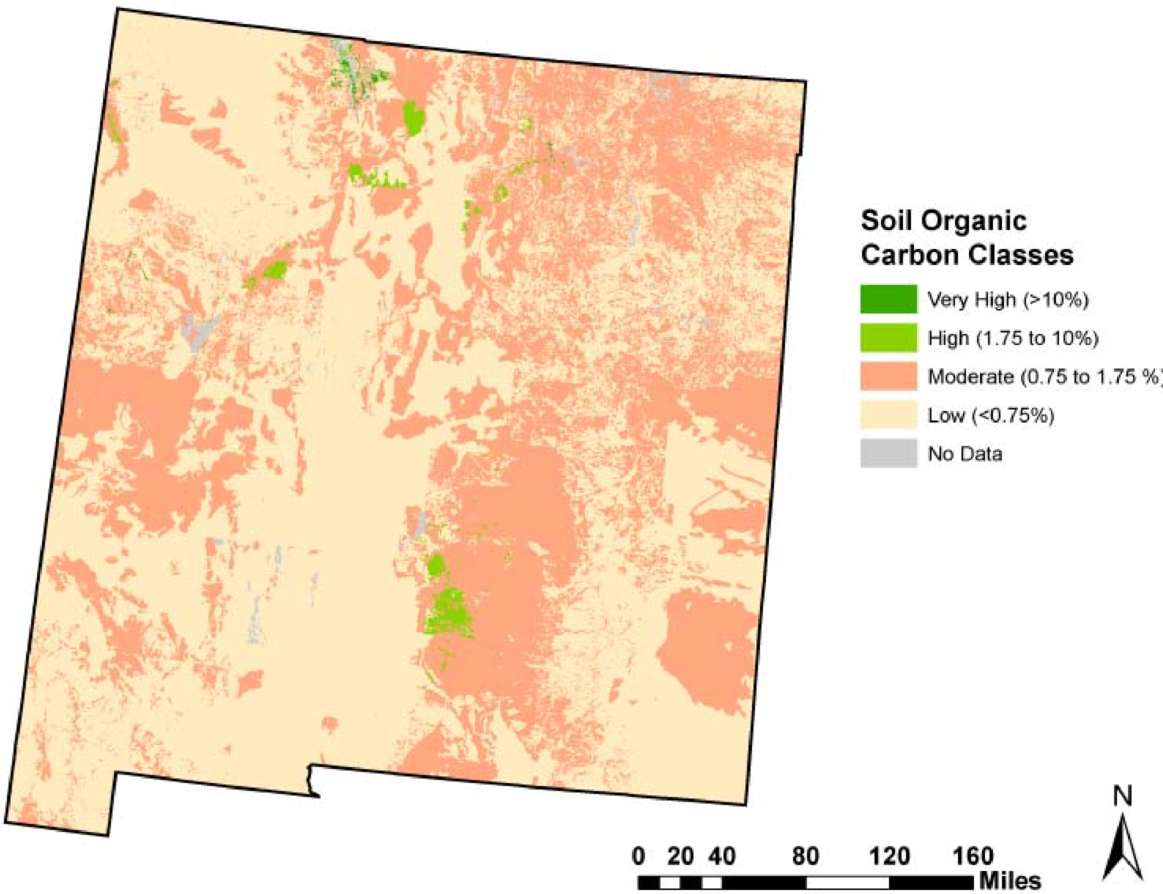

Fig. 30. Soil organic carbon classification example for New Mexico. Soils were classified based on data available from the NRCS SSURGO and STATSGO databases.

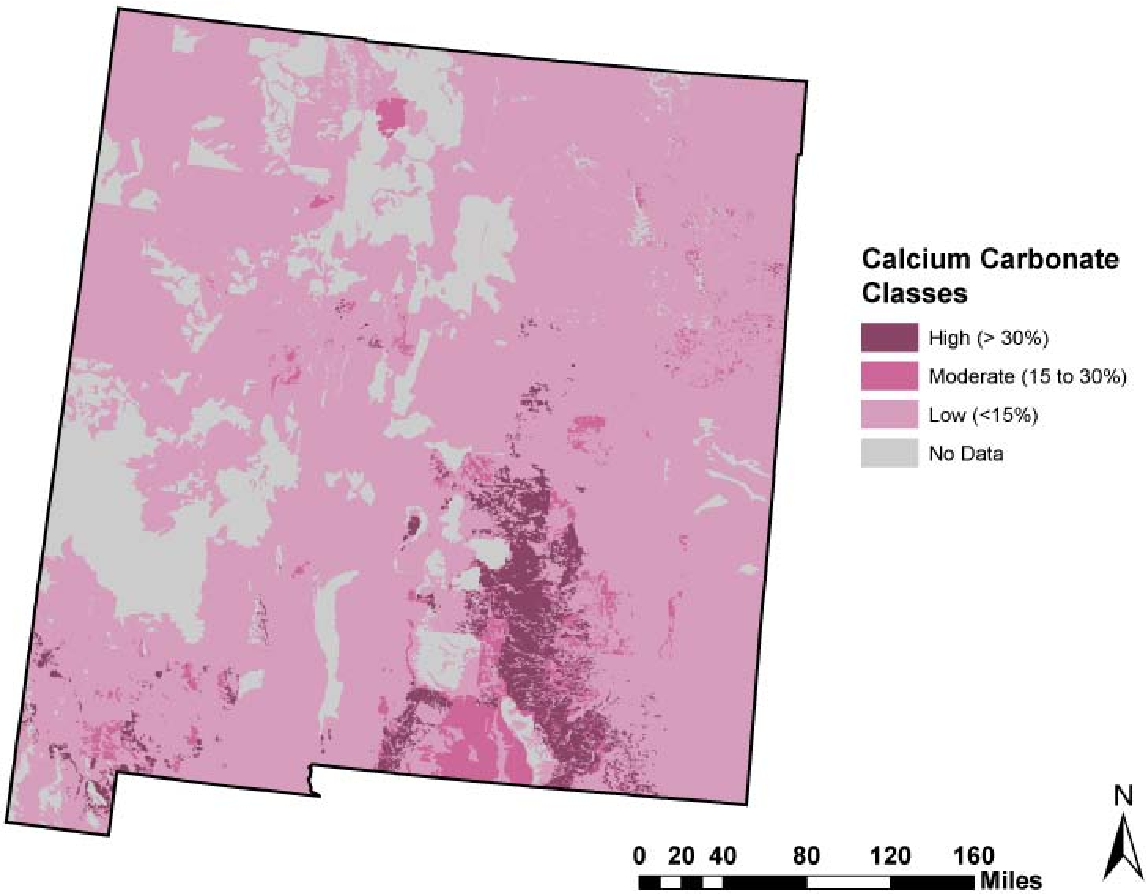

Fig. 31. Calcium carbonate ($CaCO_3$) classification example for New Mexico. Soils were classified based on data available from the NRCS SSURGO and STATSGO databases.

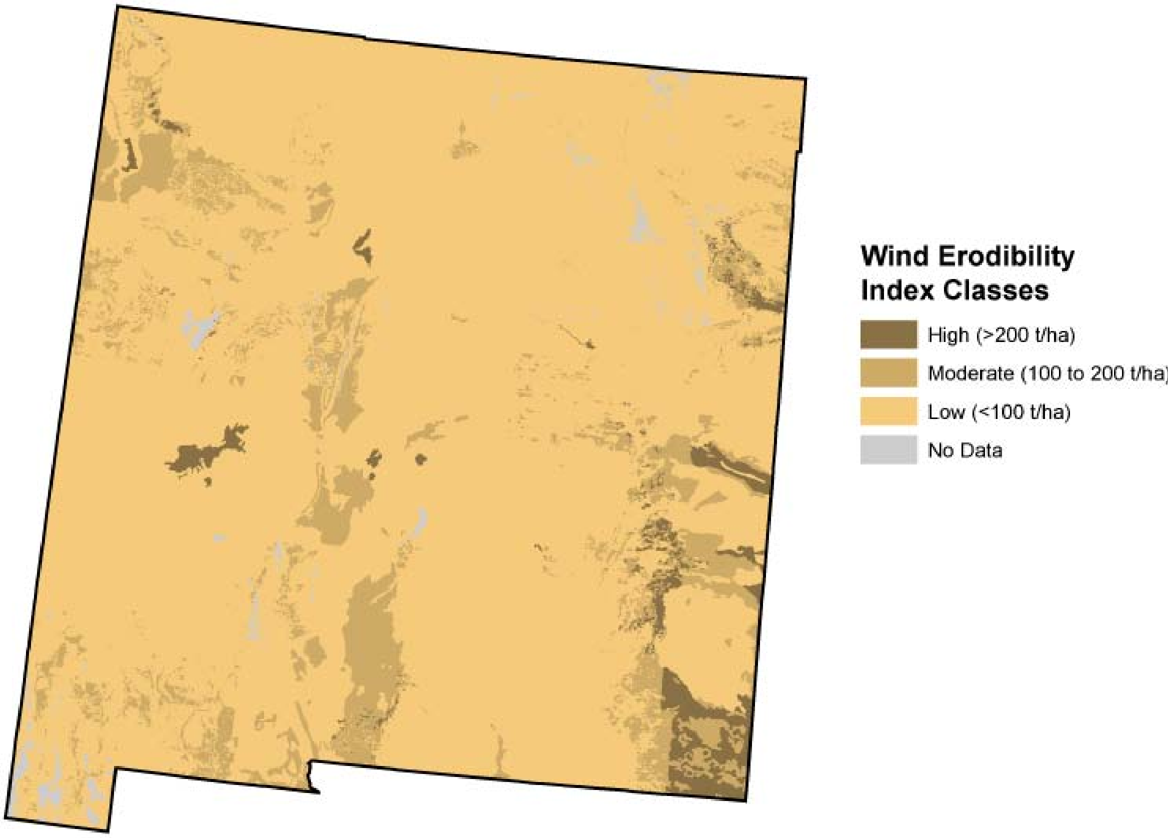

Fig. 32. Wind Erodibility Index (WEI) classification example for New Mexico. Soils were classified based on data available from the NRCS SSURGO and STATSGO databases.

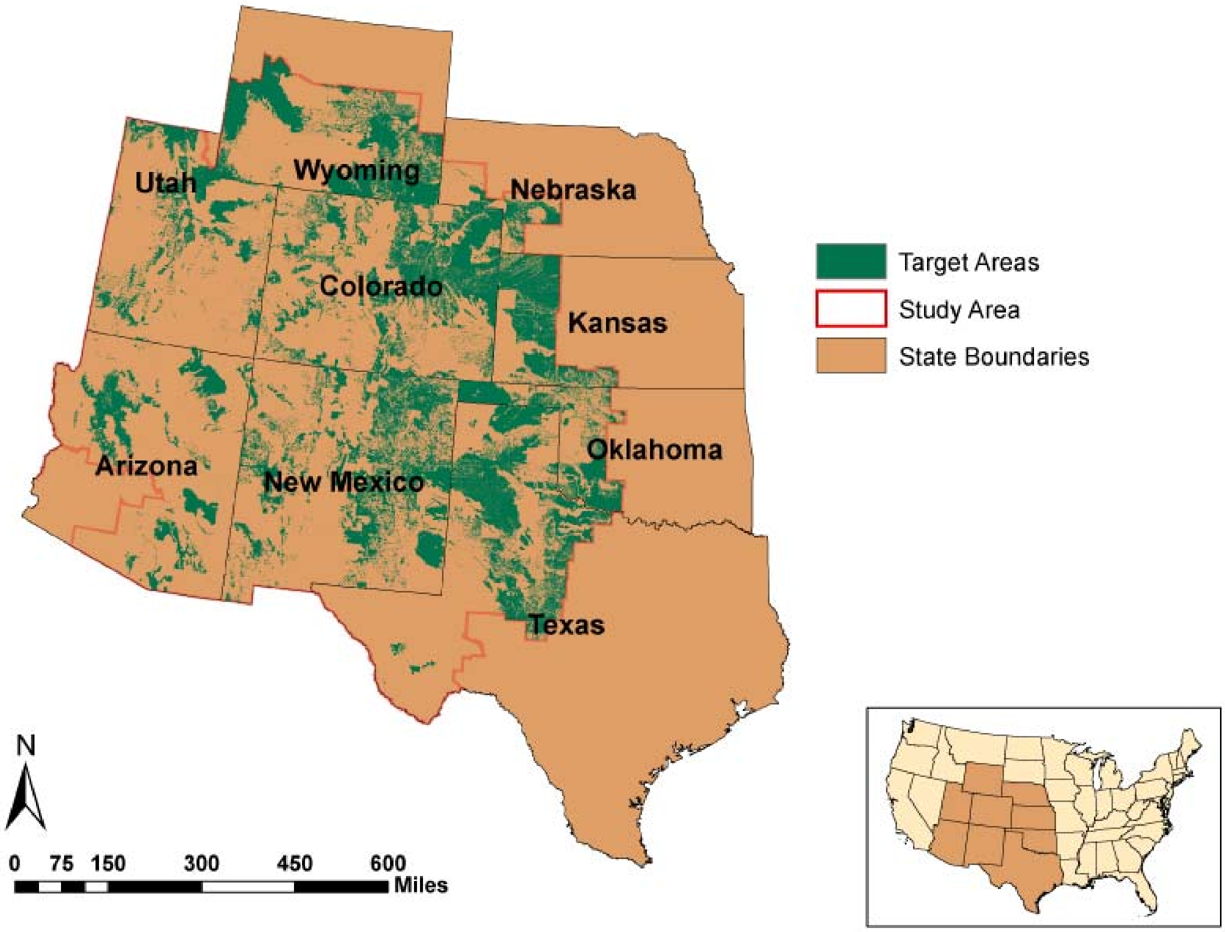

Fig. 33. Results of spatial query to identify target areas for assessing carbon sequestration potential for regional carbon seqestration programs/interventions.

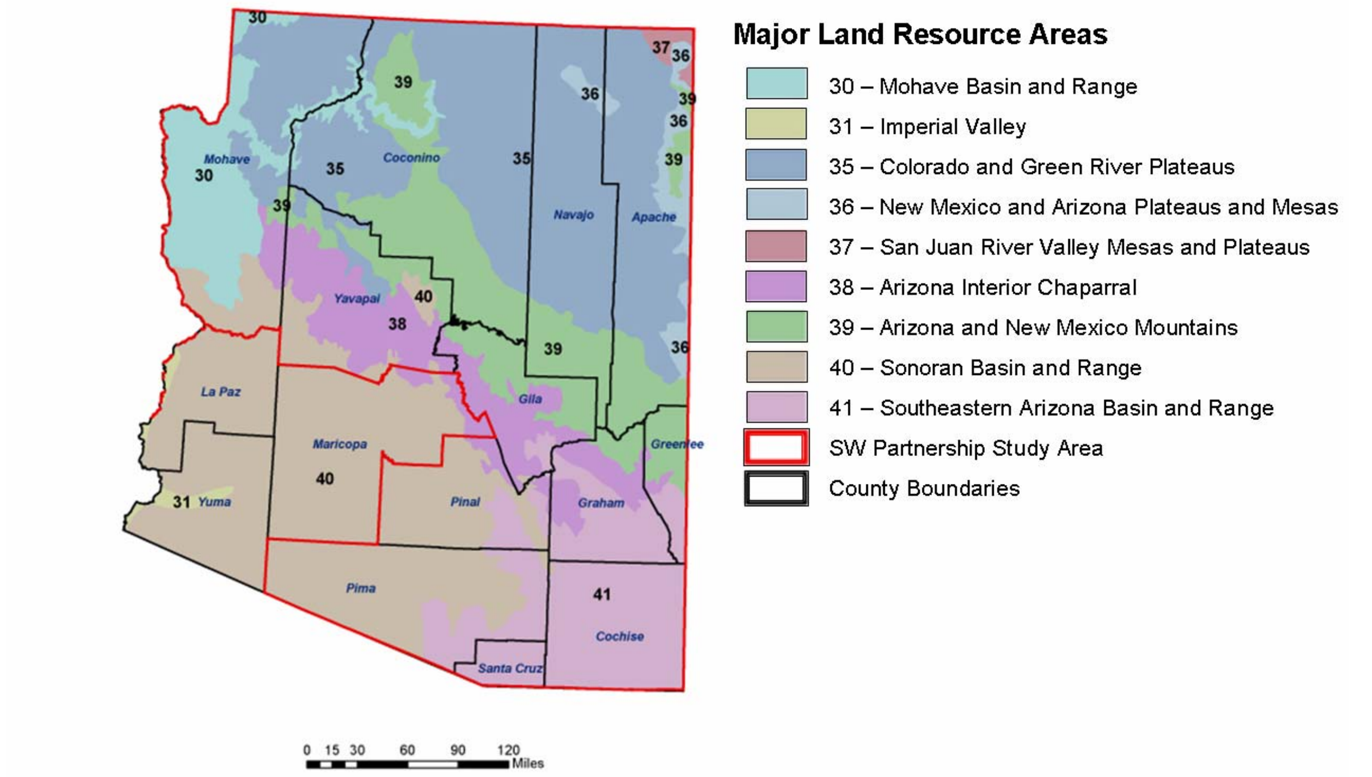

Fig. 34. Arizona—spatial distribution of MLRA.

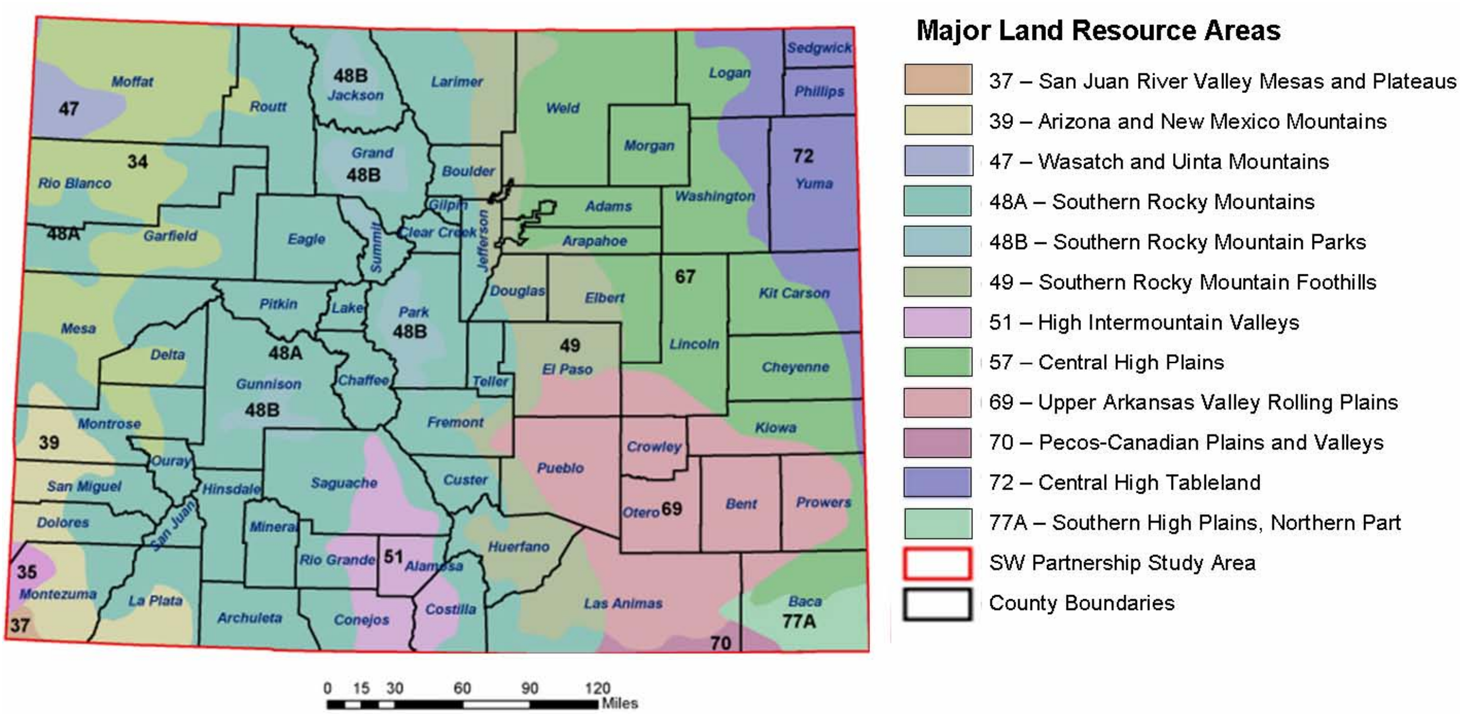

Fig. 35. Colorado—MLRA distribution.

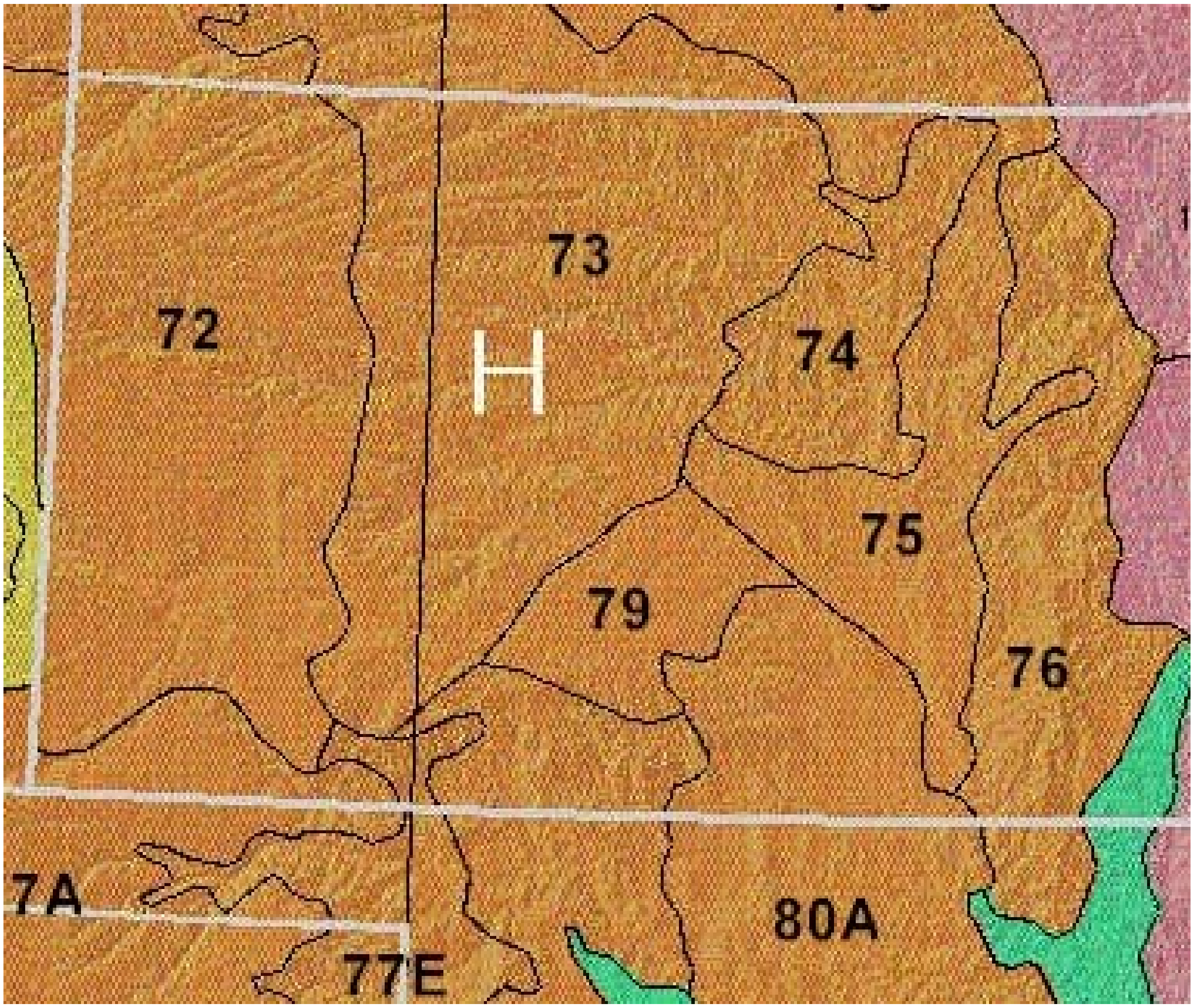

Fig. 36. Kansas —MLRA (Southern Plains Range Research Station)

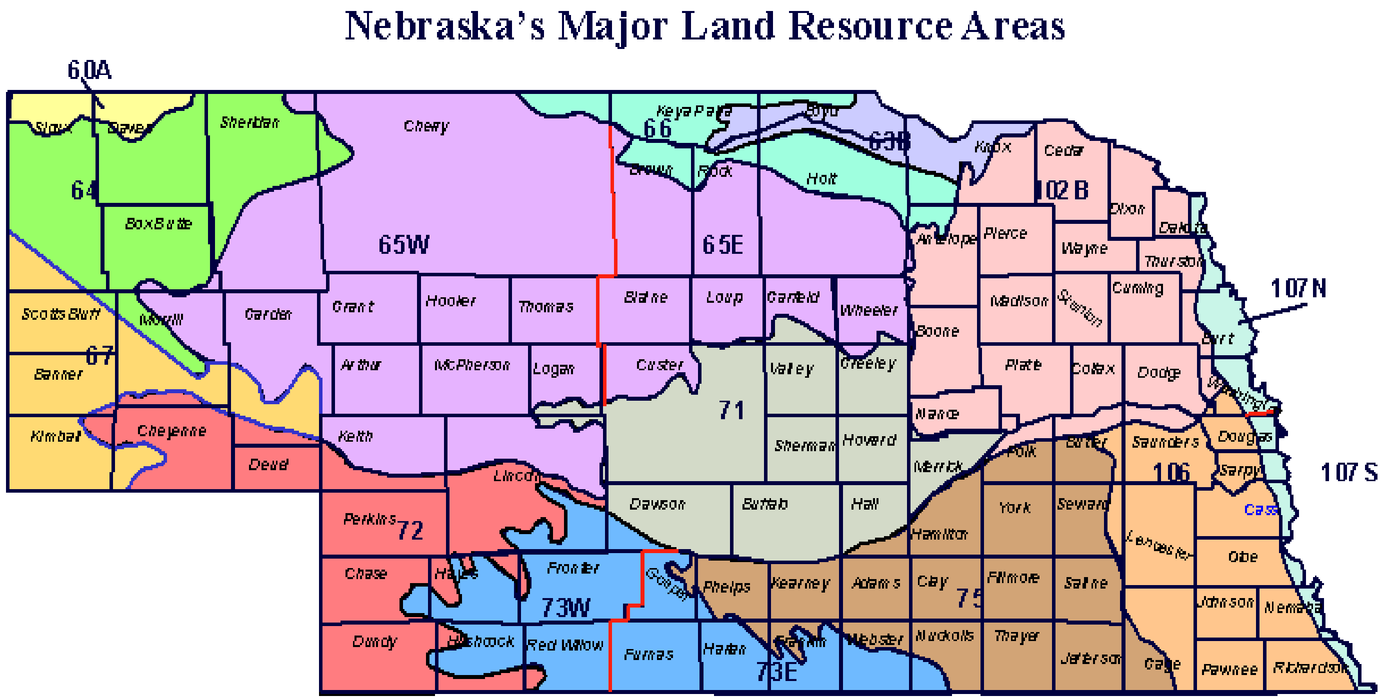

Fig. 37. Nebraska—MLRA distribution.

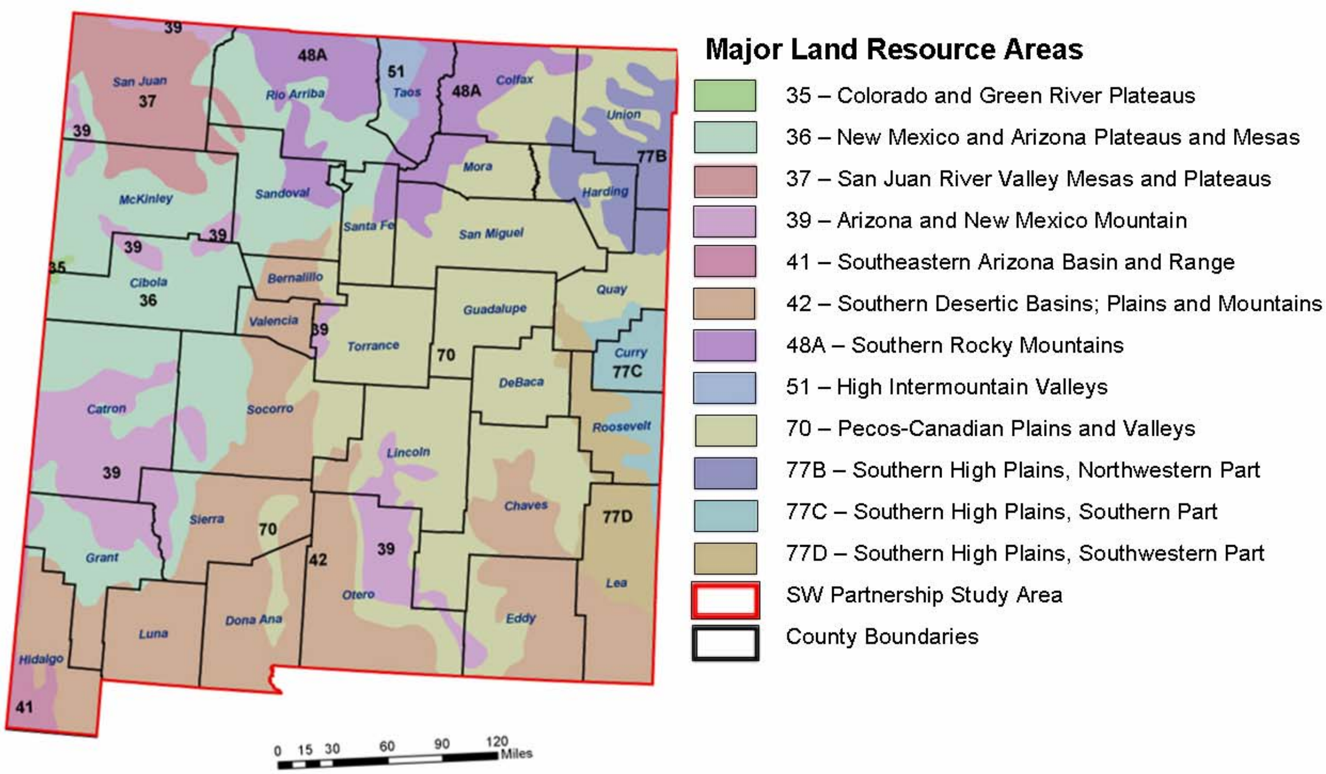

Fig. 38. New Mexico—MLRA distribution.

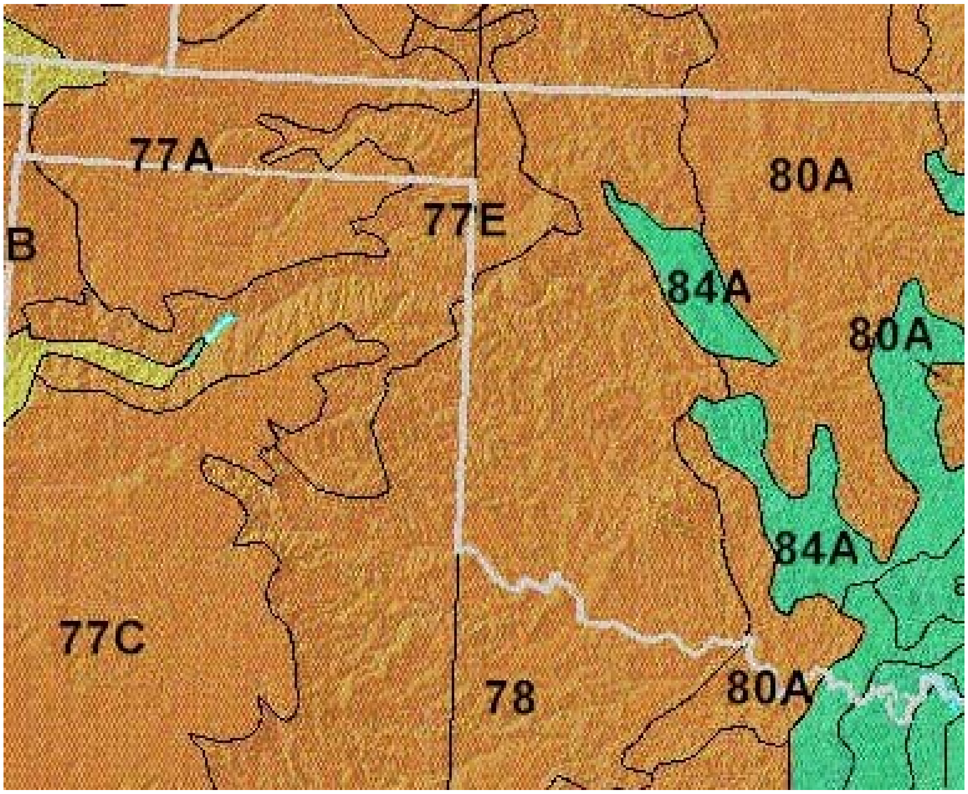

Fig. 39. Oklahoma—MLRA distribution.

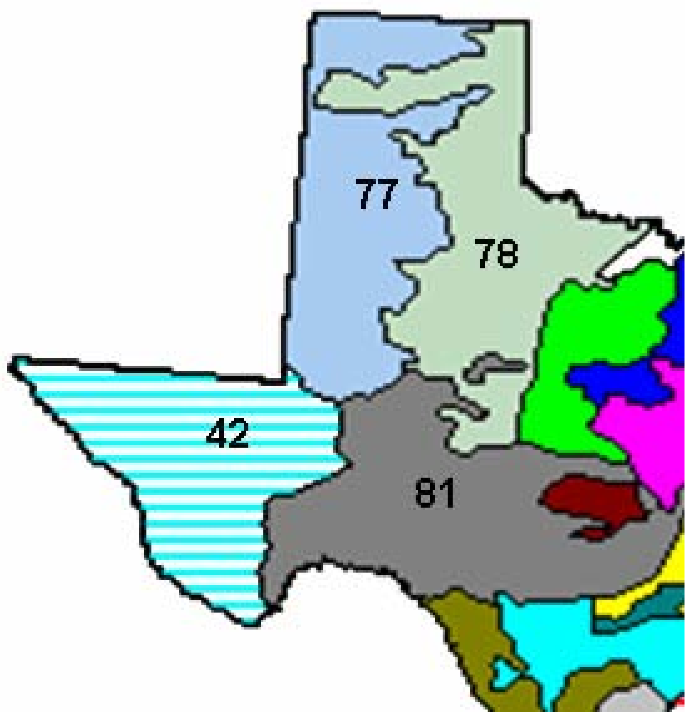

Fig. 40. Texas—MLRA distribution.

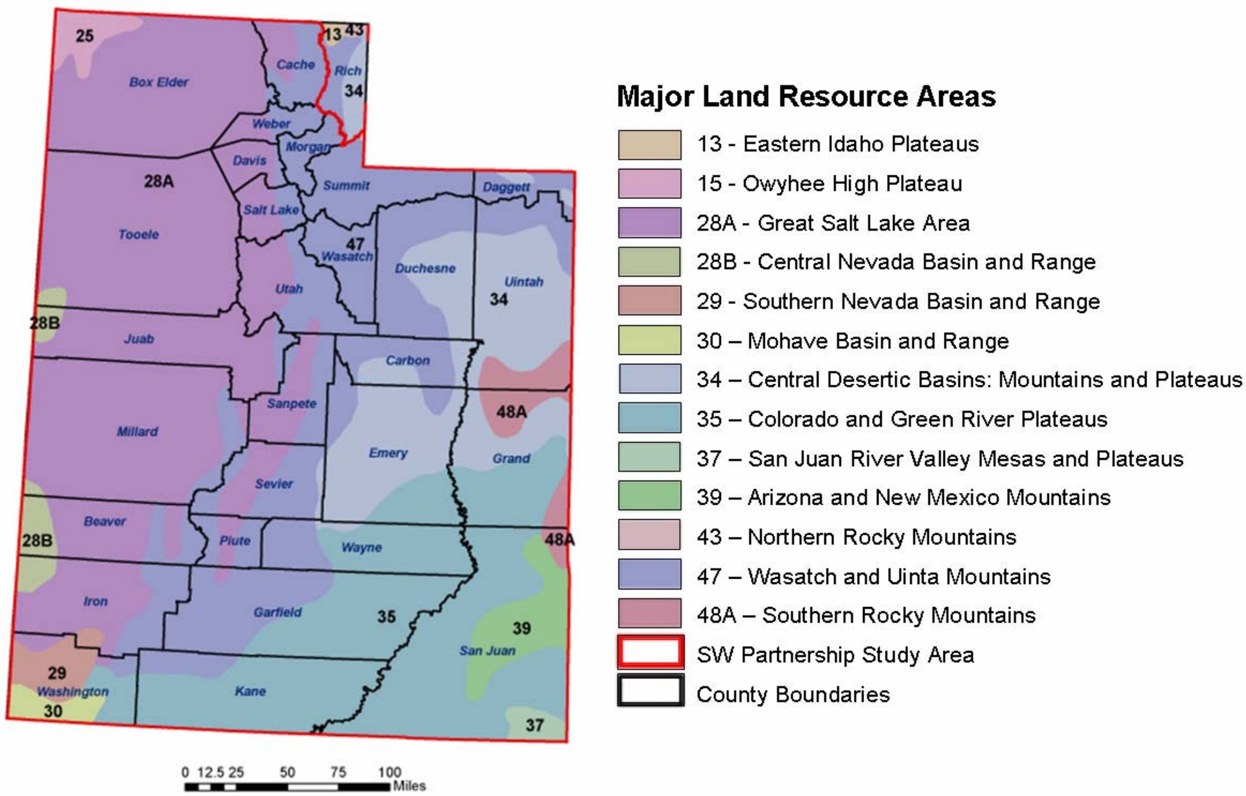

Fig. 41. Utah—spatial distribution of MLRA.

Regulatory Summary

The objective of Phase 1 regulatory activities was to determine the regulatory frameworks of each state, specifically as they relate to carbon sequestration. This information serves both as a tool for future sequestration projects, including the Pilot Tests of Phase II, and to identify regulatory gaps that may be obstacles to such projects. The Southwest Partnership began developing regulatory and permitting action plans during Phase I for possible Pilot Tests, and this effort is being continued and integrated seamlessly with Phase II activities.

Researchers in Arizona, Colorado, New Mexico, Oklahoma, Texas, and Utah reviewed the relevant State statutes and rules, and consulted with respective State regulators to assess current regulatory framework for carbon sequestration. The general consensus is that because most of the partnership States have oil production, often handling CO_2 injection for Enhanced Oil Recovery (EOR), the existing regulatory framework is sufficient to handle the Pilot Test scale projects. As discussed below, however, it is possible that these test projects will reveal gaps that must be closed through regulatory action.

A significant start in assessing the current regulatory framework has been made by the IOGCC Geological Sequestration Task Force, who during the time period of Phase I assembled a regulatory framework for carbon capture and geological storage at the request of the Department of Energy Its report summarizes the current regulatory regime for CO_2 on a state-by-state basis. One of our partnership researchers also participated in the Interstate Oil and Gas Compact Commission (IOGCC) Geological Sequestration Task Force (detailed below), assisting by providing information and guidance.

Our expectation is that as carbon sequestration activities intensify the current regulatory environment will shift to accommodate emerging technologies and realities. An area where this is particularly important is the realm of measurement, monitoring, and verification (MMV). The development of MMV protocols is an evolutionary process, and activities in Phase II will likely involve new regulatory requirements. During Phase I we were able to develop close working relationships with several State regulators, keeping them informed of our progress and new developments. These relationships should enable effective technology transfer.

A product of the Phase I project was identification of three geological and one terrestrial sequestration validation project: (1) Aneth Field, Paradox basin; (2) San Juan basin Coal fairway; (3) SACROC-Claytonville fields, Permian basin; (4) San Juan basin terrestrial project. Fortunately, Utah, New Mexico, and Texas already have existing regulatory regimes handling CO2 injection for EOR projects, which should streamline the permitting process for the geological sequestration projects. The terrestrial project would be permitted in accordance with USDA regulations.

Aneth Field, Paradox basin – In Utah, wells that are used for the enhanced recovery of oil and gas are considered Class II wells under the Underground Injection Control (UIC) program, and normally regulated by the Utah Division of Oil, Gas, and Mining of the State's Department of Natural Resources. However, the regulation of Class II injection on Native American tribal lands is retained by the federal government through the U.S. Environmental Protection Agency, specifically the Region 8 office in Denver, Colorado. The proposed Aneth Field project is in the Navajo Nation, and therefore falls under EPA jurisdiction.

San Juan Basin Coal fairway – New Mexico already has an existing regulatory construct for CO_2 injection, and classifies EOR and EGR injection activity as Class II under UIC. The State has also adopted specific rules and regulations governing long-term CO_2 storage through the Oil Conservation Division. Thus, the enhanced coalbed methane project in the San Juan Basin will be permitted under rules and regulations developed and administered by the New Mexico Oil Conservation Division (IOGCC, 2005)

SACROC-Claytonville fields, Permian basin – In Texas CO_2 is currently being injected for EOR, and such activity is classified as Class II injection under UIC. Furthermore, the industry partner for this project, Kinder Morgan, has extensive experience transporting and injecting CO_2, and is familiar with the permitting requirements.

Attached to the end of this report are a series of Appendices A through F that summarize the current regulatory framework applicable to the oil and gas industry and geologic sequestration of carbon:

1. Appendix A – Arizona
2. Appendix B – Colorado
3. Appendix C – New Mexico
4. Appendix D – Oklahoma
5. Appendix E – Texas
6. Appendix F – Utah

CO_2 Sources in the Southwest Region

The Gas Technology Institute (GTI) prepared an extensive report, for this project, "Source Location Data for SW Regional Carbon Sequestration Partnership – Phase I," comprises a summary of various databases assembled to help locate and quantify the CO_2 emissions in the Southwest Region. These point sources in the southwest region are mainly coal-fired power plants. Other sources include natural gas processing plants, refineries, ammonia/fertilizer production, ethylene and ethanol plants, and cement plants. Because of its size (more than 300 pages) and scope, GTI's report will be presented in full at the end of the Final Report, as Appendix G.

Separation and Capture Technologies in the Southwest Region

The Regional Partnerships for Carbon Sequestration programs were required to identify the best carbon sequestration options in their respective regions, consisting of a CO_2 source, applicable CO_2 capture technology, transportation logistics (if applicable) and destination formation for non-terrestial sequestration approaches. In most cases the carbon capture step is the most costly, and selecting the appropriate least-cost options will be of particular importance. GTI was selected to provide advice and consultation on capture technologies for the Southwest Partnership.

This report consists of a summary of commercial technology and costs applicable to point sources in the southwest region, which are mainly coal-fired power plants. Other sources include natural gas processing plants, refineries, ethanol plants, and cement plants. Research in progress to develop new technologies for carbon dioxide capture will also be briefly summarized.

This information will assist in identifying candidate projects for Phase II.

The objective of this section is to delineate technologies applicable to capturing carbon dioxide from point sources and to provide estimates from various sources of the specific costs of such technologies. Research and Development on new technologies will be reviewed and a listing of those that appear promising and are sufficiently in the development cycle will be presented.

Background Information about CO_2 Capture

The capture of CO_2 must occur before CO_2 can be sequestered. Several excellent reviews of the subject have been published (see particularly Curt M. White et al., 2003 Critical Review: Separation and Capture of CO_2 from Large Stationary Sources and Sequestration in Geological Formations—Coalbeds and Saline Aquifers, presented at A&WMA's 96th Annual Conference & Exhibition in San Diego, CA, June 2004.)

The approach to capture has been delineated into three major approaches: post-combustion, oxycombustion, and precombustion (or decarbonization). Figure 42 (courtesy Carbon Capture Project) illustrates these approaches in a simplistic way.

Post Combustion Decarbonisation

Post-combustion approaches refer to the application of various technologies to removing the carbon dioxide from the flue gases resulting from combustion. As will be discussed in more detail in the following sections, amine (a weak base) absorption processes are commercially available to effect this removal. Drawbacks are residual oxygen in the flue gas, which degrades the amine, low concentration of oxygen, low working pressures resulting in large equipment, and low concentration of CO_2 to be removed (<15%) also resulting in large equipment sizes and high solvent circulation rates. This approach is generally the only one available to remove CO_2 from already existing power plants and other large "point sources". Both Fluor and ABB offer commercial embodiments of this technology based on the amine MEA; monoethanolamine. Mitsubishi offers a newer solvent KS-1, but the basic process is the same. Relatively limited experience exists with coal fired flue gases in "PC" or pulverized combustion power stations.

Precombustion Decarbonisation

Precombustion decarbonisation refers to various processes which convert the fuel at high-pressure into a synthesis gas, mainly CO, CO_2 and H_2. The non-hydrogen species can be more readily and inexpensively removed at the high pressure, high concentration, oxygen-free conditions that result. Typically this approach is coal gasification followed by CO_2 removal using a physical solvent and possibly chemical reactors conducting water gas shift to produce additional hydrogen from the H_2O and CO in the syngas. Reforming, where natural gas and certain liquid hydrocarbon fuels, e.g., naphtha, are heated over a catalyst at moderate pressures of several hundred pounds is currently widely employed to make synthesis gas for fertilizer manufacture or hydrogen for chemical and refinery operations, is another prominent example of precombustion decarbonisation. Integrated Gasification Combined Cycle (IGCC) is an advanced approach along these lines to produce electricity at large central stations, replacing the conventional approach of PC-fired boilers. EPRI was instrumental in developing this technology by funding the first commercial demonstration plant, Cool Water, in California, a few decades ago. Seven early adopter plants of this type have been built worldwide but further adoption has been hampered by a perception of risk unacceptable to the utility industry and higher costs (in the absence of a current requirement to remove CO_2 and other trace substances). AEP has nonetheless announced it will build an IGCC plant in the near future. A photograph of a Selexol installation at a new IGCC plant in Italy is shown in Fig. 43.

Removal of naturally occurring CO_2 from natural gas in the course of preparing natural gas for pipeline transport is another example of precombustion decarbonisation, although the carbon inherent in the fuel molecular structure is not affected. Ultimately, an end user fuel of pure hydrogen could be produced. The product of combustion of hydrogen is water only. Provided the CO_2 capture and sequestration was carried out at the hydrogen production plant, there would not be any net carbon emissions from the combustion of fuels processed in this manner.

Oxycombustion

The third major approach is oxyfiring or oxycombustion. Since all fuels are hydrocarbons, the products of complete combustion are H_2O and CO_2. If oxygen is used instead of air in the combustion process, then no nitrogen, N_2, will be present in the combustion offgas or flue gas, which will increase the concentration of CO_2 in the flue gas and simplify and make less expensive the process to remove or capture CO_2 from the flue gas. In order to avoid the excessive temperatures that will occur in the complete combustion of a fuel in oxygen, recycle of cooled flue gas or injection of water to the inlet of the system is required. This technology is in trials in California being conducted by Clean Energy Systems at the nominal 5 Mwe scale.

MEA for CO_2 Capture from Post-combustion

Since the major sources of CO_2 in the southwest region are coal-fired power plants, any approach to lowering the emissions significantly must ultimately deal with these sources. At present the only technology which is near enough to commercialization is the Mitsubishi offers an advanced solvent, KS-1, that has a number of advantages over MEA, but this is in early commercialization at this point. Fluor and ABB both market a technology based on MEA. Fluor has the larger installed capacity of the two. They refer to their process as the Econamine FG process, which was developed by DOW and was previously available as the GAS/SPEC FT-1 process. Sixteen commercial plants were built of which seven are still operating. None of the large plants are operating on coal-fired systems, but several pilot units were tested with coal. Applications of this process to cement plants should be straightforward. A flow diagram of this process is shown in Fig. 44.

MEA (a solution of 30% MEA in water) is circulated to the top of the absorber tower where it contacts upflowing flue gas. This flue gas needs to have been cooled to approximately 50°C, so in plants without wet FGD units a direct contact cooler will need to be added. Also a blower is required to provide the "head," or to overcome the pressure drop that flowing through the absorber tower entails. It reacts with the CO_2, which is then carried out of the absorber along to a regenerator or stripper. Steam is used to heat the solution, which boils off some of the solution water and "strips" out the CO_{2}, which is then captured, polished, dried and compressed, usually to 2000 psi, for transport. The stripped or lean MEA solution is then pumped back to the absorber for reuse. The process needs steam for the stripping operations and this steam will come from steam that would otherwise be available in the power plant steam circuit; thus, there is a "parasitic" power loss. The compressor, blower and solvent circulation pumps also introduce parasitic power losses. The total loss of power due to addition of CO_2 capture is on the order of 20%.

Drawbacks of this process are high corrosion potential, large MEA losses due to vaporization and degradation, inefficiency, and parasitic power loss.

Estimation of Costs of CO_2 Capture

It is to be understood that CO_2 capture from large stationary sources has been very sparsely applied and usually in unique situations, for example where there was a particularly robust market for the CO_2, such as for food grade use, or for EOR in a particularly amenable reservoir. Since capture from electric power stations will be the largest source in most regions, we need mainly to be concerned with those costs including the costs from near-term power generation technology such as IGCC and possibly natural gas-fired turbine plants. Costs for such applications can be presently estimated with accuracy probably on the order of ±25% and no better, and not considering site specifics which will further broaden the range of estimation accuracy. Estimating the costs of CO_2 capture and related metrics (see below) for hypothetical processes and processes in early stages, R&D cannot be done within a range of even 200%. Rand Corporation studied the accuracy of cost estimation of pioneer plants in DOE funded studies in the 1980s (E.W. Merrow, K.E. Phillips, and C.W. Myers, Understanding Cost Growth and Performance Shortfalls in Pioneer Process Plants (Santa Monica, CA: The RAND Corporation, 1981). Even with technology that is proven and well understood, cost estimates can differ widely based on assumptions of fuel costs, inflation, financing costs, capacity factors, reliability, sparing philosophy, location, site specifics, design philosophy, tax basis, depreciation approach, tax credits and other factors.

In order to bring some sense of order to this a transparent, common basis needs to be established setting down the assumptions and values of as many parameters as possible. NETL, recognizing this, commissioned the Carnegie Mellon University Center for Energy and Environmental Studies to produce a computer software to produce consistent estimates for major power generation approaches with a variety of fuels (natural gas, various coals). Using this program apple-to-apple comparisons can be made and the necessary comparison metrics for different processes, such as cost of CO_2 avoidance (see below) can be generated relatively easily. The model, IECM or Integrated Environmental Control Model, is publicly available from the CMU Center for Energy and Environmental Studies website http://www.iecm-online.com/cees_download.htm and is currently in version 4.0.4.1, released in September 2004. The program is not complete; for example, at present the only IGCC scheme is Texaco cold quench, but despite these limitations, representative costs can currently be generated. GTI has developed similar information for the cost of CO_2 removal from natural gas using various processes and at various plant capacities.

Metrics for Evaluation of CO_2 Capture

Important metrics for evaluation of CO_2 capture are the "cost of CO_2 removal" and the "cost of CO_2 avoidance". The former metric is simply the cost of removal of CO_2 per unit mass removed. Since there are efficiency penalties associated with removing CO_2, the net power from any plant fitted with CO_2 capture will be lowered, so the cost per net kWh delivered will be higher than the cost of CO_2 removal. Thus, additional investment may be required to bring the plant back up to the rated capacity or alternatively, add incremental power by some other acceptable approach without adding to the CO_2 emissions. The cost of CO_2 avoidance can also be interpreted as the value of the carbon tax (fixed and proportional to C emissions) at which the "power plant" is indifferent, at a fixed level of CO_2 capture, to paying the carbon tax or the cost of CO_2 mitigation. The plant would therefore prefer the CO_2 mitigation costs at any higher level of carbon taxes.

Other metrics are the cost of electricity (COE) with and w/o carbon capture and the total plant annualized investment.

Costs for CO_2 Capture from Power Plants

Results from applying the IECM model (see above) to a number of scenarios were presented by Rubin at the Third International Conference on Carbon Sequestration held in May 2004 in Alexandria, VA USA. Figures 45 through 47 are significant slides excerpted from his paper "Comparative Assessments of PC, NGCC, and IGCC Power Plants with and without CO_2 Capture and Storage".

The comparison is based on 2% S bituminous coal and assumes a capacity factor of 75% for all of the plants. PC plants are supercritical (but not ultra supercritical) design and the IGCC is based on Texaco cold quench and the Selexol process for CO_2 removal. The NGCC uses two GE frame 7 turbines. All reference power plants are 560 MW. Since current natural gas prices are so high, the COE form NGCC is also high and actual capacity factors for NGCC plants has been below 35% in the past year or two. Therefore the calculations and charts are unrealistic for current natural gas prices. NGCC would not be the preferred option for least cost electricity and actual reductions of CO_2 emissions would not be realized at the low capacity factors.

Figure 45 plots CO_2 emission rates as kg/MWh for the three plant types. As can be easily seen, PC and IGCC have similar emission rates, mainly because of using the same fuel, coal. The NGCC plant has an emission rate less than half of the coal-fired units. The values for emission rates are of course less when capture is added at the nominal 90% capture level but the advantage of NGCC at less than half the emission rate for the coal-fired units is maintained.

Figure 46 illustrates the cost of electricity from the three power plant types as well as the respective contributions of the reference plant, capture and transport+storage, showing that the differences in the three plant types is not pronounced when there is no CO_2 capture. IGCC is slightly more expensive but by less than 10% of the COE for the PC plant and less than 15% of the COE of the NGCC plant. The COE with capture is significantly higher than w/o capture, more than 50% higher for the PC plant and if transportation and storage is taken into account, 75% higher. We see the increase due to capture and due to capture plus storage for the IGCC plant is much less and in fact the COE of the IGCC plant with capture and storage is less than the PC plant with capture and storage and is therefore preferred. NGCC is still the preferred option on the COE metric. If EOR utilization of the CO_2 is a possibility, all of the COEs are reduced but the IGCC produces more CO_2 than the NGCC and receives a larger offsetting credit with the result that it now becomes the preferred option. The cost of CO_2 capture in this case for IGCC represents only a 10% increase over the cost without capture. The avoided cost of CO_2 for these cases is shown in Fig. 47. For the prevalent PC-fired plants we are looking at \$50 per ton, nominally. The avoided cost for IGCC plants is approximately 50% of that for PC plants. NGCC plants have the highest avoided cost. The absolute values of these costs are reduced significantly for the EOR case, but the trends remain and IGCC is still the lowest cost option in this instance.

It should be recognized that these charts are merely an example and depending on assumptions taken, particularly for fuel costs, we can get different absolute values and draw different conclusions. For this set of assumptions, we can fairly well conclude that IGCC is a preferred option provided the relatively minor increase in electricity cost (COE) over the cost of electricity from NGCC would be acceptable to PUCs and the public in exchange for the societal benefits of reduced CO_2 emissions. Barring any legislation or other requirement to capture CO_2, it should be clear that capturing CO_2 is still an expensive proposition with high costs to the economy and society and results in 40% more expensive electricity.

This confirms the need to develop advanced technologies to lower the incremental cost of CO_2 capture. The approaches currently being pursued worldwide are listed in the next section.

Ongoing Research

DOE has an aggressive R&D Program with the objective of reducing the costs of CO_2 capture. Table 28, with links to more detailed information (from DOE's website) summarizes the research program.

The IEA Greenhouse Gas Programme has developed a website of Carbon Capture and Sequestration Projects (http://script3.ftech.net/~ieagreen/co2sequestration.htm). The Carbon Capture R&D listing from their database as of 10/30/04 is shown in Table 29. (links in the title column are to more detailed information) and includes many of the DOE projects listed in Table 28. Additionally, the IEA database lists 11 "commercial-scale" projects (shown in Table 30).

The Carbon Capture Project has devoted considerable effort to optimizing the process schemes used for CO_2 capture. They selected three cases to evaluate: North European Refining and Petrochemical Complex, Alaska Open Cycle Gas Turbines, and a Norwegian 400MW NGCC power plant. Their study confirmed the ballpark figures for CO_2 capture cost – their reference case was set at \$60/tonne of CO_2 avoided. Through a series of value engineering and design integrations, estimated avoidance costs were reduced ultimately to \$28/tonne.

Conclusions

Technology exists to remove CO_2 from major stationary sources such as power plants, refineries, gas plants and chemical plants. CO_2 is already being removed from natural gas if it is present in the raw gas (about 30% of natural gas contains significant amounts of CO_2), but this CO_2 is vented to the atmosphere except in a few instances where the gas is needed for EOR. Power plants are the most significant source of CO_2 emissions in the southwest region. The estimated cost with current technology would result in a nominal \$50 per tonne CO_2 avoided cost. Unless a CO_2 emissions tax of this magnitude (or in the alternative an available trading credit) is imposed, utilities will not implement CO_2 capture.

New technology under development from numerous parties worldwide will likely lower the cost of CO_2 capture. Most such technology is many years away and some may never be realized for a variety of reasons.

IGCC electricity generation is, in many situations, a relatively inexpensive approach to effective CO_2 capture in the near-term. Although the cost is slightly higher (and the risk higher) than standard PC power plants, utilities are now beginning to include these in their generation forward planning since they provide a hedge against future emissions regulations more stringent than today's (whether including CO_2 emissions requirements or not). Additional implementations of IGCC in several utility territories will increase the broad acceptance of this approach and should be encouraged by government incentives.

Many of the new, advanced technologies which can potentially offer lower-cost capture will require field experiment testing and demonstrations. These technologies will be screened in the southwest region in conjunction with the region's source/sink database to identify a suitable candidates for Phase II projects. The baseline information described above is essential to identify current opportunities for CO_2 capture in the region and to determine, when coupled with cost information or estimates for the new technology, the most promising options compared to current state-of-the-art technology.

Table 28. Summary of U.S. DOE's CO_2 Capture R & D Program

CO_2 Capture

- **PRE-COMBUSTION DE-CARBONIZATION** There are currently 10 oxygen-fired gasifiers in operation in the U.S. today. Syngas from an oxygen-fired gasifier can be shifted to provide a stream of primarily H_2 and CO_2 at 400-800 psi. Glycol solvents can capture CO_2 and be regenerated via flash (no steam use) to produce pure CO_2 at 15-25 psi.

Supporting Program R&D Projects:

- **CO_2 Selective Ceramic Membrane:** Develop a high temperature CO_2-selective membrane to enhance the water-gas-shift reaction efficiency, while recovering CO_2 for sequestration. The improved membrane is suited to integrated gasification combined-cycle power generation systems. *[Media and Process Technology Inc (MPT) University of Southern California]*

    - Fact Sheet: CO_2 Selective Ceramic Membrane for Water-Gas-Shift Reaction with Simultaneous Recovery of CO_2 [PDF-61KB]

- **CO_2 Hydrate Capture Process:** Develop a process that captures CO_2 by combining it with water at low temperature and high pressure, thus forming CO_2/water hydrates, ice-like macromolecular structures of CO_2 and water. Laboratory experiments seek to determine the level of CO_2 removal achievable, measure energy requirements, and assess any negative effects attributable to hydrogen sulfide and methane gases. *[Los Alamos National Laboratory, Nexant, Inc. (A Bechtel Technology and Consulting Firm), Simteche]*

    - Fact Sheet: CO_2 Hydrate Process for Gas Separation from a Shifted Synthesis Gas Stream [PDF-239KB]

- **High Temperature Polymer Membrane:** Manufacture a thermally optimized membrane with better separation capabilities than current polymer membranes. The project focuses on the separation of CO_2, methane, and nitrogen gases in the range of 100 to 400°C. *[Los Alamos National Laboratory, University of Colorado, Idaho National Energy and Environmental Laboratory, Pall Corporation, and Shell Oil]*

    - Fact Sheet: CO_2 Separation Using a Thermally Optimized Membrane [PDF-197KB]

- **Evaluation of CO_2 Capture/Utilization/Disposal Options:** Develop engineering evaluations of technologies for the capture, use, and disposal of CO_2. This project emphasizes CO_2-capture technologies combined with integrated gasification combined-cycle (IGCC) power systems that produce both merchant hydrogen and electricity. *[Argonne National Lab]*
    - Fact Sheet : CO_2 Capture for PC-Boiler Using Flue-Gas Recirculation: Evaluation of CO_2 Capture/Utilization/Disposal Options [PDF-81KB]

- **OXYGEN-FIRED COMBUSTION** No oxygen-fired PC plants in commercial operation. Current minimum CO_2 recycle is 5 lbs CO_2 per lb coal feed. 90% pure CO_2 is produced from the boiler at 10-15 psi. Oxygen combustion requires roughly three times more oxygen per kWh of electricity generation than gasification.

Supporting Program R&D Projects:

- **Advanced Oxy-fuel Boilers and Process Heaters:** Design a novel "oxy-fuel" boiler that incorporates a membrane to separate oxygen from the air which is then used for combustion. *[Praxair]*

    - Fact sheet: Advanced Oxyfuel Boilers and Process Heaters for Cost Effective CO2 Capture and Sequestration [PDF-147KB]

- **Oxygen Firing in Circulating Fluidized Bed Boilers:** Build on international work in advanced combustion in mixtures of oxygen and recycled flue gas. *[Alstom Power]*

  - Fact sheet: Greenhouse Gas Emissions Control by Oxygen Firing in Circulating Fluidized Bed Boilers [PDF-563KB]

- **Oxygen-enriched Combustion:** Conduct pilot-scale tests of oxygen enhanced coal combustion with the objective of lowering the cost of retrofit systems. *[CanMet Energy Technology Center, and a consortia of industrial companies including McDermott Technology, Trans Alta Corp., Saskatchewan Power, Air Liquide Canada, Nova Scotia Power, Ontario Power Generation, and Edmonton Power]*

- **POST-COMBUSTION CAPTURE** 300 GW of PC boiler capacity in the United States. Flue gas from a PC boiler is exhausted at 10-15 psi and contains 12-18 volume percent CO_2. Amine scrubbing with CO_2 compression to 1200 psi costs roughly 2000 $/kW and reduces the net power plant output by 12.5%.

Supporting Program R&D Projects:

- **Dry Regenerable CO_2 Sorbents:** Develop a CO_2 separation technology that uses a regenerable, sodium-based sorbent to capture CO_2 from flue gas. Thermodynamic analysis and preliminary laboratory tests indicate that the technology is viable. Process data will be collected to assess the technical and economic feasibility of various process configurations. This retrofit process is amenable to all conventional steam-generating power plants. *[Research Triangle Institute, Church and Dwight, Inc.]*

  - Fact sheet: Carbon Dioxide Capture from Flue Gas Using Dry Regenerable Sorbents [PDF-112KB]

- **Electrochemical Devices for Separating CO2 from Flue Gas:**
Develop cost effective electrochemical devices for the separation (electrochemical pumps) and detection (sensors) of CO_2. Tasks include separation of CO_2 from a simulated flue gas, comparison of electrode and electrolyte performance, and a mechanism of CO_2 transport/ development of new solid electrolyte separators and sensors. *[Carbon Sequestration Science Focus Area, CSSFA]*

- **Integrated R&D:** Integrated collaborative technology development project aimed at proving the feasibility of advanced CO_2 separation and capture technologies. *[BP Amoco Corporation, Anchorage, AK, CCP]*

  - Fact Sheet: CO_2 Capture Project: Collaborative Technology Development Project for Next Generation CO_2 Separation, Capture and Geologic Storage [PDF-206KB]

- **Amine Enriched Adsorbents:** These sorbents will be prepared by chemical treatment of high surface oxide surface materials with various amine compounds. Tasks include modification of oxidized solid surfaces, chemical characterization of the amine-enriched sorbents, determination of CO_2 capture capacity, and examination of the performance durability of amine-enriched adsorbents. Optimize chemical scrubbing processes for CO_2 separation. Develop improved gas-liquid mass transfer; develop improved amine absorbent systems which require less thermal energy for regeneration; increase the loading of the absorbent within the aqueous amine solution, and reduce the content of water in the amine solution. *[CSSFA]*

  - Fact sheet: Sorbent and Catalyst Preparation Facilities [PDF-659KB]

- **Carbonate-based CO_2 Capture:** Simultaneous removal of CO_2 and SO_2 by ammonia solution, recover pure CO_2 by converting ammonium carbonate to ammonium bicarbonate solution.

Ammonia is recycled for CO_2 capture. This allows simultaneous capture of CO_2, SO_2, and NOx. *[CSSFA]*

- o Fact sheet: Small Scale Facilities for Air Pollution Research [PDF-987KB]

- **CO_2 capture by absorption with potassium carbonate:** Predict performance of absorption/stripping of CO_2 with aqueous K_2CO_2 promoted by piperazine *[University of Texas at Austin]*

- **An Integrated Modeling Framework for Carbon Management Technologies:** Develop an integrated modeling framework for evaluating alternative carbon sequestration technologies for electric power plants *[Carnegie Mellon]*

- **Zero Emissions Power Plants Using SOFCs and Oxygen Transport Membranes:** Modify the design of the tubular solid oxide fuel cell (SOFC) module to incorporate an afterburner stack of tubular oxygen transport membranes, oxidizing the SOFC depleted fuel in the anode exhaust to CO2 that can then be easily separated *[Siemens Westinghouse Power Corp.-Pittsburgh]*

- **Conceptual Design of Optimized Fossil Energy Systems with Capture and Sequestration of CO_2:** The project aims to develop viable technological solutions for the safe and economic capture and storage of CO_2 underground. *[Princeton University]*

- **Sorbent Development for CO_2 Separation and Removal: Pressure and/or Temperature Swing Adsorption:** Modification of surface area and pore structure of the sorbents, modification of the chemical properties of the sorbents, and characterization and solid/surface reactions. *[CSSFA]*

  - o Fact sheet: Sorbent Development for Carbon Dioxide Separation and Removal - Pressure Swing Adsorption & Temperature Swing Adsorption [PDF-50KB]

  - o Fact sheet: Modular Carbon Dioxide Capture Facility [PDF-113KB]

  - o Fact sheet: Carbon Sequestration Science Focus Area [PDF-57KB]

  - o Fact sheet: Advanced Analytical Instrumentation and Facilities for In-Situ Reaction Studies [PDF-529KB]

- **ADVANCED CONVERSION** There are a limited number of promising ideas in this area. None of them are at the commercial or demonstration phase.

Supporting Program R&D Projects:

- **Electricity Generation Using a Metal Oxide Reducing Agent:** Develop a method to use gasified coal or natural gas to reduce a metal-oxide sorbent, thereby producing steam and high pressure CO_2. The steam condenses in a heat-recovery steam generator, and the CO_2 is sequestered using compressed energy. The metal oxide sorbent is treated in a secondary reactor, where the reduced metal is oxidized in air and recycled. Sorbent materials with desirable properties will be developed and tested, and the economics and emissions performance of integrated electricity generation systems based on the various sorbents will be estimated. *[TDA Research, Inc. Louisiana State University]*

Table 29. IEA Greenhouse Gas Programme Carbon Capture and Sequestration Projects

Project Title	Project Overview	Location
The Capture and Storage of Carbon Emissions	The project is examining improvements to the chemical absorption process (using a variety of solvents) as well as developing new technology and carrying out technology screening studies	Boundary Dam Power Plant University of Regina
CO2 Capture Project (CCP)	The project is a joint initiative carrying out a development programme leading to the reduction in the cost of CO_2 capture from combustion sources, followed by its safe, economical underground storage	Various Locations
NorCap Project	The project is developing and testing promising technologies for reducing the costs of separating and capturing CO2 from fossil fuel combustion sources, plus its transport and storage	Europe
Power Generation with CO2 Capture	The project aims to improve the energy conversion of natural gas in power cycles that significantly reduce CO_2 emissions.	Europe
Future Energy Plants	The project is developing and testing a concept for co-production of power and hydrogen from natural gas with integrated CO2 capture.	Europe
Separation of CO2 Using Membrane Gas/Liquid Contactors	N/A	Europe
Advanced Zero Emissions Power Plant (AZEP)	This multi-partner project is developing an advanced, gas turbine-based power generation system that will produce no emissions to	Europe

	atmosphere	
Advanced CO2 Separation and Geologic Storage Technologies	The project will demonstrate the feasibility of capturing CO_2 from a variety of fuel types and combustion sources and storing it in unminable coal seams and saline aquifers	North America
CO2 Separation Using Thermally Optimized Membranes	Los Alamos National Laboratory and Idaho National Engineering and Environmental Laboratory are collaborating with the University of Colorado, Pall Corp. and Shell Oil Co, in a 3-year project to develop an improved high-temperature polymer membrane for separating carbon dioxide from methane and nitrogen gas streams.	Los Alamos
Dry Regenerable CO2 Sorbents	The project will investigate and develop a separation technology that uses a regenerable, sodium-based sorbent to capture CO_2 from flue gas	North America
CO2 Dioxide Process for Gas Separation from Shifted Syngas	The project will develop a process that captures CO_2 by combining it with water at low temperature and high pressure, thus forming CO_2/water hydrates	North America
A Novel CO2 Separation System	The project aims to develop a novel electricity generation and CO_2 separation system based on the reduction of a metal oxide	North America
Vortex Tube Design and Demonstration for the Removal of Carbon Dioxide from Natural and Flue Gas	The project is studying CO_2-liquid absorption kinetics, solvent generation requirements, and scaleup parameters for Vortex Tube contactors	North America
Carbon Dioxide Capture by Absorption with Potassium Carbonate	The project will develop an alternative solvent that captures more CO_2 whilst using 25-50% less energy than conventional, state-of-the-art	Austin, Texas

	MEA (monoethanol amine) scrubbing	
Development of oxy-fuel boiler concept	The project will develop a novel oxy-fuel boiler - a new design that incorporates a membrane to separate oxygen from the air which is then used for combustion	Tonowanda, New York
Development of inorganic palladium-based membranes	The project is developing an advanced palladium-based membrane for the reforming of hydrocarbon fuels	North America
Development of a computer model for the evaluation of different CO2 capture from power plant options	The project is developing a model for the systematic evaluation and comparison of different technological options for CO_2 capture from power plant	Pittsburgh
Detailed cost analysis of three options for CO2 capture from an existing coal-fired power plant	The project is examining several technological options for the capture of CO_2 from coal-fired power plants	North America
Research on Physical Adsorption Method for CO2 Recovery	The present project forms part of an on-going programme examining the Pressure Temperature Swing Adsorption technique for CO_2 capture	Yokosuka, Japan
Development of the HiOx Technology	The project is developing a power generation technology whereby oxygen if firstly separated from the air, followed by the combustion of natural gas and concentrated oxygen in an atmosphere of recirculated exhaust gases. A concentrated CO_2 stream is produced	Norway
FutureGen	A US$1 billion, 10 year research project to build the world's first coal-fuelled plant to produce electricity and hydrogen with zero emissions. The FutureGen plant will establish the technical and economic feasibility	U.S.A.

	of producing electricity and hydrogen from coal while capturing and sequestering CO_2 generated in the process.	
Grangemouth Advanced CO2 Capture Project (GRACE)	Cost effective environmental abatement technologies for power production.	UK and Europe
Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC)	In December 2002, the Australian Minister for Science announced the approval of a new Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC). CO2CRC will undertake research into existing and new capture technologies to reduce the cost of capture and to assess and enhance their suitability for Australian industrial and power generation activities.	Australia
CO2 Capture, Transport and Storage in the Netherlands (CATO)	Several institutions in the Netherlands have worked on a number of aspects or components of Clean Fossil Fuel (CFF) systems. Often these institutions have very different perspectives but CATO aims to streamline the objectives and perspectives of these activities and integrate them into a comprehensive programme and network, closely connected to international networks in which the partners of CATO participate.	Netherlands
CASTOR, "CO2 from Capture to Storage"	The project's objective is to make possible the capture and geological storage of 10% of European CO_2 emissions, or 30% of the emissions of large industrial facilities (mainly conventional power stations). To accomplish this, two types of approach must be validated and developed: new technologies for the capture and separation of CO_2 from flue gases and its geological storage,	Europe

	and tools and methods to quantify and minimize the uncertainties and risks linked to the storage of CO_2. In this context, the Castor project program is aimed more specifically at reducing the costs of capture and separation of CO_2 (from 40-60€/ton CO_2 to 20-30€/ton), improving the performance, safety, and environmental impact of geological storage concepts, and, finally, validating the concept at actual sites.	
Clean Energy Systems (CES), Kimberlina demonstration plant	CES is a privately funded company based in California that is develop-ing an oxy-combustion process based on rocket propulsion technology. The company is conducting a series of developments aimed at demon-strating a complete oxy-combustion, zero-emissions power generation system. The first step involved the development of a high-pressure gas generator (burner) that burns natural gas with pure oxygen in the pres-ence of a large water recycle to control flame temperature. The gas generator produces a mixture of high-pressure steam and CO_2 that drives an expansion turbine to generate power. The second part of the development is to demonstrate the complete power cycle by adding the turbine, condensing the steam, recycling the condensate, and capturing the CO_2. The final stages of development will involve developing tur-bines capable of operating at higher temperatures and pressures in order to maximise the efficiency of the power cycle. Successful tests of up to three minutes duration have been achieved on a gas generator of 20 MW thermal capacity.	CES Base at Rancho Cordova CA, USA. Demonstration facility at Kimberlina Power Plant, near Bakersfield, CA, USA
Enhanced Capture of CO2 (ENCAP)	The ENCAP project is a research	Europe

	project for the development of Pre-combustion technologies for Enhanced Capture of CO_2 in large power plants.	

Table 30. Commercial-Scale Projects Listed by IEA.

Project Title	**Project Overview**	**Location**
Shady Point Power Plant	The plant generates electricity and produces food-grade CO_2 from flue gases	Oklahoma
Sleipner Project	The storage in underground geological formations is an attractive option for the removal, essentially permanently, of very large quantities of CO_2 generated from a variety of industrial operations. One promising technological option is that of capturing CO_2 and injecting it into deep underground saline aquifers, found in many parts of the world. One such formation is located above the Sleipner field, one of the larger natural gas producers in the North Sea.	Europe
Warrior Run Power Plant	The plant generates electricity and produces food-grade CO_2 from flue gases	Cumberland, Maryland
Bellingham Cogeneration Facility	The plant generates electricity and produces food-grade CO_2 from flue gases	Bellingham, Massachusetts
Sumitomo Chemicals Plant, Chiba, Japan/Kokusai Carbon Dioxide	The plant generates electricity and produces food-grade CO_2 from flue gases	Chiba, Japan
Prosint Methanol Production Plant	The plant uses an MEA-based scrubber to capture CO_2 from boiler flue gas for use in beverage	Rio de Janeiro, Brazil

	production	
IMC Global Inc. Soda Ash plant, Trona	Part of this large soda ash production plant comprises a coal-fired power generation plant featuring CO_2 capture from the flue gas. The CO_2 is used for the carbonisation of brine	Trona, California
The Indo Gulf Fertilizer Company Plant, India	The fertiliser plant incorporates a CO_2 capture facility that feeds a urea manufacturing unit	Jagdishpur, Uttar Pradesh
Luzhou Natural Gas Chemicals (Group)	The plant produces urea and ammonia for the fertiliser industry in China. Part of the plant features a scrubber system that captures CO_2 from the process for urea production	Luzhou City
Petronas Fertilizer Co, Malaysia	The plant features an amine-based scrubbing system, operating with a novel solvent, as part of its operations producing ammonia and urea for the fertiliser market	Malaysia
Great Plains Synfuels Plant (GPSP) CO2 Capture and Compression	The GPSP is the only commercial-scale coal gasification plant in the United States that manufactures natural gas. Located five miles northwest of Beulah, North Dakota, the GPSP has been owned and operated by Dakota Gasification Company (DGC), a subsidiary of Basin Electric Power Cooperative, Bismarck, North Dakota, since 1988. This $2.1-billion plant began operating in 1984. Using the Lurgi process, the GPSP gasifies lignite coal to produce valuable gases, liquids, and byproducts (including CO_2). Delivers CO_2 to the Weyburn Unit in Canada	Five miles northwest of Beulah, North Dakota

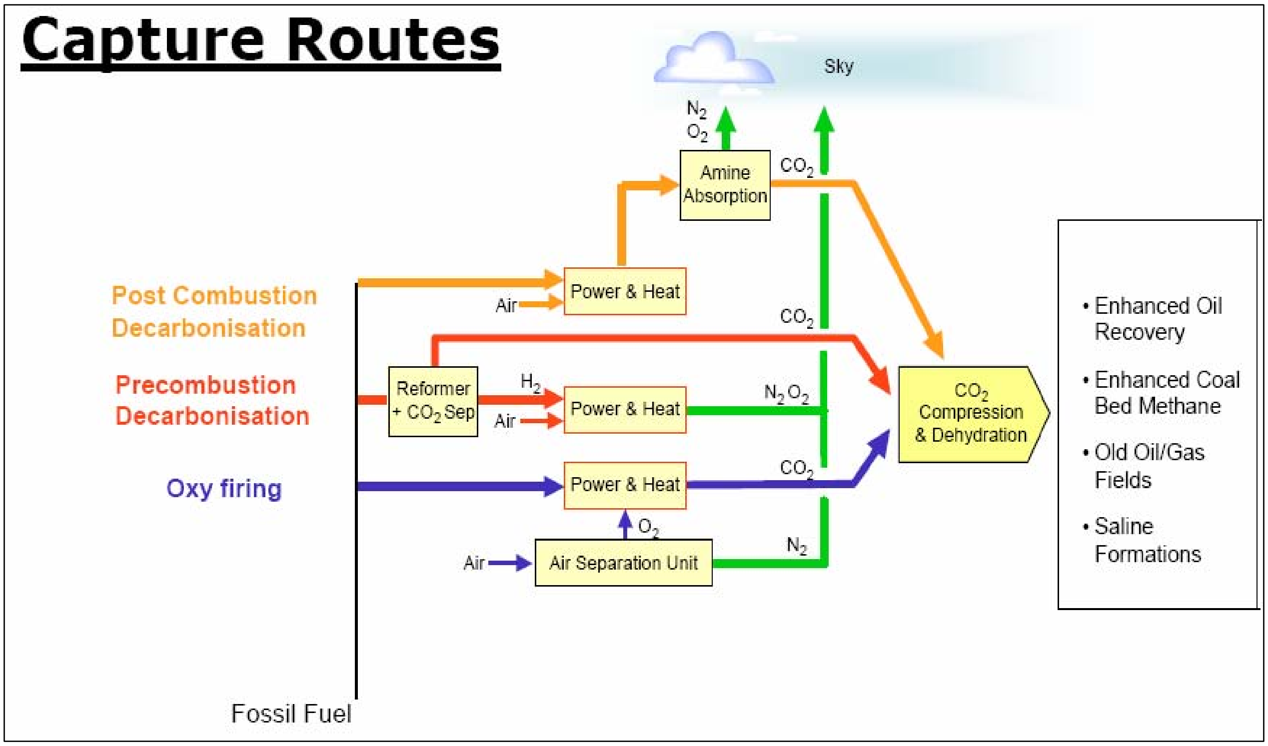

Fig. 42. CO_2 capture approaches (Carbon Capture Project).

Fig. 43. Selexol unit at Sarlux plant, Sardinia.

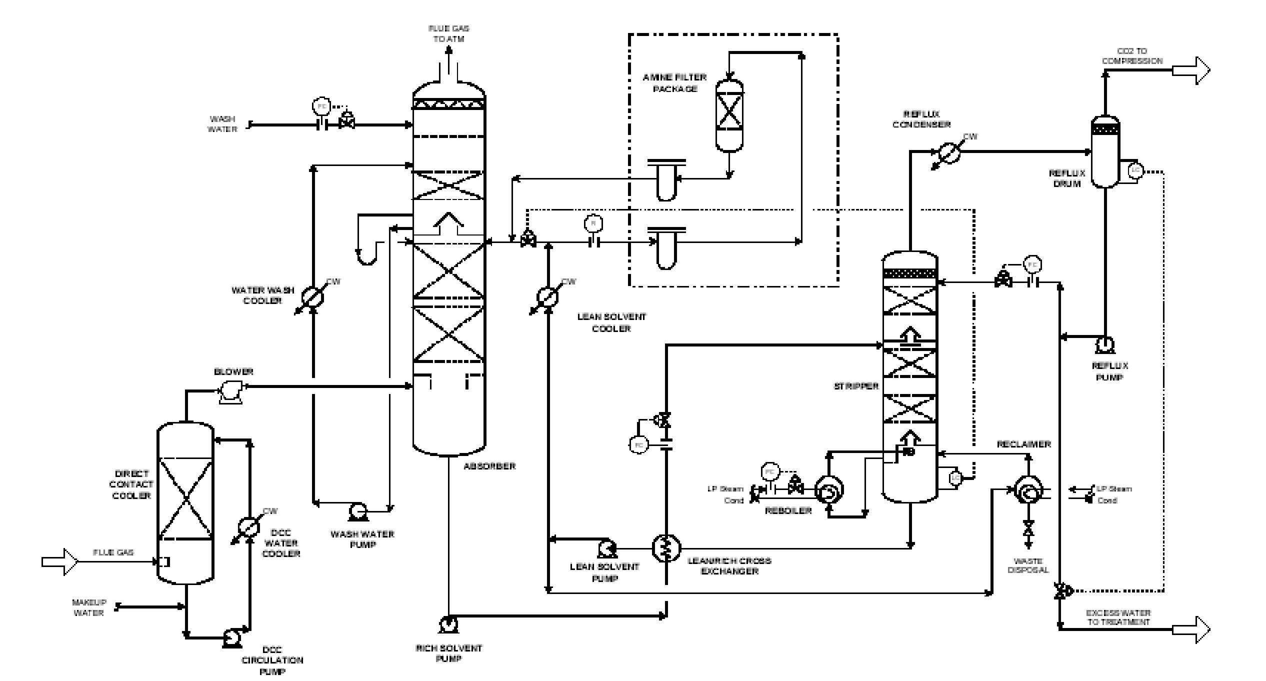

Fig. 44. Process flow diagram for MEA-based solvent capture technology.

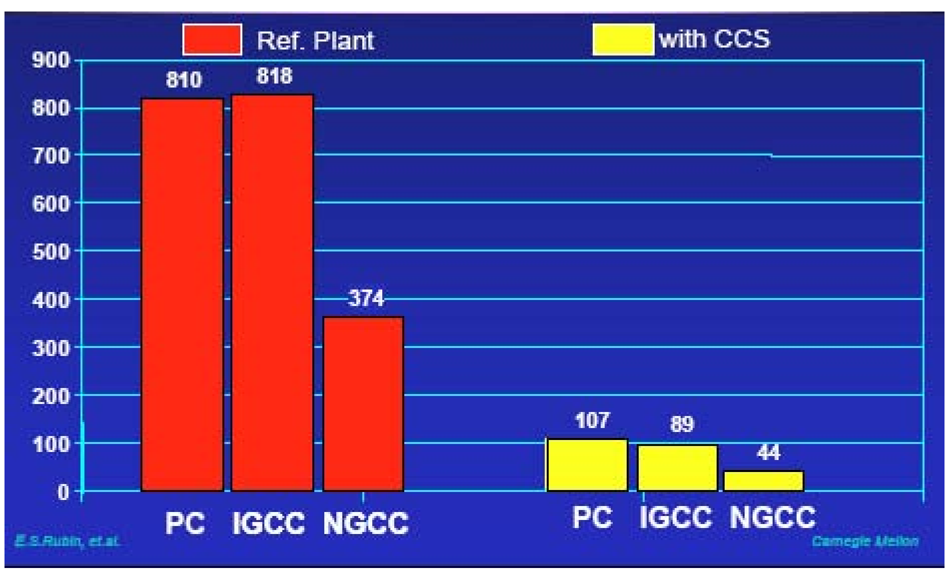

Fig. 45 CO_2 Emission Rates (kg/MWh) (Rubin, 2004).

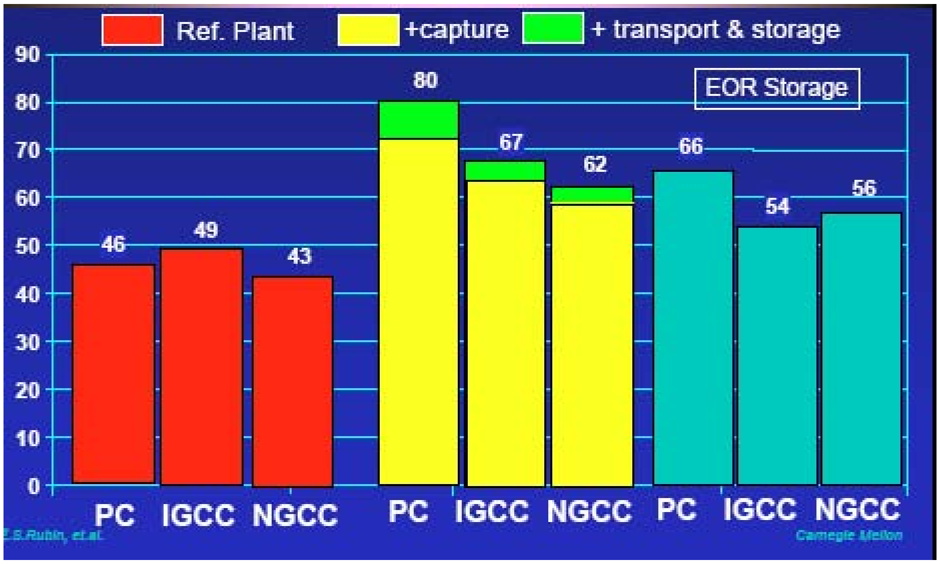

Fig. 46. Cost of electricity, COE (levelized $/MWh) (Rubin, 2004).

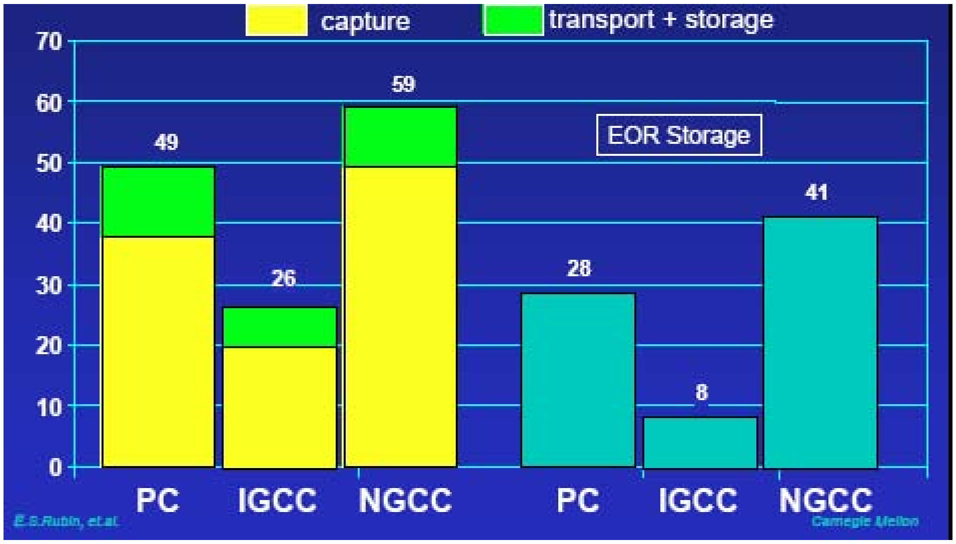

Fig. 47. Cost of CO_2 Avoided ($/tonne CO_2) (Rubin, 2004).

Outreach and Education

The *goal* of the outreach component of the Southwest Regional Partnership for Carbon Sequestration was to *identify current public opinion and knowledge, and enable the public to more effectively evaluate costs and benefits* associated with carbon sequestration.

We subdivided that goal into the following *objectives*:
(1) identify and respond to constituent needs, fears, and desires;
(2) inform constituents about carbon sequestration strategies;
(3) involve constituents in a joint discovery of opportunities associated with carbon sequestration;
(4) enable constituents to negotiate opportunities for mutual benefit among the diverse parties with an interest in carbon sequestration.

As is the case with many public policy processes, the Southwest Regional Partnership on Carbon Sequestration is a complex situation involving multiple stakeholders. The interests of these stakeholders must be recognized if the Southwest Partnership is to successfully integrate best science and practice (Daniels & Walker, 2001). Each stakeholder group has varying levels of and interests for participation in the process. The negotiation among their interests is thoroughly integrated into the outreach plan for participation. Furthermore, these various interests groups enter the carbon sequestration process with differing degrees of scientific background, which impacts their ability to participate (Kinsella, 2004). This presents a challenge to public participation for the integration of science and practice to be both feasible and desirable (Daniels & Walker, 2001).

Our constituents constituted multiple audiences, all of which have different motivations for their responses (or non-responses) to carbon sequestration. These audiences include (1) private industry, (2) environmental groups, (3) the general public, and (4) governments. We did not designate nongovernmental organizations (NGOs) as a distinct category, because we found that the motivational base of NGOs representing private industry (for example coal) is quite different from the motivational base of NGOs representing environmental groups (for example the Sierra Club). These multiple audiences come to the table with vastly different knowledge levels and skills, and they care about carbon sequestration for different reasons. We attempted to design, and begin implementation of, an outreach program that responds directly to them.

Communication

We define communication not as a psychological task of putting two minds together, but as a political challenge of establishing conditions under which mutual recognition of self-conscious individuals is possible (Peters). This shifts the crux of communication from fidelity to responsibility. Rather than using communication primarily for the purpose of sharing absolute truth with our constituents, we focused on how our words and deeds might play before them—what our activities would mean to our audience. This seemed an essential move given the scientific and technological uncertainties involved with carbon sequestration itself, and the inherent uncertainties associated with attempts to forecast the future of anything (including, but not limited to climate change).

Dissemination and dialogue are the fundamental communication strategies employed to achieve our objectives. By dissemination, we refer to the transmission, or broadcasting of information. This information is available to everyone, without prejudice. The risk associated with dissemination is that information may fall into the wrong hands, or that people might interpret it differently than we would like them to. If we really want broad public involvement, we have to be willing to take that risk. Dialogue, on the other hand, refers to personal interaction and direct connection among people. To engage in dialogue with someone requires that we spend considerable effort getting to know that person. The advantages are that we can design information to specifically respond to that person's needs, and we are able to learn from that person. The disadvantage is that we reach only a very small audience through this mode.

The communication techniques we identified to achieve our goals were formal presentations, learning activities, and process training. Formal presentations allowed us to share information about infrastructure requirements, different technical possibilities, and opportunities for both specific industries and location-based communities to become involved. The learning activities focused on mediated modeling, which enables participants to share their learning with each other. The process training was built into the modeling activities, and was designed to help participants become more effective communicators.

The tools, or media, through which we implemented these techniques included a web page, mediated modeling workshops, and an information packet disseminated for virtual town hall meetings and for various face-to-face presentations.

The web page provides an opportunity to disseminate information about our partnership activities, the regional partnership program, carbon sequestration, and its relationship to global climate change. It allows us to disseminate information to a broad range of potential constituents, even reaching those who have never heard of carbon sequestration. Secondarily, it generated possibilities for dialogue with audiences we might fail to identify. For the benefit of anyone who chooses to initiate a dialogue, the web site provides information on how to contact the partnership. The information packet fulfills similar functions, but, because it is print based, both its spatial and temporal boundaries are more rigid. We took advantage of the relative stability of this platform to disseminate information that focuses on operational possibilities suggested by scientific and technical research. Our target audience for this medium was industry. The two media are most effective when used together. For example, the information packet directs readers to specific parts of the database, which can be accessed through the web page. Although people do not have to possess the information packet to access these data, the interpretive information in the information packet will make the data much more useful.

Our second communication medium is a variant on the town hall meeting. We conducted two virtual town hall meetings in several sites throughout the area covered by the Southwest Partnership. These meetings incorporated both face-to-face and electronic interaction. Meetings were electronically facilitated through a central source, which ensured consistency among all informational presentations. Each meeting, on the other hand, encouraged participants to introduce perspectives unique to their communities (whether spatial or interest-based) as they engaged each other in embodied interaction. Participants had an opportunity to interact others in the same physical setting, at the same time they interacted (electronically) with participants from other communities throughout the region. This medium facilitated both information dissemination and group dialogue.

Our third communication medium was the mediated modeling workshop. Mediating modeling is designed to facilitate additional group learning (Vennix). This venue for face-to-face interaction provides opportunities for embodied relationship building, open discussion, and information sharing. Thus, although dialogue is the primary strategy here, some dissemination also occurs. Using this tool, we involved the participants in active learning exercises to identify key issues, concerns, and interrelationships within the system. Participants worked together to develop a conceptual model, and then reframed it as a quantitative model. This involved translating the conceptual model into a series of mathematical equations that collectively form the quantitative model. Ultimately, the model evolved into a communication interface between project scientists, regional decision makers, and industry partners, as constituents developed a sense of joint ownership, thus making the modeling process more important than the model itself (Peterson, Kenimer, and Grant).

The outreach system built through integrating these media facilitated a substantive interaction between all constituents, enabling them to more effectively evaluate costs and benefits associated with alternative carbon sequestration strategies, both as an economically viable technology and as a useful component in a national greenhouse gas reduction portfolio.

These processes have occurred as distinct efforts to contact and serve sometimes similar and sometimes different publics; taken together they substantiate a broad-based approach to public outreach and education.

Summary: The public participation process developed opportunities for various interest-groups (industry, utility, environmental advocates, and environmental policy decision-makers, and scientists) to learn fundamental information about carbon capture and sequestration, and then to collaborate in deciding how best to manage the implementation of this technology in the Southwest Region.

Below we report the objectives, process, and results of these programs beginning with the website.

Website Development and Implementation

http://www.southwestcarbonpartnership.org/

The goal of the Southwest Regional Partnership on Carbon Sequestration website was to utilize the World Wide Web as a medium to communicate information on the issue of carbon sequestration to internal and external project stakeholders. The website, **http://www.southwestcarbonpartnership.org/**, was a part of the larger public participation initiative to engage stakeholders.

Objective: The objective of the website design phase was to create a website that communicates scientific information in an accessible manner and to design the website in a way that allows the user to easily get the information they need.

Process: The development of the Southwest Regional Partnership on Carbon Sequestration website was informed by a review of existing websites on the topic of carbon sequestration, and similar topics such as energy. The existing websites provided information on what works and what does not work in terms of communicating information on carbon sequestration. The information from this website review was communicated to the principle stakeholders to assist them in understanding some of the design implications for the Southwest Regional Partnership on Carbon Sequestration website. The term principle stakeholders is used here to describe those individuals and agencies that are responsible for meeting the objectives and milestones outlined in the Department of Energy grant application.

Meetings were set up with the principle stakeholders to go over their interests and concerns regarding the website. If a principle stakeholder was unable to attend a meeting, he or she received updates via email regarding what was discussed. The initial meetings were an opportunity to understand some of the users of the website. These meetings occurred prior to writing content for the site and its web pages. Communication occurred with the host of the website, the state of Utah, Information Technology Services (ITS) data center regarding the requirements for the web layout and content. The ITS department is responsible for maintaining the website on their server.

Once there was an understanding of the scope and overall goal of the website, categories were developed for the website. These categories were approved by the principle stakeholders prior to writing text for the website. The categories were consistent with the goals of the project overall and with the principles of the public participation plan for the project. Writing text for the website was the next step, and this process was informed by the review of the existing websites, the views and messages of the funding agency, and the goals of the principle stakeholders. The overall goal of the website, category construction, and the content were combined in the development stage of the website. The development and implementation of these elements were consistent with the principles of human-computer interface design and usability. Changes and modifications will be made to the website based upon the users' experiences.

Results: The website design and implementation went well. The design and writing of copy occurred January through March 2004, and the website was functional by April 2004. Feedback from project partners was very positive about the website and its functionality. There were a few technical difficulties with implementing the "Partners Only" web page but these issues were resolved by June 2004.

The website was advertised to both the internal and external audiences through email, meetings, and the workshops. The website was reviewed on a weekly basis, and updates are posted as needed. The website was used to disseminate information about the workshops. Agendas and presentations were posted under the "Workshops/Get Involved" page. News stories and other current information were posted on the homepage and also on the "Carbon in the News" page. This page represented our effort to maintain interest in the issue of carbon sequestration in relationship to climate change. Project partners were also encouraged to contribute to the website and suggest updates.

Background

The next section provides background on the theories and principles of web design that were used in the development of the SW Partnership website.

Computer Mediated Communication

The Internet has become an important medium for communication and the dissemination of information. With so many websites available to people, it is important to assess a website in terms of usability and good web design. Good web design includes elements that draw the audience into the web and break down barriers for the user to access the information. This compliments the public participation goals to inform and involve the public. Good design was important to allow the user to learn about the project from the SW Partnership project partners. In the area of website development the research areas of hypertext, usability, and human-computer interface provide answers to some of those questions. Hypertext theory creates an understanding of how users manage the huge amount of information that is available on the Internet and manage information within a website. Human-computer interface relies upon cognitive psychology in order to better understand how people use computers and websites. Each of these areas will be touched upon, with an additional focus on usability. The user is the focus of web design and by maintaining this perspective it is possible to create websites that inform and interest users.

General information on who uses the web and for what purpose is readily available, but as an agency thinks about how it will interface with the public through the web some basic questions may include "who will be using the website?" This is similar to the development of a public participation plan; target audiences are the primary focus when deciding on the development of the plan. All aspects of the web design (including content, style and text) are influenced by the intended audience. The area of public relations and mass communication provides techniques to identify, segment, and target audiences in order to better develop messages. The categories of the audiences that should be captured include age, gender, ethnicity, income and financial information, educational background and area of the country in which they live. These variables will have different levels of importance depending on the type of site being constructed (Thompson, 1996).

By segmenting the audience, it is possible to offer different links for each type of audience that may visit the website (Farkas & Farkas, 2001). Segmenting can be useful for the look and usability of the website.

Hypertext theory

Hypertext theory is the basis for the World Wide Web and web design. The web can easily confuse and disorient users; users may lose their place and become unsure of their direction and navigation (Landow, 1997). Hypertext, the term for interactive content, provides a mechanism for the user to move throughout a website; it provides the means for the user to navigate. The concept of hypertext was conceptualized by Vannevar Bush in the 1940s as he described a need to manage and organize massive amounts of information. His idea for the device called the "memex" enabled users to access a lot of information with a few keystrokes (Bush, 2003). But it was not until 1965 that Ted Nelson coined the term *hypertext*. Hypertext theory describes how text nodes, or words, graphics, and sounds are linked to other relevant pieces of information. Hypertext links the text nodes to one or more other text nodes and holds websites together and supports user navigation (Neilsen, 2003). The nodes and links can be arranged into both hierarchical and non-hierarchical structures and information structures (Farkas & Farkas, 2001; Nielsen, 2000). Most people who work with web design draw upon hypertext theory. Hypertext works by association rather than indexing and is nonlinear and dynamic (Nielson, 2000). Nielsen believed that computers will continue to have a presence in people's lives and they should learn as much as they can about them; computers should be embraced as a personal device. Nelson advocated for making computers as easily understood as a camera (Nielsn, 2000).

Usability

In addition to hypertext, usability is an important area for consideration. Jakob Nielsen is a prominent proponent of ensuring that websites are as usable as possible. Nielsen suggests that appropriate design ideas comes from watching users and seeing what they like, what they find easy, and where they have difficulties. This will help in the design phase (Nielsen, 2000).

Site design is important because the reason users are using the web page is to access information. Once they leave the homepage and start navigating, it is important that they are able to find what they are looking for. The home page is the first page and should include a directory of the main areas and news. Navigation is an essential element of site design. "Navigation interfaces need to help users answer the three fundamental questions of navigation: Where am I? Where have I been? Where can I go?" (Nielsen, 2000, p. 188). Some considerations for web design and usability include allowing the user to freely navigate the site, the technological limitations of the user, speed of web page loading, and writing for the web.

Users have little tolerance for slow loading web pages, and web pages should be designed with speed in mind. Research has shown that the audience wants response times of less than one second when moving among pages. The response time goal when building web pages should be that it should take no more than ten seconds for users to get to other pages (Farkas & Farkas, 2002; Nielsen, 2000). Slow response times can lead to feelings of dissatisfaction with the site, people will go elsewhere for the information believing the site does not provide a good service.

Writing for the web is as important, if not more important, than some of the previously mentioned usability recommendations. The first rule is to be succinct: "Research has shown that reading from computer screens is about 25 % slower than reading from paper" (Nielsen & Tahir, 2002, p. 101). Because people do not want to scroll through pages, all the information should fit without having to scroll to see the end. When people read on the web, they scan and look for keywords. Consequently, designers should use short paragraphs with subheadings and bulleted lists. It is a good idea to structure articles with two or even three levels of headlines, with one idea per paragraph. Again, hypertext can be useful for splitting up long information into multiple pages. Although each page may be brief, with hypertext links a lot of information can be made available (Nielsen, 2002).

Linking is another function of usability; it allows users to go to other pages and sites on the Web. The use of link titles offers a short explanation that helps the user understand where he or she will be directed. By reading what they will be linked to prior to using the link, the user can understand the content of the destination pages (Nielsen, 2000). Hypertext is useful for splitting up long information into multiple pages, each page can be brief, but with hypertext links a lot of information can be available and users can scan the information quickly (Nielsen, 2000; Thompson, 1996).

Human-computer interface

The focus of human-computer interface is on the user and the design of technologies with the user in mind. In the case of websites, the focus is to make websites more responsive to the users' needs within the website. Human-computer interface has been applied in the areas of computers, virtual realities, video games, and websites. Where hypertext provides a mechanism for the user to navigate the website, human-computer interface design focuses on the users' needs and cognitive abilities during the design phase. One researcher suggests that "Users should set the pace of an interaction" (Raskin, 2000, p. 8).

It is important for computer users and, consequently web users, to be able to find the information they need to conduct their work. As technology has evolved people's patience for slow, non-user friendly computers has dramatically decreased. Computer technology needs to be hassle-free and fast; this is also true for websites. Human-computer interface has many implications for the study of web design.

As people interact with computers and the web, everything the user reads and sees will affect how the user will interact with the system. Consequently, it becomes important to prevent as many barriers as possible to enhance the users' experience. The role of the interface is to find and display information and support the user as they navigate the website (Farkas & Farkas, 2001). Buttons and text links are examples of user interface. Some criteria for interface design include usability, functionality, visual communication, and aesthetics (Laurel, 1990).

Computers and websites should be sensitive to the needs of the users. The emotional and cognitive needs of the user should be incorporated into computer and web design: "Such disciplines as cognitive psychology, ergonomics, and optics have been drawn in to support computer scientists in the task of designing interfaces for their application" (Laurel, 1992, p.xvii). Part of this challenge is to identify the users and define them in order to build a product to suit their needs-a website cannot be built in isolation. Some of the questions that should be posed include: what does the user need the website for, what is the information they are seeking, and what tools would be useful for people to do their work (Laurel, 1990)?

Communication Goals and Objectives of the SW Partnership Website

Three communication goals for the website were developed: use the website as a communication medium for outreach and other communication, use the website as a public participation tool, and use the website to communicate scientific information in an accessible way to a variety of stakeholders. Within the three communication goals, there were two planned outcomes for the Southwest Regional Partnership on Carbon Sequestration website (SW Partnership website): develop the overall design of the website, including color scheme, content categories and layout, and create a usable website.

The SW Partnership wanted a website in order to communicate with both the internal and external stakeholders. External stakeholders, including Clean Air Coalition and Sierra Club, needed information about the issue, upcoming meetings, and the project partners. Internal stakeholders, including New Mexico Tech at Socorro and University of Utah, needed a tool that had enough information that they could direct external stakeholders and project partners to for additional information. The website was created to disseminate information and create dialogue by getting feedback from the participants.

Website Development

The website was developed using hypertext theory (Farkas & Farkas, 2001; Nielson, 2000), usability (Nielson, 2000), and the principles of human-computer interface (Farkas & Farkas, 2001; Laurel, 1990). A review of carbon sequestration and energy related websites was performed (Global Energy Technology Strategy Program, 2005; National Energy Technology Laboratory, 2005; U.S. Department of Energy, 2005). The websites were evaluated in terms of their visual appeal, ease of navigation, ability to understand the content, and type of information provided. The existing websites provided information on what works and what does not work when communicating information regarding energy related issues. The information from the website review was communicated to the principle stakeholders to assist them in understanding some of the design implications for the SW Partnership website.

The overall goal of the website was to create a communication medium for outreach and education for primary and secondary audiences (see *Table 1*). Categories or themes were developed for the website. These categories were approved by the principle stakeholders prior to writing the website text. The categories were consistent will the goals of the project and with the principles of the public participation plan for the project. A conceptual map was generated in a stakeholder meeting, and was used to guide the development of the website and communicate information about the website to the project partners and stakeholders. Figure 48 shows this SW Partnership website conceptual map.

Stakeholder involvement

Meetings with the principle stakeholders of the SW Partnership were established in order to communicate information about the website development. The term *principle stakeholders* is used here to describe those individuals and agencies that were responsible for meeting the objectives and milestones outlined in the DOE grant application. The initial meetings created a better understanding of the scope of the SW Partnership and the project's goals and objectives. The meetings provided an opportunity to go over interests and concerns regarding the website. If a principle stakeholder was unable to attend a meeting, he or she received updates via email regarding what was discussed. The initial meetings were an opportunity to understand some of the users of the website as discussed in human-computer interface design (Laurel, 1990, 1993; Raskin, 2000).

Evaluation

The website was evaluated and tested using the principles outlined by Farkas and Farkas (2001) and Nielsen (2000). The evaluation occurred once the majority of the website was posted for at least three months. Evaluation included querying the stakeholders regarding their user experience by asking the questions: are you able to find information regarding the workshop, what is confusing about the website, and what is most interesting? People who were similar to the eventual users were asked these questions. The number of people was four and they represented a variety of education and web experience levels. This is consistent with Neilson's (2000) observation that most usability errors can be noticed by four to six users. Most used the web for basic tasks such as Google searches and email; others used the web more frequently for purchasing products, research, and news information. The people had varying degrees of knowledge of the issue of carbon sequestration, some had no knowledge at all and others were familiar with issue from conversations I had had with them. They were also asked to perform tasks such as finding the names of the project stakeholders, workshop dates and locations, and the main issues related to carbon sequestration.

Development Process

The content and text of the website was written after the website's conceptual map was approved by the stakeholders. This process was informed by the review of existing websites, the views and messages of the funding agency, and the goals of the principle stakeholders as defined in the DOE grant proposal (McPherson, 2003; U.S. Department of Energy, 2005). Once a draft of the content for the website was available, the principle stakeholders and the funding agency had ample opportunity to review it and make suggestions. The suggestions were incorporated in the draft document. Communication occurred with the host of the website, the state of Utah, Information Technology Services (ITS) data center regarding the requirements for the web layout and content, and loading the data on to the website. ITS was responsible for maintaining the website on their server. Once the website was populated with the content, the stakeholders had opportunity to view the content and make additional suggestions based upon their user experience.

The website was advertised to both the internal and external audience. I reviewed the website on a weekly basis and made updates as needed. Updates were collected from the stakeholders and posted to the website.

Evaluation

Evaluation occurred in the planning phase and throughout the project. Similar to getting feedback in the pre-design phase to identify the audiences, it was a good idea to get the input of the people who would use the system or a least a representative sample of the typical user. Formal evaluation included testing the site against other well-designed and published guidelines (Farkas & Farkas, 2001). It was also possible to have the users test the prototype of the site and observe what interested them and caused difficulties. It was possible to ask the users to guess what different buttons and links would do. Tasks were designed for the user to work through the website and try to locate an item (Farkas & Farkas, 2001).

Mediated Modeling

The objective of these modeling efforts is to develop a working model of sources, capture, storage, and sequestration issues in the Southwest Region. Given this applied focus, the model needs to be useful to industry participants, policy makers, and other decision makers regarding carbon sequestration. The modeling, then, is an integration of best science and best practice. To this end, the outreach committee formed a series of workshops and on-line meetings to collaborate between multiple stakeholder and interest groups. The mediated modeling process began at the January 2004 workshop in Salt Lake City, and reconvened at the June 2004 workshop in Albuquerque. At that time, participants were invited to meet virtually for a series of on-line meetings. After participating in two on-line meetings, participants met for a final workshop in Albuquerque in January 2005. At this time the participants refined the model, and then presented it to the larger partnership team.

Workshop 1

Objective: The objective of the first workshop was to join scientific and various publics (industry and local stakeholders) in an effort to conceptualize sequestration issues in the Southwest Region.

Process: Consistent with mediated modeling processes, the first session included information presentations given by experts in various fields, including carbon sources and capture technology; sinks and sequestration, including various terrestrial and geological options; and data needs and availability, including GIS and modeling processes.

With these presentations as information sources, participants were then divided into groups and discussed the key aspects of implementing sequestration in the Southwest Region. After thoroughly discussing their respective and similar vantage points, groups developed conceptual models of these issues. This initial step encourages cross-disciplinary communication as the groups are comprised of people from different sectors—e.g., a team is likely to contain a geologist, various industry experts, and an environmental advocate.

After coming to agreement on this group model, each group presented their model to the entire group. The large group then discussed similarities and differences between the various models. This secondary step encourages a better understanding of the desirability and feasibility of various aspects of sequestration.

Results: The models developed at this workshop were transferred into Stella© modeling software and presented again to the participants at the June workshop in Albuquerque, New Mexico. This provided continuity to the modeling process and served as a starting point for workshop 2.

Workshop 2

Objective: The objective of workshop 2 in Albuquerque was to move from conceptual modeling to more substantive and specific modeling of sequestration issues. Working in conjunction with the modeling committee from Sandia Laboratories in New Mexico, our purpose was to get participants to begin modeling sequestration using computer modeling software—PowerSim©.

Process: The two-day workshop was a collaborative effort between the modeling and outreach committees with the outreach committee providing the tutorials on systems modeling and facilitating the workshop and the modeling committee overseeing specific modeling issues and helping participants move toward a better understanding of how to model.

The beginning of the first day was spent on modeling tutorials. Modeling software is useful but only after participants develop an understanding what the icons of the software represent.

After the tutorials were complete, the outreach team made available the conceptual models developed in Salt Lake City. Participants then formed groups and spent the remainder of the first day and the beginning of the second day developing models using PowerSim.

In the last portion of the second day, Leonard Malczynski—the modeler with whom the outreach committee organized this workshop—took all four group models and connected them to create a single model. Consistent with mediated modeling processes, this was done with significant feedback from and discussion among participants. For example, one discussion brought about by an industry participant focused on the difference between modeling energy consumption and energy production. This discussion ensured greater legitimacy to issues the model focused on and, in turn, the likelihood it would serve as a useful decision tool as the Southwest Partnership for Carbon Sequestration completes Phase I and begins Phase II, as well as other decision makers examining the prospects of sequestration in this region.

Results: This workshop was of significant import as it provided a bridge between the conceptual modeling of workshop 1 and the continued development of the model in preparation for workshop 3. Specifically, two things were gained from this workshop: First, a model was developed which a broad-range of participants (e.g., environmental policy experts, coal, and energy/utility company representatives) agreed traced the key aspects of capture, transfer, sequestration, and storage. Second, participants were engaged and committed enough to the process that they volunteered to continue working on the model between workshops 2 and 3.

Online Workshops

The model which emerged from workshop 2 was qualitative in nature and needed considerable data before it would be of substantive value. The modeling was scheduled to be completed for workshop 3, January 2005 in Albuquerque. Additional interaction was needed prior to this final meeting.

Objective: The objective of the online workshops was to facilitate communication between participants and partners (specifically the participants from workshop 2 and the technical modeling team at Sandia Laboratories in New Mexico) to continue building the Carbon Sequestration model. The difficult aspect of this need was that participants and partners were dispersed throughout the Southwest Region.

Process: Working in conjunction with New Mexico State University and Tom Freelove of WERC—a consortium for environmental education and technology development—we utilized WERC's on-line webcast software Centra. Centra has been useful both from a public participation and a modeling standpoint because (a) it allows the modeler to present the model, (b) engages all in a discussion of the model's parameters and data, (c) enhances participants' ability to make alterations to the model while in session (using application share, the modeler and participants can alter the model on-line), and (d) permits participants and modelers to view the Centra meeting after it has ended as the sessions are recorded.

Results: We conducted three Centra meetings, with the final one held on November 15, 2004. These meetings have been particularly useful because they provide an opportunity for participants to give feedback to the modeling committee very quickly after they make alterations to the model. In turn, it allows the modeling committee to respond quickly to participants' questions and suggestions. At the close of the October 4 meeting, for example, one participant sent the modeler some suggestions regarding the GIS data that would be needed to connect geological issues to economic concerns in an effort to discriminate between sequestration options. Members of the technical team took this suggestion under consideration, and used it to revise the version that was presented in the November 1 meeting. All participants understood and supported the changes.

<u>Workshop 3</u>

Objective: The objective of workshop 3 was to finalize a model that participants could use as an educational tool, and that regional partners could use as a basis for moving from phase 2 into phase 3 of the project.

Process: Most of this one-day workshop was held in a computer lab, so that each participant was able to manipulate the model as desired. The workshop was facilitated by Leonard Malczynski, with assistance from other Sandia colleagues, as well as members of the outreach committee. By this point all participants were familiar with modeling software, and everyone worked on the model individually. Participants spent the morning and early afternoon refining the model that had emerged from the three Centra meetings, and then prepared to present it to other members of the partnership.

Results: In the late afternoon, the model was presented to the full partnership at the final review meeting. It then became the basis for negotiation over appropriate activities and sites to be considered for phase 2. Workshop participants became teachers for other partnership members during this phase.

<u>Background</u>

There is a growing tendency to shift environmental management away from individual planning tools for separate economic sectors or management for single issues and towards an ecosystem management approach where a range of different stakeholders are included. To improve decision-making for sustainable development, new tools to facilitate common goal development and to test alternative scenarios are needed. These tools have to be able to communicate the complexity and uncertainties of the decisions and allow for broad stakeholder participation, while integrating different aspects (economic and ecological) of the situation involved. Integrated assessments use tools and inputs from multi-disciplinary, multi-scale and multi-social backgrounds to support decision making processes. (van Asselt, 2000). Rather than the equilibrium-based view of decision and policy making, adaptive environmental management (Holling, 1987) adds the emphasis on the ever evolving cyclic goal for societal organization structures centered on the behavior of ecological systems. Collaborative Learning emphasizes a process oriented approach from a team learning perspective (Daniels & Walker, 1996).

Addressing today's complex environmental challenges deals with finding balance between different sides of an issue. There is constant tension between the opposite sides of the same coin and the game is played with a variety of coins with varying values and even varying currencies. For example, should decisions be made by one person or should all stakeholders be involved? Should we strive for a single answer to a problem or instead should we not commit to any answers in the face of overwhelming uncertainty? Should we rely on answers generated within the borders of individual disciplines or do we need to move beyond disciplinary analysis? Many different forces are at work at the same time. Most likely there is no black or white choice involved, but rather the need to choose an appropriate position along many different continua. For example, rather than having decisions made by one or by all, we can examine the trade offs and chose a position where relevant stakeholders can participate in designing an answer. Rather than assuming one compartmentalized answer that fits the static legislative structure or becoming overwhelmed by uncertainty, a complex dynamic situation can be acknowledged and managed in an adaptive manner. Rather than relying on a single discipline or doing away with deep analysis, we can chose a format where relevant disciplines can constructively contribute toward synthesis and practical problem solving. This does require some looking outside the usual boxes, revising the roles of the stakeholders, original thinking and learning and effective communication. In order to make the different forces at work more tangible, they need to be labeled. Only when they are identified will these tensions enter the conscious domain, where they can be faced and incorporated into our communications with others. Left in the unconscious domain they will remain out of balance, driven by habit, fear or hope.

Mediated modeling is an experimental process that is useful in such complex situations. It is best initiated at the scoping level, when a problem arises or as a way to support an ongoing research program. In the case of the Southwest Partnership, we used it as a means for supporting and gaining additional participation in an ongoing research program.

Potential results for the participating groups or communities include the following.

- *Team learning*. The industry partners who chose to participate in these sessions developed a higher level of understanding.
- *Consensus.* A successful process generates a workable level of consensus. Ideally, every participant is equally enthusiastic about the resulting recommendations. However, a situation where everyone can "live with" the recommendations can still be considered a success, and is much more common. While our participants all were enthusiastic about the model that resulted from their efforts, that enthusiasm differed between individuals.
- *Communication tool.* Every participant should be able to operate the final model. The resulting model can be used as a basis for discussion with stakeholder groups and as an educational and communication tool. Although every participant in our workshops was able to operate the model with guidance, the timing (conclusion of phase 2), mitigated against additional training sessions that would have enabled them to independently use the model as a communication tool. We intend to continue this activity in the next phase.

- *Decision aid for policy and management.* A basis for more equitable, resilient and sustainable policies and management options is established because stakeholders have effectively been involved. The model was used by the larger partnership group as a basis for negotiating activities and sites for Phase II of the project.
- *Adaptive management.* The resulting model was flexible and can be updated and changed as new information is available due to monitoring and assessment of the implemented recommendations. Again, this flexibility will be used as we begin Phase II.

Virtual Town Meetings

Personnel from WERC, a Consortium for Environmental Education and Technology Development at New Mexico State University, developed the materials for, and facilitated 2 virtual town hall meetings, using CENTRA (see description of online modeling above). Members of the Southwest Partnership's technical team made oral presentations that were telecast to various sites in Colorado, New Mexico, and Utah. Participants in the meetings came from every state in our partnership. Written informational materials were provided to all audience members. All participants also had opportunities to ask questions of all presenters.

Recommendations and Summary

We began by attempting to design and disseminate appropriate outreach materials for external stakeholders. Our efforts evolved to include an examination of the process of communicating information within an interdisciplinary and cross-sector team. The literature related to public participation, computer mediated communication, and organizational communication is revisited here in terms of recommendations.

The primary communication goals were achieved. Based upon these positive experiences three recommendations can be made to anyone attempting to design and implement outreach programs for governmental agencies:

(1) Meet regularly with stakeholders to ensure everyone is informed about the progress of the project;

(2) Spend more time than you think necessary in the beginning, to understand the overall scope of the project; and

(3) Review potentially relevant theoretical and applied literature to understand what works and what does not work.

The first recommendation, meet regularly with stakeholders to ensure everyone is informed about the progress of the project, is important because as elements of the project progressed, the concerns of individuals were quickly addressed. Regular meetings also helped establish rapport which led to a better working relationship.

The completion of the outreach materials also depended on spending a significant amount of time understanding the overall scope of the project, before beginning to develop materials. The preliminary meetings not only established rapport, but provided a framework for what different stakeholders were responsible for in order to accomplish the project objectives. As issues relating to organizational communication became apparent, I was able to put those issues in context of the overall project scope. General readings on energy, climate change/global warming, US energy policy, and environmental controversy were critical to increasing understanding and enabling us to design appropriate outreach materials (Gellici, 2003; Kojimaa, 1998; LVC, 2003; McPherson, 2003; NETL, n.d.; NRDC, n.d.a). The time spent up front was also consistent with public participation recommendations of understanding stakeholders and the issues (Daniels & Walker, 2001).

It was important to review existing literature and similar projects to gain an understanding of what works and does not work. The review was particularly helpful because it provided background on how other agencies communicated information regarding energy policy and carbon sequestration via the web, and helped us better understand the multiple aspects of the carbon sequestration issue. This understanding led to better informed web content. This review was also consistent with web design and web usability literature (Farkas & Farkas, 2002; Nielsen, 2000).

More generally speaking, by utilizing basic organizational communication theory as a guide, outreach personnel can help develop positive and supportive working relationships within a team, thus enabling team members to devote more energy to their own tasks (such as developing educational materials). The fact that all major participants (including, but not limited to, the DOE, industry partners, university partners, etc.) have generically bureaucratic structures suggests several recommendations that can be consistently applied across a variety of outreach efforts that involve large and complex stakeholders, such as the U.S. federal government (Hamilton, 1991; Perrow, 1990; Weber, 1903-1904/1958). Note that we do not intend the word “bureaucratic” as a pejorative term. Rather, it describes the most commonly occurring and most thoroughly researched form taken by complex organizations. Many researchers have concluded that bureaucracy evolved because it was the most efficient organizational form (Perrow, Weber). The contemporary political and socio-economic scene, however, is increasingly chaotic, and may pose challenges to traditional (bureaucratic) forms of organizing, which do not cope well with rapid and erratic changes in their environments.

It makes sense to apply what we know of organizational theory to increase the efficiency of teams such as the regional partnerships. An organization’s structure occurs as a result of communication and, at the same time shape the organization’s communication processes. All organizations have structures, which creates efficiency by minimizing the need for organizations to reinvent themselves. Bureaucracy is a specific organizational structure that incorporates elements of hierarchy, specialization, and formalization. Understanding bureaucracy is helpful for understanding how decisions are made in organizations.

All organizations need to communicate within themselves and with other organizations in order to get work accomplished. In a bureaucracy the process necessary for that transmission of information is defined and constrained by certain elements. Individuals with specialized expertise divide up the work and operate within a defined hierarchy (Cheney, et al. 2004). Max Weber (1903-1904/1958) showed that information in organizations was controlled by a small number of people at the top of the organization, where the power was located. Bureaucracies legitimize power and authority within institutions, especially large institutions (Hamilton, 1991; Weber, 1903-1904/1958). Weber also suggested that control was especially important in the area of scientific research and political administration.

Weick (1990) notes that “there is ambivalence within organizations toward being open and closed, . . . suspicious and trusting” (p.132). . Weik further suggests, than when working with large bureaucratic organizations it is important to provide constant communication, even to the point of redundancy, because, “there can be enormous differences among organizations and industries with respect to the level of clarity that they regard as sufficient for action. Members of organizations spend considerable time negotiating among themselves an acceptable version of what is going on (p.127). These differences can be recognized and mitigated with planning. It does take a lot of time and that should be anticipated.

We offer the following additional recommendations as relevant to similar projects:
(1) Understand how organizational structures within each stakeholder organization work and keep abreast of any changes;
(2) Send information and requests to the funding agency early in the project development phase, request input and suggestions, and repeatedly provide feedback;
(3) Include a funding agency representative in all communications regarding opportunities to review material
(4) Review all project deliverables with all the stakeholders prior to beginning work on the project; and frequently throughout the project;
(5) Provide project management opportunities to participate in all discussions with other contractors, and ensure that they take advantage of this opportunity for any discussions directly related to key decisions. .

This project demonstrates that, beyond producing outreach materials, communication research can bring greater understanding of both internal and external relationships relevant to complex projects such as this one. Areas of communication theory had were directly relevant for this project included public participation (Craig, 2003; Daniels & Walker, 2001; Hawkins, 2001;

Susskind, Moomaw, & Gallagher, 2002), computer mediated communication (Farkas & Farkas, 2002; Nielsen, 2000), and organizational communication (Cheney, et al., 2004; Corman, et al., 1990; Weitz, 1990). Interdisciplinary and cross-sector partnerships are becoming increasingly common as we seek the best ways to manage large and complex issues such as climate change. Despite the fact that we have much to learn, these partnerships hold great promise.

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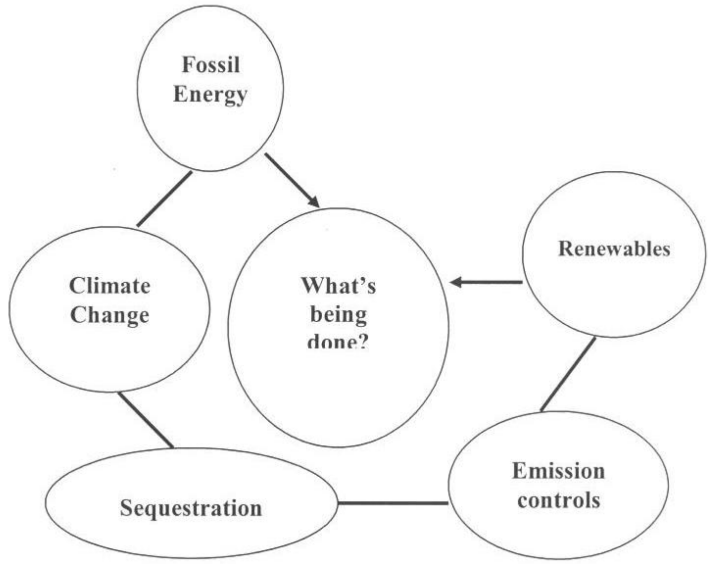

Issues
-carbon calculator
-public health concerns/respiratory (American Lung Assoc)

Pages
-Audience identification (Scientists, policy makers, landowners, etc)
-design pages according to these audience members
-Glossary
-Page labeling, site map
-Search engine

Questions
-How do we provide context & additional information?
-Asking the question, how does this impact your community or state?
-What would be useful to you?

Other issues for consideration:
Industry and other areas of the partnership
Policy/regulatory
Technology (discuss different kinds of sequestration and potential sequestration)

Priority of web pages:
#2 Partnership (goals, specifics)
#3 Technology
#4 Industry
#5 Policy/Regulatory

#6 State by state
#7 Workshops
#8 Integrated model

Fig. 48. Southwest Partnership website conceptual map.

Integrated Assessment of Sequestration Options

A team of collaborators within the Southwest Regional Partnership for Carbon Sequestration developed an interactive software tool to help facilitate discussions involving the science, engineering, economics and policy analyzed throughout the larger Partnership community. The integrated assessment team, largely based at Sandia National Laboratories, developed a dynamic simulation computer model to help interested parties understand the potential screening criteria necessary to develop a carbon sequestration project. The screening criteria include geologic considerations for underground storage of carbon dioxide (CO_2), the relative size of the CO_2 flow from the source to the sink, and the associated economics with the system.

With these screening criteria, the test case model has successfully been used to bring together participants across the Southwest Regional Partnership (SRP). Workshops with the collective participation of the SRP provided feedback regarding the model's framework, and allowed for the multidisciplinary team to begin thinking about where the important aspects of such a project may lie (e.g., the geological science, the industry collaboration, the public involvement) and how the SRP could address these aspects in subsequent analytical efforts. In the earlier workshops of the SRP, the Integrated Assessment team discussed a companion model of the economy of the Southwestern United States. Based on the SRP community's feedback regarding how the software tool could be used to highlight the overarching issues within the region (e.g., high level costs, distance between the sources and sinks for CO_2) it was decided to focus the modeling effort. The focus efforts developed into a "String of Pearls"-based model that allows the SRP to explore multiple source and sink combinations for potential pilot projects.

The methodological framework developed for the integrated assessment was first applied to four power plants in New Mexico and several geologic sinks in the San Juan Basin as a test case for the framework. Using this framework, the Integrated Assessment team then developed a path forward towards characterizing the whole state of New Mexico, and laying the groundwork to cover additional regions both within the Partnership, and beyond where appropriate. The initial findings suggest that the capture costs of CO_2 at the power plant may comprise a large component of the systems costs, but Measurement, Monitoring and Verification (MMV) costs could change the overall system's cost balance depending upon the length of time the sinks are to be monitored.

Timeline of the Integrated Assessment and Modeling Efforts

The purpose of the integrated assessment in Phase I was to bring together the large amounts of quantitative data and qualitative issues from the SRP. To achieve this goal, several workshops were held by the SRP to solicit ideas, insights and general knowledge from the larger body of collaborators as to what, why and how the partnership should include. It was collectively decided the analysis should help 'tell the story' involving the multitude of science, economic and policy issues involved with the educational outreach aspects of the partnership. A user-friendly dynamic simulation model was developed to help facilitate these discussions. The model was developed through an interactive process which included several interactive web-based sessions and annual workshops as a basis from which to work. As the partnership's collaborators developed additional information and questions regarding the project's overall scope and level of detail, the modelers built, modified and developed the integrated assessment around this information. Table 31 shows a timeline of the major events used to develop the Integrated Assessment's analysis.

The Integrated Assessment Model

The Southwest Regional Partnership on Carbon Sequestration Integrated Assessment Model is a high level, dynamic simulation model that is meant as a learning tool for policy makers and members of the public who would like to understand some of the implications for future energy demand and the potential corresponding stationary CO_2 sequestration options. Figure 49 illustrates that the majority of the stationary CO_2 emissions from a few states within the SRP were from utility (electricity generation) sources, while smaller amounts were from other non-utility sources.

The modeling team decided to focus on electricity production by utilities from coal and gas fired power plants as a point source for CO_2 emissions for the initial test case model framework. The test case region focused on the San Juan Basin in Northwestern New Mexico and Southeastern Colorado.

The Integrated Assessment model team worked closely with the geologic sinks, physical infrastructure, and sources teams to characterize the power plants and geologic sinks, and the costs associated with sequestration options in the test case. Sources were characterized by accounting for their annual CO_2 emissions and other select attributes. Sink characterization included location, depth, volume, relative risk of leaks (based on geologic features), and other select features. The distances between sources and sinks were calculated using a great circle distance (GCD) formulation.

The model structure allows the user broad flexibility in changing key assumptions, and the base case assumptions were developed from the topical experts of the SRP and information drawn from the literature. The test case cost equations for CO_2 separation and capture at the source were developed using historical power plant data from the 2002 version of the Emissions and Generation Resource Integrated Database (eGRID), and the Integrated Environmental Control Model (IECM) (EPA, 2005; CMU, 2004). The Integrated Assessment model employs transport and injection equations for storage based on the relevant literature, and they were assessed by members of the physical infrastructure and sources team (Ogden, 2002, Williams, 2002, Hirl, 2004). The model develops prototype cost algorithms for the Integrated Assessment model from this information. Figure 50 depicts the overall structure of the modeling effort, and Fig. 51 illustrates the stages of the test case model.

The basic framework allows interested parties to assess different regional sequestration options for CO_2 emissions sources, and to evaluate the total CO_2 emissions in the region. The model has an additional role to help the public gain insight to the tradeoffs between different sequestration strategies by providing opportunities to perform 'what if' analyses of different approaches to CO_2 sequestration.

Four workshops/meetings and several web-based conferences have been held, involving individuals from the electric power industry and state regulatory agencies. Members of the Integrated Assessment team presented aspects of the test case model at the third and fourth annual Carbon Capture and Sequestration conferences, and attended the MIT Carbon Sequestration Forum VI to further expose the analysis for additional vetting and professional feedback (Paananen, 2004; Kobos et al., 2005a). The model's analytical capabilities and interface development process incorporated the feedback from the workshops and conferences to help guide the ongoing development of the Integrated Assessment model.

First Results: Applying the Integrated Assessment Model Framework

Four CO_2 emissions sources – all electric power plants – were selected from the Emissions and Generation Resource Integrated Database (eGRID) for the initial test case. Power plant capacity ranges from approximately 13 megawatts (MW) to 2300 MW. Seven geologic sinks have been identified in the test area by the geologic sinks team. The variable inputs to this dynamic simulation model (largely an illustrative tool) include the percentage of CO_2 captured from the four power plants. The Integrated Assessment aligns the CO_2 emissions from the four power plants with the seven sinks to calculate sink lifetime given these conditions. The criteria for test case sink selection included those that are ≥ 3000 feet deep, have desirable geological characteristics (e.g., low chance of CO_2 escaping into surrounding strata or the surface), and are within varying distances from the power plant(s) used in the test case analysis.

The CO_2 sources and sinks selected for the model test case result in many combinations of potential sequestration actions, with associated sequestration rates and capital, operation and maintenance costs. These combinations provided the initial high-level 'what if' analysis opportunities for sequestration in the test case area. Figure 52 shows the locations of the power plants and the geologic sinks in the test case area.

Figure 53 illustrates the summary screen model interface for the test case's base case results. The summary screen offers the base case scenario results that include the lowest total capture, pipeline transport and well-associated costs (upper left-hand graph), the kilometers (km) to the sink used for the base case within the test case region (upper right-hand graph), the overall lifetime of the sink selected (lower left-hand graph), and the annual amount of CO_2 captured at each plant (lower right-hand graph).

The capture costs for CO_2 at the Animas, Raton, Four Corners and San Juan power plant sites represents 94, 91, 93 and 95 % of the total capture, transport and injection cost total for each of the base case systems, respectively. The model calculates all of the illustrative cost and CO_2 flow combinations between the four power plants, and the seven geological sequestration sites, and ranks them from lowest to highest. At the 90% level of capture for CO_2, the Animas, Raton, Four Corner and San Juan working results indicate the cost of electricity could roughly double. This, however, is related to the plant's size, derating of capacity, and other salient variables.

The model's framework has also been extended to include future cost and CO_2 flow calculations for the Escalante, Carlsbad, Cunningham, Maddox, Reeves, and Rio Grande power plants as of December, 2005. Combined with the initial four power plants, these plants represent the coal and gas-fired power plants in New Mexico.

Discussion

This section discusses the test case model's sensitivities and provides several examples of additional work both underway and to be completed as appropriate for the larger analysis. The initial observations are listed below.

Model Results are Sensitive to Carbon Capture Percentage

The model results are sensitive to the percentage of CO_2 captured from the power plants. Based on the results of the IEGM model, several levels of percent CO_2 captured illustrate the affects on the dollars per tonne of CO_2 ($/t$CO_2$) and annual amount of CO_2 captured. The cost to capture additional CO_2 increases as the percentage captured at the plant decreases. The costs for the overall systems, driven largely by the capture costs under the current working results, are high because the test case uses existing plants to calculate capture costs from the IECM. A recent study reports carbon capture costs may range from approximately 15 $/t$CO_2$ for integrated gas combined cycle plants to 30 $/t$CO_2$ for pulverized coal facilities (DOE/EPRI, 2000).

Amount of CO_2 Accounted for in the Test Case is Small Relative to the Total for the Region

To add perspective to the regional aspects of the project, Fig. 54 illustrates the total CO_2 stationary source emissions for the Southwestern Region of the U.S., the state of New Mexico, and the four initial test case power plants. The four power plant-based test case analysis represents only 11% of the region's total, and 69% of that from New Mexico (EPA, 2005).

Additionally, several states within the SRP have net exports of electricity. The states of Arizona, New Mexico, Oklahoma and Utah, for example, exported approximately 26, 41, 3 and 30 % of their electricity outside of the state's borders in 2000, respectively (EIA, 2005). This poses both a modeling, and more importantly policy challenge as to how and who will be held responsible for CO_2 emissions in a carbon-constrained world; the electricity producers or the users. Figures 55 and 56 illustrate the installed megawatts and the corresponding CO_2 emissions within the selected Southwestern states.

The "String of Pearls" pipeline network tool in the Integrated Assessment Model

The Integrated Assessment team expanded the initial test case model to include all New Mexico sinks and sources in a new, revised prototype model in the latter half of 2005. The Integrated Assessment team developed the "String of Pearls" in response to feedback from the Final Project Review in January of 2005. The model calculates the distance to transport CO_2 from the source to the closest sink to be utilized. An algorithm was developed to calculate a route of pipelines from the source of CO_2 (e.g., power plant) to each of the geologic sinks and then can calculate the total (Great Circle) distance (and eventually cost) of the pipelines (Stephens, 1998).

The sinks are used in such a way that as each one fills to capacity the transportation network extends to the next viable sink, and then to the next to eventually develop a pipeline network system. This allocation mechanism or "String of Pearls" concept is also known as a minimal spanning tree approach. The links between all combinations of the particular source selected to various sinks are the potential pipeline routes. This technique serves as a linear proxy for pipeline length, and lays the groundwork for future, additional "String of Pearls" analysis throughout both the Southwestern Regional Partnership area in the United States, and other regions interested in carbon capture and sequestration analysis. With this technique, the model could address additional metrics (e.g. lowest overall cost, largest sink volume, etc.) for systems insight. Figure 57 illustrates a prototype pipeline route within the Integrated Assessment model.

The "String of Pearls" model builds on the original test case model that involved four power plants and seven geological sinks in New Mexico. The larger "String of Pearls" model now includes four coal fired power plants, six gas fired power plants, and twenty nine geological sinks in New Mexico. The prototype "String of Pearls" model now can determine the source to sink distances and associated economics (various components remain to be refined) for any of the source sink combinations between these ten power plants, and the twenty nine geological sinks. The prototype model as of December 2005 can illustrate up to the top ten closest sinks to any of the ten power plants. Additionally, the model now includes high-level MMV costs based on Benson et al. (2004) of approximately \$0.16 to \$0.31 per tonne of CO_2 to begin assessing how these costs will affect the overall system's economics. Figure 58 illustrates the source and sink input options on the left and right of the graphic, respectively for the coal-fired power plants in New Mexico.

The prototype, illustrative results of Fig. 58 indicate that using the coal-fired San Juan power plant, the "String of Pearls" algorithm determined that the sink categorized as number 5 is the closest to the power plant. The next closest sink to sink number 5 among all the remaining 28 sinks is sink number 26, and so on. The user may also select sinks that are within a certain distance from the source, sinks that are of at least a certain capacity, or the specific sinks the "String of Pearls" algorithm should consider. The cost metrics will likely change as more site-specific installation and technology scenarios develop. For example, the carbon capture community is looking to reduce the uncertainty regarding overall carbon capture systems' cost and performance parameters. Recent work suggests the cost to capture carbon dioxide using an amine (MEA)-based system holds substantial potential to reduce the cost to half or less of their current costs (Rao, 2002; Rao and Rubin, *in press*).

The model can also be used to determine the closest sinks to any given gas-fired power plant in New Mexico. Figure 59 illustrates the results of a gas-fired power plant, the Maddox plant, and the combinations with carbon sequestration sinks.

Finally, the user is able to select a 'custom' location for a power plant by specifying the latitude and longitude coordinates of the power plant. With this ability, the interested model user can determine where to cite a new power plant when considering carbon sequestration infrastructure (existing CO_2 pipelines are to be added to the "String of Pearls" in Phase II) and geological sinks. Figure 60 illustrates a map of the CO_2 sources and sinks considered in the "String of Pearls" prototype model for New Mexico.

Regional Energy and Economic Issues: Addressing Carbon Intensity

In 2002, the current U.S. administration announced the 'Global Climate Change Initiative' to help achieve a reduction in greenhouse gas intensity throughout the U.S. economy (Bush, 2002). The goal is to reduce greenhouse gas intensity, a ratio of the amount of greenhouse gases emitted divided by the gross economic output of the economy in the same time period (e.g., emissions for 2002 divided by the economic output from 2002), by 18% between 2002 and 2012 (EIA, 2003). Carbon dioxide emissions from power plants are one of the several greenhouse gases included in the initiative. Addressing these emissions, through carbon sequestration, clean coal technologies, and other potential greenhouse gas reduction emissions, will help the U.S. to achieve this goal.

In the United States, the amount of energy consumed throughout the economy has been increasing over the last several decades. Additionally, the amount of energy consumed to generate electricity has also been increasing. Figure 61 illustrates total energy consumption for the U.S., and the total energy consumed by fuel type to generate electricity, respectively.

Regionally, the Southwestern United States represents one of the fastest growing areas of the country. With this economic and population growth comes a growing demand for energy, including electricity. Figure 62 highlights both the increasing levels of energy required for the state of New Mexico, as well as the relatively large share that coal-fired power plants represent of the electricity generation base.

Combined, coal and natural gas-fired power plants represented 99.9% of the electricity generation in New Mexico in 2000 (EPA, 2000). These plants represent opportunities to sequester the carbon dioxide from the existing infrastructure (e.g., retrofit) or potential future technological options (e.g., replace the existing electricity generation infrastructure as it reaches retirement with advanced coal, gas or other electricity generation technologies).

Ultimately, opportunities exist to address the 18% greenhouse gas intensity target by both increasing the economic output from the economy, and also by reducing the amount of carbon dioxide from sources throughout both the regional partnership, and the country.

Ongoing Modeling Efforts and Applications in Phase II

The Integrated Assessment Team will address the larger region covered by the Southwest Regional Partnership beyond the initial "String of Pearls" model for New Mexico. As the data develops for both the sources and the sinks from the Southwest Partnership's several thematic committees, the Integrated Assessment team will include it in the "String of Pearls" model. The model will also address additional developing Measurement, Monitoring and Verification (MMV) cost metrics, evolving system economics, and suggestions from the larger Southwest Partnership body of participants.

Additionally, the Southwest Regional Partnership on Carbon Sequestration has proposed a Phase 2 program that would carry out several field pilot tests to validate the most promising sequestration technologies and infrastructure concepts in the region. The Integrated Assessment Model may include metrics and information for these pilots as appropriate to continue to develop a 'systems view' of Southwest Regional Partnership's full analytical scope. The Integrated Assessment model will continue to play an important role in the Southwest Regional Partnership outreach and education plans in Phase 2, with a focus on mediated modeling. Potential future meetings or web-based meetings were discussed at the December 15 and 16, 2005 Phase II project kickoff meeting in Socorro, NM to demonstrate the working "String of Pearls" model to members of the Southwest Partnership who were unable to attend the kickoff meeting. This would allow additional participants to provide suggestions for model improvements and extensions, based on their interests and concerns about CO_2 sequestration, leading to an integrated model that is constructed collaboratively with the broader SRP.

The Integrated Assessment will also address risk issues as they relate to costs, MMV, and related topics. Specifically, the analysis will address levels of economic risk (e.g., what are the price thresholds for projects to move forwards and/or continue), performance risk (e.g., how might the plant (CO_2 source) life affect the CO_2 volumes captured and sequestered), and address what leak rates might be to integrate this information with MMV issues where appropriate. The Integrated Assessment team will continue to include work from the MMV team, with leading contributions from Julianna Fessenden of Los Alamos National Laboratories and David Borns of Sandia National Laboratories. Several broader issues will be explored as they relate to the types of technologies used for MMV, when their use is more appropriate, and what the potential costs might be. Figure 63 illustrates how the integrated assessment may characterize technologies and the central issues involving MMV. Additionally, questions the MMV cost modeling activities might consider include; Can the MMV costs be linked to the current model parameters (e.g., number of wells, costs, and their depth, sink capacity, length of the pipeline, power plant or other

CO_2 source capacity / technology); Could the MMV costs relate to the sinks (e.g., geology, depth, surface area)?

Several tasks and ideas remain to be fully developed as part of the Integrated Assessment as appropriate to meet the Southwest Regional Partnership's goals. These ideas include the following:

- Plan for and extend the model where appropriate to additional datasets to allow for increased model flexibility (e.g., potentially utilize the underlying framework for other CO_2 source and sink combinations/regions).
- Within the Integrated Assessment Model, allow users to implement a 'search space' option where they can determine where a potential power plant (or other carbon dioxide source) should be developed within the region given the distribution of the sinks.
- Potentially break down the region into grids to allow for a higher resolution model to be developed
- More fully integrate the existing CO_2 pipeline infrastructure into the model's calculations, thereby effectively treating the infrastructure like a CO_2 sink when planning connections and routing of CO_2 for sequestration and other purposes
- Explore additional cost reduction potential for amine-based carbon capture systems – this will add perspective on where the most efficient use of Research and Development spending may decrease the overall carbon capture and sequestration system's cost. A relatively small reduction in capture costs will translate into a relatively large percentage decrease in the overall system's costs. (Rao, *in press*; Rao, 2002).
- Look to other existing CO_2 capture and sequestration projects for geologic and economic lessons learned that could be applied to the Southwest Regional Partnership (Gunter et al., 1996; Thambimuthu, 2002; Bachu and Shaw, 2004; Dahowski et al., 2004; Wilson et al., 2004;).
- Explore how a carbon credit system would affect the overall economic attractiveness of select carbon sequestration system planning scenarios
- Include additional metrics on the altered performance (derating of the power plants) and electricity costs often characteristic of power plants with carbon capture systems when compared to their base case (no capture) counterparts. O'Dowd (2005), for example, explained that interested individuals would like to understand more fully how carbon capture technologies on power plants might affect electricity prices.

Final Remarks

The Integrated Assessment team solicited and addressed questions regarding the overall Southwest Regional Partnership's initial tasks in Phase I regarding geological constraints, spatial distribution of CO_2 sinks and sources, and the associated economics of scenario-based planning. The initial results indicate the capture costs represent by far the largest component of the overall carbon capture, transportation and sequestration system's cost. It was important for the Integrated Assessment team to calculate and demonstrate this result, similar to that found in other studies (Rao and Rubin, 2002), for a potential carbon sequestration system in New Mexico as a lead-in toward characterizing the larger Southwestern United States.

The modeling framework developed in Phase I through the multi-stakeholder process serves as the basis for more specific pilot projects in Phase II. In addition to refining the "String of Pearls" modeling technique and capabilities, the Integrated Assessment team strives to bring together the science, engineering and economics developed for the greater body of collaborators within the Southwest Regional Partnership for Carbon Sequestration.

This summary of the integrated assessment effort draws from the following select SAND documents and meetings as part of the Southwest Regional Partnership for Carbon Sequestration Integrated Assessment efforts, and serves as the basis for future Integrated Assessment:

- Peter H. Kobos, David J. Borns, Len A. Malczynski and Orman H. Paananen. (2005). Southwest Regional Partnership on Carbon Sequestration: A Test Case Model in the San Juan Basin Sandia National Laboratories, Poster Presentation at the Fourth Annual Conference On Carbon Capture & Sequestration May 2 − 5, 2005 Alexandria, Virginia. SAND2005-2481C.

- Peter H. Kobos, David J. Borns, Leonard A. Malczynski, and Orman H. Paananen. (2005). The Southwest Regional Partnership on Carbon Sequestration: Employing the Integrated Assessment Model for Systems Insight. SAND2005-4902C and Proceedings of the 25thAnnual North American Conference of the USAEE/IAEE, September 19 − 21, 2005, Denver, CO.

- MIT Carbon Sequestration Forum VI: Taking Stock of CO_2 Capture & Storage. Royal Sonesta Hotel, Cambridge, MA, November 3 − 4, 2005.

- Coupling MMV to models and risk assessment: Developing the Integrated Assessment Model Based on the Input From Experts. (2005). Discussions at MMV Workshop for SW Partnership, November 17, 2005, NMT Building, Albuquerque, NM.

- Peter H. Kobos, Leonard A. Malczynski and David J. Borns. (2005). The Integrated Assessment Overview. Southwest Regional Partnership on Carbon Sequestration Project Kick-off Meeting, New Mexico Institute of Mining and Technology Socorro, NM, December 15 –16, 2005. SAND2005-7906P.

- Paananen, O. (2004). A Framework for Assessing Carbon Storage in the Southwestern United States. Presentation at the Third Annual Conference on Carbon Sequestration, Alexandria, VA, May 3 – 6, SAND2004-1744C.

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Table 31. Integrated Assessment Modeling, Analysis and Presentation Timeline

Date	Event	Purpose
March 25 – 26, 2004	First Partnership Workshop	Assess Carbon Options
April 20 – 21, 2004	CO2 Sequestration Integrated Model Workshop, Albuquerque, NM	Assess CO_2 capture, transportation and storage costs from the literature
May 5, 2004	Third Annual Conference on Carbon Capture and Sequestration, NETL, Alexandria, Virginia	Presented on the SW Partnership Integrated Assessment's (IA) Goals
June 7 – 8, 2004	Southwest Regional Partnership on Carbon Sequestration Workshop, Albuquerque, NM	Introduced the methods the Integrated Assessment team use for interactive modeling
November 1, 2004; December 6, 2004	Web-based mediated modeling sessions through New Mexico State University (Centra, Web-based meetings)	Interact with the Partnership to establish and refine requirements for the IA model
January 11 – 12, 2005	Final Project Review, Albuquerque, NM	Demonstrate the IA model, additional group feedback
May 4, 2005	Fourth Annual Conference on Carbon Capture and Sequestration, NETL, Alexandria, VA	Poster Presentation on the SW Partnership's IA model
November 17, 2005	MMV Workshop, Albuquerque, NM	Coordinating Phase I and II MMV assessment activities
December 15 – 16, 2005	Southwest Regional Partnership on Carbon Sequestration: Phase II Kickoff meeting	Demonstrate the IA model to date, highlight the "String of Pearls" capabilities, discuss future IA activities

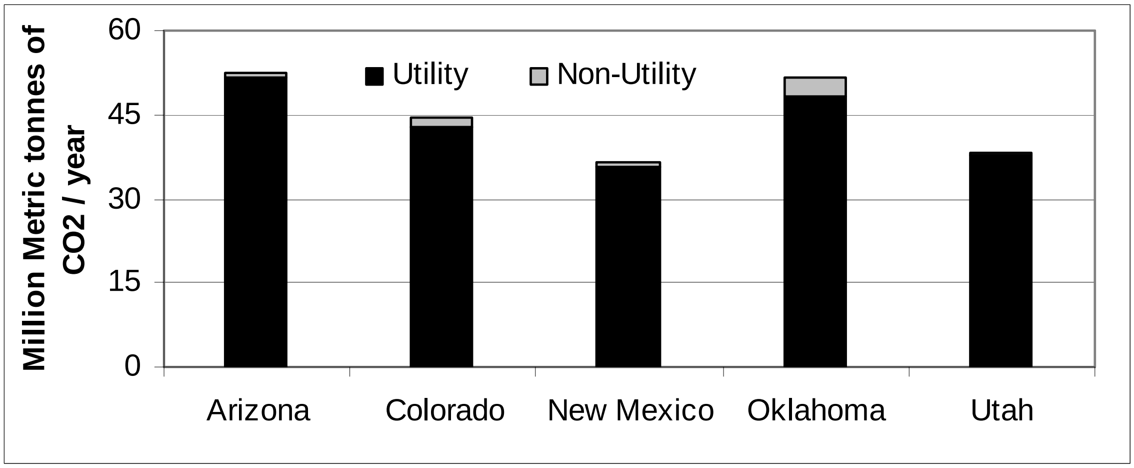

Figure 49. Most of the carbon dioxide emissions in 2000 that occurred in the states shown were from electricity generation (EPA, 2005).

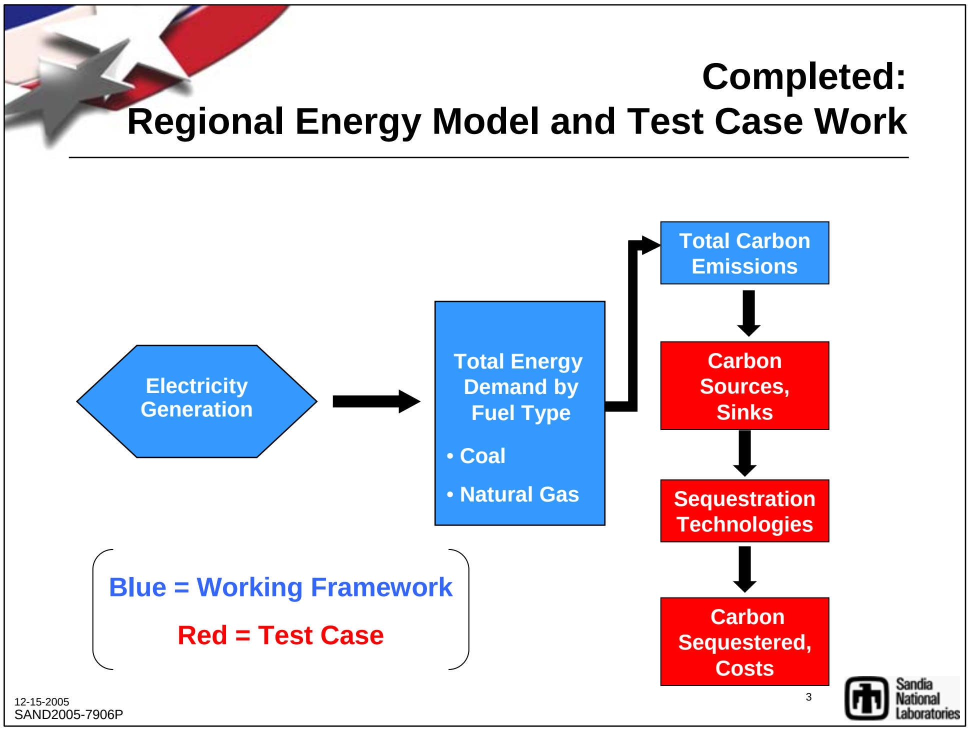

Fig. 50. Schematic of the Integrated Assessment Model's overall structure.

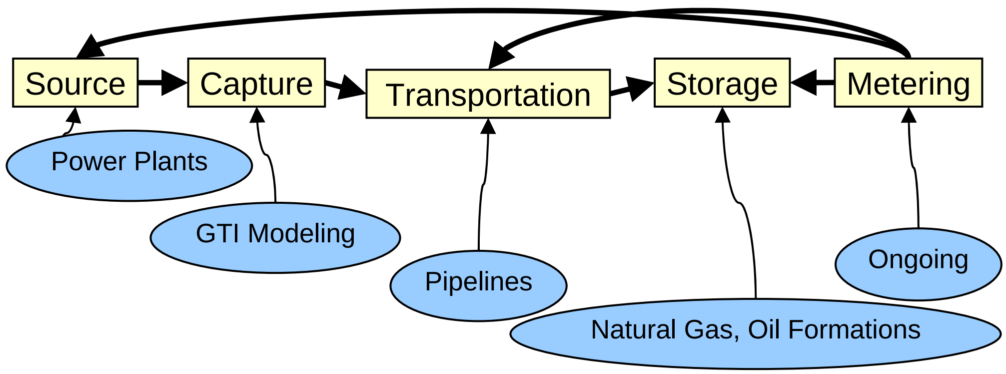

Fig. 51. Schematic of the CO_2 pathway in the Southwest Regional Partnership on Carbon Sequestration Integrated Assessment Model.

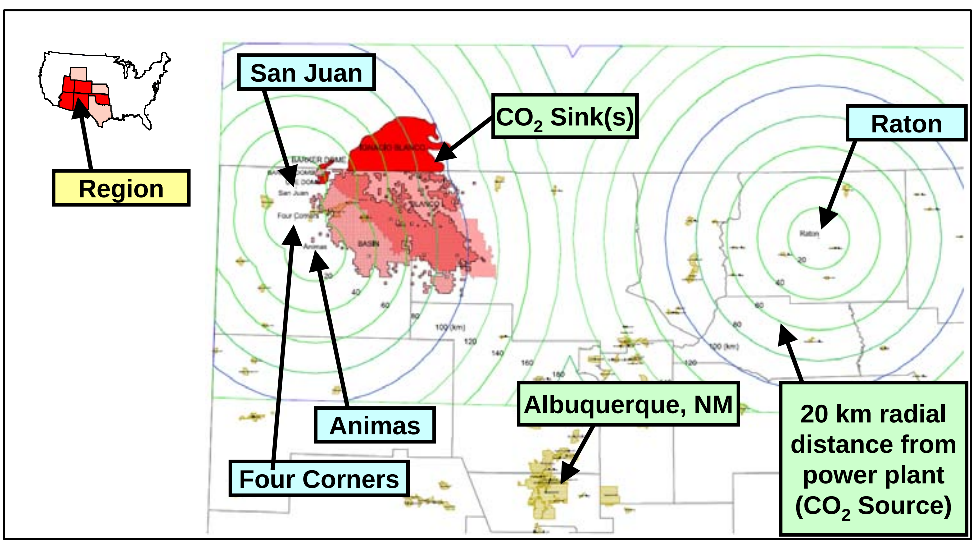

Fig. 52. Test case region for the Southwest Regional Partnership on Carbon Sequestration Integrated Assessment Model.

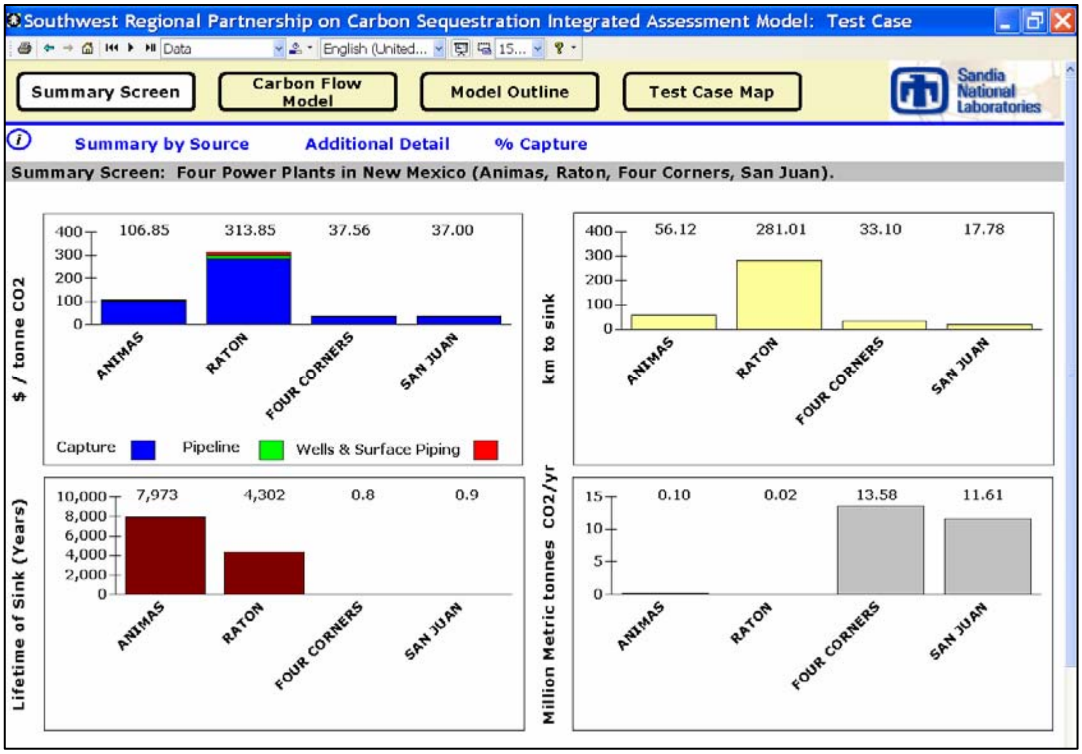

Fig. 53. Base case results, Integrated Model summary screen interface.

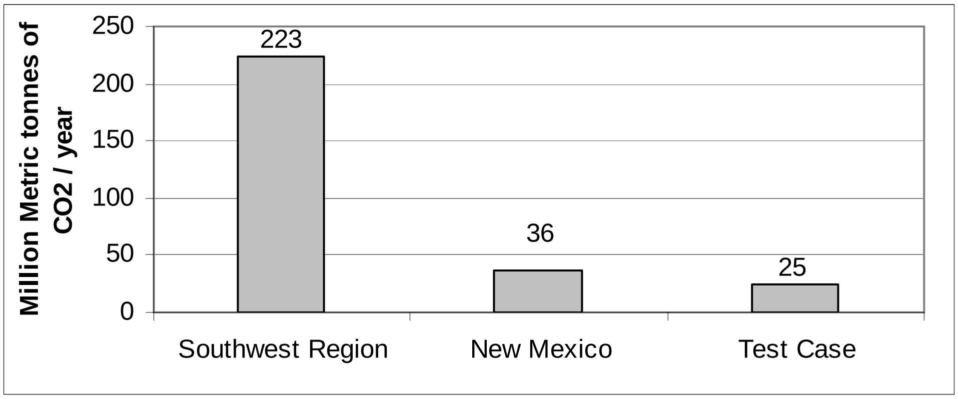

Fig. 54. Electricity generating-based CO_2 emissions in 2000 for the Southwest Region, New Mexico, and the Base Case of the Integrated Assessment Test Case Model. (Note: "Southwest Region" is the sum of Arizona, Colorado, New Mexico, Oklahoma and Utah, (EPA, 2005)).

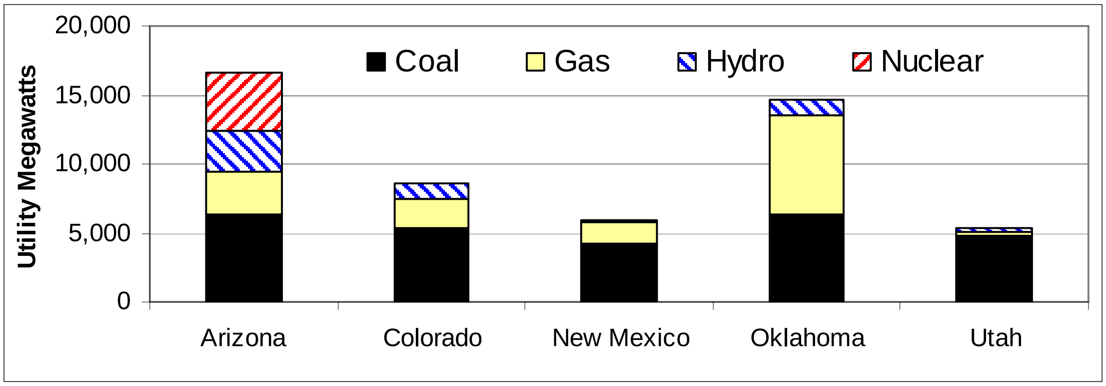

Fig. 55. Utility-based installed megawatts in the Southwestern United States in 2000 (Note: Oil-based and other fuels represented 2% or less of the total installed MW) (EPA, 2005).

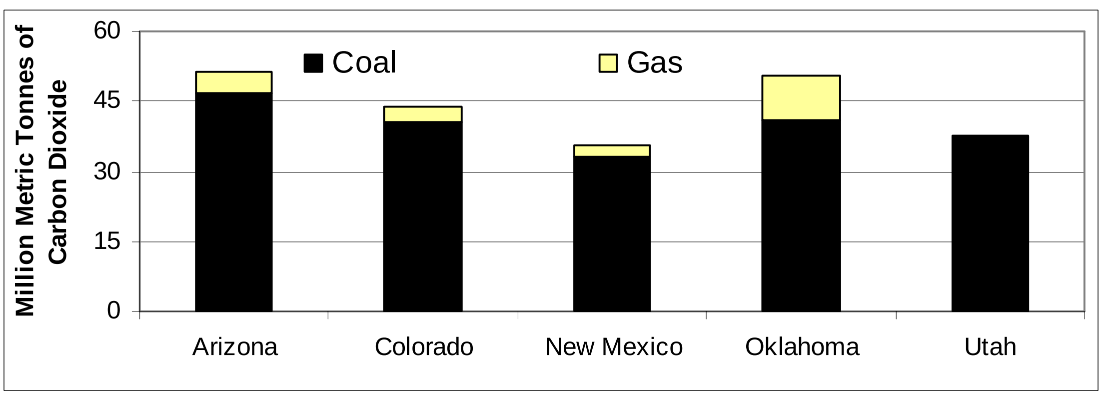

Fig. 56. Million metric tonnes of CO_2 emissions from utilities in the Southwestern United States in 2000 (Note: Oil-based and other fuels represented 1% or less of the total CO_2 emissions) (EPA, 2005).

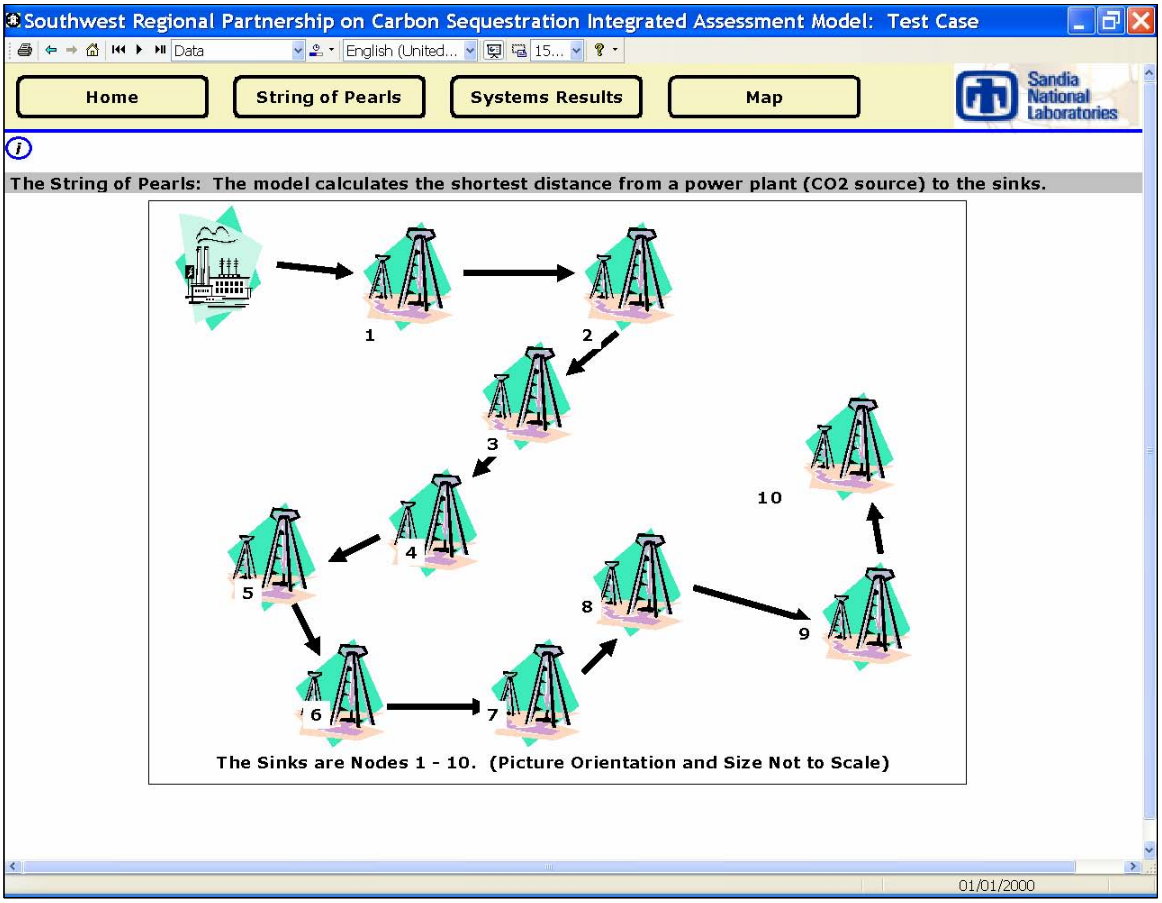

Fig. 57. Illustrative "String of Pearls" network showing the least distance solution to allocate CO_2 between sinks from a point source.

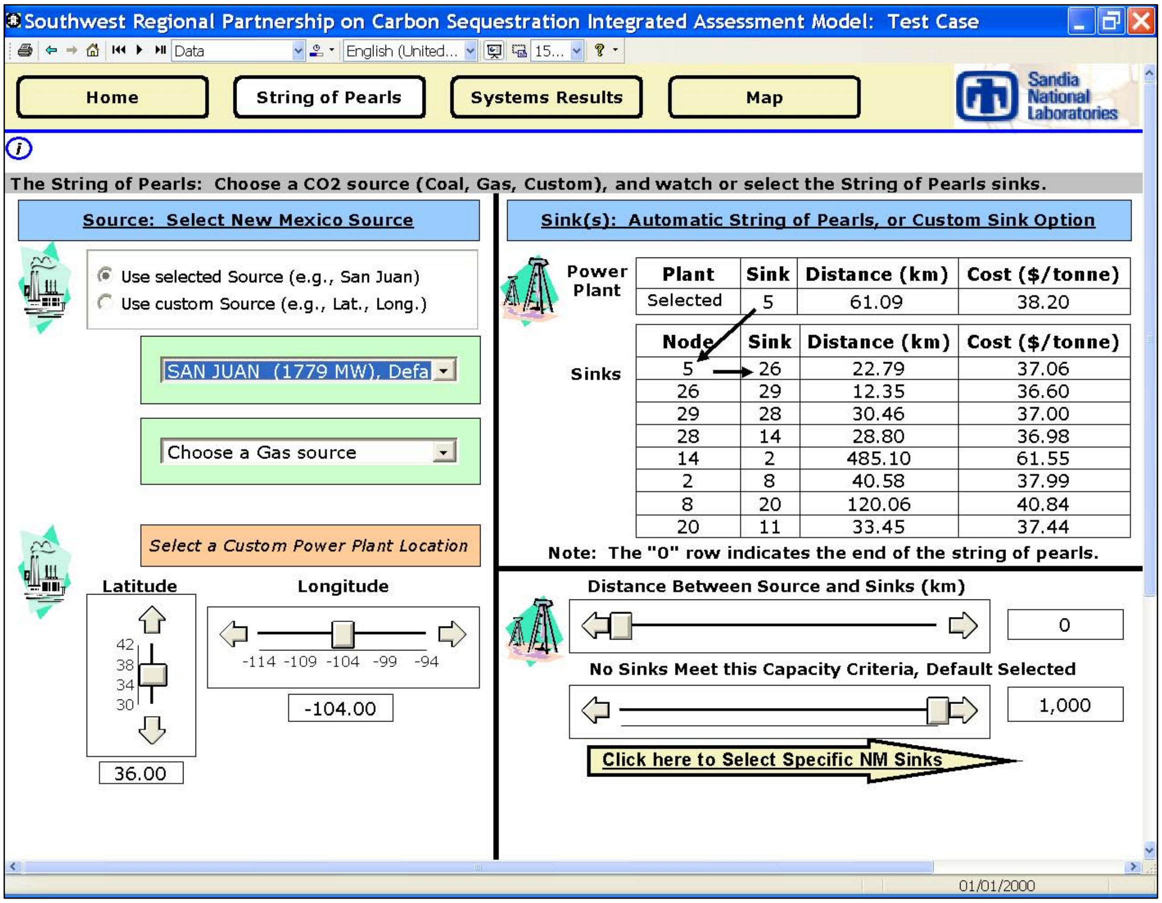

Fig. 58. Illustrative "String of Pearls" network showing the prototype least distance solution to allocate CO_2 between sinks from a coal-fired point source (e.g. San Juan).

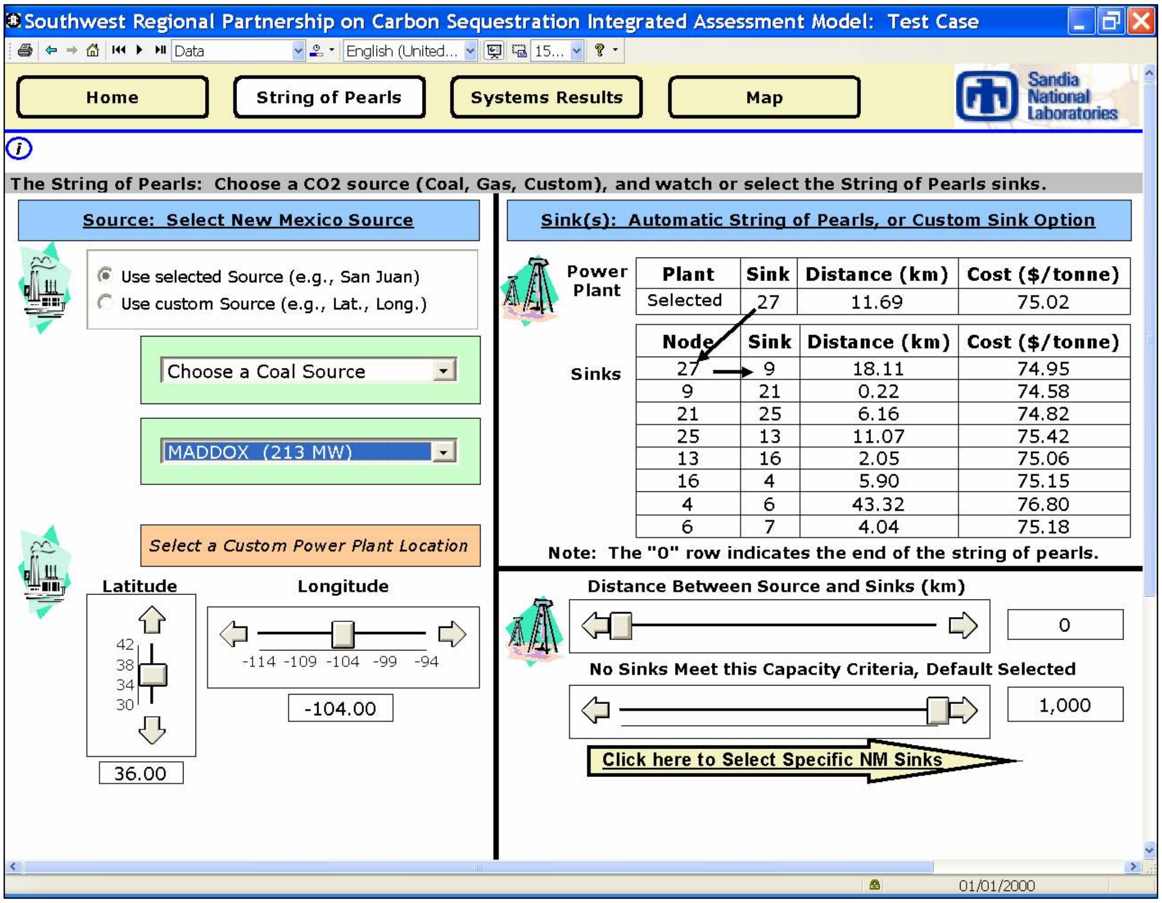

Fig. 59. Illustrative "String of Pearls" network showing the prototype least distance solution to allocate CO_2 between sinks from a gas-fired point source (e.g. Maddox).

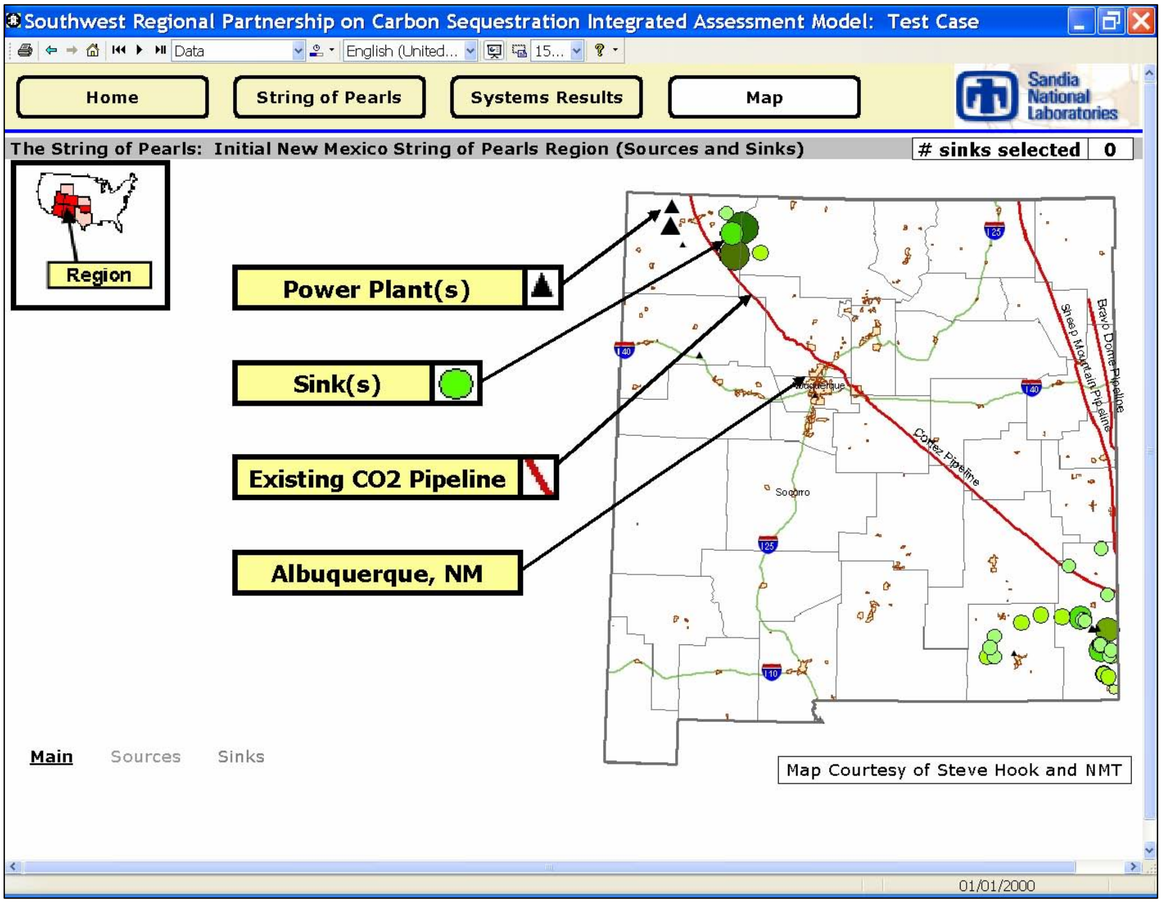

Fig. 60. Map of the CO_2 sources (power plants) and geological sinks considered in the "String of Pearls" prototype model for New Mexico.

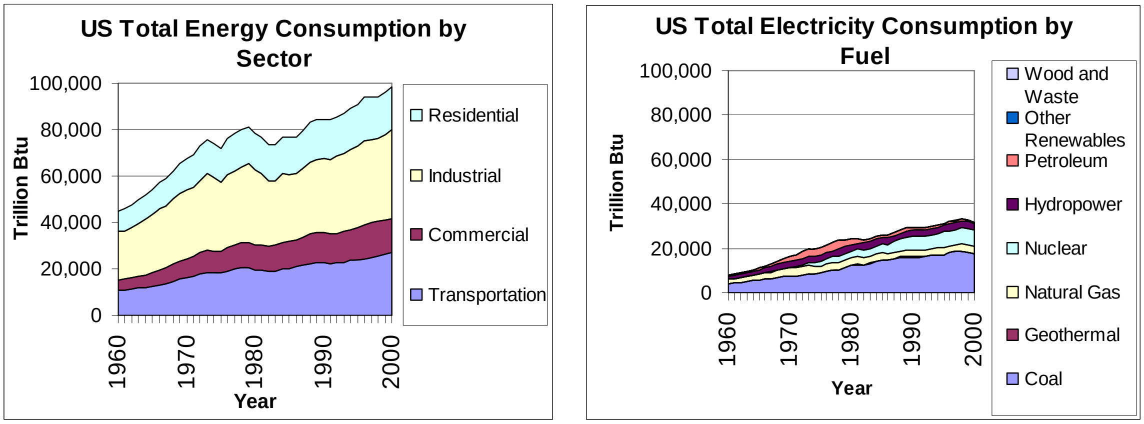

Fig. 61. Total energy and electricity consumption in the United States. (EIA, 2004).

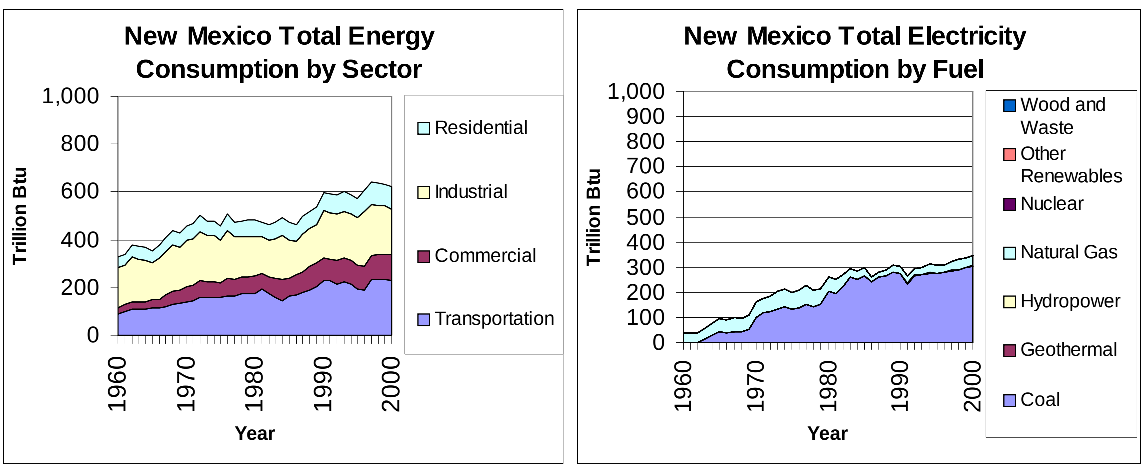

Fig. 62. Total energy and electricity consumption for New Mexico. (EIA, 2004).

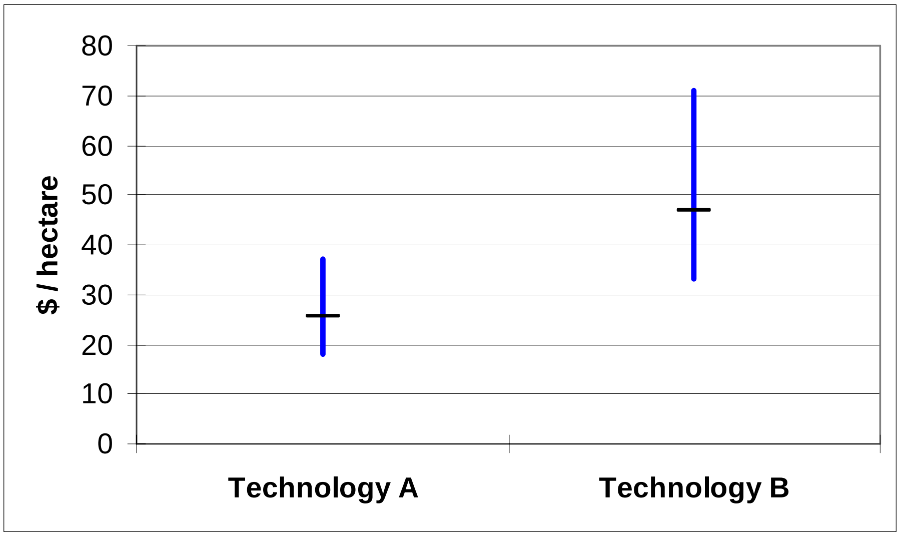

Fig. 63. Conceptual cost metrics for MMV technologies (additional metrics such as $/tonne CO_2 will also help the Integrated Assessment).

Summary of Database Compilation

The Southwest partnership GIS data is maintained in an ESRI ArcSDE (spatial database engine) database utilizing Microsoft SQL Server as the underlying relational database application. The data can be accessed by partners directly providing they have access to ArcGIS 9.1 software. All of the layers can also be output in ESRI Geodatabase format for distribution on CD or by FTP download. Shapefiles, which are readable by a number of widely available GIS programs can also be output from the database.

Oil and Gas Sinks

Oil and gas sink layers with capacities have been created using the capacity calculator tables provided by the partners in Arizona, Colorado, New Mexico, Oklahoma and Utah. The data in these tables were added to the GIS layers using a standardized data model which defines 34 characterization attributes including sequestration capacity. This data model insures attribute consistency between the layers and makes it possible to combine them into one layer for certain uses, including the simplification of the sharing of data layers with NATCARB.

Saline Aquifers

These layers were also created from the data provided by the partners in Arizona, Colorado, New Mexico, Oklahoma and Utah in the form of tables and in most cases shapefiles delineating the boundaries of the aquifers. AGRC created the outlines for New Mexico's aquifers based on criteria provided by Stephen Hook. As with the oil and gas fields, a standardized data model was developed with 17 characterization attributes including the estimated sequestration capacity.

Coalbed Methane

Generalized boundaries for coal bed methane sinks are included in the database. These will be refined as more data becomes available. More detailed coalbed methane areas for Utah were provided by the Utah Geological Survey.

Point Sources

A GIS layer portraying power plants in the region has been created. This layer includes total CO_2 emitted annually as an attribute. Layers representing smaller sources have also been created. Also included in the database are layers showing areas within 10, 25, 50, 75, and 100 miles of major sources. These layers help give a quick view of what features, including sinks, are within the respective distances of these sources.

All source and sink data in the database has been shared with the integrated assessment team at Sandia National Laboratory. This entailed writing scripts to provide output in the format required by Sandia's assessment application. AGRC also wrote a program to calculate true distances given the latitude and longitude used by the application.

AGRC helped Stephen Hook calculate preliminary capacity figures for saline aquifers and oil and gas fields before more refined methods became available. AGRC has also produced many maps and figures for use in posters and presentations.

The source and sink layers can be explored via an interactive internet map, http://atlas.utah.gov/co2sw , which has been developed and maintained by AGRC. Anyone with internet access can view this map. The various data layers can be queried. For example, all oil and gas fields with a capacity of greater than 100 million tonnes can be selected. The data layers can also be interactively explored with the map navigation tools and any feature can be clicked on for a list of its attributes to be displayed. Other tools are available to allow the user to measure distances and find features within a specified distance of another feature. Printable maps can be generated from the site as well. Upgrades to the usability of this map, as well as the addition of more layers are planned for the coming weeks.

In addition to the partnership's interactive map, AGRC has cooperated with NATCARB by creating a map service and adding the source and sinks layers in the database to the NATCARB interactive map via their administration interface. In addition to sharing this data, AGRC has participated in conference calls as well as meetings in Kansas and California with the NATCARB team.

Conclusions

The Southwest Regional Partnership on Carbon Sequestration is pleased to present this summary of its Phase 1 program, which concluded in December, 2005. The Partnership was tasked to evaluate and demonstrate plans for achieving an 18% reduction in carbon intensity by 2012. To achieve this objective, the Partnership carried out the following tasks:

(1) analysis of CO_2 storage options in the region, including characterization of storage capacities and transportation options,

(2) analysis and summary of CO_2 sources,

(3) analysis and summary of CO_2 separation and capture technologies employed in the region,

(4) evaluation and ranking of the most appropriate sequestration technologies for capture and storage of CO_2 in the Southwest Region,

(5) dissemination of existing regulatory/permitting requirements, and

(6) assessment and initiation of public knowledge and acceptance of possible sequestration approaches.

A conclusion of the Southwest Partnership's Phase I program is that the most convenient and practical "first opportunities" for sequestration would lie with existing CO_2 pipelines in the region. The Partnership also developed action plans for six Phase II validation tests in the region. The suite of tests includes four geologic pilot tests distributed among Utah, New Mexico, and Texas, in addition to a regional terrestrial sequestration pilot program focusing on improved terrestrial MMV methods and reporting approaches specific for the Southwest region. The remaining validation test consists of a local-scale terrestrial pilot involving restoration of riparian lands for sequestration purposes. The validation test will use desalinated waters produced from one of the geologic pilot tests.

Phase I regional characterization efforts, including and especially better resolved estimates of storage capacities and identification of ideal storage sites, is continuing in Phase II.

References

Instead of a cumulative body of References, owing to the great scope of the Phase I Partnership's research, there is a Reference section following each part of this Final Report.

Appendices

Appendices A—K follow the text of this report.

Appendix A—Arizona Regulatory Summary

Appendix B—Colorado Regulatory Summary

Appendix C—New Mexico Regulatory Summary

Appendix D—Oklahoma Regulatory Summary

Appendix E—Texas Regulatory Summary

Appendix F—Utah Regulatory Summary

Appendix G— SWP Regional Carbon Sources Report

Appendix H— SWP Regional Carbon Sources Report

Appendix I— Monitoring Protocols and Gaps in Coverage

Appendix J— Western Governors Association Activities

Appendix K— SWP Proposed Phase 2 Action Plans

Appendix A – Arizona Regulatory Summary (General)

TITLE 12. NATURAL RESOURCES

CHAPTER 7. OIL AND GAS CONSERVATION COMMISSION

(Authority: A.R.S. § 27-514 et seq.)

ARTICLE 1. OIL, GAS, HELIUM, AND GEOTHERMAL RESOURCES

ARTICLE 2. REPEALED

Article 2, consisting of R12-7-201 through R12-7-221, R12-7-231 through R12-7-234, R12-7-241 through R12-7-246, R12-7-251, R12-7-252, R12-7-261 through R12-7-264, R12-7-271, R12-7-272, R12-7-281, R12-7-291 through R12-7-294, and Appendix 1, repealed effective January 2, 1996 (Supp. 96-1).

ARTICLE 1. OIL, GAS, HELIUM, AND GEOTHERMAL RESOURCES

R12-7-101. Definitions

In this Chapter, unless the context otherwise requires:

"API" means American Petroleum Institute.

"Barrel" means 42 (US) gallons measured at 60° F and atmospheric pressure at sea level.

"BTU" means British thermal unit and represents the quantity of heat required to raise the temperature of 1 pound of water 1° F at or near 39.2° F.

"Condensate" means liquid hydrocarbons recovered at the earth's surface as a result of condensation due to reduced pressure or temperature of petroleum hydrocarbons that exist in a gaseous phase in subsurface reservoir rocks.

"Cubic foot of gas" means the volume of gas contained in 1 cubic foot of space at a standard pressure base of 14.73 pounds per square inch absolute and a standard temperature base of 60° F.

"Gas well" means a well that produces with a gas-oil ratio in excess of 50,000 cubic feet of gas per barrel of oil.

"Injection well" means a well used to inject air, gas, water, or other substance into an underground stratum.

"Mcf" means 1000 cubic feet of gas reported at a pressure base of 14.73 pounds per square inch absolute and a standard temperature base of 60° F.

"Oil well" means a well that produces with a gas-oil ratio less than 50,000 cubic feet of gas per barrel of oil.

"Operator" means any person authorized by an owner to control the day-to-day activities of a well or production or refining facility.

"Shut-in well" means a well that is capable of production in paying quantities, is completed as a producing well, and is not presently being operated.

"Stratigraphic test or core hole test" means drilling a hole for the sole purpose of obtaining geological information.

"Temporarily abandoned well" means a well that is not capable of production in paying quantities and is not presently being operated.

Historical Note

Former B; Former Section R12-7-101 renumbered and amended as Section R12-7-102, former Section R12-7-100 renumbered and amended as Section R12-7-101 effective September 29, 1982 (Supp. 82-5). Amended effective January 2, 1996 (Supp. 96-1). Amended by final rulemaking at 6 A.A.R. 4827, effective December 7, 2000 (Supp. 00-4).

R12-7-102. Repealed

Historical Note

Former 101; Former Section R12-7-102 renumbered and amended as Section R12-7-103, former Section R12-7-101 renumbered and amended as Section R12-7-102 effective September 29, 1982 (Supp. 82-5). Repealed effective January 19, 1994 (Supp. 94-1).

R12-7-103. Bond

A. An operator shall file a performance bond with the Commission prior to approval of a permit to drill a new well, re-enter an abandoned well, or assume responsibility as operator of existing wells. The bond amount shall be $10,000 for a well drilled to a total depth of 10,000 feet or less, $20,000 for a well drilled deeper than 10,000 feet, or $25,000 as a blanket bond to cover all wells and shall be payable to the Oil and Gas Conservation Commission, State of Arizona, and conditioned upon the faithful performance by the operator of the duty to drill each well in a manner to prevent waste, plug each dry or abandoned well, repair each well causing waste or pollution, and maintain and restore the well site.

B. The Commission shall accept a bond in the form of a surety bond, executed by the operator as principal and a corporate surety authorized to do business in Arizona, a certified check, or a certificate of deposit at a federally insured bank authorized to do business in Arizona.

C. Transfer of property does not release the bond. If a property is transferred and the principal desires to be released from the bond, the procedure shall be as follows:

1. The principal on the bond shall notify the Commission in writing of the proposed transfer, giving the location of each well, the date and number of each permit to drill, and the name, address, and telephone number of the proposed transferee.
2. The transferee of any well or of the operation of any well shall declare to the Commission in writing acceptance of the transfer and of the responsibility of each well and shall submit a new bond or bonds unless the transferee's blanket bond applies to the well or wells.
3. When the Commission approves the transfer, the transferor is released from all responsibility with respect to the well or wells, and the Commission shall notify the principal and the bonding company in writing that the transferor's applicable bond or bonds are subject to release.

Historical Note

Former Rule 102; Former Section R12-7-103 renumbered and amended as Section R12-7-104, former Section R12-7-102 renumbered and amended as Section R12-7-103 effective September 29, 1982 (Supp. 82-5). Amended effective January 19, 1994 (Supp. 94-1).

R12-7-104. Application for Permit to Drill

A. Before drilling or re-entering any well or conducting any surface disturbance associated with such activity, the operator shall submit to the Commission an application for permit to drill or re-enter and obtain approval. The complete application package shall contain:

1. An application for permit to drill on a form provided by the Commission, which shall include the operator's name, address, and phone number, and a description of the proposed well and its location;
2. A well and well-site construction plan that meets the requirements of R12-7-108 through R12-7-118;
3. A plat, prepared and certified by a registered surveyor bearing the surveyor's certificate number, on which is shown the exact acreage or legal subdivision allotted to the well as required by R12-7-107, the well's exact location, and its ground-level elevation;
4. An organization report as required by R12-7-194;
5. A performance bond, as required by R12-7-103; and
6. A fee of $25.00 per well.

B. The Commission shall mail to the applicant, within 30 days of receipt of the application required in subsection (A), written notice of administrative completeness or a detailed list of deficiencies. Within 30 days of receipt of all items required in subsection (A), the Commission shall review the application and:

1. Issue a permit to drill, or
2. Provide a written explanation in compliance with A.R.S. § 41-1076 to the applicant if the application is not approved.

C. Time-frames
1. The administrative review period is 30 days. The substantive review period is 30 days. The overall time-frame is 60 days.
2. For the purpose of this subsection, intermediate Saturdays, Sundays, and legal holidays shall be included in the time-frame computation. The last day of the notice period shall be included in the computation unless it is a Saturday, Sunday, or legal holiday.

D. Unless operations are commenced within 180 days after date of approval, the permit to drill shall become null and void unless an extension in writing is granted by the Commission.

E. In case of imminent danger to public safety or of contamination of the environment, the Commission may authorize the drilling of an emergency relief or offset well to reduce the danger or hazard. Within 10 days of commencing an emergency relief or offset well, the operator shall file an application as required in subsection (A). No well drilled under this subsection shall be used for production unless it conforms to the provisions of R12-7-107.

Historical Note

Former Rule 103; Former Section R12-7-104 renumbered and amended as Section R12-7-105, former Section R12-7-103 renumbered and amended as Section R12-7-104 effective September 29, 1982 (Supp. 82-5). Amended effective January 19, 1994 (Supp. 94-1). Amended effective June 6, 1997 (Supp. 97-2).

R12-7-105. Change of Location

A. No operator shall drill a well in a location other than that authorized by the permit issued pursuant to R12-7-104 until the following requirements have been met:
1. If the operator decides to change the location before drilling the well, an amended application for permit to drill shall be filed showing the new location.
2. If it is determined that the location is erroneously described on the permit after drilling has begun, the operator shall obtain a new permit showing the correct location.

B. If the new location is at an authorized point in the approved drilling unit as provided in the initial permit, the application may be made by electronic communication and the Commission may by electronic communication authorize the commencement or continuance of drilling operations. Within ten days after obtaining such authorization, the operator shall file an amended application showing the new location. An amended permit may be issued and the old permit cancelled without payment of additional fee.

C. If the new location is located outside the approved drilling unit covered by the initial permit, no drilling shall be commenced or continued until a new application for permit to drill is filed and approved as required by R12-7-104, including payment of an additional fee.

Historical Note

Former Rule 104; Former Section R12-7-105 renumbered and amended as Section R12-7-106, former Section R12-7-104 renumbered and amended as Section R12-7-105 effective September 29, 1982 (Supp. 82-5). Amended effective January 19, 1994 (Supp. 94-1).

R12-7-106. Identification of Wells, Producing Leases, Tanks, Refineries, Buildings, and Facilities

A. The operator shall mark each drilling, producing, injection, or shut-in well in a conspicuous place with the operator's name, lease name or number, well number, and the legal description of the well's location.

B. The operator shall mark each abandoned well as required in R12-7-127(F).

C. The operator shall mark all tank batteries, gasoline plants, structures, storage buildings, compressors, and compressor buildings, and all other storage or transportation equipment with the operator's name, address, telephone number, lease name or number, and location. All structures within a fenced yard may be identified by a single sign at the principal outside entrance to the yard.

D. The operator of a storage-well facility shall clearly mark each well with the operator's name, lease name or number, and well number. Each outside entrance to the facility shall be marked with the operator's name, address, and one or more emergency response telephone numbers.

E. The operator of a refinery shall mark each facility at each outside entrance with the operator's name, address, and one or more emergency response telephone numbers.

F. Sign lettering shall contrast strongly with the background and be large enough to be legible under normal conditions at a distance of 25 feet. The operator shall preserve these markings and keep them legible and up to date.

Historical Note

Former Rule 105; Former Section R12-7-106 renumbered and amended as Section R12-7-107, former Section R12-7-105 renumbered and amended as Section R12-7-106 effective September 29, 1982 (Supp. 82-5). Amended effective January 19, 1994 (Supp. 94-1).

R12-7-107. Spacing of Wells

A. Every well drilled for oil shall be located on a drilling unit consisting of approximately 80 contiguous surface acres within two governmental quarter-quarter sections or lots having one side in common, upon which there is not located, and of which no part is attributed to, any other well completed in or drilling to, the same pool.
1. In areas not covered by United States Public Land Surveys, the oil drilling unit shall consist of an area bounded by four sides intersecting at angles of not less than 85 degrees or more than 95 degrees. The unit shall contain at least 76 contiguous surface acres and its maximum dimension shall not exceed 3,000 feet.
2. No well drilled for oil shall be located closer than 330 feet to any boundary of the drilling unit or closer than 330 feet to the shortest center line of the drilling unit.
3. No well drilled for oil shall be located within a quarter-quarter section or lot having one side in common with another quarter-quarter section or lot upon which there is located a well completed in or drilling to the same pool.

B. Every well drilled for gas shall be located on a drilling unit consisting of approximately 640 but not less than 600 contiguous surface acres within one governmental section upon which there is not located, and of which no part is attributed to, any other well completed in or drilling to the same pool.
1. In areas not covered by United States Public Land Surveys, the gas drilling unit shall consist of an area bounded by four sides intersecting at angles of not less than 85 degrees or more than 95 degrees. The unit shall contain at least 600 contiguous surface acres and its maximum dimension shall not exceed 8,500 feet.
2. No well drilled for gas shall be located closer than 1,660 feet from any boundary of the drilling unit.

C. Every well drilled for geothermal resources shall be located on a drilling unit approved or as modified by the Commission. The Commission may require modification to minimize well interference and provide the necessary volume of geothermal resources for the intended use, to protect correlative rights, and to protect the environment.

D. If the operator drills a horizontal segment, that horizontal segment shall be located:
1. At least 330 feet from the boundary of the spacing unit in the case of an oil well;
2. At least 1,660 feet from the boundary of the spacing unit in the case of a gas well; and
3. As approved or modified by the Commission in the case of a geothermal well.

E. The Commission may grant exceptions to the regular locations specified in subsections (A), (B), and (C) only after notice and hearing.
1. Applications for exception shall fully state the reasons why the exception is necessary and shall include a plat prepared and certified by a registered surveyor bearing the surveyor's certificate number showing all other completed, drilling, and permitted wells on the property and all adjoining surrounding properties and wells.
2. Exceptions shall be granted only after the operator provides by certified mail a copy of the application to all adjoining lessees, and only after the Commission deter mines in a duly noted public hearing that the application is valid.
3. The Commission may grant an exception location without notice or hearing when topography prohibits drilling at a regular location on the drilling unit.
4. If an existing well's classification changes due to its recompletion or due to a change in the nature of the product being produced, the Commission may approve an irregular location application with supporting data and ten days' notice and hearing, provided that the operator furnish the Commission with proof of mailing of a copy of the application to all operators within a one-mile radius of the acreage to be dedicated.

F. In order to prevent waste, the Commission may, after notice and hearing, fix different spacing requirements and require lesser or greater acreage for drilling units in any specific oil, gas, or geothermal resource pool notwithstanding the provisions of subsections (A), (B), and (C).

G. The Commission may order pooling and integration of interests pursuant to A.R.S. §§ 27-505 and 27-666.

Historical Note

Former Rule 106; Former Section R12-7-107 renumbered and amended as Section R12-7-108, former Section R12-7-106 renumbered and amended as Section R12-7-107 effective September 29, 1982 (Supp. 82-5). Correction, paragraph (1) "No well drilled for oil shall be located within the bounds of a quarter-quarter section or lot . . ." (Supp. 82-6). Amended effective January 19, 1994 (Supp. 94-1).

R12-7-108. Pit for Drilling Mud and Drill Cuttings

A. Each operator shall maintain an adequate supply of drilling mud to confine oil, gas, or water to its native stratum during the drilling of any well and shall provide, before drilling is commenced, an adequate pit, either earthen or portable, for the drilling mud or the accumulation of drill cuttings.

B. An earthen pit used for drilling, deepening, testing, reworking, or fracturing shall be constructed of or sealed with an impervious material and shall be maintained to prevent escape of any contained substance. Earthen pits shall be fenced on all sides at all times.

C. Earthen pits shall be constructed and maintained to prevent the entrance of outside runoff water and the fluid level in earthen pits shall be kept at all times at least 18 inches below the lowest point of the embankment.

D. Any mud contained in an earthen pit shall be water-based and contain no more than one pound per barrel of thinner for each 25 pounds per barrel of barite or hematite. Mud containing chromium lignosulfonate, ferrochrome lignosulfonate or other chromium compounds shall not be used.

E. Drilling mud shall be disposed of by either recycling or commercial off-site disposal. Mud described in subsection (D) may be disposed of by evaporation and subsequent leveling of the pits.

Historical Note

Former Rule 107; Former Section R12-7-108 renumbered and amended as Section R12-7-109, former Section R12-7-107 renumbered and amended as Section R12-7-108 effective September 29, 1982 (Supp. 82-5). Amended effective January 19, 1994 (Supp. 94-1).

R12-7-109. Repealed

Historical Note

Former Rule 108; Former Section R12-7-109 renumbered and amended as Section R12-7-110, former Section R12-7-108 renumbered and amended as Section R12-7-109 effective September 29, 1982 (Supp. 82-5). Repealed effective January 19, 1994 (Supp. 94-1).

R12-7-110. Surface Casing Requirements

A. Surface casing shall be set at a sufficient depth to protect and isolate all known or reasonably estimated freshwater zones and to prevent blowouts or uncontrolled flows. The surface casing shall:
1. Be of sufficient size to permit the use of an intermediate string or strings of casing;
2. Be set in or through an impervious formation and shall be cemented by the pump and plug, displacement, or other method approved by the Commission;
3. Be cemented back to surface either during the primary cement job or by remedial action; and
4. Have API-approved centralizers on the bottom three joints as a minimum.

B. Cement shall be allowed to set a minimum of 12 hours under the lowest necessary pressure before drilling the cementing plugs or initiating tests.

C. Surface casing shall be pressure tested for at least 30 minutes to 70% of internal yield pressure or one psi per foot of casing depth, whichever is less. If a drop of more than 10% of the test pressure should occur, the casing shall be considered defective and corrective measures shall be applied. In wells drilled with cable tools, casing may be tested by bailing the well dry. The hole shall remain satisfactorily dry for one hour before commencing further operations. Results of the above test and any remedial action shall be reported in writing to the Commission within 15 days following the test.

D. The operator of a well shall notify the Commission at least 48 hours before setting surface casing so that a representative of the Commission may witness all or a part of the operations required in this Section.

Historical Note

Former Rule 109; Former Section R12-7-110 renumbered and amended as Section R12-7-111, former Section R12-7-109 renumbered and amended as Section R12-7-110 effective September 29, 1982 (Supp. 82-5). Amended effective January 19, 1994 (Supp. 94-1).

R12-7-111. Intermediate and Production Casing and Tubing Requirements

A. All producing wells shall be completed with production casing set directly above or through the producing interval and cemented by the pump and plug method, or other method approved by the Commission, to protect the zones to be produced. An intermediate string of casing may be required to seal off all potentially productive, lost circulation, and abnormally pressured zones that may be encountered in the well, except those to be produced. The Commission may require casing strings to be cemented from the maximum depth of the casing to at least 50 feet inside the previously run string of casing. For liners, a minimum of 100 feet of overlap between a string of casing and the next larger casing is required.

B. Strings of casing shall stand cemented for at least 12 hours before drilling out the cementing plugs or initiating such tests as the Commission may require.

C. Strings of intermediate and production casing shall be pressure tested to 70% of the manufacturer's rated internal yield pressure or one psi per foot of casing depth, whichever is less. In cases where combination strings utilizing casing of varied grades and weights are used, the above test pressures shall apply to the lowest pressure rated component used. If pressure declines more than 10% in 30 minutes, the casing shall be considered defective and corrective measures shall be applied.

1. In wells drilled with cable tools, casing may be tested by bailing the well dry, in which case the hole shall remain satisfactorily dry for at least one hour before commencing further operations on the well. Results of the above test and any remedial action shall be reported in writing to the Commission within 15 days following the test.

D. All flowing oil wells shall have tubing set as near the bottom as practical with tubing perforations not more than 250 feet above the top of the zone to be produced. Wells may be completed with small-diameter casing, which is generally understood in the industry to be "slim hole" or "tubingless" completions, in lieu of tubing.

E. The operator shall notify the Commission at least 48 hours before setting any casing string so that a representative of the Commission may witness all or a part of the operations required in this Section.

Historical Note

Former Rule 110; Former Section R12-7-111 renumbered and amended as Section R12-7-112, former Section R12-7-110 renumbered and amended as Section R12-7-111 effective September 29, 1982 (Supp. 82-5). Amended effective January 19, 1994 (Supp. 94-1).

R12-7-112. Defective Casing or Cementing

A. The operator shall take immediate steps to correct the casing condition of any well that may cause, or is causing, underground waste of oil, gas, or geothermal resources or contamination of fresh waters. These steps shall restore the integrity of the casing to the standards set in R12-7-110(C) and R12-7-111(C).

B. The operator shall report the corrective actions taken in writing to the Commission within 15 days of the completion of the work. If the condition of the casing cannot be corrected, the well shall be plugged and abandoned in compliance with R12-7-127.

Historical Note

Former Rule 111; Former Section R12-7-112 renumbered and amended as Section R12-7-113, former Section R12-7-111 renumbered and amended as Section R12-7-112 effective September 29, 1982 (Supp. 82-5). Amended effective January 19, 1994 (Supp. 94-1).

R12-7-113. Blowout Prevention and Related Well-control Equipment

A. When drilling in areas where pressures are unknown or high pressures do or are likely to exist, a blowout preventer, control head and related lines, and connections necessary to control the pressures and to keep the well under control at all times shall be installed as soon as the surface casing is set.

B. Upon installation, all ram-type blowout preventers and related equipment shall be pressure tested to the lesser of the manufacturer's full working pressure rating of the equipment, 70% of the minimum internal yield pressure of any casing subject to test, or one psi per foot of the last casing string depth. Annular or bag-type preventers shall be tested to the lesser of 1000 psi or 50% of full working pressure on installation. The blowout preventer and related equipment shall be tested:

1. After each string of casing is set in the well,
2. Not less than once each 14 days from each control station, and
3. Following repairs that require disconnection of any pressure seal in the assembly. Only the component repaired or replaced needs be tested unless alteration or repair occurs at a normal full blowout preventer test period.

C. The operator shall maintain records of the tests required in this Section until the well is completed and shall submit copies of these records to the Commission if required.

Historical Note

Former Rule 112; Former Section R12-7-113 renumbered and amended as Section R12-7-114, former Section R12-7-112 renumbered and amended as Section R12-7-113 effective September 29, 1982 (Supp. 82-5). Amended effective January 19, 1994 (Supp. 94-1).

R12-7-114. Recovery of Casing

Recovery of inside or outside strings of casing is prohibited unless written approval is obtained from the Commission. Approval shall be given only for wells where mudding and plugging operations can be carried out safely and the well abandoned in compliance with R12-7-127.

Historical Note

Former Rule 113; Former Section R12-7-114 renumbered and amended as Section R12-7-115, former Section R12-7-113 renumbered and amended as Section R12-7-114 effective September 29, 1982 (Supp. 82-5). Section repealed, new Section adopted effective January 19, 1994 (Supp. 94-1).

R12-7-115. Deviation of Hole and Directional Drilling

A. No drilling well may be intentionally deviated from its normal vertical course unless the operator shall first file application and obtain approval from the Commission after notice and hearing. The normal vertical course of a well is defined by a tolerance wherein the maximum deviation of the well does not exceed a 100-foot radius from the surface location. Deviation from the vertical for short distances is permitted in the drilling of a well without special approval only to straighten the hole, sidetrack junk, or correct other mechanical difficulties.

B. An application for directional drilling shall include:

1. The name, address, and phone number of the operator;
2. The field name, lease name, well number, state permit number, reservoir name, and county where the proposed well is located;
3. A plat or sketch showing the distance from the surface location to section and lease lines and to the target location within the intended producing interval;
4. The reason for the intentional deviation; and
5. The signature of the operator.

C. The operator of any well capable of production and whose producing interval or any portion thereof is located 330 feet or less in the case of an oil well or 1,660 feet or less in the case of a gas well from the boundary of any drilling unit shall run a directional survey before running the production casing.

D. In order to ensure compliance with this Section, the Commission may require the operator to run a directional survey of any hole at the operator's expense. The Commission may require an operator to run a directional survey of any hole at the request of an offset operator at the expense and risk of the offset operator unless the survey shows that the well is completed at a point outside the drilling unit, or at an unauthorized point.

E. Within 30 days following the completion of a directionally drilled well, the operator shall file with the Commission a complete angular deviation and directional survey of the well obtained by a well survey company.

F. Nothing in these rules shall be interpreted to permit the drilling of any well in such manner that it crosses the drilling unit lines, except by approval obtained after notice and hearing.

Historical Note

Former Rule 114; Former Section R12-7-115 renumbered and amended as Section R12-7-116, former Section R12-7-114 renumbered and amended as Section R12-7-115 effective September 29, 1982 (Supp. 82-5). Amended effective January 19, 1994 (Supp. 94-1).

R12-7-116. Multiple Zone Completions

A. Completions to include production from more than one common source of supply from a single well are prohibited except as authorized by the Commission after notice and hearing. After notice and hearing, the Commission shall maintain a list of zones or reservoirs, by fields, for which multiple completions have been authorized.

B. Operators shall file an application for multiple completion with the Commission and shall demonstrate the method to be used to keep the production streams separate. The application shall be accompanied by:

1. An electrical log or other acceptable log with tops and bottoms of formations or producing zones and perforated intervals shown and marked;
2. A diagrammatic sketch of the multiple completion installation indicating make, type, and setting depths of packer or packers;
3. A plat showing the location of the well and all offset wells and the names and addresses of operators of all leases offsetting acreage dedicated to applicant's well; and
4. Proof of mailing of application for multiple completion to all offset operators.

C. The Commission may approve subsequent applications for multiple completion of the same zones or reservoirs in a field administratively without a hearing, provided that:

1. The applicant can show that the Commission has approved and listed the zones or reservoirs as required in subsection (A);
2. The subsequent application is filed as required in subsection (B); and
3. The Commission receives no protest to the application after a 15-day holding period. A hearing shall be called if a protest is received.

D. Within 15 days of setting the final packer or packers, the operator shall file a report with the Commission identifying the well and its location showing the make, type, and depth set of each packer and the signature of the supervisor of the work. This report shall include the results of a packer leakage test and detail for each separate common source of supply, its stabilized shut-in pressure, producing pressure, and the simultaneous shut-in pressure on each other separate common source of supply. The operator shall notify the Commission at least 48 hours in advance of performing the tests required in this subsection.

E. Every operator of a multi-completed well shall operate, produce, and maintain the well to prevent commingling of production from the separate sources of supply. The Commission may require any multi-completed well to be tested at any time to demonstrate the effectiveness of the separation of sources of supply. These tests may be witnessed by representatives of the Commission and by offset operators.

Historical Note

Former Rule 115; Former Section R12-7-116 renumbered and amended as Section R12-7-117, former Section R12-7-115 renumbered and amended as Section R12-7-116 effective September 29, 1982 (Supp. 82-5). Amended effective January 19, 1994 (Supp. 94-1).

R12-7-117. Artificial Stimulation of Oil and Gas Wells

A. An operator shall report the artificial stimulation of any well to the Commission in writing within 15 days of the stimulation showing the type of stimulation, the amounts and types of materials used, stimulation pressures applied, and the flow and pressure results before and after stimulation.

B. If the artificial stimulation of a well results in any damage to the producing formation, a freshwater formation, casing, or casingseat that permits communication between fluid-bearing zones, the operator shall immediately notify the Commission and proceed with diligence to correct the damage. If the artificial stimulation results in irreparable damage to the well, the operator shall plug and abandon the well pursuant to R12-7-127.

Historical Note

Former Rule 116; Former Section R12-7-117 renumbered and amended as Section R12-7-118, former Section R12-7-116 renumbered and amended as Section R12-7-117 effective September 29, 1982 (Supp. 82-5). Amended effective January 19, 1994 (Supp. 94-1). Amended effective June 5, 1998 (Supp. 98-2).

R12-7-118. Operations in Hydrogen Sulfide Environments

A. When drilling, redrilling, deepening, or plugging back operations in areas where the formations to be penetrated are known to contain or are expected to contain hydrogen sulfide gas (H_2S) in excess of 10 ppm and in areas where the presence or absence or H_2S is unknown, the operator shall contract the services of an approved H_2S safety company to be on location at the known or expected depths.

B. A written contingency plan providing details of actions to be taken to alert and protect operating personnel and members of the public in the event of an accidental release of H_2S gas shall be submitted to the Commission as part of the initial application for a permit to drill or as a sundry notice.

Historical Note

Former Rule 117; Former Section R12-7-118 renumbered and amended as Section R12-7-119, former Section R12-7-117 renumbered and amended as Section R12-7-118 effective September 29, 1982 (Supp. 82-5). Amended effective January 19, 1994 (Supp. 94-1).

R12-7-119. Wellhead and Lease Equipment

A. The operator shall install and maintain valves, fittings, and wellhead connections that

1. Have a rated working pressure equivalent to at least 100% of the calculated or known surface pressure to which they may be subjected from the producing zone;
2. Allow well production, productivity, deliverability, and transient pressure tests;
3. Permit pressures to be obtained on both casing and tubing; and
4. Control the flow of the oil, gas, or geothermal resources on a flowing well.

B. The operator shall produce flowing oil wells into tanks equipped with high-low pressure and high-low level shut-in controls and shall install a safety valve that automatically closes on the wellhead in the event of surface production equipment malfunctions.

C. The operator shall equip artificial lift wells with wellhead safety sensors to shut off the source of power in the event of abnormally high or low flowline pressures.

Historical Note

Former Rule 118; Former Section R12-7-119 renumbered and amended as Section R12-7-120, former Section R12-7-118 renumbered and amended as Section R12-7-119 effective September 29, 1982 (Supp. 82-5). Amended effective January 2, 1996 (Supp. 96-1).

R12-7-120. Notification of Fire, Leaks, Spills, and Blowouts

A. Each operator shall notify the Commission within 24 hours of any fire, break, leak, spill, overflow, or blowout that occurs at any oil, gas, or geothermal drilling, producing, or transportation facility, or at any injection, disposal, or storage facility.

B. Each operator shall file a final written report within 15 days of resolving incidents described in subsection (A) giving the location by quarter-quarter section, township, and range; date and time of occurrence; specific nature and cause of the incident; resultant damage; action taken to correct the situation and prevent its reoccurrence; and losses of hydrocarbons or geothermal resources.

Historical Note

Former Rule 119; Former Section R12-7-120 renumbered and amended as Section R12-7-121, former Section R12-7-119 renumbered and amended as Section R12-7-120 effective September 29, 1982 (Supp. 82-5). Amended effective January 2, 1996 (Supp. 96-1).

R12-7-121. Well Completion and Filing Requirements

A. An operator shall file a completion report with the Commission within 30 days after a well is completed. The completion report shall contain a description of the well and lease, the casing, tubing, liner, perforation, stimulation, and cement squeeze records, and data on the initial production. The operator shall submit other well data to the Commission within 30 days of the date the work is done, including any:

1. Lithologic, mud, or wireline log;
2. Directional survey;
3. Core description and analysis;
4. Stratigraphic or faunal determination;
5. Formation or drill-stem test;
6. Formation fluid analysis; or
7. Other similar information or survey.

B. An operator shall furnish samples of drilled cuttings, at a maximum interval of 10 feet, to the Commission within 30 days after drilling is completed. The operator may furnish samples of continuous core in chips at 1-foot intervals. The operator shall:

1. Wash and dry all samples;
2. For each sample, place approximately 3 tablespoons of the sample in an envelope with the following identifying information: the well from which the sample originates, the location of the well, the Commission's permit number for the well, and the depth at which the sample is taken; and
3. Package sample envelopes in protective boxes and ship prepaid to:

   Oil & Gas Administrator
   Arizona Geological Survey
   416 West Congress, Suite 100
   Tucson, AZ 85701

C. The Commission shall keep all well information required by this Section confidential for 1 year after the drilling is completed unless the operator gives written permission to release the information at an earlier date. The Commission shall provide notice to the operator 60 days before confidential records become subject to public inspection and, at the operator's request, extend the confidential period for 6 months to 2 years if the Commission finds that the operator has demonstrated that release would harm the operator's competitive position with respect to unleased land in the vicinity of the well.

Historical Note

Former Rule 120; Former Section R12-7-121 renumbered and amended as Section R12-7-122, former Section R12-7-120 renumbered and amended as Section R12-7-121 effective September 29, 1982 (Supp. 82-5). Amended effective January 2, 1996 (Supp. 96-1). Amended by final rulemaking at 6 A.A.R. 4827, effective December 7, 2000 (Supp. 00-4).

R12-7-122. Recompletion and Routine Maintenance Operations

A. After a well has been completed, it shall not be deepened, redrilled, plugged back, reworked, or recompleted in a different zone, without prior approval by the Commission of a written application showing the character of the proposed work and the time it will begin. The Commission shall notify the applicant in writing whether the proposed work is approved or disapproved.

B. In the case of an emergency, an application may be made by electronic communication, and the Commission may by electronic communication authorize the work; however, written application required in subsection (A) shall be filed with the Commission within 10 days after emergency authorization is given, even though the work has already been commenced or completed. The Commission shall confirm the emergency authorization in writing upon receipt of the written application.

C. Written approval from the Commission is not required on acidizing, fracturing, and reperforating, or other routine well operations designed to restore or maintain production.

D. Within 15 days following the completion of any work described in this Section, the operator shall file a written report with the Commission identifying the well and fully describing the work performed. If the well is recompleted, a completion report shall be filed as required by R12-7-121.

Historical Note

Former Section R12-7-121 renumbered and amended as Section R12-7-122 effective September 29, 1982 (Supp. 82-5). Amended effective January 2, 1996 (Supp. 96-1).

R12-7-123. Reserved

R12-7-124. Reserved

R12-7-125. Temporarily Abandoned and Shut-in Wells

A. If drilling, injection, or production operations at a well are suspended, or have been suspended for 60 days, an operator shall plug the well under R12-7-127 unless the Commission permits the well to be temporarily abandoned or shut-in. The Commission shall not classify a well as shut-in until the operator submits a completion report under R12-7-121.

B. An operator may temporarily abandon or shut-in a well for up to 5 years if the operator demonstrates to a quorum of the Commission a future beneficial use of the well and submits a Sundry Notice to the Commission containing the following information:
1. Evidence of casing integrity as required in R12-7-112 including a complete description of the current casing, cementing, and perforation record of the well;
2. The stimulation and cement squeeze record and complete data on the results of any well tests performed to date; and
3. All other well data required in R12-7-121(A).

C. Before an approved time-frame for a temporarily abandoned or shut-in well expires, the operator shall return the well to beneficial use under a plan approved by the Commission, permanently plug and abandon the well, or apply for an extension to temporarily abandon or shut-in the well. If the integrity of the well casing is in question, the Commission may require the operator to:
1. Prove casing integrity in accordance with R12-7-112;
2. Plug any well that fails to meet the casing integrity required by R12-7-112; and
3. Re-test the well in accordance with R12-7-150 to continue shut-in status.

D. An operator shall ensure that no work begins on a temporarily abandoned or shut-in well until approved by the Commission. The operator shall give at least 24 hours' notice to the Commission before any work begins. Within 15 days of completing the proposed work, the operator shall file a written report with the Commission fully describing the work performed including a copy of all test rates, pressures, and fluid analyses.

Historical Note

Adopted effective January 2, 1996 (Supp. 96-1). Amended by final rulemaking at 6 A.A.R. 4827, effective December 7, 2000 (Supp. 00-4).

R12-7-126. Application to Plug and Abandon

A. Before abandoning any well, the operator shall submit an application to plug and abandon to the Commission and obtain approval. The application shall set forth the name and location of the well, the mechanical condition of the well, the productive zone and latest production, and a complete description of the proposed work. The plan shall provide for the protection of all formations containing usable-quality water, oil, gas, or geothermal resources.

B. In the case of a drilling well or an emergency, the application may be made by electronic communication, and the Commission may by electronic communication authorize the work; however, the operator shall file a written application within 10 days after the emergency authorization is given even though the work has already been commenced or completed. The Commission shall confirm the emergency authorization in writing upon receipt of the written application.

Historical Note

Former Rule 201; Amended effective September 29, 1982 (Supp. 82-5). Amended effective January 2, 1996 (Supp. 96-1).

R12-7-127. Plugging Methods and Procedures

A. Before abandoning any well, the operator shall submit an application to plug and abandon to the Commission for approval as required in R12-7-126. All down-hole plugging shall be conducted through drill pipe or tubing, unless otherwise approved by the Commission.

B. Open hole
1. A cement plug shall be placed to extend at least 50 feet below the bottom, except as limited by total depth or plugged back total depth, to 50 feet above the top of any zone containing fluid with a potential to migrate, any zone of lost circulation, and any zone containing potentially valuable minerals, including noncommercial hydrocarbons, coal, and oil shale.
2. All freshwater zones shall be plugged with a continuous cement plug which shall extend from at least 50 feet below to at least 50 feet above the freshwater zone, or a 100-foot plug shall be centered across the base of the freshwater zone and a 100-foot plug shall be centered across the top of the freshwater zone.
3. Open hole below the shoe of cemented casing shall be plugged with cement which shall extend from at least 50 feet below to at least 50 feet above the shoe.

C. Cased hole
1. A cement plug shall be placed opposite all open perforations and extend to a minimum of 50 feet below, except as limited by total depth or plugged back total depth, to 50 feet above the perforated interval. In lieu of the cement plug, a bridge plug may be placed within 50 to 100 feet above the open perforations and followed by at least 50 feet of cement.
2. If any casing is cut and recovered, a cement plug shall be placed to extend at least 50 feet above and below the stub.
3. No annular space that extends to the surface shall be left open to the drilled hole below. If this condition exists, a minimum of the top 100 feet of each annulus shall be plugged with cement.

D. Plugging mud having the proper weight and consistency to prevent movement of other fluids into or within the bore hole shall be placed across all intervals not plugged with cement. In the absence of other information at the time plugging is approved, plugging mud shall be made up with a minimum of 15 pounds per barrel of sodium bentonite and a nonfermenting polymer, have a minimum consistency of 9 pounds per gallon, a minimum viscosity of 50 seconds per quart, and mixed with fresh water.

E. A cement surface plug of at least 50 feet shall be placed in the smallest casing which extends to the surface. The top of this plug shall be placed as near the eventual casing cut-off point as possible.

F. The abandoned well shall be marked by a piece of metal pipe not less than 4 inches in diameter securely set in cement and extending at least 4 feet above the general ground level. The well location and identity shall be permanently inscribed as required in R12-7-106(A). An abandoned well location on tilled or otherwise unique land shall be marked in a manner approved by the Commission.

G. The drill site of an abandoned well shall be restored as nearly as possible to its natural state, to the satisfaction of the Commission. All pits shall be filled and all equipment and debris shall be removed from the location.

H. The operator shall notify the Commission at least 48 hours before starting abandonment operations to allow a representative of the Commission to witness the operations required in this Section. To ensure the integrity or placement of any plug, the representative may order the plug to be tested.

I. Within 15 days after the plugging of any well, the operator shall file with the Commission a plugging record setting forth in detail the method used in plugging the well, including the casing record; the size, kind, and depth of plugs used; and the name and depth interval of each formation containing fresh water, oil, gas, or geothermal resources.

J. Seismic shot holes
1. All seismic shot holes shall be plugged and abandoned within 30 days of firing.
2. Seismic shot holes which do not encounter freshwater zones shall be filled with a high-grade bentonite slurry or some other comparable plugging material as approved by the Commission.
3. Seismic shot holes which do encounter freshwater zones shall be plugged with cement in accordance with the applicable provisions of subsections (B) and (D).
4. Seismic shot-hole locations shall be restored in accordance with subsection (G) and the operator shall file a plugging record in accordance with subsection (I).

Historical Note

Former Rule 202; Amended effective September 29, 1982 (Supp. 82-5). Amended effective January 2, 1996 (Supp. 96-1).

R12-7-128. Stratigraphic, Core, and Seismic Holes

A. Any hole drilled for stratigraphic, core, or seismic purposes shall comply with all rules in this Chapter pertaining to the drilling of a well except the spacing provisions of R12-7-107.

B. Each hole drilled for stratigraphic, core, or seismic purposes shall be plugged in accordance with R12-7-126 and R12-7-127. The operator of a stratigraphic or core hole shall submit samples and cores and file a completion report in accordance with R12-7-121.

Historical Note

Former Rule 203; Amended effective September 29, 1982 (Supp. 82-5). Amended effective January 2, 1996 (Supp. 96-1).

R12-7-129. Wells to be Used as Water Wells

A. The landowner, landowner's agent, or lessee may use any well or exploratory hole as a water well provided that:
1. Written approval is obtained from the Arizona Department of Water Resources;
2. The operator plugs the well in accordance with R12-7-127 to a point immediately below the freshwater strata; and
3. The landowner, landowner's agent, or lessee assumes responsibility for the well and compliance with the provisions of A.R.S. Title 45, Chapter 2 in a signed and notarized water-well responsibility form provided by and filed with the Commission.

B. After filing the notarized water-well responsibility form with the Commission, the landowner, landowner's agent, or lessee shall comply with A.R.S. Title 45, Chapter 2 before modification or abandonment of the well.

C. Upon filing the notarized water-well responsibility form with the Commission, the Commission shall notify the bonding company and operator in writing so that the bond may be cancelled or made no longer effective with respect to that well.

Historical Note

Former Rule 204; Amended effective September 29, 1982 (Supp. 82-5). Amended effective January 2, 1996 (Supp. 96-1). Amended by final rulemaking at 8 A.A.R. 3363, effective July 15, 2002 (Supp. 02-3).

R12-7-130. Reserved

R12-7-131. Reserved

R12-7-132. Reserved

R12-7-133. Reserved

R12-7-134. Reserved

R12-7-135. Gas-oil Ratio and Potential Tests

A. Each operator shall conduct a gas-oil ratio test between 5 and 15 days after the completion or recompletion of any well located in a pool which contains both oil and gas. The average daily oil production, the average daily gas production, and the average gas-oil ratio shall be recorded.

B. The results of the gas-oil ratio test shall be reported in writing to the Commission within 15 days after completion of the test.

C. Each operator shall conduct a potential test within 30 days following the completion or recompletion of any well for the production of oil. The results of this test shall be reported in writing to the Commission within 15 days after completion of the test.

Historical Note

Former Rule 301; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-136. Subsurface Pressure Tests and Reservoir Surveys

A. Each operator shall conduct a test, within 30 days after completion, to determine the reservoir pressure on the discovery well of any new pool. The test shall be made after the well has been shut-in for at least 24 hours, and the results shall be reported in writing to the Commission within 15 days after the completion of the test.

B. The Commission may require subsurface pressure measurements on a number of wells in any pool to provide data to determine reservoir characteristics. The survey shall be made by the operator and shall provide a description of the test method and results including fluids, temperature, and pressure data and may require supervision by a qualified agent of the Commission. The results shall be reported in writing to the Commission within 15 days of the completion of the survey.

Historical Note

Former Rule 302; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-137. Commingling of Production from Pools

A. Unless authorized by the Commission, each pool shall be produced as a single common reservoir, with the wells completed, cased, maintained, and operated as the producing media for that pool. Oil production from each pool shall at all times be segregated into separate, identified tanks. The commingling of production from different pools is prohibited, unless authorized by order of the Commission after notice and hearing.

B. The Commission may approve commingling of production upon demonstration by the applicant that such commingling shall not cause waste of reservoir energy or diminish recovery of the resource. Application for approval of commingling shall include the following:
1. Electric or porosity log with tops and bottoms of formations or producing zones and perforated intervals shown and marked;
2. Diagrammatic sketch of the proposed well structure, including make, type and setting depths of packers;
3. The reservoir pressure for each zone or formation pro posed for commingling, the specific gravity and BTU content of the gas if the zone produces gas, and the API gravity and gas-oil ratio of the oil if the zone produces oil;
4. Plat showing the location of the well and all offset wells, and a list of the names and addresses of operators of all leases offsetting the acreage dedicated to the applicant's well;

5. Waiver consenting to the proposed commingling from each offset operator, or in lieu thereof, copies of letters requesting such waiver; and
6. Proof of mailing of notice of application for commingling to all offset operators.

C. The first application for commingling of pools in a field shall be approved by the Commission only after notice and hearing. Subsequent applications, completed as required in subsection (B), for commingling of the same zones in the same field may be approved administratively if, after a 15-day holding period, there are no protests from offsetting operators.

Historical Note

Former Rule 303; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-138. Casinghead Gas

A. All casinghead gas produced and sold or transported away from a lease, except amounts of flare gas, shall be metered and reported monthly in writing to the Commission in standard Mcf and gallons of liquids per Mcf. If the casinghead gas is sold as supply stock for a gasoline plant, the gallons of liquids per Mcf shall be reported. The operator of a lease shall not be required to measure the exact amount of casinghead gas produced and used for fuel purposes in the development and normal operation of the lease.

B. Pending arrangements for disposition of some useful purpose, all casinghead gas that is authorized to be vented shall be burned, and the estimated volume reported monthly as required by R12-7-161.

Historical Note

Former Rule 304; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-139. Use of Vacuum Pumps

A. The use of any device for the purpose of putting a vacuum on any stratum containing oil, gas, or geothermal resources is prohibited unless authorized by the Commission.

B. The Commission may, after notice and hearing, authorize the use of vacuum pumps if the applicant can show that use of the vacuum will not create waste or infringe on correlative rights.

Historical Note

Former Rule 305. Amended effective February 23, 1993 (Supp. 93-1).

R12-7-140. Pollution, Surface Damage, and Noise Abatement

A. An operator of a well, production facility, gasoline plant, gas plant, or pipeline shall conduct operations in a manner that prevents surface or subsurface pollution.

B. An operator shall conduct operations in a manner that prevents oil, gas, salt water, fracturing fluid or any other substance from polluting any surface or subsurface waters.

C. During swabbing and bailing operations or when purging a well, all substances removed from the bore hole shall be placed in a pit or tank and shall not be allowed to pollute any surface or subsurface waters.

D. An operator shall maintain all wellhead connections, surface equipment, lease flow lines, and tank batteries at all times to prevent the escape of oil, gas, produced water, or any other substance.

E. An operator shall report any fire, leak, or blowout to the Commission in accordance with R12-7-120. An operator shall ensure that any pit is constructed and operated in accordance with R12-7-108.

F. An operator shall minimize noise when conducting air drilling operations or when the well is allowed to produce while drilling. An operator shall ensure that the welfare of the operating personnel and the public is not negatively affected by the noise created by the expanding gases.

Historical Note

Former Rule 306. Amended effective February 23, 1993 (Supp. 93-1). Amended by final rulemaking at 8 A.A.R. 3363, effective July 15, 2002 (Supp. 02-3).

R12-7-141. Renumbered

Historical Note

Former Rule 307; Language transferred and amended, see Section R12-7-176 (Supp. 82-5).

R12-7-142. Measurement of Oil

Oil or condensate shall not be transported from a lease until it has been measured. Each transporter shall file a monthly report of the amount of oil or condensate transported from the lease as required by R12-7-185.

Historical Note

Former Rule 308; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-143. Oil Tanks, Fire Walls, and Fire Hazards

A. Oil shall not be stored or retained in an earthen reservoir or an open receptacle. The Commission may require dikes or fire walls to protect life, health, or property. All dikes or fire walls shall be erected and continuously maintained around all permanent oil tanks or batteries that are within the corporate limits of any city, town or village, or where such tanks are closer than 150 feet to any highway or inhabited dwelling, or closer than 1,000 feet to any school or church. The capacity of the dike or firewall shall be 1 1/2 times the capacity of the tank or tanks that it surrounds. The reservoir so formed within the dike shall be kept free from vegetation, water and oil.

B. Anything that might constitute a fire hazard, including potentially flammable items and reckless behavior such as smoking, shall be moved at least 150 feet from the well, tanks, separator, or other equipment.

Historical Note

Former Rule 309. Amended effective February 23, 1993 (Supp. 93-1).

R12-7-144. Reserved

R12-7-145. Reserved

R12-7-146. Reserved

R12-7-147. Reserved

R12-7-148. Reserved

R12-7-149. Reserved

R12-7-150. Capacity Tests of Gas Wells and Geothermal Wells

A. The operator of a producing gas well shall determine its open-flow capacity within 30 days following completion. Additional tests shall be taken as requested by the Commission. When a pipeline connection is available, gas wells shall not be tested by open-flow method, but the open-flow capacity shall be determined by the multipoint or single-point back-pressure test method.

B. The Commission may require tests to determine the quantity and quality of geothermal resources or reservoir energy.

C. The results of the tests required in this Section shall be reported in writing to the Commission within 15 days after the completion of the test.

Historical Note

Former Rule 401; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-151. Measurement of Gas from Gas Wells and Geothermal Resources

A. All gas produced for whatever purpose in gaseous form from gas wells shall be accounted for by metering as approved by the Commission. If the gas is sold, the purchaser shall report the volume purchased as required by R12-7-186. If the gas is delivered to a transportation facility, the transporter shall report the volume transported as required by R12-7-185. The operator shall report the volume produced as required by R12-7-161.

B. Each operator of a geothermal lease shall measure the quantity and quality of all production in accordance with the standard practices, procedures, and specifications generally used in the industry. The operator shall report the production as required in R12-7-161 and the purchaser shall file a report as required in R12-7-186.

Historical Note

Former Rule 402; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-152. Utilization of Gas

A. No gas from any completed gas well shall be:
1. Permitted to escape into the air except for testing when no pipeline connection is available.
2. Used expansively in engines or pumps and then vented, or
3. Used to gas-lift in oil wells unless all gas produced from such gas-lift operations is processed in a gasoline plant, and the residue gas is used in the manufacture of carbon black or for some other profitable use.

B. Utilization of gas in the manufacture of carbon black may be made only if approved by the Commission, after notice and hearing, based on a finding that a more profitable use is not available or will not be available in a reasonable time.

Historical Note

Former Rule 403. Amended effective February 23, 1993 (Supp. 93-1).

R12-7-153. Non-hydrocarbon Gas

The rules of this Chapter shall also apply to helium, carbon dioxide, and any other non-hydrocarbon gas.

Historical Note

Former Rule 404. Amended effective February 23, 1993 (Supp. 93-1).

R12-7-154. Reserved

R12-7-155. Reserved

R12-7-156. Reserved

R12-7-157. Reserved

R12-7-158. Reserved

R12-7-159. Reserved

R12-7-160. Regulation of Production

If the Commission determines that oil, gas, or geothermal resources production in the state is causing waste, the Commission shall limit, allocate, and apportion the total amount of oil, gas, or geothermal resources which may be produced.

Historical Note

Former Rule 501; Amended effective September 29, 1982. See also Section R12-7-170 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-161. Producer's Monthly Report

A. Each operator shall file a producer's monthly report for each producing lease for each calendar month, setting forth the operator's name, each well's lease name or number, well number, state permit number, the actual amounts of oil, gas, water, or geothermal resources produced, the number of days each well produced, and the disposition of the produced oil, gas, water, or geothermal resources. The report shall be filed on or before the 25th day of the next succeeding month.

B. If a well is off production for a period exceeding 30 days, the Commission shall be notified in writing with the reasons given.

Historical Note

Former Rule 502; Amended effective September 29, 1982. See also Section R12-7-171 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-162. Reserved

R12-7-163. Reserved

R12-7-164. Reserved

R12-7-165. Reserved

R12-7-166. Reserved

R12-7-167. Reserved

R12-7-168. Reserved

R12-7-169. Reserved

R12-7-170. Renumbered

Historical Note

Former Rule 601; Language transferred and amended, see Section R12-7-160 (Supp. 82-5).

R12-7-171. Renumbered

Historical Note

Former Rule 602; Language transferred and amended, see Section R12-7-161 (Supp. 82-5).

R12-7-172. Reserved

R12-7-173. Reserved

R12-7-174. Reserved

R12-7-175. Injection Wells Including Enhanced Recovery, Disposal, and Storage Wells

A. The following injection wells used for enhanced recovery, disposal, or storage shall require a permit from the Commission:
1. Class II injection wells
   a. Saltwater disposal wells: wells used to return salt water associated with oil and gas production to the subsurface.
   b. Enhanced oil recovery wells: wells used to inject salt water, gases, enhanced waters, and steam in order to maintain and extend oil production;
   c. Hydrocarbon storage wells: wells used for the underground storage of crude oil, liquified petroleum gas (LPG), and other liquid hydrocarbon products in naturally occurring rock formations.
2. Other injection wells

a. Geothermal injection wells: Class V wells used to reinject groundwater or geothermal fluids that are used in or are associated with the production of geothermal energy;
b. Other wells: wells used for the underground storage of any hydrocarbons or nonhydrocarbons that are gaseous at standard temperature and pressure, wells used to dissolve salt to create a cavity to be used for underground storage, and wells used to dispose of brine produced in the course of creating a solution-mined salt cavity.

B. In addition to being subject to the applicable provisions of this Chapter, the wells listed in subsection (A) shall be subject to the following specific regulation:
1. Injection wells listed in subsections (A)(1)(a) and (b) and (A)(2)(a) shall be regulated by R12-7-176, R12-7-178, and R12-7-179.
2. Injection wells listed in subsections (A)(1)(c) and (A)(2)(b) shall be regulated by R12-7-176, R12-7-178, R12-7-179, R12-7-180, R12-7-181, and R12-7-182.

C. No permits for injection wells other than those described in this Section shall be issued by the Commission.

Historical Note

Adopted effective January 2, 1996 (Supp. 96-1).

R12-7-176. Permits for Injection Wells

A. The injection of any substance into any geologic formation is prohibited unless 1st authorized by the Commission after notice and hearing. The Commission shall give at least 15 days' notice before a hearing is held for drilling a new injection well or for converting an existing well into an injection well. A permit shall not be required for routine well operations pursuant to R12-7-122(C) whose physical effects are confined to the area near the well bore.

B. The application for a permit for an injection well as defined in R12-7-175 shall be prepared in accordance with R12-7-104, shall meet all the applicable requirements of this Chapter, and shall contain the following requirements, where applicable:
1. A plat showing the location of each proposed injection well and the location and status of all wells, including drilling wells and dry holes, within 1/2 mile of the proposed well. The plat shall include the lease boundary lines, the names of the surface and subsurface lessees and owners within 1/2 mile of the injection well or wells, and the name of each offset operator.
2. A geologic study, including:
   a. A contour map drawn on a geologic marker at or near the top of each injection zone in the project area;
   b. A thickness map of each injection zone in the project area;
   c. A geologic cross-section drawn through the site of an injection well in the project area showing structural details, any wells that may be affected by the project, and the location of the base of any freshwater strata, defined as water having 10,000 ppm or less of total dissolved solids, or a statement that no fresh water exists; and
   d. A representative electric log to a depth below the deepest producing zone identifying all geologic units including the injection and confining zones, freshwater aquifers, and oil, gas, or geothermal zones.
3. An engineering study, including:
   a. A statement of the primary purpose of the project;
   b. The characteristics of the injection and confining zones including porosity, permeability, thickness, areal extent, fracture gradient, original and present temperature and pressure, and residual oil, gas, and water saturations;
   c. The reservoir fluid data for each injection zone including oil gravity and viscosity, water quality, and specific gravity of gas;
   d. A description of each injection well's casing, or the proposed casing and cementing program, and the proposed method of testing the casing before use of the injection well. The casing shall be designed and tested in accordance with R12-7-181(C) with respect to the injection zone;
   e. A diagram of the proposed wellhead;
   f. A casing diagram, including cement plugs, and the actual or calculated cement fill behind the casing of all wells within the area affected by the project, including abandoned wells, showing that they will not cause damage to life, health, property, or natural resources;
   g. The well stimulation program if stimulation is planned; and
   h. The planned well-drilling and abandonment program to complete the project, including a flood-pattern map showing all injection, production, and abandoned wells, and unit boundaries.
4. An injection plan, including:
   a. A diagram and plan of the injection facilities;
   b. The maximum surface injection pressure expected during the life of the project and the estimated daily rate of fluid injection, by well. The operator shall provide calculations showing that the maximum injection pressure will not initiate fractures in the confining zone;
   c. A description of the area affected by the volumetric method and by the pressure-buildup method and the radius affected during the life of the project;
   d. The monitoring system or method to be used to ensure that no damage is occurring and that the injection fluid is confined to the permitted injection zone and to the area controlled by the operator;
   e. The method of injection such as casing, tubing, tubing with packer, between strings;
   f. The protective methods to be used on each injection line and well and a contingency plan for well failure or a shut-in period, including a plan for disposition of fluids not injected as a consequence of well failure;
   g. The source and chemical analysis of the injection fluid, and chemical analysis of the water in the injection zone. If the water in the injection zone has 10,000 ppm or less of total dissolved solids, the applicant shall provide evidence of commercial oil or gas producibility of the zone by means of historical production in the field or by log information, core data, and values for the porosity and permeability of the zone; and
   h. The location and depth of each water-source well that will be used in conjunction with the project.
5. Proof of notification to neighboring operators and surface owners within 1/2 mile of the proposed well.
6. Supplementary data as required in R12-7-180 for storage-well projects.
7. Any additional information that the Commission may determine is necessary to adequately clarify the informa-

tion submitted pursuant to R12-7-176(B)(1) through (B)(6).

8. All maps, diagrams, and exhibits required in this subsection shall be clearly labeled as to scale and purpose and shall clearly identify wells, boundaries, zones, contacts, and other relevant data.

C. Permits may be issued for a period up to the operating life of the well with review once every 5 years. Permits may be modified or terminated during their term if the Commission determines that the operator is not in compliance with the requirements of this Chapter.

Historical Note

Former Rule 701; Amended effective September 29, 1982. See also Section R12-7-141 (Supp. 82-5). Amended effective January 2, 1996 (Supp. 96-1).

R12-7-177. Repealed

Historical Note

Former Rule 702; Amended effective September 29, 1982 (Supp. 82-5). Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-178. Notice of Commencement, Discontinuance, and Transfer of Injection Operations

The following provisions apply to all injection projects defined in R12-7-175:

1. The operator shall notify the Commission of the date that injection operations will begin.
2. The operator shall notify the Commission of the date that injection operations will cease and provide the reasons for discontinuing the injection operations.
   a. The temporary abandonment of any injection well shall be in accordance with R12-7-125. Temporarily abandoned injection wells shall meet the testing requirements of R12-7-179(D).
   b. All injection wells shall be plugged and abandoned, in accordance with R12-7-126 and R12-7-127.
3. An injection well shall not be transferred from 1 operator to another without the written approval of the Commission.
   a. The operator shall file the request for transfer of ownership of an injection well in triplicate with the Commission at least 45 days before the proposed transfer date. The request shall include the name, address, and telephone number of the proposed new operator and provide the location and status of each well involved.
   b. The proposed new operator shall file with the Commission an organization report as required in R12-7-194 and bond as required in R12-7-103 before the request for transfer will be considered.
   c. The Commission shall return 1 copy of the request for transfer to the operator and 1 to the proposed new operator within 30 days after receipt of the information required in subsections (3)(a) and (b), designating approval or denial of the transfer of authority to inject for the subject well.
      i. If the proposed transfer is approved, a copy of the order authorizing injection shall be attached to the approved request for transfer.
      ii. If the proposed transfer is denied, the Commission shall return 1 copy of the request to the operator and 1 copy to the proposed operator together with the reasons for the denial and the steps necessary for its approval.

Historical Note

Former Rule 703; Amended effective September 29, 1982 (Supp. 82-5). Amended effective January 2, 1996 (Supp. 96-2).

R12-7-179. Testing and Monitoring of Injection Wells

A. The operator of an injection well shall file a weekly sundry report with the Commission on all drilling, completion, recompletion, and workover operations.

B. The operator of an injection well shall monitor operations to ensure that injection pressure at the wellhead does not exceed the maximum pressure authorized in the permit, and that no injection shall cause movement of injection or formation fluids into an underground source of drinking water.

C. The operator shall keep accurate records of the amount of oil, gas, water, or geothermal resources produced, the volume of substances injected, the average and maximum pressure used for injection, and the nature of the injected fluid. The operator of an enhanced recovery or disposal well shall submit a report as required in R12-7-187. The operator of a storage well shall submit a report as required in R12-7-185.

D. The operator shall run the following pressure or monitoring tests on new injection wells to establish the mechanical integrity of the tubing, casing, and packer. Existing wells being converted to an injection well shall be tested in the same manner and shall maintain the same mechanical integrity as a new well.

1. The casing-tubing annulus above the packer shall be tested upon completion and at least once every 5 years, under the supervision of the Commission, at a pressure equal to the lesser of the maximum authorized injection pressure or 1,000 psi, provided that no testing pressure shall be less than 300 psi. Documentation of the test shall be submitted to the Commission. Test pressures shall be applied for a period of 30 minutes. If a drop of more than 10% of the test pressure should occur, corrective measures shall be applied. If the tubing, casing, or packer cannot be brought up to standard, the well shall be plugged and abandoned in accordance with R12-7-126 and R12-7-127.
2. The Commission may require the operator to run a tracer survey, a temperature log, or a noise log to demonstrate the absence of fluid movement in vertical channels adjacent to the injection well.

E. Mechanical failure or downhole problems which indicate an injection well is not, or may not be, directing the injected fluid into the permitted injection zone may be cause to shut in the well. The operator shall notify the Commission within 24 hours of any such failure or problem. A written notice shall be filed within 5 days of the occurrence, with a plan for testing and repairing the well. If the well cannot be brought up to the standard required in subsection (D), it shall be plugged and abandoned in accordance with R12-7-126 and R12-7-127.

Historical Note

Former Rule 704; Amended effective September 29, 1982 (Supp. 82-5). Amended effective January 2, 1996 (Supp. 96-1).

R12-7-180. Supplementary Requirements for Storage Wells

The application for a storage well as defined in R12-7-175(B)(2) shall be prepared in accordance with R12-7-176 and shall contain the following, where applicable:

1. Information on any oil or gas production within 5 miles of each proposed well;
2. Information on the oil and gas reserves of each storage zone before starting injection, including calculations;

3. A comprehensive plan for disposition of brine and salt produced in the course of creating a solution-mined salt cavity. Cavities shall be designed and constructed in accordance with R12-7-181;
   a. Surface disposition shall be subject to the rules of the Department of Water Resources and the Department of Environmental Quality;
   b. Saltwater disposal wells shall be permitted in accordance with R12-7-176;
   c. Surface brine reservoirs used in the operation of the storage system and disposal reservoirs shall be designed to prevent the contamination of air, fresh water, and soil;
4. A list of proposed surface and subsurface safety devices, tests, and precautions to be taken to ensure safety of the project. The operator shall install a flare or other safety system acceptable to the Commission at or near each brine pit or any other location where escape of gases is likely to occur.

Historical Note

Former Rule 705; Amended effective September 29, 1982 (Supp. 82-5). Amended effective January 2, 1996 (Supp. 96-1).

R12-7-181. Design and Construction of Storage Wells and Cavities

A. Before drilling a storage well for storing liquid or gaseous hydrocarbons, or any other substances under the jurisdiction of the Commission, in an underground cavity, the applicant shall demonstrate to the Commission that the proposed storage will preserve the structural integrity of the host rock, including halite, and the overlying sediments. The evidence presented shall include:
   1. An investigation to determine the feasibility of a storage system at the particular site; and
   2. An assessment of the stability of each proposed cavity design, particularly with regard to the size, shape and depth of the storage cavity, the amount of separation between storage cavities, and the amount of separation between the storage cavity and the periphery of the host rock.

B. The design of a solution-mined storage system shall be based on site-specific geologic and engineering parameters including type of storage use, location of each cavity, number of cavities, cavity capacity, and maximum development diameter of each cavity. The design shall ensure that project development can be conducted in a reasonable, prudent, and systematic manner and shall stress physical and environmental safety and the prevention of waste. The design and solution mining shall be continually reviewed throughout the construction phase to account for any new subsurface information and shall include provisions for protection from damage caused by hydraulic shock. The original development and operational plans shall be modified, as necessary, to conform with good engineering practice. The design shall incorporate the standards outlined below:
   1. The minimum separation between the nearest outer walls of adjacent storage cavities as measured in any direction shall be established considering:
      a. The properties of the host rock;
      b. The elevation of the top and bottom of the adjacent cavities;
      c. Their maximum development diameter relative to the spacing of the cavities; and
      d. Other considerations deemed appropriate for the specific site; however, in no case shall such separation at any time during the storage project be less than 200 feet.
   2. The walls of a storage cavity shall be no less than 200 feet from the boundary of the lands included in the storage project on which the chambers are located.
   3. If the design involves the intentional subsurface connection between 2 adjacent storage cavities under 1 property (that is, a “U”-tube storage-cavity system), the minimum separation between cavities specified in subsection (B)(1)(d) shall not apply.

C. The borehole shall be dually cased from the surface into the cavity in accordance with R12-7-110 and R12-7-111. At least 2 strings of casing shall be fully cemented from the surface into the host rock either during the primary cement job or by remedial action. The Commission may administratively grant an exception to the requirement for 2 strings of cemented casing if the applicant can show that the exception is reasonable, justified by site-specific geologic or engineering parameters, is no less stringent, and consistent with the intent of these rules regarding physical and environmental safety, conservation of the resource, and the prevention of waste.
   1. The final cemented casing string shall have tensile and collapse strengths, as approved by the Commission, for the setting depth and shall be set a minimum of 200 feet into the formation to be used for the storage cavity.
   2. The casing seat of the final cemented casing string shall be pressure-tested after drilling at least 10 feet into the formation below the casing seat. The test pressure calculated at the casing seat shall equal the proposed maximum operating pressure at that point and shall not exceed 0.9 psi per foot of depth.
   3. After the wellhead has been installed and before products are stored, the system shall be pressure-tested as a unit.
   4. All tests required in this subsection shall meet the integrity standards set in R12-7-179(D).

D. Storage facilities in existence prior to June 1, 1978, shall not be required to meet the planning and construction requirements of subsections (B) and (C), except for future expansions or additions.

Historical Note

Adopted effective August 31, 1978 (Supp. 78-4). Amended effective September 29, 1982 (Supp. 82-5). Amended (and subsections (A)(1)(h) through (m) moved to Section R12-7-182) effective January 2, 1996 (Supp. 96-1)

R12-7-182. Operation, Inspection, and Closure of Storage-well Systems

A. The maximum and minimum operating pressures of a storage system shall be determined in consideration of the lithologic characteristics of the host rock. The maximum operating pressure at the shallower of the casing seat or cavity ceiling shall not exceed 0.9 psi per foot of depth.
   1. The storage system shall not be subjected to pressures exceeding the maximum operating pressure even for short periods of time, including pressure pulsation peaks and abnormal operating conditions.
   2. The wellhead, flowlines, valves, and all related connections shall have a test pressure rating equivalent to 125% of the maximum pressure which could be exerted at the surface. All valves shall be periodically inspected and maintained in good working order.
   3. The wellhead and storage system shall be protected with safety devices to prevent pressures exceeding the maximum operating pressure from being exerted on the stor-

age system and to prevent backflow of stored products in the event of flowline rupture.

4. Personnel shall be at either the well or other control sites for the well during injection or withdrawal from any storage well.

B. The flare, as required in R12-7-180(4), shall be burned continuously when a liquified gas or other flammable substance is being injected into a cavern.

C. Each operator of a storage well shall conduct semiannual safety inspections of the operator's facility and file with the Commission a written report on the inspection procedures and results within 5 days following the inspection. The operator shall notify the Commission at least 5 days before an inspection to allow a representative of the Commission to witness the inspection. Inspections shall include, the following:

1. Operation of all manual valves;
2. Operation of all automatic shut-in safety valves, including sounding or alarm devices;
3. Examination of flare system or other safety system installation;
4. Examination of earthen brine pits, tanks, firewalls, and related equipment;
5. Examination of flowlines, manifolds, and related equipment;
6. Examination of warning signs and safety fences;
7. Examination of housekeeping practices including the removal of weeds, used equipment, and debris from the area of operations;
8. The Commission may require additional inspections at any time during regular working hours and upon reasonable notice to the operator.

D. A capacity determination for each storage cavity shall be made and filed with the Commission upon completion of the storage cavity. These determinations shall be verified at least once every 5 years.

E. Safety precaution signs shall be displayed and unauthorized personnel kept out of the storage area. Each storage wellhead shall be visibly marked in accordance with R12-7-106(D). Guard rails shall be installed where the Commission determines it is necessary to ensure safety.

F. Storage wells shall be plugged and abandoned in accordance with R12-7-126 and R12-7-127.

G. If the Commission determines that the continued operation of a storage well or associated facilities, including valves, brine tanks or pits, flares, dehydrators, and loading and docking facilities, would cause unsafe operating conditions, waste, pollution, or contamination of air, fresh water, or soil, or encroachment on adjacent property, the Commission shall order discontinuance of operations of the storage facility or any part thereof until the Commission determines that the project can and will be conducted in a physically and environmentally safe manner.

H. The operator shall notify the Commission within 24 hours of every accident or equipment malfunction which causes loss of life or requires hospitalization of personnel; threatens the public health and safety; pollutes the air, soil, or fresh water; or causes loss of the stored substance. A final written report shall be filed with the Commission in accordance with R12-7-120(B).

I. The Commission may administratively grant exceptions to the guidelines and requirements of this Section if the applicant can show that the exception is reasonable, justified by site-specific geologic or engineering parameters, are no less stringent, and consistent with the intent of these rules regarding physical and environmental safety, conservation of the resource, and the prevention of waste. An applicant may request a hearing pursuant to A.R.S. § 27-517.

Historical Note

Adopted by moving subsections (A)(1)(h) through (m) of R12-7-181 and amending the text effective January 2, 1996 (Supp. 96-1).

R12-7-183. Certificate of Compliance and Authorization to Transport

A. Each producer or operator of any well shall execute under oath and file with the Commission an operator's certificate of compliance and authorization to transport oil, gas, or geothermal resources from lease provided by the Commission for each well.

B. The certificate, when properly executed and approved by the Commission, shall constitute authorization to the pipeline or other transporter to transport oil, gas or geothermal resources from the developed unit named. The Commission may provide written permission for the transportation of production in order to prevent waste, pending execution and approval of the certificate.

C. The certificate shall remain in full force and effect until:

1. The operating ownership of the developed unit changes, or
2. The transporter changes, or
3. The certificate is cancelled by the Commission.

D. When a change occurs in operating ownership of any developed unit, or when a change occurs in the transporter from any developed unit, the operator shall file a new certificate with the Commission within 10 days of the change. With respect to a temporary change in transporter which involves less than the production of one month, the producer may, in lieu of filing a new certificate, notify the Commission and the transporter in writing of the estimated amount of oil, gas, or geothermal resources to be moved by the temporary transporter, and the name of the temporary transporter. The operator shall furnish a copy of the notice to the temporary transporter.

E. The temporary transporter shall not move any greater quantity of oil, gas, or geothermal resources than the estimated amount shown in the notice.

F. Time-frames

1. The Commission shall mail to the producer or operator, within 10 days of receipt of the certificate required in subsection (A), written notice of administrative completeness or a detailed list of deficiencies. Within 10 days of receipt of an administratively complete certificate, the Commission shall approve the certificate or provide a written explanation in compliance with A.R.S. § 41-1076 to the producer or operator if the certificate is not approved. The overall time-frame is 20 days.
2. For the purpose of this subsection, intermediate Saturdays, Sundays, and legal holidays are not included in the time-frame computation.

Historical Note

Former Rule 801; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1). Amended effective June 6, 1997 (Supp. 97-2).

R12-7-184. Recovered Load Oil

Recovered load oil may be run from a lease on which it is recovered only upon approval by the Commission of a certificate for load oil credit and permit to transport recovered load oil showing the source and amount of the load oil. Upon approval, the Commission shall forward one copy to the designated transporter as authority to transport the oil. This rule applies only to oil obtained from a source other than the lease on which it is used.

Historical Note
Former Rule 802; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-185. Transporter's and Storer's Monthly Report

A. Each transporter of oil and condensate shall furnish for each calendar month a report containing information and data respecting stocks of oil and condensate on hand and all movements within the state of oil and condensate by pipeline, trucks, or other conveyances except railroad, from leases to storers or refiners; movements between transporters within the state; movements between storers within the state; movements between refiners within the state; and movements between storers and refiners within the state.

B. Each storer of oil and condensate shall furnish for each calendar month a report containing information and data respecting the storage of oil and condensate within the state.

C. Each storer of natural gas, liquified petroleum gas, or other hydrocarbon or nonhydrocarbon gases in storage wells shall furnish for each calendar month a report containing information and data respecting the storage, including receipts and deliveries, of such products within the state.

D. Transporters and storers shall file reports required in this Section with the Commission on or before the 25th day of the next succeeding month.

Historical Note
Former Rule 803; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-186. Gas or Geothermal Purchaser's Monthly Report

A. Each purchaser or taker of gas in gaseous form or geothermal resources from any well, lease, pool or proration unit shall file for each calendar month a report detailing acquisition and disposition of all gas in gaseous form or geothermal resources purchased or taken during that month.

B. Purchasers and takers shall file reports required in this Section with the Commission on or before the 25th day of the next succeeding month.

Historical Note
Former Rule 804; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-187. Injection Project Report

A. Each operator of an injection project shall furnish for each injection well for each calendar month a report of injection project containing information and data including the lease and well number, the well's state permit number, average injection pressure during the month, amount of fluid in barrels injected during the month, the total amount of fluid injected to date, the source of the injected fluid, and the number of days the injection well was operated during the month.

B. Operators of injection projects shall file reports required in this Section with the Commission on or before the 25th day of the next succeeding month.

Historical Note
Adopted effective February 23, 1993 (Supp. 93-1).

R12-7-188. Refinery Reports

A. Each refiner of oil or condensate shall furnish for each calendar month a refinery monthly report containing information and data respecting oil, condensate and products involved in the refiner's operations during each month.

B. Refiners shall file reports required in this Section with the Commission on or before the 25th day of the next succeeding month.

Historical Note
Former Rule 901; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-189. Repealed

Historical Note
Former Rule 902; Amended effective September 29, 1982 (Supp. 82-5). Repealed effective February 23, 1993 (Supp. 93-1).

R12-7-190. Gasoline Plant Reports

A. Each operator of a gasoline plant, cycling plant, or any other plant at which gasoline, butane, propane, condensate, kerosene, oil or other liquid products are extracted from gas shall furnish for each calendar month a gasoline plant or pressure maintenance plant monthly report containing information and data respecting gas and products involved in the operation of each plant during each month.

B. Operators shall file reports required by this Section with the Commission on or before the 25th day of the next succeeding month.

Historical Note
Former Rule 903; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-191. Reserved

R12-7-192. Books and Records to Substantiate Reports

A. Each operator, producer, transporter, storer, refiner, processor, gasoline or extraction or geothermal generating plant operator, and initial purchaser of oil, gas, or geothermal resources shall make and keep books and records covering operations in Arizona, from which are made and which will substantiate all reports required by the Commission.

B. Books and records required in this Section shall be available for inspection by the Commission for at least a six-year period.

Historical Note
Former Rule 1001; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-193. Repealed

Historical Note
Former Rule 1002. Amended effective February 23, 1993 (Supp. 93-1). Repealed effective September 22, 1993 (Supp. 93-3).

R12-7-194. Organization Reports

A. Before any person shall engage in any activity covered by this Chapter, that person shall file with the Commission an organization report that includes a statement under oath giving the following information:
1. The name under which the business is being operated or conducted;
2. The name and post office address of the person and the business or businesses engaged in;
3. The plan or organization, and, if a reorganization, the name and address of the previous organization;
4. The state where incorporated, if a foreign corporation, and the name and post office address of the Arizona

agent, together with the date of permit to do business in Arizona; and

5. The names and addresses of the principal officers or partners and the names and addresses of the directors.

B. When a change occurs, as to facts stated in the report filed, a new organization report shall be filed with the Commission within ten days of the change.

Historical Note

Former Rule 1003. Amended effective February 23, 1993 (Supp. 93-1).

R12-7-195. Repealed

Historical Note

Former Rule 1004; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1). Repealed effective September 22, 1993 (Supp. 93-3).

Appendix 1. Repealed

Historical Note

(For the convenience of the operator, the forms and reports in common use by the United States Geological Survey, and for the purpose for which each form was designed, may be submitted in lieu of similar Commission forms. Commission forms No. 1, 2, 3, 4, and 27 must be used for their designated purpose and no substitutes will be acceptable.) Repealed effective January 2, 1996 (Supp. 96-1).

ARTICLE 2. REPEALED

R12-7-201. Repealed

Historical Note

Former A. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-202. Repealed

Historical Note

Former B. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-203. Repealed

Historical Note

Former Rule G-101. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-204. Repealed

Historical Note

Former Rule G-102. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-205. Repealed

Historical Note

Former Rule G-103. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-206. Repealed

Historical Note

Former Rule G-104. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-207. Repealed

Historical Note

Former Rule G-105. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-208. Repealed

Historical Note

Former Rule G-106. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-209. Repealed

Historical Note

Former Rule G-107. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-210. Repealed

Historical Note

Former Rule G-108. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-211. Repealed

Historical Note

Former Rule G-109. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-212. Repealed

Historical Note

Former Rule G-110. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-213. Repealed

Historical Note

Former Rule G-111. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-214. Repealed

Historical Note

Former Rule G-112. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-215. Repealed

Historical Note

Former Rule G-113. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-216. Repealed

Historical Note

Former Rule G-114. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-217. Repealed

Historical Note

Former Rule G-115. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-218. Repealed

Historical Note

Former Rule G-116. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-219. Repealed

Historical Note

Former Rule G-117. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-220. Repealed

Historical Note

Former Rule G-118. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-221. Repealed

Historical Note
Former Rule G-119. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-222. Reserved

R12-7-223. Reserved

R12-7-224. Reserved

R12-7-225. Reserved

R12-7-226. Reserved

R12-7-227. Reserved

R12-7-228. Reserved

R12-7-229. Reserved

R12-7-230. Reserved

R12-7-231. Repealed

Historical Note
Former Rule G-201. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-232. Repealed

Historical Note
Former Rule G-202. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-233. Repealed

Historical Note
Former Rule G-203. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-234. Repealed

Historical Note
Former Rule G-204. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-235. Reserved

R12-7-236. Reserved

R12-7-237. Reserved

R12-7-238. Reserved

R12-7-239. Reserved

R12-7-240. Reserved

R12-7-241. Repealed

Historical Note
Former Rule G-301. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-242. Repealed

Historical Note
Former Rule G-302. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-243. Repealed

Historical Note
Former Rule G-303. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-244. Repealed

Historical Note
Former Rule G-304. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-245. Repealed

Historical Note
Former Rule G-305. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-246. Repealed

Historical Note
Former Rule G-306. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-247. Reserved

R12-7-248. Reserved

R12-7-249. Reserved

R12-7-250. Reserved

R12-7-251. Repealed

Historical Note
Former Rule G-401. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-252. Repealed

Historical Note
Former Rule G-402. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-253. Reserved

R12-7-254. Reserved

R12-7-255. Reserved

R12-7-256. Reserved

R12-7-257. Reserved

R12-7-258. Reserved

R12-7-259. Reserved

R12-7-260. Reserved

R12-7-261. Repealed

Historical Note
Former Rule G-501. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-262. Repealed

Historical Note
Former Rule G-502. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-263. Repealed

Historical Note
Former Rule G-503. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-264. Repealed

Historical Note
Former Rule G-504. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-265. Reserved

R12-7-266. Reserved

R12-7-267. Reserved

R12-7-268. Reserved

R12-7-269. Reserved

R12-7-270. Reserved

R12-7-271. Repealed

Historical Note
Former Rule G-601. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-272. Repealed

Historical Note
Former Rule G-602. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-273. Reserved

R12-7-274. Reserved

R12-7-275. Reserved

R12-7-276. Reserved

R12-7-277. Reserved

R12-7-278. Reserved

R12-7-279. Reserved

R12-7-280. Reserved

R12-7-281. Repealed

Historical Note
Former Rule G-701. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-282. Reserved

R12-7-283. Reserved

R12-7-284. Reserved

R12-7-285. Reserved

R12-7-286. Reserved

R12-7-287. Reserved

R12-7-288. Reserved

R12-7-289. Reserved

R12-7-290. Reserved

R12-7-291. Repealed

Historical Note
Former Rule G-801. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-292. Repealed

Historical Note
Former Rule G-802. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-293. Repealed

Historical Note
Former Rule G-803. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-294. Repealed

Historical Note
Former Rule G-804. Repealed effective January 2, 1996 (Supp. 96-1).

Appendix 1. Repealed

Historical Note
Repealed effective January 2, 1996 (Supp. 96-1).

Appendix B – Colorado Regulatory Summary (General)

RULES AND REGULATIONS

DEFINITIONS
(100 Series)

ACT shall mean the Oil and Gas Conservation Act of the State of Colorado.

APPLICANT shall mean the person who institutes a proceeding before the Commission, which it has standing to institute under these rules.

AQUIFER shall mean a geologic formation, group of formations or part of a formation that can both store and transmit ground water. It includes both the saturated and unsaturated zone but does not include the confining layer, which separates two (2) adjacent aquifers.

ASSEMBLY BUILDING shall mean any building or portion of building or structure used for the regular gathering of fifty (50) or more persons for such purposes as deliberation, education, instruction, worship, entertainment, amusement, drinking or dining, or awaiting transport.

AUTHORIZED DEPUTY shall mean a representative of the Director as authorized by the Commission.

BATTERY shall mean the point of collection (tanks) and disbursement (tank, meter, lease automated custody transfer [LACT] unit) of oil or gas from producing well(s).

BARREL shall mean forty-two (42) gallons (U.S.) at sixty degrees fahrenheit (60^{o} F) at atmospheric pressure.

BRADENHEAD TEST AREA shall mean any area designated as a bradenhead test area by the Commission under Rule 207.b.

BUILDING UNIT shall mean a building or structure intended for human occupancy. A dwelling unit is equal to one (1) building unit, every guest room in a hotel/motel is equal to one (1) building unit, and every five thousand (5,000) square feet of building floor area in commercial facilities, and every fifteen thousand (15,000) square feet of building floor area in warehouses, or other similar storage facilities, is equal to one (1) building unit.

CEASE AND DESIST ORDER shall mean an order issued by the Commission pursuant to §34-60-121(5), C.R.S.

CENTRALIZED E&P WASTE MANAGEMENT FACILITY shall mean a facility, other than a commercial disposal facility exclusively regulated by the Colorado Department of Public Health and Environment, that is: (1) used exclusively by one owner or operator; or (2) used by more than one operator under an operating agreement and which receives for collection, treatment, temporary storage, and/or disposal of produced water, drilling fluids, drill cuttings, completion fluids, and any other exempt E&P wastes that are generated from two or more production units or areas or from a set of commonly owned or operated leases. This definition includes the surface storage and disposal facilities that are present at Class II disposal well sites. This definition also includes oil-field naturally occurring radioactive materials (NORM) related storage, decontamination, treatment, or disposal.

COMMERCIAL DISPOSAL WELL FACILITY shall mean a facility whose primary objective is disposal of Class II waste from a third party for financial profit.

COMMISSION shall mean the Oil and Gas Conservation Commission of the State of Colorado.

COMPLETION. An **oil well** shall be considered completed when the first new oil is produced through wellhead equipment into lease tanks from the ultimate producing interval after the production string has been run. A **gas well** shall be considered completed when the well is capable of producing gas through wellhead equipment from the ultimate producing zone after the production string has been run. A **dry hole** shall be considered completed when all provisions of plugging are complied with as set out in these rules. Any well not previously defined as an oil or gas well, shall be considered completed ninety (90) days after reaching total depth. If approved by the Director, a well that requires extensive testing shall be considered completed when the drilling rig is released or six (6) months after reaching total depth, whichever is later.

CORNERING AND CONTIGUOUS UNITS when used in reference to an exception location shall mean those lands which make up the unit(s) immediately adjacent to and toward which a well is encroaching upon established setbacks.

CROP LAND shall mean lands which are cultivated, mechanically or manually harvested, or irrigated for vegetative agricultural production.

CUBIC FOOT of gas shall mean the volume of gas contained in one (1) cubic foot of space at a standard pressure base and a standard temperature base. The standard pressure base shall be fourteen point seventy three (14.73) psia, and the standard temperature base shall be sixty degrees fahrenheit (60°F).

D-J BASIN FOX HILLS PROTECTION AREA shall mean that area of the state consisting of Townships 5 South through Townships 5 North, Ranges 58 West through 70 West, and Township 6 South, Ranges 65 West through 70 West.

DAY shall mean a period of twenty-four (24) consecutive hours.

DEDICATED INJECTION WELL shall mean any well as defined under 40 C.F.R. §144.5 B, 1992 Edition, (adopted by the U.S. Environmental Protection Agency) used for the exclusive purpose of injecting fluids or gas from the surface. The definition of a dedicated injection well does not include gas storage wells.

DESIGNATED AGENT when used herein shall mean the designated representative of any producer, operator, transporter, refiner, gasoline or other extraction plant operator, or initial purchaser.

DESIGNATED OUTSIDE ACTIVITY AREAS shall mean a well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by twenty (20) or more persons on at least forty (40) days in any twelve (12) month period or by at least five hundred (500) or more people on at least three (3) days in any twelve (12) month period.

DIRECTOR shall mean the Director of the Oil and Gas Conservation Commission of the State of Colorado or any member of the Director's staff authorized to represent the Director.

DOMESTIC GAS WELL shall mean a gas well that produces solely for the use of the surface owner. The gas produced cannot be sold, traded or bartered.

DRILLING PITS shall mean those pits used during drilling operations and initial completion of a well, and include:

ANCILLARY PITS used to contain fluids during drilling operations and initial completion procedures, such as circulation pits and water storage pits.

COMPLETION PITS used to contain fluid during initial completion procedures, and not originally constructed for use in drilling operations.

RESERVE PITS used to store drilling fluids for use in drilling operations or to contain E&P waste generated during drilling operations and initial completion procedures.

EDUCATIONAL FACILITY shall mean any building used for legally allowed educational purposes for more than twelve (12) hours per week for more than six (6) persons. This includes any building or portion of building used for licensed day-care purposes for more than six (6) persons.

EMERGENCY ORDER shall mean an order issued by the Commission pursuant to §34-60-108(3), C.R.S.

EMERGENCY SITUATION for purposes of §34-60-121(5), C.R.S., and the rules promulgated thereunder shall mean a fact situation which presents an immediate danger to public health, safety or welfare.

EXPLORATION AND PRODUCTION WASTE (E&P WASTE) shall mean those wastes associated with operations to locate or remove oil or gas from the ground or to remove impurities from such substances, and which are uniquely associated with and intrinsic to oil and gas exploration, development or production operations of which are exempt from regulation under Subtitle C of the Resource Conservation and Recovery Act (RCRA), 42 USC Sections 6921, et. seq. For a waste to be considered an E&P waste, it shall be associated with operations to locate or remove oil or gas from the ground or to remove impurities from such substances and it shall be intrinsic to and uniquely associated with oil and gas exploration, development or production. For natural gas, primary field operations include those production-related activities at or near the wellhead and at the gas plant (regardless of whether or not the gas plant is at or near the wellhead), but prior to transport of the natural gas from the gas plant to market. In addition, uniquely associated wastes derived from the production stream along the gas plant feeder pipelines are considered E&P wastes, even if a change of custody in the natural gas has occurred between the wellhead and the gas plant. In addition, wastes uniquely associated with the operations to recover natural gas from underground storage fields are considered to be E&P waste.

FIELD shall mean the general area which is underlaid or appears to be underlaid by at least one (1) pool; and "field" shall include the underground reservoir or reservoirs containing oil or gas or both. The words "field" and "pool" mean the same thing when only one (1) underground reservoir is involved; however, "field", unlike "pool", may relate to two (2) or more pools.

FINANCIAL ASSURANCE shall mean a surety bond, cash collateral, certificate of deposit, letter of credit, sinking fund, escrow account, lien on property, security interest, guarantee, or other instrument or method in favor of and acceptable to the Commission. With regard to third party liability concerns related to public health, safety and welfare, the term encompasses general liability insurance.

FLOWLINES shall mean those segments of pipe from the wellhead downstream through the production facilities ending at:

In the case of gas lines, the gas metering equipment; or
In the case of oil lines, the oil loading point or LACT unit; or

GAS FACILITY shall mean those facilities that process or compress natural gas after production-related activities which are conducted at or near the wellhead and prior to a point where the gas is transferred to a carrier for transport.

GAS STORAGE WELL means any well drilled for the injection, withdrawal, production, observation, and/or monitoring of natural gas stored in underground formations. The fact that any such well is used incidentally for the production of native gas or the enhanced recovery of native hydrocarbons shall not affect its status as a gas storage well.

GAS WELL shall mean a well, the principal production of which at the mouth of the well is gas, as defined by the Act.

GROUND WATER means subsurface waters in a zone of saturation.

HIGH DENSITY AREA shall mean any tract of land determined to be a high density area in accordance with Rule 603.b.

HOSPITAL, NURSING HOME, BOARD AND CARE FACILITIES shall mean buildings used for the licensed care of more than five (5) in-patients or residents.

INACTIVE WELL shall mean any shut-in well from which no production has been sold for a period of twelve (12) consecutive months; any well which has been temporarily abandoned for a period of six (6) consecutive months; or, any injection well which has not been utilized for a period of twelve (12) consecutive months.

INDIAN LANDS shall mean those lands located within the exterior boundaries of a defined Indian reservation, including allotted Indian lands, in which the legal, beneficial, or restricted ownership of the underlying oil, gas, or coal bed methane or of the right to explore for and develop the oil, gas, or coal bed methane belongs to or is leased from an Indian tribe.

INTERVENOR shall mean a local government intervening solely to raise environmental or public health, safety and welfare concerns in which case the intervention shall be granted of right, or a person who has timely filed an intervention in a relevant proceeding and has demonstrated to the satisfaction of the commission that the intervention will serve the public interest, in which case the person may be recognized as a permissive intervenor at the Commission’s discretion.

JAIL shall mean those structures where the personal liberties of occupants are restrained, including but not limited to, mental hospitals, mental sanitariums, prisons, reformatories.

LAND APPLICATION shall mean the disposal method by which E&P waste is spread upon or sometimes mixed into soils.

LAND TREATMENT shall mean the treatment method by which E&P waste is applied to soils and treated to result in a reduction of hydrocarbon concentration by biodegradation and other natural attenuation processes. Land treatment may be enhanced by tilling, disking, aerating, composting and the addition of nutrients or microbes.

LOCAL GOVERNMENT means a county, home rule or statutory city, town, territorial charter city or city and county, or any special district established pursuant to the Special District Act, §32-1-101, C.R.S. to §32-1-1505, C.R.S.

LOCAL GOVERNMENTAL DESIGNEE means the office designated to receive, on behalf of the local government, copies of all documents required to be filed with the local governmental designee pursuant to these rules.

LOG or WELL LOG shall mean a systematic detailed record of formations encountered in the drilling of a well.

MULTI-WELL PITS shall mean pits used for treatment or disposal of E&P wastes generated from more than one (1) well.

MULTI-WELL SITE shall mean a common well pad from which multiple wells may be drilled to various bottomhole locations.

NON-CROP LAND shall mean all lands which are not defined as crop land, including range land.

OIL AND GAS OPERATIONS means exploration for oil and gas, including the conduct of seismic operations and the drilling of test bores; the siting, drilling, deepening, recompletion, reworking, or abandonment of an oil and gas well, underground injection well, or gas storage well; production operations related to any such well including the installation of flowlines and gathering systems; the generation, transportation, storage, treatment, or disposal of exploration and production wastes; and any construction, site preparation, or reclamation activities associated with such operations.

OIL WELL shall mean a well, the principal production of which at the mouth of the well is oil, as defined by the Act.

ORPHANED SITE shall mean a site, where a significant adverse environmental impact may be or has been caused by oil and gas operations for which no responsible party can be found, or where such responsible party is unwilling or unable to mitigate such impact.

ORPHAN WELL shall mean a well for which no owner or operator can be found, or where such owner or operator is unwilling or unable to plug and abandon such well.

OWNER shall mean the person who has the right to drill into and produce from a pool and to appropriate the oil or gas produced therefrom either for such owner or others or for such owner and others, including owners of a well capable of producing oil or gas, or both.

PIT shall mean any natural or man-made depression in the ground used for oil or gas exploration or production purposes. Pit does not include steel, fiberglass, concrete or other similar vessels which do not release their contents to surrounding soils.

PLUGGING AND ABANDONMENT shall mean the cementing of a well, the removal of its associated production facilities, the removal or abandonment in-place of its flowline, and the remediation and reclamation of the wellsite.

POINT OF COMPLIANCE means one (1) or more points or locations at which compliance with applicable ground water standards established under Water Quality Control Commission Basic Standards for Ground Water, §3.11.4, must be achieved.

POLLUTION means man-made or man-induced contamination or other degradation of the physical, chemical, biological, or radiological integrity of air, water, soil, or biological resource.

The words **POOL, PERSON, OWNER, PRODUCER, OIL, GAS, WASTE, CORRELATIVE RIGHTS and COMMON SOURCE OF SUPPLY** are defined by the Act, and said definitions are hereby adopted in these rules and Regulations. The word "operator" is used in these rules and regulations and accompanying forms interchangeably with the same meaning as the term "owner" except in Rules 301., 325., and 401. where the word "operator" is used to identify the persons designated by the owner or owners to perform the functions covered by those rules.

PRODUCED AND MARKETED as used in the Act, shall mean, when oil shall have left the lease tank battery or when natural gas shall have passed the metering point and entered into the stream of commerce as its first step toward the ultimate consumer.

PRODUCTION FACILITIES shall mean all storage, separation, treating, dehydration, artificial lift, power supply, compression, pumping, metering, monitoring, flowline, and other equipment directly associated with oil wells, gas wells, or injection wells.

PRODUCTION PITS shall mean those pits used after drilling operations and initial completion of a well, including natural gas gathering, processing and storage facility pits, multi-well pits and:

SKIMMING/SETTLING PITS used to provide retention time for settling of solids and separation of residual oil.

PRODUCED WATER PITS used to temporarily store produced water prior to injection for enhanced recovery or disposal, off-site transport, or surface-water discharge.

PERCOLATION PITS used to dispose of produced water by percolation and evaporation through the bottom and/or sides of the pits into surrounding soils.

EVAPORATION PITS used to contain produced waters which evaporate into the atmosphere by natural thermal forces.

PROTESTANT shall mean a person who has timely filed a protest in a relevant proceeding and has demonstrated to the Commission's satisfaction that the person filing the protest would be directly and adversely affected or aggrieved by the Commission's ruling in the proceeding, and that any injury or threat of injury sustained would be entitled to legal protection under the Act.

RELEASE shall mean any unauthorized discharge of E&P waste to the environment over time.

REMEDIATION shall mean the process of reducing the concentration of a contaminant or contaminants in water or soil to the extent necessary to ensure compliance with the allowable concentrations and levels in Table 910-1 and other applicable ground water standards and classifications.

RESERVE PITS shall mean those pits used to store drilling fluids for use in drilling operations or to contain E&P waste generated during drilling operations.

RESPONDENT shall mean a party against whom a proceeding is instituted, or a **PROTESTANT** who protests the granting of the relief sought in the application as provided in Rule 509.

RESPONSIBLE PARTY shall mean a person who conducts an oil and gas operation in a manner which is in contravention of any then-applicable provision of the Act, or of any rule, regulation, or order of the Commission, or of any permit, that threatens to cause, or actually causes, a significant adverse environmental impact to any air, water, soil, or biological resource. **RESPONSIBLE PARTY** includes any person who disposes of any other waste by mixing it with exploration and production waste so as to threaten to cause, or actually cause, a significant adverse environmental impact to any air, water, soil, or biological resource.

SEISMIC OPERATIONS shall mean all activities associated with acquisition of seismic data including but not limited to surveying, shothole drilling, recording, shothole plugging and reclamation.

SENSITIVE AREA is an area vulnerable to potential significant adverse ground water impacts, due to factors such as the presence of shallow economically usable ground water or pathways for communication with deeper economically usable ground water; proximity to surface water, including lakes, rivers, perennial or intermittent streams, creeks, irrigation canals, and wetlands. The procedure for identifying Sensitive Areas is set forth in the Sensitive Area Identification Decision Tree and Guidance Document.

SHUT-IN WELL shall mean a well which is capable of production or injection by opening valves, activating existing equipment or supplying a power source.

SIMULTANEOUS INJECTION WELL shall mean any well in which water produced from oil and gas producing zones is injected into a lower injection zone and such water production is not brought to the surface.

SPECIAL FIELD RULES shall mean those rules promulgated for and which are limited in their application to individual pools or fields within the State of Colorado.

SPECIAL PURPOSE PITS shall mean those pits used in oil and gas operations, including natural gas gathering, processing and storage facility pits, multi-well pits, and:

BLOWDOWN PITS used to collect material resulting from, including but not limited to, the emptying or depressurizating of wells, vessels, or gas gathering systems.

FLARE PITS used exclusively for flaring gas.

EMERGENCY PITS used to contain liquids on a temporary basis due to process upset conditions.

BASIC SEDIMENT/TANK BOTTOM PITS used to temporarily store or treat the extraneous materials in crude oil which may settle to the bottoms of tanks or production vessels and which may contain residual oil.

WORKOVER PITS used to contain liquids during the performance of remedial operations on a producing well in an effort to increase production.

PLUGGING PITS used for containment of fluids encountered during the plugging process.

SPILL shall mean any unauthorized sudden discharge of E&P waste to the environment.

STRATIGRAPHIC WELL means a well drilled for stratigraphic information only. Wells drilled in a delineated field to known productive horizons shall not be classified as "stratigraphic". Neither the term "well" nor "stratigraphic well" shall include seismic holes drilled for the purpose of obtaining geophysical information only.

SUBSURFACE DISPOSAL FACILITY means a facility or system for disposing of water or other oil field wastes into a subsurface reservoir or reservoirs.

TEMPORARILY ABANDONED WELL shall mean a well which is incapable of production or injection without the addition of one or more pieces of wellhead or other equipment, including valves, tubing, rods, pumps, heater-treaters, separators, dehydrators, compressors, piping or tanks.

VOLUNTARY SELF-EVALUATION shall mean a self-initiated assessment, audit, or review, not otherwise expressly required by environmental law, that is performed by any person or entity, for itself, either by an employee or employees employed by such person or entity who are assigned the responsibility of performing such assessment, audit, or review or by a consultant engaged by such person or entity expressly and specifically for the purpose of performing such assessment, audit, or review to determine whether such person or entity is in compliance with environmental laws.

WATERS OF THE STATE mean any and all surface and subsurface waters which are contained in or flow in or through this state, but does not include waters in sewage systems, waters in treatment works of disposal systems, water in potable water distribution systems, and all water withdrawn for use until use and treatment have been completed. Waters of the state include, but are not limited to, all streams, lakes, ponds, impounding reservoirs, wetlands, watercourses, waterways, wells, springs, irrigation ditches or canals, drainage systems, and all other bodies or accumulations of water, surface and underground, natural or artificial, public or private, situated wholly or partly within or bordering upon the state.

WELL when used alone in these Rules and Regulations, shall mean an oil or gas well, a hole drilled for the purpose of producing oil or gas, a well into which fluids are injected, a stratigraphic well, a gas storage well, or a well used for the purpose of monitoring or observing a reservoir.

WELL SITE shall mean the areas which are directly disturbed during the drilling and subsequent operation of, or affected by production facilities directly associated with, any oil well, gas well, or injection well.

WILDCAT (Exploratory) WELL means any well drilled beyond the known producing limits of a pool.

ZONE OF INCORPORATION shall mean the soil layer from the soil surface to a depth of twelve (12) inches below the surface.

ALL OTHER WORDS used herein shall be given their usual customary and accepted meaning, and all words of a technical nature, or peculiar to the oil and gas industry, shall be given that meaning which is generally accepted in said oil and gas industry.

GENERAL RULES

201. EFFECTIVE SCOPE OF RULES AND REGULATIONS

All rules and regulations of a general nature herein promulgated to prevent waste and to conserve oil and gas in the State of Colorado shall be effective throughout the State of Colorado and be in force in all pools and fields except as may be amended, modified, altered or enlarged generally or in specific individual pools or fields by orders heretofore or hereafter issued by the Commission, and except where special field rules apply, in which case the special field rules shall govern to the extent of any conflict.

202. OFFICE AND DUTIES OF DIRECTOR

The office of Director of the Commission is hereby created. It shall be the duty of the Director to aid the Commission in the administration of the Act, as may be required of the Director from time to time and to act as Hearing Officer when so directed by the Commission.

203. OFFICE AND DUTIES OF SECRETARY

The office of Secretary to the Commission is hereby created. The duties of the Secretary shall be as determined from time to time by the Commission.

204. GENERAL FUNCTIONS OF DIRECTOR

The Director and the authorized deputies shall also have the right at all reasonable times to go upon and inspect any oil and/or gas properties, disposal facilities, or transporters facilities and wells for the purpose of making any investigation or tests to ascertain whether the provisions of the Act or these rules or any special field rules are being complied with, and shall report any violation thereof to the Commission.

205. ACCESS TO RECORDS

All producers, operators, transporters, refiners, gasoline or other extraction plant operators and initial purchasers of oil and gas within this state, shall make and keep appropriate books and records covering their operations in the state from which they may be able to make and substantiate the reports required by the Commission. Such books, records and copies of said reports required by the Commission shall be kept on file and available for inspection by the Commission for a period of at least five (5) years. The Director and the authorized deputies shall have access to all well records wherever located. All owners, drilling contractors, drillers, service companies, or other persons engaged in drilling or servicing wells, shall permit the Director, or authorized deputy, at the Director's or their risk, in the absence of negligence on the part of the owner, to come upon any lease, property or well operated or controlled by them, and to inspect the record and operation of such wells and to have access at all times to any and all records of wells; provided, that information so obtained shall be kept confidential and shall be reported only to the Commission or its authorized agents.

206. REPORTS

All producers, operators, transporters, refiners, gasoline and other extraction plant operators and initial purchasers of oil and gas within the state shall from time to time file accurate and complete reports containing such information and covering such periods as the Commission shall require.

207. TESTS AND SURVEYS

a. **Tests and surveys**. When deemed necessary or advisable, the Commission is authorized to require that tests or surveys be made to determine the presence of waste or occurrence of pollution. The Commission, in calling for reports under Rule 206. and tests or surveys to be made as provided in this rule, shall designate the time allowed the operator for compliance, which provisions as to time shall prevail over any other time provisions in these rules.

b. **Bradenhead monitoring**.

(1) The Director shall have authority to designate specific fields or portions of fields as bradenhead test areas within which, on any well, the bradenhead access to the annulus between the production and surface casing, as well as any intermediate casing, shall be equipped with fittings to allow safe and convenient determinations of pressure and fluid flow. Any such proposed designation shall occur by notice describing the proposed bradenhead test area. Such notice shall be given to all operators of record within such area and by publication. The proposed designation, if no protests are timely filed, shall be placed upon the Commission consent agenda for the regular monthly meeting of the Commission following the month in which such notice is given, and shall be approved or heard by the Commission in accordance with Rule 520. Such designation shall be effective immediately, upon approval by the Commission.

(2) All operators within any bradenhead test area shall have thirty (30) days after the effective date of the designation to commence the taking of bradenhead pressure readings in all wells located therein which are equipped for such readings. The operator shall equip any well which is not so equipped within ninety (90) days of the effective date, and within thirty (30) days thereafter the operator shall take the required reading. Such readings shall include the date, time and pressure of each reading, and the type of fluid reported. Such readings shall be taken in bradenhead test areas annually, maintained at the operator's office for a period of five (5) years, and shall be reported to the Director upon written request.

208. CORRECTIVE ACTION

The Commission shall require correction, in a manner to be prescribed or approved by it, of any condition which is causing or is likely to cause waste or pollution; and require the proper plugging and abandonment of any well or wells no longer used or useful in accordance with such reasonable plan as may be prescribed by it.

209. PROTECTION OF COAL SEAMS AND WATER-BEARING FORMATIONS

In the conduct of oil and gas operations each owner shall exercise due care in the protection of coal seams and water-bearing formations as required by the applicable statutes of the State of Colorado.

Special precautions shall be taken in drilling and abandoning wells to guard against any loss of artesian water from the stratum in which it occurs and the contamination of fresh water by objectionable water, oil, or gas. Before any oil or gas well is completed as a producer, all oil, gas and water strata above and below the producing horizon shall be sealed or separated in order to prevent the intermingling of their contents.

210. SIGNS AND MARKERS

The operator shall mark each and every well in a conspicuous place, from the time of initial drilling until final abandonment, as follows:

a. **Drilling and Recompletion Operations**. Directional signs, no less than three (3) and no more than six (6) square feet in size, shall be provided during any drilling or recompletion operation, by the operator or drilling contractor. Such signs shall be at locations sufficient to advise emergency crews where drilling is taking place; at a minimum, such locations shall include (i) the first point of intersection of a public road and the rig access road and (ii) thereafter at each intersection of the rig access route, except where the route to the rig is clearly obvious to uninformed third parties. Signs not necessary to meet other obligations under these rules shall be removed as soon as practicable after the operation is complete.

b. **Permanent Designations**.

(1) **Wells**. Within sixty (60) days after the completion of a well, a permanent sign shall be located at the wellhead, which shall identify the well and provide its legal location, including the quarter quarter section. When no associated battery is present, the additional information required under Rule 210.b.(2) shall be required on the sign.

(2) **Batteries**. Within sixty (60) days after the installation of a battery, a permanent sign shall be located at the battery. At the option of the operator, or at the request of local emergency response authorities, the sign may be placed at the intersection of the lease access road with a public, farm or ranch road if the referenced battery is readily apparent from such location. Such sign, which shall be no less than three (3) square feet and no more than six (6) square feet, shall provide: the name of the operator; a phone number at which the operator can be reached at all times; a phone number for local emergency services (911 where available); the lease name or well name(s) associated with the battery; the public road used to access the site; and, the legal location, including the quarter-quarter section. In lieu of providing the legal location on the permanent sign, it may be stenciled on a tank in characters visible from one hundred (100) feet.

c. **Centralized E&P Waste Management Facilities**. The main point of access to a centralized E&P waste management facility shall be marked by a sign captioned “(operator name) E&P Waste Management Facility”. Such sign, which shall be no less than three (3) square feet and no more than six (6) square feet shall provide: a phone number at which the operator can be reached at all times; a phone number for local emergency services (911 where available); the public road used to access the facility; and the legal location, including quarter quarter section, of the facility.

d. **General sign requirements**. No sign required under this Rule 210. shall be installed at a height exceeding six (6) feet. Operators shall maintain signs in a legible condition, and shall replace damaged or vandalized signs within sixty (60) days. New operators shall update signs within sixty (60) days after change of operator approval is received from the Commission.

211. NAMING OF FIELDS

All oil and gas fields discovered in the state subsequent to the adoption of these rules and regulations shall be named by the Director or at the Director's direction.

212. SAFETY

For safety regulations regarding industry personnel, contact the U.S. Department of Labor, Occupational Safety and Health Administration, Regional Administrator, Colorado Region VIII, 1999 Broadway, Suite 1690, Denver, Colorado 80202, telephone (303) 391-5858. For State Safety regulations regarding public safety see Rules 601-607.

213. FORMS UPON REQUEST

Forms required by the Commission will be furnished upon request. (Please see Procedures and Forms Guidelines)

214. LOCAL GOVERNMENTAL DESIGNEE

Each local government which designates an office for the purposes set forth in the 100 Series shall provide the Commission written notice of such designation, including the name, address and telephone number, facsimile number, electronic mail address, local emergency dispatch and other emergency numbers of the local governmental designee. It shall be the responsibility of such local governmental designee to ensure that all documents provided to the local governmental designee by oil and gas operators and the Commission or the Director are distributed to the appropriate persons and offices.

DRILLING, DEVELOPMENT, PRODUCING AND ABANDONMENT

301. RECORDS, REPORTS, NOTICES-GENERAL

Any written notice of intention to do work or to change plans previously approved must be filed with the Director, and must reach the Director and receive approval before the work is begun, or such approval may be given orally and, if so given, shall thereafter be confirmed to the Director in writing.

In case of emergency, or any situation where operations might be unduly delayed, any notice or information required by these rules and regulations to be given to the Director may be given orally or by wire, and if approval is obtained the transaction shall be promptly confirmed in writing to the Director, as a matter of record.

Immediate notice shall be given to the Director when public health or safety is in jeopardy. Notice shall also be given to the Director of any other significant downhole problem or mechanical failure in any well within ten (10) days.

The owner shall keep on the leased premises, or at the owner's headquarters in the field, or otherwise conveniently available to the Director, accurate and complete records of the drilling, redrilling, deepening, repairing, plugging or abandoning of all wells, and of all other well operations, and of all alterations to casing. These records shall show all the formations penetrated, the content and quality of oil, gas or water in each formation tested, and the grade, weight and size, and landed depth of casing used in drilling each well on the leased premises, and any other information obtained in the course of well operation. Such records on each well shall be maintained by any subsequent owner.

Whenever a person has been designated as an operator by an owner or owners of the lease or well, such an operator may submit the reports as herein required by the Commission.

302. COGCC Form 1. REGISTRATION FOR OIL AND GAS OPERATIONS

a. Prior to the commencement of its operations, all producers, operators, transporters, refiners, gasoline or other extraction plant operators, and initial purchasers who are conducting operations subject to this Act in the State of Colorado, shall, for purposes of the Act, file a Registration For Oil and Gas Operations, Form 1, with the Director in the manner and form approved by the Commission. Any producer, operator, transporter, refiner, gasoline or other extraction plant operator, and initial purchaser conducting operations subject to the Act who has not previously filed a Registration For Oil and Gas Operations, Form 1 shall do so. Any person providing financial assurance for oil and gas operators in Colorado shall file a Form 1 with the Director. All changes of address of the parties required to file a Form 1 shall be immediately reported by submitting a new Form 1.

b. Any party may act on or for the behalf of the owner/operator provided the owner/operator has filed a Designation of Agent, Form 1A. This agent shall remain in effect until it is terminated in writing by the owner/operator. All changes of address of the agent shall be immediately reported by submitting a new Form 1A.

303. COGCC Form 2. APPLICATION FOR PERMIT-TO-DRILL, DEEPEN, RE-ENTER, OR RECOMPLETE, AND OPERATE

a. Before any person shall commence operations for the drilling or re-entry of any well, such person shall file with the Director an application on Form 2 for a permit-to-drill, along with a filing and service fee established by the Commission (see Appendix III), and shall secure the Director's approval before commencement of operations with heavy equipment. The permit-to-drill shall be binding with respect to any conflicting local governmental permit or land use approval process. Wells drilled for stratigraphic information only shall be exempt from paying the filing and service fee. The re-entry of a well in a unitized, storage, or secondary recovery operation is exempt from the provisions of this rule and notice of intent to re-enter a well shall be filed on a Sundry Notice, Form 4.

b. A request to recomplete or deepen a well to a different reservoir shall be filed on an Application for Permit-to-Drill, Form 2, with a filing and service fee established by the Commission (see Appendix III), along with a Sundry Notice, Form 4, detailing the work, and a wellbore diagram.

c. Attached to and part of the Permit-to-Drill, Form 2, as filed shall be a current 8 1/2" by 11" scaled drawing of the entire section(s) containing the proposed well location with the following minimum information:

(1) Dimensions on adjacent exterior section lines sufficient to completely describe the quarter section containing the proposed well shall be indicated. If dimensions are not field measured, state how the dimensions were determined.

(2) For directional drilling into an adjacent section, that section shall also be shown on the location plat and dimensions on exterior section lines sufficient to completely describe the quarter section containing the proposed productive interval and bottom hole location shall be indicated. (Additional requirements related to directional drilling are found in Rule 321.)

(3) For irregular, partial or truncated sections, dimensions will be furnished to completely describe the entire section containing the proposed well.

(4) The field-measured distances from the nearer north/south and nearer east/west section lines shall be measured at ninety (90) degrees from said section lines to the well location and referenced on the plat. For unsurveyed land grants and other areas where an official public land survey system does not exist, the well locations shall be spotted as footages on a protracted section plat using Global Positioning System (GPS) technology and also reported as latitude and longitude in accordance with the requirements set forth below:

A. All GPS data reported to the Commission shall be differentially corrected using base station data or other correction sources. The base station or other correction source shall be identified and reported with the coordinate values.

B. Coordinates shall be reported as latitude and longitude in decimal degrees to an accuracy of at least five (5) decimal places (e.g.; latitude 37.12345 N, longitude 104.45632 W).

C. All data shall be referenced to the North American Datum (NAD) of 1927.

D. The date of the survey shall be reported.

(5) A map legend.

(6) A north arrow.

(7) A scale expressed as an equivalent (e.g. - 1" = 1000').

(8) A bar scale.

(9) The ground elevation.

(10) The basis of the elevation (how it was calculated or its source).

(11) The basis of bearing or interior angles used.

(12) Complete description of monuments and/or collateral evidence found; all aliquot corners used shall be described.

(13) The legal land description by section, township, range, principal meridian, baseline and county.

(14) Operator name.

(15) Well name and well number.

(16) Date of completion of scaled drawing.

(17) All visible improvements within two hundred (200) feet of a wellhead (or, in a high density area within four hundred (400) feet of a wellhead) shall be physically tied in and plotted on the well location plat or on an addendum, with a horizontal distance and approximate bearing from the well location. Visible improvements shall include, but not be limited to, all buildings, publicly maintained roads and trails, major above-ground utility lines, railroads, pipelines, mines, oil wells, gas wells, injection wells, water wells, visible plugged wells, sewers with manholes, standing bodies of water, and natural channels including permanent canals and ditches through which water flows. If there are no visible improvements within two hundred (200) feet of a wellhead (or in a high density area within four hundred (400) feet of a wellhead), it shall be so noted on the Permit-to-Drill, Form 2.

(18) Surface use shall be described within the two hundred (200) foot radius of a wellhead (or in a high density area within the four hundred (400) foot radius of a wellhead).

(19) In addition to the scaled drawing, the applicant shall attach to the Permit-to-Drill, Form 2, an 8½" by 11" vicinity or U.S.G.S. topographic map of at least a three (3) mile radius around the proposed well which clearly shows access from one (1) or more public roads, a map showing surface and mineral lease ownership within two hundred (200) feet of a wellhead (or in a high density area within four hundred (400) feet of a wellhead). Where the applicant is not the lessee, mineral ownership shall be described for the entire drilling and spacing unit.

303.d. Form 2/2A application and copies to local governmental designees. In addition to the above, an applicant filing a Permit-to-Drill, Form 2, shall also attach a completed Form 2A, except that the Form 2A shall not be required on federal or Indian owned surface lands when a Federal 13 Point Surface Use Plan is included. The Form 2A requires the attachment of a minimum of two (2) color photographs; one (1) of the staked location and one (1) of the existing or proposed access road. Each photograph shall be identified by: date taken, well name, location and direction of view. Permit-to-Drill, Form 2, shall be filed with the Director in triplicate for wells on all patented, state and federal surface lands. A single, informational (not official notice) copy of the Permit-to-Drill, Form 2 and Form 2A and all attachments shall be delivered by the applicant to the local governmental designee(s) of the county or municipal corporation within whose jurisdiction the activity is occurring or is proposed to occur at or before the time of filing with the Director. It shall be the responsibility of the Director to promptly provide the local governmental designee(s) with formal notification of the filing of the Permit-to-Drill, Form 2. Such notice is to be sent by facsimile if requested, and, if not, then by first class U.S. Mail. Any comments from the local government designee concerning the Permit-to-Drill, Form 2, and Form 2A as filed shall be provided to the Director and to the applicant in writing within ten (10) days after the date on which the Permit-to-Drill, Form 2 was sent to the local government designee(s) by the Director. The Director shall take no action with respect to the Permit-to-Drill, Form 2, prior to the expiration of the ten (10) day period, except under the circumstances provided for in Rule 303.j(1) and (2), or when the Director has received notice from the local governmental designee(s) waiving the ten (10) day period. Upon written request to the Director received prior to the expiration of the ten (10) day period, the local government designee shall be granted an extension of up to twenty (20) additional days to consider the application. If, prior to the expiration of the comment period provided herein and after participation in an onsite consultation under Rule 306.a.(3), the local governmental designee files an application for hearing on the permit-to-drill, Form 2, under Rule 503.b.(6), alleging significant impacts on public health, safety and welfare, including the environment, the director shall withhold the issuance of such permit and the provisions of Rule 303.k. shall apply.

e. **Well sites and access roads in wetlands.** In the event that an operator acquires an Army Corps of Engineers permit pursuant to 33 U.S.C.A. §1342 and 1344 of the Water Pollution and Control Act (Section 404 of the federal Clean Water Act) for construction of a wellsite, access road, or production facility, the operator shall so indicate on the Form 2A.

f. **Revisions to Form 2/2A.** Prior to approval of the Form 2/2A, minor revisions or requested information may be provided by contacting the COGCC staff. After approval, any substantive changes shall be submitted for approval on a Form 2/2A. A Sundry Notice, Form 4, shall be submitted when non-substantive revisions are made after approval, and no additional fee shall be imposed.

g. **Incomplete applications.** Applications for permit-to-drill which are submitted without the necessary attachments, the proper signature or the required information shall be considered incomplete and shall not be approved. The COGCC staff shall notify the applicant in not more than thirty (30) days of permit application receipt of such inadequacies. The applicant shall then have thirty (30) days from the date which they were contacted to correct and/or provide requested information for that well, otherwise the permit application shall be considered withdrawn and the fee shall not be refunded.

h. **Permit expiration.** If operations are not commenced on the permitted well within one (1) year after date of approval, the permit shall become null and void. The Director shall not approve extensions to applications for Permit-to-Drill, Form 2.

i. **Permits in areas pending Commission hearing.** The Director may withhold the issuance of a permit and the granting of approval of any Permit-to-Drill, Form 2, for any well or proposed well that is located in an area for which an application has been filed, or which the Commission has sought, by its own motion, to establish drilling units or to designate any tract of land as a high density area, in which case the hearing thereon shall be held at the next meeting of the Commission at which time the matter can be legally heard.

j. **Special circumstances for permit issuance without notice or consultation.** The Director may issue a permit at any time in the event that an operator files a sworn statement and demonstrates therein to the Director's satisfaction that:

(1) The operator had the right or obligation under the terms of an existing contract to drill a well; and the owner or operator has a leasehold estate or a right to acquire a leasehold estate under said contract which will be terminated unless the operator is permitted to immediately commence the drilling of said well; or

(2) Due to exigent circumstances (including a recent change in geological interpretation), significant economic hardship to a drilling contractor will result or significant economic hardship to an operator in the form of drilling standby charges will result.

In the event the Director issues a permit under this rule, the operator shall not be required to meet obligations to surface owners and local governmental designees under Rules 303.d., 305.b.(1) & (3), and 306.a. The Director shall report permits granted in such manner to the Commission at regularly scheduled monthly hearings.

k. **Withholding Permit-to-Drill, Form 2, approval.** The Director may withhold the issuance of a permit and the granting of approval of any Permit-to-Drill, Form 2, for any proposed well when, based on information supplied by a surface owner or by staff analysis, and where appropriate as confirmed by an onsite inspection, the Director has reasonable cause to believe that a proposed well location raises significant concerns regarding potential significant adverse impacts to public health, safety and welfare, including the environment. If a request is made by a local governmental designee under Rules 303.d. and 503.b.(6), such application shall be granted and the director shall withhold issuance of the permit-to-drill, Form 2, unless the local government has been disqualified from making such request under Rule 501.b. Any hearing granted pursuant to this rule shall be expedited and the matter shall be heard at the next scheduled commission hearing, and all parties shall be deemed to have waived any notice requirements to the contrary. In the event such approval is not granted, when requested by the operator, the Director shall ask the Commission to issue an emergency order under Rule 502.a. suspending approval of the Permit-to-Drill for such well and setting the matter for the next hearing. The Director shall use best efforts to notify the applicant, local governmental designee, surface owner and other interested parties as applicable of such request in order that such parties may participate in the Commission's emergency consideration of the matter

l. **Reclassification of stratigraphic well.** If a test for productivity is made in a stratigraphic well, the well must be reclassified as a well drilled for oil or gas and is subject to all of the rules and regulations for a well drilled for oil or gas, including filing of reports and mechanical logs.

304. FINANCIAL ASSURANCE REQUIREMENTS

Prior to drilling or assuming the operations for a well an operator shall provide financial assurance in accordance with the 700 Series rules. When an operator's existing wells are not in compliance with the 700 Series, the Director may withhold action on an Application for Permit-to-Drill, Form 2, until such time as a hearing on the permit application is held by the Commission. Such hearing shall be held at the next regularly scheduled Commission hearing at which time the matter can be legally heard.

305. NOTICES OF OIL AND GAS OPERATIONS

a. The provisions of this Rule 305. shall not be applicable on federal or Indian owned surface lands.

b. **Notices.**

(1) **Notice of drilling.** Before an operator shall commence operations for the drilling of any well, such operator shall evidence its intention to conduct such operations by giving the surface owner and local governmental designee written notice thereof as provided in subparagraph c. below. Such notice of drilling shall be mailed or hand delivered to the surface owner not less than thirty (30) days prior to the date of estimated commencement of operations with heavy equipment as set forth in the notice and shall be mailed to the local governmental designee not less than thirty (30) days prior to the date of estimated commencement of operations with heavy equipment as set forth in the notice. Operators shall retain a record of such notice of drilling for a minimum of one (1) year. Such written notice also shall be posted on or near the proposed drillsite at least thirty (30) days prior to commencement of operations with heavy equipment. If notice for the commencement of operations is waived by the surface owner under this rule, the local governmental designee notice under this Rule 305.b. shall be received no later than the business day preceding commencement of operations with heavy equipment. The operator shall confirm that the surface owner notice requirements of this Rule 305.b. have been completed or waived before the Director approves an Application for Permit-to-Drill, Form 2.

(2) **Notice of subsequent well operations.** Before an operator shall commence subsequent well operations, such operator shall evidence its intention to conduct such operations by giving the surface owner

written notice thereof in accordance with paragraph c. below. **Subsequent well operations** shall mean those operations that will materially impact surface areas beyond the existing access road or well site for any well, including operations such as fracturing or recompletion of the well but shall not include routine service and maintenance operations including but not limited to the changing of pumps. The notice of subsequent operations shall be mailed or hand delivered not less than seven (7) days prior to the date of estimated commencement of operations with heavy equipment as set forth in the notice.

(3) **Notice during irrigation season.** If a well is to be drilled on irrigated crop lands between March 1 and October 31, the operator, in addition to meeting the consultation requirements of Rule 306., shall contact the surface owner, or at the request of the surface owner, the tenant at least fourteen (14) days prior to the commencement of surface activities by the operator and arrange to coordinate drilling operations to avoid unreasonable interference with irrigation plans and activities.

(4) **Final reclamation notice.** The following notice requirements shall apply only to final reclamation operations commenced more than thirty (30) days after the completion of a well.

A. Not less than thirty (30) days before any final reclamation operations are to take place pursuant to Rule 1004., the operator shall notify the surface owner in accordance with paragraph c. below. Final reclamation operations shall mean those reclamation operations to be undertaken when a well is to be plugged and abandoned or when production facilities are to be permanently removed.

B. Not less than seven (7) days before any final reclamation operations are to take place, the operator shall notify the Director on a Sundry Notice, Form 4.

c. **Notice requirements.** As to notices to be given pursuant to this Rule 305., included with each such notice shall be the following:

(1) The estimated date that the operations for which notice is being given are to commence.

(2) The name of the operator and the name, address and phone number of the individual representing the operator who can be contacted concerning the proposed operations.

(3) The legal description (or plat) indicating the quarter quarter section upon which the operations will be conducted.

(4) A statement that the surface owner has responsibility for notifying any affected tenant of the proposed operations.

(5) With respect to the notices of drilling, the notice mailed or hand delivered to the surface owner shall also include a return addressed, postage prepaid postcard upon which surface owners may request their preference with respect to the consultation requirement under Rule 306., including the preference to appoint a tenant for consultation. If the surface owner appoints a tenant for consultation, that person's name, address, and telephone number must be provided to the operator by the surface owner on the postcard.

(6) A copy of the Commission's informational brochure for surface owners, containing the rules pertaining to notice of oil and gas operations and opportunities for consultation thereon, as well as the rules of procedure for filing complaints and making applications for hearing. The brochure shall provide contact information for the Commission's main office, field offices and website, and shall describe the services and information available to the public, including access to a listing of local governmental designees. The brochure shall contain a prominent disclaimer advising surface owners to obtain legal advice as may be appropriate to their particular circumstances.

d. **Identifying surface owner.** In determining the identity and address of a surface owner for the purpose of giving all notices under this Rule 305., the records of the assessor for the county in which the lands are situated may be relied upon.

e. **Tenants.** With respect to notices given under this Rule 305., it shall be the responsibility of the notified surface owner to give notice of the proposed operation to the tenant farmer, lessee or other party that may own or have an interest in any crops or surface improvements that could be affected by such proposed operation.

f. **Waiver.** Any and all of the surface owner notice requirements set forth in this Rule 305. may be waived by the affected surface owner at any time. Any and all local governmental designee notice requirements set forth in this Rule 305. may be waived by the affected local governmental designee(s) at any time.

306. CONSULTATION.

In locating roads, production facilities and well sites, and in preparation for reclamation and final abandonment, the operator shall use its best efforts to consult in good faith with the affected surface owner, or the surface owner's appointed tenant as provided for in Rule 305. Consultation with local governmental designees is addressed in Rule 306.a. (3) below. The following shall apply to each such consultation:

a. **Drilling consultation.** The good faith effort to consult shall occur at a time mutually agreed to by the parties prior to the commencement of operations with heavy equipment upon the lands of the surface owner. The operator shall confirm that the surface owner consultation requirements of this Rule 306. have been completed or waived before the Director approves an Application for Permit-to-Drill, Form 2.

(1) **Information provided by operator.** When consulting with the surface owner or appointed tenant, the operator shall furnish a description or diagram of the proposed drilling location; dimensions of the well site; and, if known, the location of associated production or injection facilities, pipelines, roads and any other areas to be used for oil and gas operations (if not previously furnished to such surface owner or if different from what was previously furnished).

(2) **Good faith consultation.** Such good faith consultation shall allow the surface owner or appointed tenant the opportunity to provide comments to the operator regarding preferences for the timing of oil and gas operations and preferred locations for wells and associated facilities.

(3) **Local government consultation.** Local governments which have appointed a local governmental designee and have indicated to the Director a desire for onsite consultation shall be given an opportunity to engage in such consultation concerning the location of roads, production facilities and well sites prior to the commencing of operations with heavy equipment.

b. **Final reclamation consultation.** In preparing for final reclamation and plugging and abandonment, the operator shall use its best efforts to consult in good faith with the affected surface owner (or the tenant when the surface owner has requested that such consultation be made with the tenant). Such good faith consultation shall allow the surface owner (or appointed tenant) the opportunity to provide comments concerning preference for timing of such operations and all aspects of final reclamation.

c. **Tenants.** Operators shall have no obligation to consult with tenant farmers, lessees, or any other party ("tenant") that may own or have an interest in any crops or surface improvements that could be affected by the proposed operation unless the surface owner appoints such tenant for such purposes. Nothing shall prevent the surface owner from including the tenant during the consultation.

d. **Waiver.** The requirement to consult with the surface owner under this Rule 306. may be waived by the affected surface owner or the surface owner's appointed tenant at any time.

307. COGCC Form 4. SUNDRY NOTICES AND REPORTS ON WELLS

The Sundry Notice, Form 4, is a multipurpose form which shall be used by an operator to request approval from or provide notice to the Director as required by rule or when no other specific form exists, i.e., well name or number change. The rules requiring the use of the Sundry Notice, Form 4, are listed in Appendix I.

308A. COGCC Form 5. DRILLING COMPLETION REPORT

Within thirty (30) days of the setting of production casing, the plugging of a dry hole, the deepening or sidetracking of a well, or any time the wellbore configuration is changed, the operator shall transmit to the Director the Drilling Completion Report, Form 5, and one (1) copy of all logs run, be they mechanical, mud, or other. Additionally, if drill stem tests, core analyses, or directional surveys are run, they shall be submitted at the same time and together with this completion report. All Sections 1 - 22 (if applicable) and the attachment checklist shall be completely filled out.

Within thirty (30) days of the suspension of commenced drilling activities prior to reaching total depth, the operator shall file a Drilling Completion Report, Form 5, notifying the Director of the date of such suspension of drilling activity stating the reason for suspension and the anticipated date and method of resumption of drilling, showing the details of all work performed to date. In cases of an uncompleted well, the initial Drilling Completion Report, Form 5, shall state "preliminary" at the top of the form. A supplementary Form 5 shall be submitted within thirty (30) days of reaching total depth.

308B. COGCC Form 5A. COMPLETED INTERVAL REPORT

The Completed Interval Report, Form 5A, shall be submitted within thirty (30) days of completing a formation (successful or not), when a formation is temporarily abandoned or permanently abandoned, for a recompletion, reperforation or restimulation, or when a formation is commingled.

In order to resolve completed interval information uncertainties, the Director may require an operator to submit a Completed Interval Report, Form 5A.

308C. CONFIDENTIALITY

Upon submittal of a Sundry Notice, Form 4, request by the operator, completion reports, including Drilling Completion Reports, Form 5 and Completed Interval Reports, Form 5A, and mechanical logs of exploratory or wildcat wells shall be marked "confidential" by the Director and kept confidential for six (6) months after the date of completion, unless the operator gives written permission to release such logs at an earlier date.

309. COGCC Form 7. OPERATOR'S MONTHLY PRODUCTION REPORT

Each producer or operator of an oil or gas well shall file with the Commission, within forty-five (45) days after the month in which production occurs, a report on Operator's Monthly Production Report, Form 7, containing all information required by said form. In addition, all fluids produced during the initial testing and completion shall be reported on Operator's Monthly Production Report, Form 7 within forty-five (45) days after the month in which testing and completion occurs.

310A. COGCC Form 8. MILL LEVY

On or before March 1, June 1, September 1 and December 1 of each year, every producer or purchaser, whichever disburses funds directly to each and every person owning a working interest, a royalty interest, an overriding royalty interest, a production payment and other similar interests from the sale of oil or natural gas subject to the charge imposed by §34-60-122 (1) (a) C.R.S., 1973, as amended, shall file a return with the Director showing by operator, the volume of oil, gas or condensate produced or purchased during the preceding calendar quarter, including the total consideration due or received at the point of delivery. No filing shall be required when the charge imposed is zero mill ($0.0000) per dollar value.

The Levy shall be an amount fixed by order of the Commission. The levy amount may, from time to time, be reduced or increased to meet the expenses chargeable against the oil and gas conservation fund. The present charge imposed, as of July 1, 2002, is one and one tenth mill ($0.0011) per dollar value.

310B. COGCC Form 8A. ENVIRONMENTAL RESPONSE FUND LEVY

On or before March 1, June 1, September 1 and December 1 of each year, every producer or purchaser, whichever disburses funds directly to each and every person owning a working interest, a royalty interest, an overriding royalty interest, a production payment and other similar interests from the sale of oil or natural gas subject to the charge imposed by §34-60-122 (1) (b) C.R.S., 1973, as amended, shall file a Form 8A, Environmental Response Fund report with the Director showing the total volume of oil, gas or condensate produced or purchased during the preceding calendar quarter, including the total consideration due or received at the point of delivery from all leases listed on the corresponding mill levy, Form 8. No filing shall be required when the surcharge imposed is zero.

The Environmental Response Fund surcharge shall be an amount fixed by order of the Commission. The surcharge amount may, from time to time, be reduced or increased to meet the expenses chargeable against the oil and gas Environmental Response Fund. As of October 1, 1996, the surcharge shall be zero mill ($0.0000) on the dollar.

311. COGCC Form 6. WELL ABANDONMENT REPORT

Notice shall be given to the Director, and approval obtained in advance of the time the operator expects to abandon a well on Form 6. When filing an intent to abandon, the form shall be completed and attachments included to fully describe the proposed operations. This includes the proposed depths of mechanical plugs and casing cuts, the proposed depths and volumes of all cement plugs, the amount, size and depth of casing and junk to be left in the well, the volume and weight of fluid to be left in the wellbore and the nature and quantities of any other materials to be used in the plugging. If the well is not plugged within six (6) months of intent approval a new intent shall be filed.

Within thirty (30) days after abandonment, the Well Abandonment Report, Form 6, shall be filed with the Director. The abandonment details shall include an account of the manner in which the abandonment or plugging work was performed. Additionally, plugging verification reports detailing all procedures are required. A Plugging Verification Report shall be submitted for each person or contractor actually setting the plugs. The Well Abandonment Report, Form 6, and the Plugging Verification Reports shall detail the depths of mechanical plugs and casing cuts, the depths and volumes of all cement plugs, the amount, size and depth of casing and junk left in the well, the volume and weight of fluid left in the wellbore and the nature and quantities of any other materials used in the plugging. Plugging Verification Reports shall conform with the operator's report and both shall show that plugging procedures are at least as extensive as those approved by the Director. When filing a subsequent report of abandonment, the entire form shall be completed except for the second block, background information. (See Rule 319 for well abandonment requirements and procedures.)

312. COGCC Form 10. CERTIFICATE OF CLEARANCE AND/OR CHANGE OF OPERATOR

a. Each operator of any oil or gas well completed after April 30, 1956, shall file with the Director, within thirty (30) days after initial sale of oil or gas a Certificate of Clearance and/or Change of Operator, Form 10, in accordance with the instructions appearing on such form, for each well producing oil or gas or both oil and gas. A Certificate of Clearance shall be filed for any well from which oil, gas or other hydrocarbon is being produced.

A Certificate of Clearance shall be filed within thirty (30) days should the producing formation(s), the oil transporter (first purchaser) and/or the gas gatherer (first purchaser) change. In addition, within fifteen (15) days of an operator change for any well, a Change of Operator, Form 10, shall be filed with a filing and service fee as set by the Commission. (See Appendix III)

b. Each operator of a Class II injection well shall file a new Certificate of Clearance and/or Change of Operator, Form 10 with the Director within fifteen (15) days of the transfer of ownership.

c. Whenever there shall occur a change in the producer or operator filing the certificate under Rule 312.a. hereof, or whenever there shall occur a change of transporter from any well within the state, a new Certificate of Clearance and/or Change of Operator, Form 10 shall be executed and filed within fifteen (15) days in accordance with the instructions appearing on such form. In the case of temporary use of oil for well treating or stimulating purposes, no new form need be executed. In the case of other temporary change in transporter involving the production of less than one (1) month, the producer or operator may, in lieu of filing a new certificate, notify the Commission and the transporter authorized by the certificate on file with the Commission by letter of the estimated amount to be moved by the temporary transporter and the name of such temporary transporter. A copy of such notice shall also be furnished such temporary transporter.

d. In no instance shall the temporary transporter move any quantity greater than the estimated amount shown in said notice.

e. The certificate, when properly executed and approved by the Commission, shall constitute authorization to the pipeline or other transporter to transport the authorized volume from the well named therein; provided that this section shall not prevent the production or transportation in order to prevent waste, pending execution and approval of said certificate. Permission for the transportation of such production shall be granted in writing to the producer and transporter.

f. The certificate shall remain in force and effect until:

(1) The producer or operator filing the certificate is changed; or
(2) The transporter is changed; or
(3) The certificate is canceled by the Commission.

g. A copy of each Certificate of Clearance and/or Change of Operator, Form 10 to be filed hereunder shall be sent by the Director to those local governmental designees who so request.

h. It is the operator's responsibility to mail approved copies of the Certificate of Clearance and/or Change of Operator, Form 10, to the transporter and/or gatherer for each well listed.

313. COGCC Form 11. MONTHLY REPORT OF GASOLINE OR OTHER EXTRACTION PLANTS

All operators of gasoline or other extraction plants shall make monthly reports to the Director on Form 11. Such forms shall contain all information required thereon and shall be filed with the Director on or before the twenty-fifth (25th) day of each month covering the preceding month.

314. COGCC Form 17. BRADENHEAD TEST REPORT

Results of bradenhead tests, as required by Rule 207.b., shall be submitted to the Director within ten (10) days of completion. A wellbore diagram shall be submitted if not previously submitted or if the wellbore configuration has changed. If sampled, then the results of any gas and liquid analysis shall be submitted.

315. REPORT OF RESERVOIR PRESSURE TEST

Where the Director believes it is necessary to prevent waste, protect correlative rights, or prevent a significant adverse impact, the Director may require subsurface pressure measurements. Whenever such measurements are made, results shall be reported on Sundry Notice, Form 4, within twenty (20) days after completion of tests, or submitted on any company form approved by the Director containing the same information.

316A. COGCC Form 14. MONTHLY REPORT OF FLUIDS INJECTED

Except for fluids involved with fracturing, acidizing or other similar treatment elsewhere required to be reported on a Completed Interval Report, Form 5A, all operators engaged in the injection of fluids into any formation in dedicated injection wells shall file monthly with the Commission a detailed account of such operation on Form 14, or any company form containing the same information previously approved by the Director. Types of chemicals used to treat injection water, as well as the date of initial fluid injection for new injection wells, are to be reported on said form under Remarks. The type and amount of fluids received from transporters shall be included on the report. Operators of simultaneous injection wells shall, by March 1 of each year, report to the Director the calculated injected volume for the previous year by month on Form 14. Operators of gas storage projects shall, by March 1 of each year, report to the Director the amount of gas injected and withdrawn for the previous year and the amount of gas remaining in the reservoir as of December 31 of that year.

316B. COGCC Form 21. MECHANICAL INTEGRITY TEST

Results of mechanical integrity tests of injection wells or shut-in wells shall be submitted on Form 21, within thirty (30) days after the test. A pressure chart shall accompany this report. Not less than ten (10) days prior to the performance of any mechanical integrity test, the Director shall be notified, in writing, of the scheduled date on which the test will be performed. The form shall be completely filled out except for Part II, which is required only if the well is a permitted or pending injection well.

317. GENERAL DRILLING RULES

Unless altered, modified, or changed for a particular field or formation upon hearing before the Commission the following shall apply to the drilling or deepening of all wells.

a. **Blowout preventer equipment ("BOPE")**. The operator shall take all necessary precautions for keeping a well under control while being drilled or deepened. BOPE, if any, shall be indicated on the Application for Permit to Drill, Form 2, as well as any known subsurface conditions (e.g. under or over-pressured formations). The working pressure of any BOPE shall exceed the anticipated surface pressure to which it may be subjected, assuming a partially evacuated hole with a pressure gradient of 0.22 psi/ft. (For BOPE requirements in high density areas see Rule 603.b(4)B. For statewide BOPE specification, inspection, operation and testing requirements see Rule 603.f.)

(1) The Director shall have the authority to designate specific areas, fields or formations as requiring certain BOPE. Any such proposed designation shall occur by notice describing the area, field or formation in question and shall be given to all operators of record within such area or field and by publication. The proposed designation, if no protest is timely filed, shall be placed on the Commission consent agenda for its next regularly scheduled meeting following the month in which such notice was given. The matter shall be approved or heard by the Commission in accordance with Rule 520. Such designation shall be effective immediately upon approval by the Commission, except as to any previously approved Permit to Drill, Form 2.

(2) The Director shall have the authority, outside areas designated pursuant to Rule 317.a.(1), to condition approval of any Application for Permit to Drill by requiring BOPE which the Director determines to be necessary for keeping the well under control. Should the operator object to such condition of approval, the matter shall be heard at the next regularly scheduled meeting of the Commission, subject to the notice requirements of Rule 507.

b. **Bottom hole location**. Unless authorized by the provisions of Rule 321., all wells shall be so drilled that the horizontal distance between the bottom of the hole and the location at the top of the hole shall be at all times a practical minimum.

c. **Requirement to post permit at the rig and provide spud notice**. A copy of the approved Application for Permit to Drill, Deepen, Re-enter, or Recomplete and Operate, Form 2, shall be posted in a conspicuous place on the drilling rig or workover rig. A notice shall be provided to the Director on a Sundry Notice, Form 4, no later than five (5) days following the spudding of a well. The Director may apply a condition of approval for Application for Permit to Drill, Deepen, Re-enter, or Recomplete and Operate, Form 2 requiring not less than twenty-four (24) hours nor more than seventy-two (72) hours verbal or written notice prior to spud.

d. **Casing program to protect hydrocarbon horizons and ground water.** The casing program adopted for each well must be so planned and maintained as to protect any potential oil or gas bearing horizons penetrated during drilling from infiltration of injurious waters from other sources, and to prevent the migration of oil, gas or water from one (1) horizon to another, that may result in the degradation of ground water. A Sundry Notice, Form 4, including a detailed work plan and a wellbore diagram, shall be submitted and approved by the Director prior to any routine or planned casing repair operations. During well operations, prior verbal approval for unforseen casing repairs followed by the filing of a Sundry Notice, Form 4, after completion of operations shall be acceptable.

e. **Surface casing where subsurface conditions are unknown**. In areas where pressure and formations are unknown, sufficient surface casing shall be run to reach a depth below all known or reasonably estimated utilizable domestic fresh water levels and to prevent blowouts or uncontrolled flows and shall be of sufficient size to permit the use of an intermediate string or strings of casings. Surface casing shall be set in or through an impervious formation and shall be cemented by pump and plug or displacement or other approved method with sufficient cement to fill the annulus to the top of the hole, all in accordance with reasonable requirements of the Director. In the D-J Basin Fox Hills Protection Area surface casing will be set in accordance with Rule 317A. (See also subparagraph g.).

f. **Surface casing where subsurface conditions are known**. In wells drilled in areas where subsurface conditions have been established by drilling experience, surface casing size, at the owner's option, shall be set and cemented to the surface by the pump and plug or displacement or other approved method at a depth and in a manner sufficient to protect all fresh water and to ensure against blowouts or uncontrolled flows. In the D-J Basin Fox Hills Protection Area surface casing will be set in accordance with Rule 317A. (See also subparagraph g.).

g. **Alternate aquifer protection by stage cementing**. In areas where fresh water aquifers are of such depth as to make it impractical or uneconomical to set the full amount of surface casing necessary to comply fully with the requirement to cover or isolate all fresh water aquifers as required in subparagraph e. and f., the owner may, at its option, comply with this requirement by stage cementing the intermediate and/or production string so as to accomplish the required result. If unanticipated fresh water aquifers are encountered after setting the surface pipe they shall be protected or isolated by stage cementing the intermediate and/or production string with a solid cement plug extending from fifty (50) feet below each fresh water aquifer to fifty (50) feet above said fresh water aquifer or by other methods approved by the Director in each case. In the D-J Basin Fox Hills Protection Area any stage cementing shall occur only in accordance with Rule 317A. If the stage cement is not circulated to surface, a temperature log or cement bond log shall be run to determine the top of the stage cement to ensure aquifers are protected.

h. **Surface and intermediate casing cementing**. The operator shall ensure that all surface and intermediate casing cement required under this rule shall be of adequate quality to achieve a minimum compressive strength of three hundred (300) psi after twenty-four (24) hours and eight hundred (800) psi after seventy-two (72) hours measured at ninety-five degrees fahrenheit (95°F) and at eight hundred (800) psi. All surface casing shall be cemented with a continuous column from the bottom of the casing to the surface. After thorough circulation of the wellbore, cement shall be pumped behind the intermediate casing to at least two hundred (200) feet above the top of the shallowest known production horizon and as required in 317.g. Cement placed behind the surface and intermediate casing shall be allowed to set a minimum of eight (8) hours, or until three hundred (300) psi calculated compressive strength is developed, whichever occurs first, prior to commencing drilling operations. If the surface casing cement level falls below the surface, to the extent safety or aquifer protection is compromised, remedial cementing operations shall be performed.

i. **Production casing cementing**. The operator shall ensure that all cement required under this rule placed behind production casing shall be of adequate quality to achieve a minimum compressive strength of at least three hundred (300) psi after twenty-four (24) hours and eight hundred (800) psi after seventy-two (72) hours measured at ninety-five degrees fahrenheit (95°F) and at eight hundred (800) psi. After thorough circulation of a wellbore, cement shall be pumped behind the production casing two hundred (200) feet above the top of the shallowest known producing horizon. All fresh water aquifers which are exposed below the surface casing shall be cemented behind the production casing. All such cementing around an aquifer shall consist of a continuous cement column extending from at least fifty (50) feet below the bottom of the fresh water aquifer which is being protected to at least fifty (50) feet above the top of said fresh water aquifer. Cement placed behind the production casing shall be allowed to set seventy-two (72) hours, or until eight hundred (800) psi calculated compressive strength is developed, whichever occurs first, prior to the undertaking of any completion operation.

j. **Production casing pressure testing**. The installed production casing shall be adequately pressure tested for the conditions anticipated to be encountered during completion and production operations.

k. **Protection of aquifers and production stratum and suspension of drilling operations before running production casing**. In the event drilling operations are suspended before production string is run, the Commission shall be notified immediately and the owner shall take adequate and proper precautions to assure that no alien water enters oil or gas strata, nor potential fresh water aquifers during such suspension period or periods. If alien water is found to be entering the production stratum or to be causing significant adverse environmental impact to fresh water aquifers during completion testing or after the well has been put on production, the condition shall be promptly remedied.

l. **Flaring of gas during drilling and notice to local emergency dispatch**. Any gas escaping from the well during drilling operations shall be, so far as practicable, conducted to a safe distance from the well site and burned. The operator shall notify the local emergency dispatch as provided by the local governmental designee of any such flaring. Such notice shall be given prior to the flaring if the flaring can be reasonably anticipated, and in all other cases as soon as possible but in no event more than two (2) hours after the flaring occurs.

m. **Protection of productive strata during deepening operations**. If a well is deepened for the purpose of producing oil and gas from a lower stratum, such deepening to and completion in the lower stratum shall be conducted in such a manner as to protect all upper productive strata.

n. **Requirement to evaluate disposal zones for hydrocarbon potential**. If a well is drilled as a disposal well then the disposal zone shall be evaluated for hydrocarbon potential. The proposed hydrocarbon evaluation method shall be submitted in writing and approved by the Director prior to implementation. The productivity results shall be submitted to the Director upon completion of the well.

o. **Requirement to log well**. For all new drilling operations, the operator shall be required to run a minimum of a resistivity log with gamma-ray or other petrophysical log(s) approved by the Director that adequately describe the stratigraphy of the wellbore. This log and all other logs run shall be submitted with the Well Completion or Recompletion Report and Log, Form 5. Open hole logs shall be run to adequately verify setting depth of surface casing and aquifer coverage. These requirements shall not apply to the unlogged open hole completion intervals, or to wells in which no open hole logs are run.

p. **Remedial cementing during recompletion.** The Director may apply a condition of approval for Application for Permit to Drill, Deepen, Re-enter, or Recomplete and Operate, Form 2, to require remedial cementing during recompletion operations consistent with the provisions for protecting aquifers and hydrocarbon bearing zones in this Rule 317.

317A. SPECIAL DRILLING RULES - D-J BASIN FOX HILLS PROTECTION AREA

The following special drilling rules shall apply to wells in the D-J Basin Fox Hills Protection Area:

a. **Surface Casing - Minimum Requirements for Well Control**. In all wells drilled within the D-J Basin Fox Hills Protection Area, surface casing shall be run to a minimum depth of five percent (5%) of the projected total depth to which the well is to be drilled, provided that in no event shall the surface casing be run to a depth less than two hundred (200) feet. The Director may, on a case-by-case basis, grant variances in this five percent (5%) requirement where the Director finds that the well is a development well in which pressures can be accurately predicted and finds that, based upon those predictions, the five percent (5%) requirement should be varied to achieve effective well control. In all cases, however, the actual depth at which the surface casing is set shall be calculated to position the casing seat to a depth within a competent formation (preferably shale) which will contain the maximum pressure to which the casing will be exposed during normal drilling operations.

b. **Surface Casing - Aquifer Protection**. For purposes of aquifer protection, surface casing must be set as follows in wells which are not exploratory wells:

(1) Surface casing shall be run to a depth at least fifty (50) feet below the Fox Hills transition zone in wells drilled within Townships 5 South through 5 North, Ranges 65 West through 70 West or within Townships 3 North through 5 North, Range 64 West.

(2) With respect to Townships 5 South through 5 North, Ranges 58 West through 63 West, Townships 5 South through 2 North, Range 64 West; and Township 6 South, Ranges 65 West through 70 West, in all wells located within one (1) mile of a permitted producing water well, surface casing shall be set to a depth sufficient to protect the deepest permitted producing water well within such one (1) mile area. Said depth shall be at least fifty (50) feet below the depth of the base of the aquifer from which said deepest water well is producing, or fifty (50) feet below the base of the Fox Hills Transition Zone if such deepest water well produces from the Fox Hills Aquifer.

Upon the request of the operator, the Director (or the Commission upon appeal) may grant a variance to the requirements of this subparagraph b. upon a showing to the Director, or the Commission upon appeal, that the variance does not violate the basic intent of said requirements. For such variance purpose, the basic intent of said requirements is stated to be to provide reasonable aquifer protection for the water well(s) which are permitted by the State of Colorado Division of Water Resources and are currently producing in the area potentially affected by the oil or gas well to be drilled.

c. **Exploratory Wells**. For purposes of the D-J Basin Fox Hills Protection Area only, the term exploratory well means any well:

(1) Which targets the classically demonstrated zones with limited geographic extent such as channel, bar, valley fill and levee type sandstones that were deposited prior to the x-bentonite time stratigraphic event; or

(2) Which can be demonstrated to be separated from a known producing horizon by a dry hole; or

(3) Which can be demonstrated to be targeted to a horizon which is geologically separate from the producing horizon in an offsetting producing well, or

(4) Which the Director, or the Commission upon appeal, may define as an exploratory well by variance, it being the basic intent of this definition that the requirements of subparagraph b. not operate to discourage the drilling of high risk wells.

318. LOCATION OF WELLS

All wells drilled for oil or gas to a common source of supply shall have the following setbacks:

a. **Wells deeper than 2,500 feet in depth**. A well to be drilled in excess of two thousand five hundred (2,500) feet in depth shall be located not less than six hundred (600) feet from any lease line, and shall be located not less than one thousand two hundred (1,200) feet from any other producible or drilling oil or gas well when drilling to the same common source of supply, unless authorized by order of the Commission upon hearing.

b. **Wells less than 2,500 feet in depth**. A well to be drilled to less than a depth of two thousand five hundred (2,500) feet below the surface shall be located not less than two hundred (200) feet from any lease line, and not less than three hundred (300) feet from any other producible oil or gas well, or drilling well, in said source of supply, except that only one producible oil or gas well in each such source of supply shall be allowed in each governmental quarter-quarter section unless an exception under Rule 318.c. is obtained.

c. **Exception locations.** The Director may grant an operator's request for a well location exception to the requirements of this rule or any order because of geologic, environmental, topographic or archaeologic conditions, irregular sections, a surface owner request, or for other good cause shown, provided that a waiver or consent signed by the lease owner toward whom the well location is proposed to be moved, agreeing that said well may be located at the point at which the operator proposes to drill the well and where correlative rights are protected. If the operator of the proposed well is also the operator of the drilling unit or unspaced offset lease toward which the well is proposed to be moved, waivers shall be obtained from the mineral interest owners under such lands. If waivers cannot be obtained from all parties and no party objects to the location, the operator may apply for a variance under Rule 502.b. If a party or parties object to a location and cannot reach an agreement, the operator may apply for a Commission hearing on the exception location.

d. **Exemptions to Rule 318**.

(1) This rule shall not apply to authorized secondary recovery projects.

(2) This rule shall apply to fracture or crevice production found in shale, except from fields previously exempted from this rule.

(3) In a unit operation, approved by federal or state authorities, the rules herein set forth shall not apply except that no well in excess of two thousand five hundred (2,500) feet in depth shall be located less than six hundred (600) feet from the exterior or interior (if there be one) boundary of the unit area and no well less than two thousand five hundred (2,500) feet in depth below the surface shall be located less than two hundred (200) feet from the exterior or interior (if there be one) boundary of the unit area unless otherwise authorized by the order of the Commission after proper notice to owners outside the unit area.

e. **Wells located near a mine**. No well drilled for oil or gas shall be located within two hundred (200) feet of a shaft or entrance to a coal mine not definitely abandoned or sealed, nor shall such well be located within one hundred (100) feet of any mine shaft house, mine boiler house, mine engine house, or mine fan; and the location of any proposed well shall insure that when drilled it will be at least fifteen (15) feet from any mine haulage or airway.

318A. GREATER WATTENBERG AREA SPECIAL WELL LOCATION RULE

a. The Greater Wattenberg Area ("GWA") is defined to include those lands from and including Townships 2 South to 7 North and Ranges 61 West to 69 West, 6^{th} P.M. In GWA, operators may utilize the following described drilling locations to drill or twin a well, deepen a well, or recomplete a well and to commingle any or all of the Cretaceous Age formations from the base of the Dakota to the surface ("GWA wells"):

(1) A square with sides four hundred (400) feet in length, the center of which is the center of any quarter/quarter section; and,

(2) A square with sides eight hundred (800) feet in length, the center of which is the center of any quarter section.

b. Any GWA well in existence prior to the effective date of this rule, which is not located as described above, may also be utilized for deepening to or recompletion in any Cretaceous Age formation, and for the commingling of production therefrom.

c. Where an existing well cannot be utilized for deepening or recompletion, for reasons including, but not limited to, differing ownership or wellbore limitations, any new, twinned well shall be located as close to such existing well as is practicable, consistent with sound engineering practice.

d. This rule does not alter the size or configuration of drilling units for GWA wells in existence prior to its effective date. Where deemed necessary an operator for purposes of allocating production, such operator may allocate production to an expanded drilling unit with respect to a particular Cretaceous Age formation consistent with the provisions of this rule.

e. This rule shall not serve to bar the granting of relief to owners who file an application alleging abuse of their correlative rights to the extent that such owners can demonstrate that their opportunity to produce the Cretaceous Age formations from the drilling locations herein authorized does not provide an equal opportunity to obtain their just and equitable share of oil and gas from such formations.

f. Subject to paragraph d. above, this rule supersedes all prior Commission drilling and spacing orders affecting the GWA wells. Well location exceptions to this rule shall be subject to the provisions of Rule 318.c.

319. ABANDONMENT

The requirements for abandoning a well shall be as follows:

a. **Plugging**

(1) A dry or abandoned well, seismic, core, or other exploratory hole, must be plugged in such a manner that oil, gas, water, or other substance shall be confined to the reservoir in which it originally occurred. Any cement plug shall be a minimum of fifty (50) feet in length and shall extend a minimum of fifty (50) feet above each zone to be protected. The material used in plugging, whether cement, mechanical plug, or some other equivalent method approved in writing by the Director, must be placed in the well in a manner to permanently prevent migration of oil, gas, water, or other substance from the formation or horizon in which it originally occurred. The preferred plugging cement slurry is that recommended by the American Petroleum Institute (API) Environmental Guidance Document: Well Abandonment and Inactive Well Practices for U.S. Exploration and Production Operations, i.e., a neat cement slurry mixed to API standards. However, pozzolan, gel and other approved extenders may be used if the operator can document, to the Director's satisfaction, that the slurry design will achieve a minimum compressive strength of three hundred (300) psi after twenty-four (24) hours and eight hundred (800) psi after seventy-two (72) hours measured at ninety-five (95) degrees fahrenheit and at eight hundred (800) psi.

(2) The operator shall have the option as to the method of placing cement in the hole by (a) dump bailer, (b) pumping a balanced cement plug through tubing or drill pipe, (c) pump and plug, or (d) equivalent method approved by the Director prior to plugging. Unless prior approval is given, all wellbores will have water, mud or other approved fluid between all plugs.

(3) No substance of any nature or description other than normally used in plugging operations shall be placed in any well at any time during plugging operations. All final reports of plugging and abandonment shall be submitted on a Well Abandonment Report, Form 6, and accompanied by a job log or cement verification report from the plugging contractor specifying the type of fluid used to fill the wellbore, type and slurry volume of API Class cement used, date of work, and depth the plugs were placed.

(4) In order to protect the fresh water strata, no surface casing shall be pulled from any well unless authorized by the Director.

(5) All abandoned wells shall have a plug or seal placed at the surface of the ground or the bottom of the cellar in the hole in such manner as not to interfere with soil cultivation or other surface use. The top of the pipe must be sealed with either a cement plug and a screw cap, or cement plug and a steel plate welded in place or by other approved method, or in the alternative be marked with a permanent monument which shall consist of a piece of pipe not less than four (4) inches in diameter and not less than ten (10) feet in length, of which four (4) feet shall be above the general ground level, the remainder to be embedded in cement or to be welded to the surface casing.

(6) The operator must obtain approval from the Director of the plugging method prior to plugging, and shall notify the Director of the estimated time and date the plugging operation of any well is to commence, and identify the depth and thickness of all known sources of ground water. For good cause shown, the Director may require that a cement plug be tagged if a cement retainer or bridge plug is not used. If requested by the operator, the Director shall furnish written follow-up documentation for a requirement to tag cement plugs.

(7) **Wells Used for Fresh Water**. When the well, seismic, core, or other exploratory hole to be plugged may safely be used as a fresh water well, and such utilization is desired by the landowner, the well need not be filled above the required sealing plug set below fresh water; provided that written authority for such use is secured from the landowner and, in such written authority, the landowner assumes the responsibility to plug the well upon its abandonment as a water well in accordance with these rules. Such written authority and assumption of responsibility shall be filed with the Commission, provided further that the landowner furnish a copy of the permit for a water well approved by the Division of Water Resources.

b. **Shut-in and Temporary Abandonment**.

(1) A well may be shut-in or temporarily abandoned when completed, upon approval of the Director, for a period not to exceed six (6) months provided the hole is cased or left in such a manner as to prevent migration of oil, gas, water or other substance from the formation or horizon in which it originally occurred. All shut-in or temporarily abandoned wells shall be closed to the atmosphere with a swedge and valve or packer, or other approved method. The well sign shall remain in place. If an operator requests shut-in or temporary

abandonment status in excess of six (6) months the operator shall state the reason for requesting such extension and state plans for future operation. A Sundry Notice, Form 4, or other form approved by the Director, shall be submitted annually stating the status of the well and plans for future operation. The Director shall submit copies of any Sundry Notice, Form 4, to the local governmental designees who so requests.

(2) The manner in which the well is to be maintained should be reported to the Commission, and bonding requirements, as provided for in Rule 304., kept in force until such time as the well is permanently abandoned.

(3) A well which has ceased production or injection or is incapable of production or injection shall be abandoned within six (6) months thereafter unless the time is extended by the Director upon application by the owner. The application shall indicate why the well is shut-in and future plans for utilization. In the event the well is covered by a blanket bond, the Director may require an individual plugging bond on the shut-in or temporarily abandoned well. Gas storage wells are to be considered active at all times unless physically plugged.

(4) In addition to the requirements of Rule 325., an injection well that is shut-in or temporarily abandoned shall have a mechanical integrity test performed within two (2) years after the shut-in date in order to be retained in shut-in or temporarily abandoned status.

(5) If an injection well which has been shut-in or temporarily abandoned is determined not to have mechanical integrity as a result of any test required by the Commission rules and regulations, it must, within six (6) months following such a test, be either repaired and pass a mechanical integrity test or be plugged and abandoned.

320. LIABILITY

The owner and operator of any well drilled for oil or gas production or injection purposes, or any seismic, core, or other exploratory holes, whether cased or uncased, shall be liable and responsible for the plugging thereof in accordance with the rules and regulations of the Commission regardless of whether the cost of such plugging and abandonment exceeds the amount of security as set forth in Rule 304.

321. DIRECTIONAL DRILLING

If an operator intends to drill a horizontal or deviated wellbore utilizing controlled directional drilling methods, other than whipstocking due to hole conditions, the plans shall accompany an application for Permit-to-Drill, Form 2. In addition to the information required on the plat in Rule 303.c., the plat shall also show the surface and bottom hole location. If the surface location is in a different section than the bottom hole location, a plat depicting each section is required. Additionally, the proposed directional survey including two (2) wellbore deviation plots, one depicting the plan view and one depicting the side view, shall accompany the application.

Within thirty (30) days of completion the operator shall submit a Drilling Completion Report, Form 5, according to Rule 308., with a copy of the directional survey coordinate listing and the wellbore deviation plots (plan and side views). The survey data shall be provided in a single analysis report with sufficient detail to determine the location of the wellbore from the base of the surface casing to the kick off point and from that point to total depth.

Any changes to an approved Application for Permit-to-Drill, Form 2, shall be submitted and approved on a Sundry Notice, Form 4, prior to implementation. Any request to change either the surface or bottom hole location shall be accompanied by a new proposed directional plan, an updated plat and updated wellbore deviation plots (plan and side view).

322. COMMINGLING

The commingling of production from multiple formations or wells is encouraged in order to maximize the efficient use of wellbores and to minimize the surface disturbance from oil and gas operations. Commingling may be conducted at the discretion of an operator, unless the Commission has issued an order or promulgated a rule excluding specific wells, geologic formations, geographic areas, or field from commingling in response to an application filed by a directly and adversely affected or aggrieved party or on the Commission's own motion.

This rule supercedes the procedural requirements to establish commingling and allocation contained in any Commission order as of the effective date of this rule, but does not supersede any allocation made under such order.

323. OPEN PIT STORAGE OF OIL OR HYDROCARBON SUBSTANCES

Storage of oil or any other produced liquid hydrocarbon substance in earthen pits or reservoirs is considered to constitute waste, except in emergencies where such substances cannot be otherwise contained. In such cases, these substances must be reclaimed and such storage eliminated as soon as practicable after the emergency is controlled, unless special permission to delay or continue is obtained from the Director.

324A. POLLUTION

a. The operator shall take precautions to prevent significant adverse environmental impacts to air, water, soil, or biological resources to the extent necessary to protect public health, safety and welfare, by using cost-effective and technically feasible measures to protect environmental quality and to prevent the unauthorized discharge or disposal of oil, gas, E&P waste, chemical substances, trash, discarded equipment or other oil field waste.

b. No operator, in the conduct of any oil or gas operation shall perform any act or practice which shall constitute a violation of water quality standards or classifications established by the Water Quality Control Commission for waters of the state, or any point of compliance established by the Director pursuant to Rule 324D. The Director may establish one (1) or more points of compliance for any event of pollution, which shall be complied with by all parties determined to be a responsible party for such pollution.

c. No owner, in the conduct of any oil or gas operation, shall perform any act or practice which shall constitute a violation of any comprehensive plan adopted by the Air Quality Control Commission for the prevention, control and abatement of pollution of the air of the state.

d. No injection shall be authorized pursuant to Rule 325. or Rule 401. unless the person applying for authorization to conduct the injection activities demonstrates that those activities will not result in the presence in an underground source of drinking water of any physical, chemical, biological or radiological substance or matter which may cause a violation of any primary drinking water regulation in effect as of July 12, 1982 and found at 40 C.F.R. Part 142, as amended, or may otherwise adversely affect the health of persons. An underground source of drinking water is an aquifer or its portion:

(1) A. Which supplies any public water system; or

B. Which contains a sufficient quantity of ground water to supply a public water system; and

i. Currently supplies drinking water for human consumption; or
ii. Contains fewer than ten thousand (10,000) milligrams per liter total dissolved solids; and

(2) Which is not an exempted aquifer.

e. No person shall accept water produced from oil and gas operations, or other oil field waste for disposal in a commercial disposal facility, without first obtaining a Certificate of Designation from the County in which such facility is located, in accord with the regulations pertaining to solid waste disposal sites and facilities as promulgated by the Colorado Department of Public Health and Environment.

324B. EXEMPT AQUIFERS

a. **Criteria for aquifer exemption.** An aquifer or a portion thereof may be designated by the Director or the Commission as an exempted aquifer, in connection with the filing of an application pursuant to Rule 325. or Rule 401. if it meets the following criteria:

(1) It does not currently serve as a source of drinking water; and either subparagraph (2) or (3) below apply:

(2) It cannot now and will not in the future serve as a source of drinking water because:

A. It is mineral, hydrocarbon or geothermal energy producing, or can be demonstrated by a person filing an application pursuant to Rule 324. or Rule 401. to contain minerals or hydrocarbons that considering their quantity and location are expected to be commercially producible; or

B. It is situated at a depth or location which makes recovery of water for drinking water purposes economically or technologically impractical; or

C. It is so contaminated that it would be economically or technologically impractical to render the water fit for human consumption;

(3) The total dissolved solids content of the ground water is more than three thousand (3,000) and less than ten thousand (10,000) milligrams per liter and it is not reasonably expected to supply a public water system.

b. **Aquifer exemption public notice.** If an aquifer exemption is required as part of an injection permit process, the injection well applicant shall apply for an aquifer exemption. This application shall contain data and information which show that applicable aquifer exemption criteria set forth in Rule 324B.a. are met. After evaluation of the application and prior to designating an aquifer or a portion thereof as an exempted aquifer, the Director shall publish a notice of proposed designation in a newspaper of general circulation serving the area where the aquifer is located. The notice shall identify such aquifer or portion thereof which the Director proposes to designate as exempted, and shall state that any person who can make a showing to the Director that the requested designation does not meet the critera set forth in Rule 324B.a.

c. **Evaluation of written requests for public hearing.** Written requests for a public hearing before the Commission shall be reviewed and evaluated by the Director in consultation with the applicant to determine if the criteria set forth in Rule 324B.a. have been met. If, within thirty (30) days after publication of the notice, the Commission receives a hearing request for which the Director determines the criteria set forth in Rule 324B.a. have not been met, the Commission shall hold such a hearing in accordance with the provisions of §34-60-108, C.R.S., 1973, as amended, and shall make a final determination regarding designation.

d. **Aquifer exemption designation**. If, within thirty (30) days after publication of the notice described in subparagraph b. above, the Commission does not receive a hearing request or receives a hearing request for which the Director determines the criteria set forth in Rule 324B.a. have been met, said aquifer or portion thereof shall be considered exempted thirty (30) days after publication of the notice.

324C. QUALITY ASSURANCE FOR CHEMICAL ANALYSIS

For the purpose of application for a permit for all wells authorized under Rule 325. and Rule 401., collection and analysis of water samples must comply with the Commission's approved quality assurance project plan.

324D. CRITERIA TO ESTABLISH POINTS OF COMPLIANCE

In determining a point of compliance, the Director shall take into consideration recommendations of the operator or any responsible party or parties, if applicable, including technical and economic feasibility, together with the following factors:

a. The classified use established by the Water Quality Control Commission, for any ground water or surface water which will be impacted by contamination. If not so classified, the Director shall consider the quality, quantity, potential economic use and accessibility of such water;

b. The geologic and hydrologic characteristics of the site, such as depth to ground water, ground water flow, direction and velocity, soil types, surface water impacts, and climate;

c. The toxicity, mobility, and persistence in the environment of contaminants released or discharged from the site;

d. Established wellhead protection areas;

e. The potential of the site as an aquifer recharge area; and

f. The distance to the nearest permitted domestic water well or public water supply well completed in the same aquifer affected by the event.

g. The distance to the nearest permitted livestock or irrigation water well completed in the same aquifer affected by the event.

325. UNDERGROUND DISPOSAL OF WATER

a. No person shall commence operations for the underground disposal of water, or any other fluids, into a Class II well, or any well regulated by the Commission, nor shall any person commence construction of such a well, without having first obtained written authorization for such operations from the Director. Persons wishing to obtain authorization to conduct underground disposal activities shall file with the Director an Underground Injection Formation Permit Application, Form 31 and an Injection Well Permit Application, Form 33. If the disposal well is to be drilled, this application shall be submitted concurrently with the Application for Permit-to-Drill, Form 2, along with a service and filing fee to be determined by the Commission. (See Appendix III)

b. **Withholding approval of underground disposal of water.** The Director may withhold the issuance of a permit and the granting of approval of any Underground Injection Formation Permit Application, Form 31 and any Injection Well Permit Application, Form 33 for any proposed disposal well when the Director has reasonable cause to believe that the proposed disposal well could result in a significant adverse impact on the environment or public health, safety and welfare. In the event such approval is not granted, the Director shall immediately advise the operator and bring the matter to the Commission at its next regularly scheduled hearing.

c. The application for a dedicated injection well shall include the following information:

(1) The name, description and depth of the formation into which water is to be injected, and all underground sources of drinking water which may be affected by the proposed operation. A water analysis of the injection formation (if the total dissolved solids of the injection formation is determined to be less than ten thousand (10,000) milligrams per liter, the aquifer must be exempted in accordance with Rule 324B.). The fracture pressure or fracture gradient of the injection formation.

(2) A base plat covering the area within one-quarter (1/4) mile of the proposed disposal well showing location of the proposed disposal well or wells and the location of all oil and gas wells, domestic and irrigation wells of public record and the identification of all oil and gas wells currently producing from the proposed injection zone within one-half (1/2) mile of the disposal zone. The names, addresses and holdings of all surface and mineral owners as defined in §34-60-103 (7), C.R.S., within one-quarter (1/4) mile of the proposed disposal well or wells, or all owners of record in the field if a field-wide system is proposed. These owners shall be specifically outlined and identified on the base plat. A list of all domestic an irrigation wells of public record, within one-quarter mile of the proposed disposal well or wells, including their location and depth. (This information may be obtained at the Colorado Division of Water Resources.) Remedial action shall be required for any well within one-quarter (1/4) mile of the proposed disposal well or wells, which the applicant may or may not operate and a plan for the performance of any such remedial work. A copy of all plans and specifications for the system and its appurtenances.

(3) A resistivity log, run from the bottom of the surface casing to total depth of the disposal well or wells or any well within one (1) mile together with a log from that well that can be correlated with the injection well. If the disposal well is to be drilled, a description of the typical stratigraphic level of the disposal formation in the disposal well or wells, and any other available logging or testing data, on the disposal well or wells.

(4) A full description of the casing in the disposal well or wells. This shall include any information available on any remedial cement work performed to any casing string. This shall also include a schematic drawing showing all casing strings with cement volumes and tops, existing or as proposed, plug back total depth, depth of any existing open or squeezed perforations, setting depths of any bridge plugs existing or proposed, planned perforations in the injection zone, tubing and packer size and setting depth. A diagram of the surface facility showing all pipelines and tanks associated with the system. A listing of all leases connected directly by pipelines to the system.

(5) A listing of all sources of water, by lease and well, to be injected shall be submitted on a Source of Produced Water for Disposal, Form 26.

(6) Any proposed stimulation program.

(7) The estimated minimum and maximum amount of water to be injected daily with anticipated injection pressures. Maximum injection pressure will be set by the Director upon approval.

(8) The names and addresses of those persons notified by the applicant, as required by subparagraph i of this rule.

d. The application for a simultaneous injection well shall include the following:

(1) The name, description and depth of the formation into which water is to be injected, and all underground sources of drinking water which may be affected by the proposed operation. A water analysis of the injection formation (if the total dissolved solids of the injection formation is determined to be less than ten thousand (10,000) milligrams per liter, the aquifer must be exempted in accordance with Rule 324B.); a water analysis from the producing formation; and the fracture pressure or fracture gradient of the injection formation.

(2) A base plat covering the area within one-quarter (1/4) mile of the proposed well showing the location of the proposed well or wells and the location of all oil and gas wells, domestic and irrigation wells of public record and the identification of all oil and gas wells currently producing from the proposed injection zone within one-half (1/2) mile of the disposal zone and the names, addresses and holdings of all mineral owners as defined in §34-60-103 (7), C.R.S., within one-quarter (1/4) mile of the proposed disposal well or wells, or all owners of record in the field if a field-wide system is proposed. These owners shall be specifically outlined and identified on the base plat. Remedial action shall be required for any well within one-quarter (1/4) mile of the proposed well or wells in which the injection zone is not adequately confined. The applicant shall include information regarding the need for remedial action on any well(s) penetrating the injection zone within one-quarter (1/4) mile of the proposed disposal well or wells, which the applicant may or may not operate and a plan for the performance of any such remedial work and a copy of all plans and specifications for the system and its appurtenances.

(3) A resistivity log, run from the bottom of the surface casing to total depth of the disposal zone or such log from a well within one (1) mile together with a log from that well that can be correlated with the simultaneous injection well. If the simultaneous injection well is to be drilled, a description of the typical stratigraphic level of the injection formation in the simultaneous injection well or wells, and any other available logging or testing data, on the simultaneous injection well or wells.

(4) A full description of the casing in the simultaneous injection well or wells. This shall include any information available on any remedial cement work performed to any casing string. This shall also include a schematic drawing showing all casing strings with cement volumes and tops, existing or as proposed, plug back total depth, depth of any existing open or squeezed perforations, setting depths of any bridge plugs existing or proposed, planned perforations in the injection zone, downhole pump setting depth and any tubing and or packer size and setting depth.

(5) Any proposed stimulation program.

(6) The estimated amount of water to be injected daily.

(7) Downhole pump specifications, together with a calculation of maximum discharge pressure created under proposed wellbore configuration. Downhole pump configurations shall be designed to inject below the injection zone fracture gradient.

(8) The names and addresses of those persons notified by the applicant, as required by subparagraph j. of this rule.

The following rules shall apply to both dedicated injection well and simultaneous injection well applications.

e. **Mechanical integrity testing requirement**. Prior to application approval, the proposed disposal well must satisfactorily pass a mechanical integrity test in accordance with Rule 326.

f. **Centralized and commercial disposal well requirements.** Prior to application approval, the appurtenant centralized and commercial disposal well operations shall comply with the requirements of Rules 704. and 908.

g. **Multiple well applications**. Application may be made to include the use of more than one (1) disposal well on the same lease, or on more than one (1) lease. Wherever feasible and applicable, the application shall contemplate a coordinated plan for the entire field.

h. The designated operator of a unitized or cooperative project shall execute the application.

i. Notice of the application for a dedicated injection well shall be given by the applicant by registered or certified mail or by personal delivery, to each surface owner and owner as defined in §34-60-103(7), C.R.S., within one-quarter (1/4) mile of the proposed well or wells and to owners and operators of oil and gas wells producing from the injection zone within one-half (1/2) mile of the disposal well or to owners of cornering and contiguous units where injection will occur into the producing zones, whichever is the greater distance.

j. Notice of the application for a simultaneous injection well shall be given by the applicant by registered or certified mail or by personal delivery, to each owner as defined in §34-60-103(7), C.R.S., within one-quarter (1/4) mile of the proposed well or wells and to owners and operators of oil and gas wells producing from the injection zone within one-half (1/2) mile of the disposal well or to owners of cornering and contiguous units where injection will occur into the producing zones, whichever is the greater distance.

k. A copy of the notice of application shall be included with the disposal application filed with the Commission, and the applicant shall certify that notice by registered or certified mail or by personal delivery, to each of the owners specified in subparagraphs i. and j., has been accomplished.

l. **Notice of application requirements**. The notice shall describe the proposed operation and shall state that any person who would be directly and adversely affected or aggrieved by the authorization of the underground disposal into the proposed injection zone may file, within fifteen (15) days of notification, a written request for a public hearing before the Commission, provided such request meets the protest requirements specified in subparagraph m. of this rule. The notice shall also state that additional information on the operation of the proposed disposal well may be obtained at the Commission office.

m. **Evaluation of written requests for public hearing**. Written requests for public hearing before the Commission by a person, notified in accordance with subparagraphs i. and j. of this rule, who may be directly and adversely affected or aggrieved by the authorization of the underground disposal into the proposed injection zone, shall be reviewed and evaluated by the Director in consultation with the applicant. Written protests shall specifically provide information on:

(1) Possible conflicts between the injection zone's proposed disposal use and present or future use as a source of drinking water or present or future use as a source of hydrocarbons, or

(2) Operations at the well site which may affect potential and current sources of drinking water.

n. **Dedicated injection well public notice**. The Director shall publish a notice of the proposed disposal permit for dedicated injection wells in a newspaper of general circulation serving the area where the well(s) is (are) located. The notice shall briefly describe the disposal application and include legal location, proposed injection zone, depth of injection and other relevant information. Comment period on the proposed disposal application shall end thirty (30) days after date of publication. If any data, information, or arguments submitted during the public comment period appear to raise substantial questions concerning potential impacts to the environment, public health, safety and welfare raised by the proposed disposal well permit the Director may request that the Commission hold a hearing.

o. **Injection application deadlines**. If all of the data or information necessary to approve the disposal application has not been received within six (6) months of the date of receipt, the application will be withdrawn from consideration. However, for good cause shown, a ninety (90) day extension may be granted, if requested prior to the date of expiration.

326. MECHANICAL INTEGRITY TESTING

For the purpose of this rule, a mechanical integrity test of a well is a test designed to determine if: there is a significant leak in the casing, tubing, or packer of the well, and there is significant fluid movement into an underground source of drinking water through vertical channels adjacent to the wellbore.

a. Injection Wells - A mechanical integrity test shall be performed on all injection wells.

(1) The mechanical integrity test shall include one (1) of the following tests to determine whether significant leaks are present in the casing, tubing, or packer;

A. A pressure test with liquid or gas at a pressure of not less than three hundred (300) psi or the minimum injection pressure, whichever is greater, and not more than the maximum injection pressure; or

B. The monitoring and reporting to the Director, on a monthly basis for sixty (60) consecutive months, of the average casing-tubing annulus pressure, following an initial pressure test; or

C. In lieu of A. and B. any equivalent test or combinations of tests approved by the Director.

(2) The mechanical integrity test shall include one (1) of the following tests to determine whether there are significant fluid movements in vertical channels adjacent to the well bore:

A. Cementing records which shall only be valid for injection wells in existence prior to July 1, 1986;

B. Tracer surveys;

C. Cement bond log or other acceptable cement evaluation log;

D. Temperature surveys; or

E. In lieu of A.-D., any other equivalent test or combination of tests approved by the Director.

(3) No person shall inject fluids into a new injection well unless a mechanical integrity test on the well has been performed and supporting documents including Mechanical Integrity Test, Form 14B, submitted and approved by the Director. Verbal approval may be granted for continuous injection following the test.

(4) Following the performance of the initial mechanical integrity test required by subparagraph (3), additional mechanical integrity tests shall be performed on each type of injection well as follows:

A. **Dedicated injection well.** As long as it is used for the injection of fluids, mechanical integrity tests shall be performed at the rate of not less than one (1) test every five (5) years. The first five (5) year period shall commence on the date the initial mechanical integrity test is performed.

B. **Simultaneous injection well.** No additional tests will be required after the initial mechanical integrity test.

(5) Following the performance of the initial mechanical integrity test required by subparagraph (3), additional mechanical integrity tests shall be performed on each well, as long as it is used for the injection of fluids, at the rate of not less than one (1) test every five (5) years. The first five (5) year period shall commence on the date the initial mechanical integrity test is performed.

b. **Shut-in Wells** - All shut-in wells shall pass a mechanical integrity test.

(1) A mechanical integrity test shall be performed on each shut-in well within two (2) years of the initial shut-in date. A mechanical integrity test shall be performed on each shut-in well on five (5) year intervals from the date the initial mechanical integrity test was performed. If, at any time, surface equipment is removed or the well becomes incapable of production, a mechanical integrity test must be performed within thirty (30) days. The mechanical integrity test for a shut-in well shall be:

A. Isolation of the wellbore with a bridge plug or similar approved isolating device set one hundred (100) feet or less above the highest perforations and a pressure test with liquid or gas at a pressure of not less than three hundred (300) psi surface pressure or any equivalent test or combination of tests approved by the Director.

B. Following the performance of the initial mechanical integrity test for shut-in wells, additional tests, other than the five (5) year interval test, may be required.

c. Not less than ten (10) days prior to the performance of any mechanical integrity test required by this rule, any person required to perform the test shall notify the Director, in writing, of the scheduled date on which the test will be performed.

d. All wells shall maintain mechanical integrity. All wells which lack mechanical integrity shall be repaired or plugged and abandoned within six (6) months of failing a mechanical integrity test or of a determination through any other means that the well lacks mechanical integrity, and the well site reclaimed in accordance with Rule 1004.a. All injection wells which fail a mechanical integrity test, or which are determined through any other means to lack mechanical integrity, shall be shut-in immediately.

327. LOSS OF WELL CONTROL

The operator shall take all reasonable precautions, in addition to fully complying with Rule 317. to prevent any oil, gas or water well from blowing uncontrolled and shall take immediate steps and exercise due diligence to bring under control any such well, and shall report such occurrence to the Director as soon as practicable, but no later than twenty four (24) hours following the incident. Within fifteen (15) days after all occurrences the operator shall submit a written report giving all details. The Director shall maintain these written reports in a central file.

328. MEASUREMENT OF OIL

The volume of production of oil shall be computed in terms of barrels of clean oil on the basis of properly calibrated meter measurements or tank measurements of oil-level differences, made and recorded to the nearest one-quarter (1/4) inch of one hundred percent (100%) capacity tables, subject to the following corrections:

a. **Correction for Impurities.** The percentage of impurities (water, sand and other foreign substances not constituting a natural component part of the oil) shall be determined to the satisfaction of the Director, and the observed gross volume of oil shall be corrected to exclude the entire volume of such impurities.

b. **Temperature Correction.** The observed volume of oil corrected for impurities shall be further corrected to the standard volume of sixty degrees fahrenheit (60°F). in accordance with A.S.T.M. D-1250 Table 7, or any revisions thereof and any supplements thereto or any close approximation thereof approved by the Director.

c. **Gravity Determination.** The gravity of oil at sixty degrees fahrenheit (60°F) shall be determined in accordance with A.S.T.M. D-1250 Table 5, or any revisions thereof and any supplements thereto or any close approximation thereof approved by the Director.

329. MEASUREMENT OF GAS

Production of gas of all kinds shall be measured by meter unless otherwise agreed to by the Director. For computing volume of gas to be reported to the Commission, the standard pressure base shall be fourteen point seventy-three (14.73) psia, regardless of atmospheric pressure at the point of measurement, and the standard temperature base shall be sixty degrees fahrenheit (60°F). All volumes of gas to be reported to the Commission shall be adjusted by computation to these standards, regardless of pressures and temperatures at which the gas was actually measured, unless otherwise authorized by the Director.

330. MEASUREMENT OF PRODUCED AND INJECTED WATER

a. The volume of produced water shall be computed and reported in terms of barrels on the basis of properly calibrated meter measurements or tank measurements of water-level differences, made and recorded to the nearest one-quarter (1/4) inch of one hundred percent (100%) capacity tables. If measurements are based on oil/water ratios, the oil/water ratio must be based on a production test performed during the last calendar year. Other equivalent methods for measurement of produced water may be approved by the Director.

b. The volume of water injected into a Class II dedicated injection well shall be computed and reported in terms of barrels on the basis of properly calibrated meter measurements or tank measurements of water-level differences, made and recorded to the nearest one-quarter (1/4) inch of one hundred percent (100%) capacity tables. If water is transported to an injection facility by means other than direct pipeline, measurement of water is required by a properly calibrated meter.

c. The volume of water injected and produced in simultaneous injection wells shall be computed and reported in terms of barrels on the basis of calculated pump volumes, on the basis of properly calibrated meter measurements, or on the basis of a produced gas to water ratio based on an annual production test.

331. VACUUM PUMPS ON WELLS

The installation of vacuum pumps or other devices for the purpose of imposing a vacuum at the wellhead or on any oil or gas bearing reservoir may be approved by the Director upon application therefore, except as herein provided. The application shall be accompanied by an exhibit showing the location of all wells on adjacent premises and all offset wells on adjacent lands, and shall set forth all material facts involved and the manner and method of installation proposed. Notice of the application shall be given by the applicant by registered or certified mail, or by delivering a copy of the application to each producer within one-half (1/2) mile of the installation.

In the event no producer within one-half (1/2) mile of the installation or the Commission itself files written objection or complaint to the application within fifteen (15) days of the date of application, then the application shall be approved, but if any producer within one-half (1/2) mile of said installation or the Commission itself files written objection within fifteen (15) days of the date of application, then a hearing shall be held as soon as practicable.

332. USE OF GAS FOR ARTIFICIAL GAS LIFTING

Gas may be used for artificial gas lifting of oil where all such gas returned to the surface with the oil is used without waste. Where the returned gas is not to be so used, the use of gas for artificial gas lifting of oil is prohibited unless otherwise specifically ordered and authorized by the Commission upon hearing.

333. SEISMIC OPERATIONS

a. **COGCC Form 20, Notice of Intent to Conduct Seismic Operations**. Seismic operations require an approved Form 20 which shall be submitted to the Director prior to commencement of shothole drilling or recording operations. An informational copy of the Form 20 shall be filed by the operator with the local governmental designee at or before the time of filing with the Director. Any change of plans or line locations may be implemented without Director approval provided that after such change is performed, the Director shall receive written notice of the change within five (5) days.

A map shall be included with the notice. This map shall be at a scale of at least 1:48,000 showing sections, townships and ranges and providing the location of the proposed seismic lines, including source and receiver line locations.

The Notice of Intent to Conduct Seismic Operations, Form 20, shall be in effect for six (6) months from the date of approval. An extension of time may be granted upon written request submitted prior to the expiration date.

b. **Surface owner consultation.** Prior to the commencement of any seismic operations, a good faith effort shall be made to consult with all surface owners of the lands included in the seismic project area.

c. **Exploration requiring the drilling of shotholes**:

(1) **Explosive storage.** All explosives shall be legally and safely stored and accounted for in magazines when not in use in accordance with relevant regulations of the Alcohol, Tobacco and Firearms Division of the Federal Department of the Treasury.

(2) **Blasting safety setbacks.** Blasting shall be kept a safe distance from occupied buildings, water wells or springs, unless by special written permission of the surface owner or lessee, according to the following minimum setback distances:

CHARGES IN LBS. GREATER THAN	CHARGES IN LBS. UP TO AND INCLUDING	MINIMUM SETBACK DISTANCE IN FEET
0	2	200
2	5	300
5	6	360
6	7	420
7	8	480
8	9	540
9	10	600
10	11	649
11	12	696
12	13	741
13	14	784
14	15	825
15	16	864
16	17	901
17	18	936
18	19	969
19	20	1000
20		1320

(3) Prior to any shothole drilling, the operator shall contact the Utility Notification Center of Colorado at 1-800-922-1987.

(4) **Drilling and plugging.** The following guidelines shall be used to plug shotholes unless the operator can demonstrate that another method will provide adequate protection to ground water quality and movement and long-term land stability:

A. Any slurry, drilling fluids, or cuttings which are deposited on the surface around the seismic hole shall be raked or otherwise spread out to at least within one (1) inch of the surface, such that the growth of the natural grasses or foliage shall not be impaired.

B. All shotholes shall be preplugged or anchored to prevent public access if not immediately shot. In the event the preplug does not hold, seismic holes shall be properly plugged and abandoned as soon as practical after the shot has been fired. However, a fired hole shall not be left unplugged for more than thirty (30) days without approval of the Director. In no event shall shotholes be left open, but shall be covered with a tin hat or other similar cover until they are properly plugged. The hats shall be imprinted with the seismic contractor's name or identification number or mark.

C. The hole shall be filled to a depth of approximately three (3) feet below ground level by returning the cuttings to the hole and tamping the returned cuttings to ensure the hole is not bridged. A non-metallic perma-plug either imprinted or tagged with the operator name or the identification number or mark described in the notice of intent shall be set at a depth of three (3) feet, and the remaining hole shall be filled and tamped to the surface with cuttings and native soil. A sufficient mound of native soil shall be left over the hole to allow for settling.

D. When non-artesian water is encountered while drilling seismic shotholes, the holes shall be filled from the bottom up with a high grade coarse ground bentonite to ten (10) feet above the static water level or to a depth of three (3) feet from the surface; the remaining hole shall be filled and tamped to the surface with cuttings and native soil, unless the operator otherwise demonstrates that use of another suitable plugging material may be substituted for bentonite without harm to ground water resources.

E. If artesian flow (water rising above the depth at which encountered) is encountered in the drilling of any seismic hole, cement or high grade coarse ground bentonite shall be used to seal off the water flow with the selected material placed from the bottom of the hole to the surface or at least fifty (50) feet above the top of the water-bearing material, thereby preventing cross-flow between aquifers, erosion or contamination of fresh water supplies. Said holes shall be plugged immediately.

d. **COGCC Form 20A, Completion Report for Seismic Operations**. A Form 20A shall be submitted to the Director within sixty (60) days after completion of the project. The report shall include: maps (with a scale not less than 1:48,000) showing the location of all receiver lines, energy source lines and any shotholes. Shotholes encountering artesian flow shall be indicated on the map.

If the program included any shotholes, then the completion report shall be accompanied by the following:

(1) a certification by the party responsible for plugging the holes that all shotholes are plugged as prescribed by these rules and approved by the Director, and

(2) the latitude and longitude of each shothole location. Latitude and longitude values shall be referenced to the NAD 1927 and reported in decimal degrees to an accuracy of at least five (5) decimal places (e.g.; latitude 37.12345 N, longitude 104.45632 W), or reported in other form as approved by the Director. If GPS technology is utilized to determine the latitude and longitude, all GPS data shall meet the requirements set forth in Rule 303.c.(4)a. through d.

e. **Bonding Requirements.** The company submitting the Notice of Intent to Conduct Seismic Operations, Form 20, shall file financial assurance in accordance with Rule 705. prior to the commencement of operations. The bond shall remain in effect until a request is made by the company to release the bond for the following reasons:

(1) The shotholes have been properly plugged and abandoned, and source and receiver lines have been reclaimed in accordance with this Rule 333., and

(2) There are no outstanding complaints received from surface owners that have not been investigated by the Director and addressed as provided for in Rule 522.

f. **Reclamation requirements.** Upon completion of seismic operations the surface of the land shall be restored as nearly as practicable to its original condition at the commencement of seismic operations. Appropriate reclamation of disturbed areas will vary depending upon site specific conditions and may include compaction alleviation and revegetation. All flagging, stakes, cables, cement, mud sacks or other materials associated with seismic operations shall be removed.

334. PUBLIC HIGHWAYS AND ROADS

All persons subject to the Act and these rules and regulations while using public highways or roads shall be subject to the State Vehicles and Traffic Laws pursuant to Title 42, C.R.S. and the State Highway and Roads Laws, Title 43, C.R.S., pertaining to the use of public highways or roads within the state.

335. COGCC Form 15. PIT CONSTRUCTION REPORT/PERMIT

A Pit Construction Report/Permit, Form 15, shall be submitted for approval by the Director in accordance with Rule 903.

336. COGCC Form 18. COMPLAINT FORM

Any party who wishes to file a complaint regarding oil and gas operations is encouraged to submit a Form 18. The Director shall investigate any complaint and determine what, if any, action shall be taken in accordance with Rule 522.

337. COGCC Form 19. SPILL/RELEASE REPORT

All spills and releases of E&P waste exceeding five (5) barrels shall be reported on a Spill/Release Report, Form 19. Form 19 shall be filed with the Director pursuant to the reporting requirements in Rule 906.

338. COGCC Form 24. SOIL ANALYSIS REPORT

Soil Analysis Report, Form 24, shall be submitted where soil composition data is required, in accordance with Rule 910.

339. COGCC Form 25. WATER ANALYSIS REPORT

Water Analysis Report, Form 25, shall be submitted where water quality data is required, in accordance with Rule 910.

340. COGCC Form 27. SITE INVESTIGATION AND REMEDIATION WORKPLAN

Site Investigation and Remediation Workplan, Form 27, shall be submitted when required in accordance with Rule 909.

UNIT OPERATIONS, ENHANCED RECOVERY PROJECTS, AND STORAGE OF LIQUID HYDROCARBONS

401. AUTHORIZATION

a. No person shall perform any enhanced recovery operations, cycling or recycling operations including the extraction and separation of liquid hydrocarbons from natural gas in connection therewith, or operations for the storage of gaseous or liquid hydrocarbons, nor shall any person carry on any other method of unit or cooperative development or operation of a field or a part of either, without having first obtained written authorization from the Commission to perform the aforementioned activities or operations. No person shall commence construction of a well for use in either enhanced recovery operations or for storage of gaseous or liquid hydrocarbons without having first obtained written authorization from the Commission to do so. These provisions shall not apply to existing gas storage projects or to projects that have received approval of the Federal Energy Regulatory Commission; provided however, that a copy of such application and approval shall be submitted to the Commission and made a part of their records.

b. Persons wishing to obtain such authorization shall file an application for authorization with the Commission. The application may be filed by any one (1) or more of the parties involved, or by the operator of the project for which authorization is sought. The application shall include the following:

(1) A plat showing the area involved, together with the well or wells, including drilling wells, dry and abandoned wells located thereon, all properly designated. If the plan of operation involves injection of fluids for enhanced recovery operations, or storage of liquid hydrocarbons, such plat shall show the names of owners of record within one-quarter (1/4) mile of the injection well or wells indicating whether they are surface owners, mineral interest owners, or working interest owners. The application shall also include information regarding the need for remedial action on wells penetrating the injection zone within one-quarter (1/4) mile of each injection well and a plan for the performance of any such remedial work.

(2) A full description of the particular operation for which authorization is required.

(3) Copies of the unit or co-operative agreement and operating agreement, unless these agreements have already been provided to the Commission.

(4) Where injection of fluids for enhanced recovery operations or storage of liquid hydrocarbons is proposed, the application shall also contain:

A. The name, description, thickness and depth of the following formations: those from which wells are producing or having produced; those which will receive any fluids to be injected; those capable of limiting the movement of any fluids to be injected;

B. The name and the depth to the bottom of all underground sources of drinking water which may be affected by the proposed activity or operation;

C. A resistivity log, run from the bottom of the surface casing to total depth of the injection well or wells, or a resistivity log of any well within one (1) mile together with a log from that well that can be correlated with a similar log of the injection well. If the injection well is to be drilled, a description of the typical stratigraphic level of the injection formation and any other available logging or testing data;

D. A description of the casing of the injection well or wells or the proposed casing program, including a schematic drawing of the surface and subsurface construction details of the system and a full description of cement jobs already in place or proposed;

E. A statement specifying the type of fluid to be injected, chemical analysis of the fluid to be injected, the source of the fluid, the estimated amounts to be injected daily, the anticipated injection pressures, water analysis of receiving formation, any available data on the compatibility of the fluid with the receiving formations and known or calculated fracture gradient (maximum authorized surface injection pressure will be set by the Director);

F. A description of any proposed stimulation program;

G. The name and address of the operator or operators of the project and those persons notified by the applicant.

(5) This rule does not apply to gas storage projects in existence on August 18, 1986.

402. NOTICE AND DATE OF HEARING

Upon the filing of any application, the Commission shall issue notice thereof, as provided by the Act and these regulations. Said application shall be set for public hearing at such time as the Commission may fix.

403. ADDITIONAL NOTICE

If injection of fluids is proposed by said application, in addition to the notice required by the Act, a copy of such application shall be given in person or by first class mail to each owner of record of the reservoir involved within one-quarter (1/4) mile of the proposed intake well or wells. Such delivery, whether in person or by mail, shall take place on or before the date the application is filed. An affidavit shall be attached to the application showing the parties to whom the notice has been given and their addresses.

404. CASING AND CEMENTING OF INJECTION WELLS

Wells used for injection of fluids into the producing formation shall be cased with safe and adequate casing or tubing so as to prevent leakage, and shall be so set or cemented that damage will not be caused to oil, gas or fresh water resources. (Each injection well must satisfactorily pass a mechanical integrity test in accord with Rule 326. prior to injection.)

405. NOTICE OF COMMENCEMENT AND DISCONTINUANCE OF INJECTION OPERATIONS

The following provisions shall apply to all injection projects whether or not they are approved by the Commission:

a. Immediately upon the commencement of injection operations, the operator shall notify the Commission of the injection date.

b. Within ten (10) days after the discontinuance of injection operations the operator shall notify the Commission of the date of such discontinuance and the reasons therefore.

c. When any well in an approved enhanced recovery unit operation is converted to or from an injection status, notice shall be given on a Sundry Notice, Form 4, within thirty (30) days.

d. Before any intake well shall be plugged, notice shall be given to the Commission by the owner of said well, and the same procedure shall be followed in the plugging of such well as is provided for the plugging of oil and gas wells.

RULES OF PRACTICE AND PROCEDURE

501. APPLICABILITY OF RULES OF PRACTICE AND PROCEDURE

a. These rules shall be known and designated as "Rules of Practice and Procedure before the Oil and Gas Conservation Commission of the State of Colorado," and shall apply to all proceedings before the Commission. These rules shall be liberally construed to secure just, speedy, and inexpensive determination of all issues presented to the Commission.

b. Notwithstanding any provision of these rules, the Commission shall, upon its own motion or upon the motion of a party to a proceeding, act to prohibit or terminate any abuse of process by an applicant, protestant, intervenor, witness or party offering a statement pursuant to Rule 510. in a proceeding. Such action may include, but is not limited to, summary dismissal of an application, protest, intervention or other pleading; limitation or prohibition of harassing or abusive testimony; and finding a party in contempt. Grounds for such action include, but are not limited to, the use of the Commission's procedures for reasons of obstruction and delay; misrepresentation in pleadings or testimony; or, other inappropriate or outrageous conduct.

c. Any rule, regulation, or final order of the Commission shall be subject to judicial review in accordance with the provisions of the Administrative Procedure Act, §§24-4-101 to 108, C.R.S., and any other applicable provisions of law.

502. PROCEEDINGS NOT REQUIRING THE FILING OF AN APPLICATION

a. **Commission's own motion.** The Commission may, on its own motion, initiate proceedings upon any questions relating to conservation of oil and gas or the conduct of oil and gas operations in the State of Colorado, or to the administration of the Act, by notice of hearing or by issuance of an emergency order without notice of hearing. Such emergency order shall be effective upon issuance and shall remain effective for a period not to exceed fifteen (15) days. Notice of an emergency order shall be given as soon as possible after issuance.

b. **Variances.**

(1) Variances to any Commission rules, regulations, or orders may be granted in writing by the Director without a hearing upon written request by an operator to the Director, or by the Commission after hearing upon application. The operator or the applicant requesting the variance shall make a showing that it has complied with the specific requirements contained in these rules to secure a variance, if any, and that the requested variance will not violate the basic intent of the Oil and Gas Conservation Act.

(2) No variance to the rules and regulations applicable to the Underground Injection Control Program shall be granted by the Director without consultation with the U.S. Environmental Protection Agency, Region VIII, Waste Water Management Division Director.

(3) The Director shall report any variances granted at the monthly Commission hearing following the date on which such variance was granted.

503. ALL OTHER PROCEEDINGS COMMENCED BY FILING AN APPLICATION

a. All proceedings other than those initiated by the Commission or variance requests submitted for Director approval shall be commenced by filing with the Commission the original and nine (9) copies of a typewritten or printed petition which shall be titled "application." Whenever possible, the application shall also be submitted on compatible electronic media. The application shall set forth in reasonable detail the relief requested and the legal and factual grounds for such relief. The original of the application shall be executed by a person with authority to do so on behalf of the applicant and the contents thereof shall be verified by a party with sufficient knowledge to confirm the facts contained therein. Each application shall be accompanied by a docket fee established by the Commission (See Appendix III), except applications seeking an order finding violation or an emergency order.

b. Applications to the Commission may be filed by the following applicants:

(1) For purposes of applications for the creation of drilling units, applications for additional wells within existing drilling units, other applications for modifications to existing drilling unit orders, or applications for exceptions to Rule 318., only those owners within the proposed drilling unit, or within the existing drilling unit to be affected by the application, may be applicants.

(2) For purposes of applications for involuntary pooling orders made pursuant to §34-60-116, C.R.S., only those persons who own an interest in the mineral estate of the tracts to be pooled may be applicants.

(3) For purposes of applications for unitization made pursuant to §34-60-118, C.R.S., only those persons who own an interest in the mineral estate underlying the tract or tracts to be unitized may be applicants.

(4) For purposes of seeking an order finding violation, only the Director or a party who made a complaint under Rule 522. may be an applicant.

(5) For purposes of seeking a variance from the Commission, only the operator, mineral owner, surface owner or tenant of the lands which will be affected by such variance, other state agencies, any local government within whose jurisdiction the affected operation is located, or any person who may be directly and adversely affected or aggrieved if such variance is not granted, may be an applicant.

(6) For purposes of seeking a hearing on a permit-to-drill, Form 2, under Rules 303.d. and 303.k., the relevant local government shall be the applicant, and the hearing shall be conducted in similar fashion as is specified in Rule 508.j., k and l. with respect to a public issues hearing. It shall be the burden of the local government applicant to bring forward evidence sufficient for the commission to make the preliminary findings specified in subsection j of Rule 508. at the outset of such hearing.

(7) For purposes of seeking relief or a ruling from the Commission on any other matter not described in (1) through (6) above, only persons who can demonstrate that they are directly and adversely affected or aggrieved by the conduct of oil and gas operations or an order of the Commission and that their interest is entitled to legal protection under the act may be an applicant.

c. Applications subject to the requirements for local public forums under Rule 508.a. shall be accompanied by a proposed plan (the "Proposed Plan") to address protection of the environment, public health, safety, and welfare and a description of the current surface occupancy/use. The Proposed Plan shall include the rules and regulations of the Commission as they are applied to oil and gas operations in the application lands along with any procedures or conditions the applicant will voluntarily follow to address the protection of the environment, public health, safety, and welfare.

d. No later than seven (7) days after the application is filed, the applicant shall submit to the Commission a certificate of service demonstrating that the applicant served a copy of the application on all persons entitled to notice pursuant to these rules by mailing a copy thereof, first-class postage prepaid, to the last known mailing address of the person to be served, or by personal delivery. The applicant shall at the same time submit to the Commission a list of all persons entitled to notice pursuant to these rules on compatible electronic media. If the applicant is unable to submit an electronic media list of persons noticed the applicant shall submit a written list of persons noticed no later than seven (7) days after the application is filed.

e. The applicant shall enjoy a rebuttable presumption that it has properly served notice on persons entitled to notice of the proceedings by demonstrating through certification or testimony that notice was provided pursuant to Rules 507. and 508.

f. In order to continue to receive copies of the pleadings filed in a specific proceeding a party who receives notice of the application shall file with the Secretary a protest or intervention in accordance with these rules.

g. Subsequent to the initiation of a proceeding, all pleadings filed by any party shall be offered by filing with the Secretary the original and nine (9) copies bearing the cause number assigned to such proceeding. Each pleading shall include the certificate of the party filing the pleading that the pleading has been served on all persons who have filed a protest or intervention in accordance with these rules, by mailing a copy thereof, first-class postage prepaid, to the last known mailing address of the person to be served, or by personal delivery.

504. DOCKET NUMBER OF PROCEEDINGS

When a proceeding is initiated the Secretary of the Commission shall assign it a new docket number and enter on a separate page of a docket provided for such purpose, the proceeding with the date of the filing of the application, or the date of the entry of the Commission order, initiating such proceeding. All subsequent pleadings shall be assigned the same docket number and shall be noted with the date of filing upon the docket page or continued docket page, for such proceeding, as the case may be.

505. REQUIREMENT OF PUBLIC HEARING

Before the Commission adopts any rule, regulation, or enters any order, or amendment thereof, or grants any variance pursuant to Rule 502., the Commission shall hold a public hearing, scheduled in accordance with Rule 506., at such time and place as may be prescribed by the Commission. Any party shall be entitled to be heard as provided in these rules and regulations. The foregoing shall not apply to the issuance of an emergency order, notice of alleged violation, or cease and desist order.

506. HEARING DATE/CONTINUANCE

a. All applications shall be filed no later than fifty (50) days in advance of the hearing date for which the applicant proposes the matter be docketed provided the docket has not been filled by the Secretary. The Secretary shall have the discretion to accept applications later than fifty (50) days prior to the hearing date, subject to docket availability and the notice requirements of Rules 507. and 508. The Secretary shall grant the first request by an applicant for a continuance of any matter three (3) business days before the scheduled hearing, provided that a protest has not been filed. For contested matters the Secretary shall have the discretion to grant any motion for continuance stipulated to by the applicant and any protestants or intervenors. The Secretary shall notify the Commission of any continuances granted at the next regularly scheduled Commission meeting. The Commission may at any time direct the Secretary to discontinue granting continuances in any matter. In all other cases, requests for continuance shall be reviewed by the Commission before approval or denial. When a continuance request is heard by the Commission the moving party shall demonstrate good cause in order for the Commission to grant the continuance.

b. In all rulemaking proceedings, hearings shall be held in accordance with Rule 529.

c. The Commission may for good cause cancel or continue any hearing to another date by issuing written notice at any time prior to the close of the record, or by announcement at hearing. Good cause shall include, but shall not be limited to, the Commission's acknowledgment that it will not have sufficient time at any regularly scheduled meeting to hear any matter. Any continuance of a hearing shall not extend the filing deadline for the filing of protests or interventions in accordance with Rule 509., unless the application is amended, or as otherwise allowed by the Commission.

d. When a Commission hearing is scheduled for multiple days the Secretary may estimate the time and date that a given matter may be heard by the Commission. The Commission may change, at its discretion, the proposed hearing docket, including the time or date of any scheduled hearing. It shall be the responsibility of the participating party and its attorney to be present when the Commission hears the matter.

507. NOTICE FOR HEARING

a. **General notice provisions**

(1) When any proceeding has been initiated, the Commission shall cause notice of such proceeding to be given to all persons specified in the relevant sections of Rules 507.b. and 507.c. at least twenty (20) days in advance of any Commission hearing at which the matter will first be heard. Notice shall be provided in accordance with the requirements of §34-60-108(4), C.R.S.

(2) The applicant shall assume the cost for publication, and if the number of notices exceeds one hundred (100), responsibility for mailing the notices.

(3) The Secretary shall give notice to any person who has filed a request to be placed on the Commission hearing notice list, and paid the annual fee therefor. Notice by publication or notice provided pursuant to the hearing notice list shall not confer interested party status on any person.

b. **Notice for specific applications**

(1) **Applications affecting drilling units.** For purposes of applications for the creation of drilling units, applications for additional wells within existing drilling units or other applications for modifications of or exceptions to existing drilling unit orders (except for applications for well exception locations to existing orders which are addressed in subsection 4 of this rule) notice of the application shall be served on the owners within the proposed drilling unit or within the existing drilling unit to be affected by the applications.

(2) **Applications for involuntary pooling.** For purposes of applications for involuntary pooling orders made pursuant to §34-60-116, C.R.S., notice of the application shall be served on those persons who own any interest in the mineral estate of the tracts to be pooled, except owners of an overriding royalty interest.

(3) **Applications for unitization.** For purposes of applications for unitization made pursuant to §34-60-118, C.R.S., notice of the application shall be served on those persons who own any interest in the mineral estate underlying the tract or tracts to be unitized and the owners within one-half (1/2) mile of the tract or tracts to be unitized.

(4) **Applications changing certain well location setbacks.** For purposes of applications that change the permitted minimum setbacks for established drilling and spacing units, notice of the application shall be served on those owners of contiguous or cornering tracts who may be affected by such change.

(5) **Applications for well location exception.** For purposes of applications made for exceptions to Rule 318., exceptions to legal locations within drilling and spacing units, or for an exception location to an existing order, notice of the application shall be served on the owners of any contiguous or cornering tract toward which the well location is proposed to be moved, provided that when the applicant owns any interest covering such tract, the person who owns the mineral estate underlying the tract covered by such lease shall also be notified. If there is more than one owner within a single drilling unit and the owners have designated a party as the operator on their behalf, notice shall be presumed sufficient if served upon the designated operator of the affected formation.

(6) **Orders related to violations.** With respect to the resolution of a Notice of Alleged Violation (NOAV) through an Administrative Order by Consent (AOC), and to applications for an Order Finding Violation (OFV), notice shall be provided to the complainant and by publication in accordance with §34-60-108(4), C.R.S.

c. **Notice to local government.** For purposes of intervention pursuant to Rule 509. notice shall also be given to the local governmental designee of applications made under sections (1), (3) and (4) of this Rule at the same time that notice is provided to the Commission.

508. LOCAL PUBLIC FORUMS, HEARINGS ON APPLICATIONS FOR INCREASED WELL DENSITY AND PUBLIC ISSUES HEARINGS.

a. Applicability of rule. Applications that would result in more than one (1) well site or multi-well site per forty (40) acre nominal governmental quarter-quarter section or that request approval for additional wells that would result in more than one (1) well site or multi-well site per forty (40) acre nominal governmental quarter-quarter section, within existing drilling units, not previously authorized by Commission order (together an "application for increased well density") shall be subject to the provisions of this Rule 508.

b. **Local public forum.**

(1) The rules and regulations of the Oil and Gas Conservation Commission as they are applied to oil and gas operations are expected to adequately address impacts to the environment and public health, safety and welfare which may be raised by an application for increased well density.

(2) A local public forum may however be convened to consider potential issues related to the environment or public health, safety, and welfare that may be raised by an application for increased well density that may not be completely addressed by these rules or the Proposed Plan submitted with the application to address protection of the environment, public health, safety, and welfare as described in Rule 503.c.

A. A local public forum shall be convened on the Commission's own motion, or upon request from a local governmental designee or the applicant.

B. A local public forum may be convened at the Director's discretion, or upon receipt of a request for a local public forum from a citizen of the county(ies) in which the application area is situated, after the Director's consideration of the following factors:

(i) The size of the application area and the number and density of surface locations requested;

(ii) The population density of the application area;

(iii) The distribution of Indian, federal and fee lands within the application area;

(iv) The level of current or past public interest in increased well density in the vicinity of the application area;

(v) Whether the application is limited to the deepening or recompletion of existing wells, or directional drilling from existing surface locations, or;

(vi) Whether the application is limited to an exploratory unit formed for involuntary pooling purposes.

(3) The Director shall notify the local governmental designee of any application for increased well density no later than five (5) days after receipt of such application. If the local governmental designee elects to require a local public forum it shall notify the Director of its decision within five (5) days of receipt of notice of the application.

(4) The Director shall notify the applicant of any decision to convene a local public forum no later than ten (10) days after receipt of the application.

c. **Local public forums on federal and Indian lands.**

(1) If the surface and the minerals of the application area are comprised in their entirety of federal or Indian lands no local public forum shall be convened because potential impacts to the environment or public health, safety, and welfare on such lands are subject to federal or tribal requirements. All proceedings on any application for increased well density on federal or Indian lands shall be conducted to comply with the obligations contained in any intergovernmental or tribal memoranda of understanding governing the conduct of oil and gas operations on federal or Indian lands.

(2) If the application area is comprised in part of federal or Indian lands, the Director shall consult with the appropriate federal or Indian authorities before scheduling any public forum on the application. Insofar as the application includes federal or Indian lands, proceedings thereon shall be conducted in accordance with this rule and any obligations contained in any intergovernmental or tribal memoranda of understanding governing the conduct of oil and gas operations on federal or Indian lands.

(3) The Director shall notify the appropriate federal and Indian authorities of any local public forum to be convened to evaluate an application area that includes federal or Indian lands. Federal or Indian participation in the local public forum may include without limitation presentation of the most recent applicable resource management plan(s) and any environmental assessment(s) or environmental impact statement(s) that cover or include all or any portion of the application area.

d. **Notice of the local public forum.**

(1) Within five (5) days from the date the applicant receives notice from the Director that a local public forum shall be convened, the applicant shall submit to the Director a list of the surface owners within the application area. In determining the identity and address of a surface owner for the purpose of giving all notices under this rule the records of the assessor for the county in which the lands are situated may be relied upon.

(2) At least twenty (20) days before the date of the local public forum the Director shall mail to the listed surface owners notice thereof.

(3) Within ten (10) days of receipt of an application for increased well density the Director shall, by regular or electronic mail or by facsimile copy, provide to the local governmental designee(s) notice of the local public forum or notice that based on the factors in Rule 508.b.(2).B. above the Director will not conduct a local public forum.

(4) At least ten (10) days before the date of the local public forum the Director shall publish notice thereof in a newspaper of general circulation in the count(ies) where the application lands are located.

(5) The notice for the local public forum shall state that the forum is being conducted to consider any issues raised by the application that may affect the environment or public health, safety, and welfare that are not addressed by the rules or the Proposed Plan.

(6) Within five (5) days of receipt of an application for increased well density, the Director shall post a description of such application on the COGCC Internet web page.

e. **Timing and location of the local public forum.**

(1) As soon as practicable after publication of notice, but at least ten (10) days prior to the scheduled Commission hearing on the application, the Director shall conduct the local public forum at a location

reasonably proximate to the lands affected by the application. In the alternative, if the hearing is to be held at a location reasonably proximate to the lands affected by the application, the local public forum shall be replaced by the presentation of statements in accordance with Rule 510 during the hearing on the application.

(2) The Director shall immediately notify the applicant of the scheduled time and location of the local public forum.

(3) To the extent practicable, the local public forum shall be scheduled to accommodate the Director or the Director's designee, the participants and the applicant.

(4) If the application area is comprised of lands located in more than one jurisdiction the Director shall coordinate the local public forum to provide for a single forum at a reasonable location proximate to the lands affected by the application.

f. **Conduct of the local public forum.**

(1) A COGCC Hearing Officer shall preside over the local public forum. The COGCC Hearing Officer shall provide to the participants an explanation of the purpose of the local public forum and how the Commission may use the information obtained from the local public forum. The purpose of the local public forum is to address the sufficiency of the rules or the Proposed Plan with respect to protection of the environment or public health, safety, and welfare.

(2) The conduct of the local public forum shall be informal, and participants shall not be required to be sworn, represented by attorneys, or subjected to cross examination.

(3) Attendance or participation at the local public forum by a Commissioner shall not constitute a violation of Rule 515.

(4) The applicant shall participate in the local public forum and present information related to the application.

(5) The Director shall create a record of the local public forum by video-tape, audio-tape or by court reporter. Such record shall be made available to all Commissioners for review prior to the hearing on the application, and may be relied upon in making a decision to convene a public issues hearing.

g. The local public forum shall be conducted to allow elected officials, local government personnel and citizens to express concerns not completely addressed by the rules or the Proposed Plan or make statements regarding the potential impacts from increased well density that relate to the environment or public health, safety, and welfare. Issues raised in the local public forum may include the following:

(1) Impact to local infrastructure;

(2) Impact to the environment;

(3) Impact to wildlife;

(4) Impact to ground water resources;

(5) Potential reclamation impact; and

(6) Other impact to public health, safety and welfare.

The local public forum shall be limited to matters that are within the jurisdiction of the Commission.

h. **Report to the Commission.** At the conclusion of the local public forum the presiding officer shall prepare and submit to the Commission a report of the proceedings. A copy of the report shall be made available, no later than five (5) days prior to the hearing on the application, to the Commissioners, the applicant, any affected local government and the public and shall be posted to the COGCC Internet web page. The report on the local public forum presented to the Commission shall be included in the administrative record for the application taking into consideration the nature of the local public forum process.

i. **Conduct of the hearing on the application.**

(1) The hearing on the application shall be conducted in accordance with Rule 528.

(2) The Commission shall approve or deny the application based solely on the application's technical merits in accordance with §34-60-116, C.R.S.

(3) The presiding officer for any local public forum shall present to the Commission the report of the local public forum.

(4) At the conclusion of the hearing on the application the Commission shall consider and decide whether to convene a public issues hearing based on the local public forum or statements made under Rule 510., and any motions to intervene, and the Commission may:

A.Approve the application without condition;

B.Approve the application with conditions based on the technical testimony presented at the hearing on the application;

C. Approve the application, and with the applicant's consent, attach to the order on the application conditions the Commission determines are necessary to address issues related to the environment or public heath, safety or welfare;

D. Approve the application and stay its effective date to convene a public issues hearing in accordance with Rule 508.j.

E.Deny the Application.

(5) If the Commission orders a public issues hearing it shall set the public issues hearing for the next regularly scheduled Commission meeting, unless the applicant requests at a prehearing conference, and the Commission agrees, to convene the public issues hearing immediately following the hearing on the application.

(6) If the Commission orders a public issues hearing it shall set the public issues hearing for the next regularly scheduled Commission meeting.

j. **Public issues hearing**

Upon a request by an applicant, protestant, or intervener, or on the Commission's own motion, a public issues hearing shall be convened provided the Commission makes the following preliminary findings:

(1) That the public issues raised by the application reasonably relate to potential significant adverse impacts to the environment or public health, safety and welfare that are within the Commission's jurisdiction to remedy; and

(2) That the potential impacts were not adequately addressed by:

A. In the case of an application for increased well density, the application or the Proposed Plan; or

B. In the case of an application for permit-to-drill, by such permit.

(3) That the potential impacts are not adequately addressed by the rules and regulations of the Commission.

k. **Conduct of the public issues hearing:**

(1) The rules and regulations of the Commission shall apply to all participants in the public issues hearing.

(2) The public issues hearing shall be conducted, to the extent practicable, in accordance with Rule 528.

(3) After the public issues hearing the Commission may attach conditions to its order to protect the environment from significant adverse impacts or to protect public health safety and welfare as are warranted by the relevant testimony, and that are not otherwise addressed by these rules and regulations and the Proposed Plan. In addition, the Commission may without limitation:

A. Direct the applicant to amend its Proposed Plan for Commission review and approval for all or a portion of the application area to address specific issues related to the environment or public health, safety and welfare, including any identified impacts of increased well density within all or a portion of the application area, rather than on a single well basis.

B. Include in any order a provision to allow the Director discretion to attach specific conditions to individual well permits as the Commission determines are reasonable and necessary to protect the environment or public health, safety, and welfare.

(4) Any plan or conditions imposed by Commission order that would affect federal or Indian lands sall take into account conditions imposed by the federal or Indian authorities and any federal environmental analysis in order to facilitate regulatory consistency and minimize duplicative regulatory efforts.

(5) Any plan or conditions imposed shall take into account cost effectiveness and technical feasibility, and shall not be applied to prevent the drilling of new wells per se.

I. The Director and the commission shall use best efforts to comply with the provisions of this Rule 508., however, any deviation from this rule shall not give rise to a challenge to Commission action on the local public forum, the application for increased well density, or the public issues hearing.

509. PARTICIPATION IN ADJUDICATORY PROCEEDINGS

a. The applicant and persons that have filed with the Commission a timely and proper protest or intervention pursuant to this rule shall have the right to participate formally in any adjudicatory proceeding. In the case of a local government, intervention shall be granted by right and without fee solely to raise environmental or public health, safety, and welfare concerns.

(1) The protest or intervention shall be filed with the Secretary, and served on the applicant and its counsel at least ten (10) business days prior to the first hearing date on the matter.

(2) Description of affected interest:

A. A protest shall include information to demonstrate that the person is a protestant under these rules in order for the protest to be accepted by the Commission.

B. A local government intervening as a matter of right shall include in the intervention information describing the environmental or public health, safety and welfare concerns raised by the application. When an intervention is filed by any local government or person on an application subject to Rule 508.a., information on the following shall be included:

i. That the public issues raised by the application reasonably relate to potential significant adverse impacts to the environment or public health, safety and welfare that are within the Commission's jurisdiction to remedy; and

ii. That the potential impacts were not adequately addressed by the application or by the Proposed Plan; and

iii. That the potential impacts are not adequately addressed by the rules and regulations of the Commission.

C. A party desiring to intervene by permission of the Commission shall include in the intervention information to demonstrate why the intervention will serve the public interest, in which case granting the intervention shall be at the Commission's sole discretion. The Commission, at its discretion, may limit the scope of the permissive intervenor's participation at the hearing.

(3) The pleading shall include:

A. A general statement of the factual or legal basis for the protest or intervention,

B. The relief requested;

C. A description of the intended presentation including a list of proposed witnesses;

D. A time estimate to hear the protest or intervention; and

E. A certificate of service attesting that the pleading has been served, at least ten (10) business days prior to the first hearing date on the matter, on the applicant and any other party which has filed a protest or intervention in the proceeding. If the pleading is served by mail the party filing the pleading shall provide a facsimile copy of the pleading to the applicant and other persons who have filed a proper protest or intervention in the matter on or before the final date for protest or intervention. If for any reason the party filing the pleading is not able to furnish a copy of the pleading to the applicant and the other persons who have filed a proper protest or intervention on or before the final date for protest or intervention, the party filing the pleading shall so notify the Secretary, the applicant and the other parties to the proceeding.

b. The Secretary or the Director may require any additional information necessary pursuant to these rules to ensure the application, protest or intervention is complete on its face.

c. Any person shall have the right to participate in an adjudicatory proceeding by making a 510. statement in accordance with these rules.

d. All pleadings filed pursuant to this rule shall be submitted with an original and nine (9) copies, and shall be accompanied by a docket fee established by the Commission (see Appendix III). The docket fee shall be refunded if an intervention is denied. In cases of extreme hardship, the docket fee may be refunded at the discretion of the Commission.

e. **Participation at the hearing:**

(1) Adjudicatory hearings shall be conducted in accordance with Rule 528. and any applicable prehearing orders of the Commission, or its designated Hearing Officer.

(2) Testimony and cross-examination by a protestant or intervenor shall be limited to those issues that reasonably relate to the interests that the protestant or intervenor seeks to protect, and which may be adversely affected by an order of the Commission.

510. STATEMENTS AT HEARING

a. Any person may make an oral statement or submit a written statement at any hearing that relates to the proceeding before the Commission. The Commission, at its discretion, may limit the length of any oral statement or restrict repetitive statements. In an adjudicatory hearing, an oral statement shall not be accepted into the record unless:

(1) The statement is made under oath, and

(2) The parties to the hearing are allowed to cross-examine the maker of the statement.

b. The Commission, at its discretion, may accept a sworn written statement into the record with due regard to the fact the statement was not subject to cross-examination.

c. The parties to the hearing shall have the right to object to inclusion of any statement under this Rule 510. into the record. The Commission shall note the objection for the record. If the Commission accepts the basis for excluding the 510. statement from the record the substance of the statement shall not be considered by the Commission in making a decision on the matter at issue.

511. APPLICATION PROCEDURE

a. Upon the filing of an application, the Secretary shall set the matter for hearing and ensure that notice is given.

b. If the matter is uncontested, the applicant may request, and the Director may recommend approval on the basis of the merits of the verified application and the supporting exhibits. If the Director does not recommend approval of the application without hearing, the applicant may request an administrative hearing on the application. For purposes of this rule an uncontested matter shall mean any application that is not subject to a protest or an intervention objecting to the relief requested in the application.

c. If the application is contested, the Commission or the Director, at their discretion, may direct the parties to engage in a prehearing conference in accordance with Rule 527. A prehearing conference may result in a continuance of the hearing, or bifurcation of hearing issues as determined by the Director, Hearing Officer or Hearing Commissioner.

512. COMMISSION MEMBERS REQUIRED FOR HEARINGS AND/OR DECISIONS

Four (4) members of the Commission constitute a quorum for the transaction of business. Testimony may be taken and oath or affirmation administered by any member of the Commission.

513. RESERVED

514. JUDICIAL REVIEW

Any Commission order constitutes final agency action for the purpose of judicial review, except as may otherwise be specified under these rules. The statutory time period for filing a notice of appeal from any Commission decision shall commence on the date the order is mailed or served.

515. EX PARTE COMMUNICATIONS

a. The following provisions shall be applied in any adjudicatory proceeding before the Commission or a Hearing Officer.

(1) No person shall make or knowingly cause to be made to any member of the Commission or a Hearing Officer, an ex parte communication concerning the merits of a proceeding which has been noticed for hearing.

(2) No Commissioner or Hearing Officer shall make or knowingly cause to be made to any interested person an ex parte communication concerning the merits of a proceeding which has been noticed for hearing.

(3) A Commissioner or Hearing Officer who receives, or who makes or knowingly causes to be made, a communication prohibited by this rule shall place on the public record of a proceeding:

A. All such written communications and any responses thereto;

B. Memoranda stating the substance of any such oral communications and any responses thereto.

(4) Upon receipt of a communication knowingly made or knowingly caused to be made by a person in violation of this Rule, the Commission or a Hearing Officer may require the person to show cause why their claim or interest in the proceeding should not be dismissed, denied, or otherwise adversely affected on account of such violation.

b. Oral or written communication with individual Commission members is permissible in a rulemaking proceeding. If such information is relied upon in final decision making it shall be made part of the record by the Commission. After the rulemaking record is closed new information that is intended for the rulemaking record shall be presented to the Commission as a whole upon approval of a request to reopen the rulemaking record.

c. This rule shall not limit the right to challenge a decision of the Commission or a Hearing Officer on the grounds of bias or prejudice due to any ex parte communication.

516. STANDARDS OF CONDUCT

a. The purpose of this rule is to ensure that the Commission's decisions are free from personal bias and that its decision making processes are consistent with the concept of fundamental fairness. The provisions of this rule are in addition to the requirements for Commission members set forth in Title 24, Article 18, Section 108.5 of the Colorado Revised Statutes. This rule should be construed and applied to further the objectives of fair and impartial decision making. To achieve these standards Commissioners and Hearing Officers should:

(1) Discharge their responsibilities with high integrity.

(2) Respect and comply with the law. Their conduct, at all times, should promote public confidence in the integrity and impartiality of the Commission.

(3) Not lend the prestige of the office to advance their own private interests, or the private interests of others, nor should they convey, or permit others to convey, the impression that special influence can be brought to bear on them.

b. **Conflicts of interest.** A conflict of interest exists in circumstances where a Commissioner or Hearing Officer has a personal or financial interest that prejudices that Commissioner's or Hearing Officer's ability to participate objectively in an official act.

(1) A Commissioner or a Hearing Officer shall disclose the basis for a potential conflict of interest to the Commission and others in attendance at the hearing before any discussion begins or as soon thereafter as the conflict is perceived. A conflict of interest may also be raised by other Commissioners, the applicant, any protestant or intervenor, or any member of the public.

(2) In response to an assertion of a conflict of interest, a Commissioner may withdraw or the Director may designate an alternate Hearing Officer. If the Commissioner does not agree to withdraw, the other Commissioners, after discussion and comments from any member of the public, shall vote on whether a conflict of interest exists. Such vote shall be binding on the Commissioner disclosing the conflict.

(3) In determining whether there is a conflict of interest that warrants withdrawal the Commission members or Hearing Officer shall take the following into consideration:

A. Whether the official act will have a direct economic benefit on a business or other undertaking in which the Commissioner or Hearing Officer has a direct or substantial financial interest.

B. Whether the potential conflict will result in the Commissioner or Hearing Officer not being capable of judging a particular controversy fairly on the basis of its own circumstances.

C. Whether the potential conflict will result in the Commissioner or Hearing Officer having an unalterable closed mind on matters critical to the disposition of the proceeding.

c. **Discharge of duties.** In the performance of their official duties, the Commission shall apply the following standards:

(1) To be faithful to and constantly strive to improve their competence in regulatory principles, and to be unswayed by partisan interests, public clamor or fear of criticism.

(2) To maintain order and decorum in the proceedings before them.

(3) To be patient, dignified and courteous to litigants, witnesses, lawyers and others with whom the Commission deals in an official capacity, and to require similar conduct of attorneys, staff and others subject to their direction and control.

(4) To afford to every person who is legally interested in a proceeding, or their attorney, full right to be heard according to law.

(5) To diligently discharge their administrative responsibilities, maintain professional confidence in Commission administration and facilitate the performance of the administrative responsibilities of other staff officials.

517. REPRESENTATION AT ADMINISTRATIVE AND COMMISSION HEARINGS

a. Natural persons may appear on their own behalf and represent themselves at hearings before the Commission and persons allowed to make oral or written statements may do so without counsel. Pro se participants shall be subject to these rules and regulations.

b. Except as provided in a. and c. of this rule, representation at hearings before the Commission shall be by attorneys licensed to practice law in the State of Colorado, and provided that any attorney duly admitted to practice law in a court of record of any state or territory of the United States or in the District of Columbia, but not admitted to practice in Colorado, who appears at a hearing before the Commission may, upon motion, be admitted for the purpose of that hearing only, if that attorney has associated for purposes of that hearing with any attorney who:

(1) Is admitted to practice law in Colorado;

(2) Is a resident or maintains a law office within Colorado; and

(3) Is personally appearing with the applicant in the matter and in all proceedings connected with it.

The resident attorney shall continue in the case unless other resident counsel is submitted. Any notice, pleading, or other paper may be served upon the resident attorney with the same effect as if personally served on the non-resident attorney within this state. Resident counsel shall be present before the Commission unless otherwise ordered by the Commission.

c. The Commission has the discretion to allow representation by a corporate officer or director of a community organization, a closely held corporation, a citizens' group duly authorized under Colorado law, or if a limited liability corporation, the member/manager in the following circumstances:

(1) Where the agency is adopting a rule of future effect;

(2) Local public forums;

(3) When an individual is appearing on behalf of a closely held corporation as provided in §13-1-127, C.R.S.;

d. Unless a non-attorney is appearing pro se or pursuant to §13-1-127, C.R.S., or the Director is participating pursuant to Rule 528.c., a non-attorney shall not be permitted to examine or cross-examine witnesses, make objections or resist objections to the introduction of testimony, or make legal arguments.

e. At administrative hearings before the Director, attorneys shall not be required.

518. SUBPOENAS

The Commission may, through the Secretary, issue subpoenas requiring attendance of witnesses and the production of books, papers, and other instruments to the same extent and in the same manner and in accordance with the procedure provided in the Colorado Rules of Civil Procedure which authorize issuance of subpoenas by Clerks of District Courts. A party seeking a subpoena shall submit the form of the subpoena to the Secretary for execution. Upon execution, the party requesting the subpoena has the responsibility to serve the subpoena in accordance with the Rules of Civil Procedure. Upon receipt of an objection to any subpoena issued by the Commission, the Commission has the discretion to limit the scope of the subpoena to matters that are within the scope of the Commission's jurisdiction under the Act.

519. APPLICABILITY OF COLORADO COURT RULES AND ADMINISTRATIVE NOTICE.

a. The Commission adopts the rules of practice and procedure contained in the Colorado Rules of Civil Procedure insofar as the same may be applicable and not inconsistent with the rules herein set forth.

b. In general, the rules of evidence applicable before a trial court without a jury shall be applicable, providing that such rules may be relaxed, where, by so doing, the ends of justice will be better served.

(1) To promote uniformity in the admission of evidence, the Commission, to the extent practical, shall observe and conform to the Colorado rules of evidence applicable in civil non-jury cases in the district courts of Colorado.

(2) When necessary to ascertain facts affecting substantial rights of the parties to a proceeding, the Commission may receive and consider evidence not admissible under the rules of evidence, if the evidence

possesses probative value commonly accepted by reasonable and prudent persons in the conduct of their affairs.

(3) Informality in any proceeding or in the manner of taking testimony shall not invalidate any Commission order, decision, rule or regulation.

c. **Administrative notice.** The Commission may take administrative notice of:

(1) Constitutions and statutes of any state and of the United States;

(2) Rules, regulations, official reports, decisions, and orders of state and federal administrative agencies;

(3) Decisions and orders of federal and state courts;

(4) Reports and other documents in the files of the Commission;

(5) Matters of common knowledge and undisputed technical or scientific fact;

(6) Matters that may be judicially noticed by a Colorado district court in a civil non-jury case; and

(7) Matters within the expertise of the Commission.

520. TIME OF HEARINGS AND HEARING AGENDA

a. Regular hearings will be held before the Commission on such days as may be set by the Commission.

b. The Secretary shall place on the consent agenda those matters recommended by a Hearing Officer for approval, those matters in which an Administrative Order by Consent (AOC) has been negotiated, and those uncontested matters for which a decision has been requested based on the verified application.

(1) The consent agenda shall be voted on without deliberation and without the necessity of reading the individual items, except any Commissioner may request clarification from the Director for any matter on the consent agenda.

(2) Any Commissioner may remove a matter from the consent agenda prior to voting thereon.

(3) Any matter removed from the consent agenda shall be heard at the end of the remaining agenda, if practicable and agreeable to the applicant, or, if not, scheduled for hearing at the next regularly scheduled meeting of the Commission.

521. RESERVED

522. PROCEDURE TO BE FOLLOWED REGARDING ALLEGED VIOLATIONS

a. **Notice of Alleged Violation.**

(1) A complaint requesting that the Director issue a Notice of Alleged Violation (NOAV) may be made by the mineral owner, surface owner or tenant of the lands upon which the alleged violation took place, by other state agencies, by the local government within whose boundaries the lands are located upon which the alleged violation took place, or by any other person who may be directly and adversely affected or aggrieved as a result of the alleged violation.

(2) Oral complaints shall be confirmed in writing. Persons making a complaint are encouraged to submit a Complaint Form, Form 18.

(3) If the Director, on the Director's own initiative or based on a complaint, has reasonable cause to believe that a violation of the Act, or of any rule, regulation, or order of the Commission, or of any permit issued by the Director, has occurred, the Director shall cause the operator to voluntarily remedy the violation, or shall issue a NOAV to the operator. Reasonable cause requires, at least, physical evidence of the alleged violation, as verified by the Director.

(4) If the Director, after investigating a complaint made in accordance with this Rule 522.a.(1), decides not to issue a NOAV, the complainant may file an application to the Commission pursuant to Rule 503.b.(4), requesting the Commission enter an Order Finding Violation (OFV) in accordance with this rule.

(5) **NOAV process**

A. A NOAV issued by the Director shall be served on the operator's designated agent, or on the operator if no agent has been designated, by personal delivery or by certified mail, return receipt requested.

B. The NOAV shall not be placed on the Commission docket, except as part of an application filed pursuant to subparagraph c. of this rule.

C. The NOAV does not constitute final agency action for purposes of judicial appeal.

D. The NOAV shall identify the statute, rule, regulation, order, permit or permit condition subject to Commission jurisdiction allegedly violated and the facts alleged to constitute the violation. The NOAV may propose appropriate corrective action and an abatement schedule, if any, that the Director elects to require. The NOAV shall also describe the penalty, if any, which the Director may propose, to be recommended in accordance with Rule 523.

b. **Resolution of a Notice of Alleged Violation.**

(1) Informal procedures to resolve issues raised by a NOAV with the Director are encouraged. Such procedures may include, but are not limited to, meetings, phone conferences and the exchange of information. If, as a result of such procedures, the Director determines that no violation has occurred, the Director shall revoke the NOAV in writing and shall provide a copy of the written notification to the complainant, if any.

(2) NOAVs may be resolved by written agreement of the operator and the Director as to the appropriate corrective action and abatement schedule, a copy of which shall be provided by the Director to the complainant, if any. Such agreements do not require Commission approval and shall not be placed on the Commission docket, except at the request of the operator.

(3) NOAVs which are not resolved by written agreement for correction and abatement or which recommend the imposition of a penalty may be provisionally resolved by negotiation between the operator and the Director. If such negotiations result in a proposed agreement, an Administrative Order By Consent (AOC) containing such agreement shall be prepared and noticed for review and approval by the Commission. The Director may propose the terms for an AOC directly to the alleged violator. Upon Commission approval, the AOC shall become a final order, and the agreed penalty imposed. The AOC shall be placed on the consent agenda and Commission approval may be granted without hearing, unless a protest thereto is filed. Unless the operator so agrees, such AOC shall not constitute an admission of the alleged violation.

(4) The Director shall advise the complainant of any informal procedures used to facilitate resolution of the NOAV. A complainant may object to the proposed resolution by AOC. At the Director's discretion the AOC may be reviewed and modified based on the complainant's concerns, with the consent of the operator. If the complainant objects to the Director's final decision to revoke or settle the NOAV, the complainant shall have the right to file with the Commission an application for an Order Finding Violation (OFV). Such application shall be filed within forty-five (45) days of the Director's decision and shall be served on the Director and the operator.

c. **Order Finding Violation.**

(1) If the operator contests the NOAV, as to the existence of the violation, the appropriate corrective action and abatement schedule, or as to any proposed penalty, the Director shall make application to the Commission for an OFV and shall place the matter on the next available Commission docket, providing that at least twenty (20) days notice of such application is provided to the operator.

(2) If the Director decides not to issue a NOAV, the Commission may conduct a hearing to consider whether to issue an OFV upon twenty (20) days notice to the affected operator under the following circumstances:

A. On the Commission's own initiative if it believes that the Director has failed to enforce a provision of statute, rule, regulation, order, permit or permit condition subject to Commission jurisdiction.

B. On the application of a complainant pursuant to Rule 503.b.(4), provided that such complainant has first made a written request to the Director to issue an NOAV and the Director has determined in writing not to do so. An application by a complainant shall be filed within forty-five (45) days of the Director's written determination.

(3) Upon an operator's request a settlement conference shall be held with the Director no less than five (5) days before the hearing on an OFV. If an agreement is reached, an AOC containing such agreement shall be prepared and noticed for review and approval by the Commission, at its discretion. Upon such approval, the AOC shall become a final order, and the agreed penalty shall be imposed. Such approval may be granted without hearing, unless a hearing thereon is requested by a complainant. Unless the operator so agrees, such AOC shall not constitute an admission of the alleged violation.

(4) A hearing to consider whether to issue an OFV shall be a de novo proceeding, unless the parties stipulate as to the facts, or as to the appropriate corrective action and abatement schedule, in which case the hearing may be accordingly limited.

(5) The Director is always a necessary party to a hearing on an OFV. The operator against which an OFV is sought is always a necessary party but need not present a case. Any person, which is not the applicant for an OFV, but whose complaint initiated the enforcement proceeding, shall be granted intervenor status if so requested, pursuant to Rule 509., except that the filing fee shall be waived.

d. **Cease and Desist Orders.**

(1) The Commission or the Director may issue a cease and desist order whenever an operator fails to take corrective action required by final AOC or OFV.

(2) Whenever the Commission has evidence that a violation of any provision of the Act, any rule, permit, or order of the Commission has occurred under circumstances deemed to constitute an emergency situation, the Commission or the Director may issue a cease and desist order. If the order is entered by the Director it shall be immediately reported to the Commission for review and approval. Such order shall be considered a final order for purposes of judicial review.

(3) The order shall be served by personal delivery or by certified mail, return receipt requested, or by confirmed facsimile copy followed by a copy provided by certified mail, return receipt requested, to the operator's designated agent, or on the operator if no agent has been designated, for service of process and shall state the provision alleged to have been violated, the facts alleged to constitute the violation, the time by which the acts or practices cited are required to cease, and any corrective action the Commission or the Director elects to require of the operator. Any protest by an operator to a cease and desist order issued by the Director shall automatically stay the effective date of the order, in which case the order shall not be considered final for purposes of judicial review until such protest is heard.

(4) In the event an operator fails to comply with a cease and desist order, the Commission may request the attorney general to bring suit pursuant to §34-60-109, C.R.S.

523. PROCEDURE FOR ASSESSING FINES

a. **Fines.** An operator who violates any provision of the Act or any rule, permit, or order issued by the Commission shall be subject to a fine which shall be imposed only by order of the Commission, after hearing, or by an AOC approved by the Commission. All fines shall be calculated using the base fine amount for the particular violation as set forth in the fine schedule in subparagraph c. of this Rule 523., subject to the following:

(1) The Commission may in its discretion find that each day a violation exists constitutes a separate violation; however, no fine for any single violation shall exceed one thousand dollars ($1,000) per day.

(2) All fines shall be subject to adjustment based upon the factors listed in subparagraph d. of this Rule 523.

(3) For a violation which does not result in significant waste of oil and gas resources, damage to correlative rights, or a significant adverse impact on public health, safety or welfare, the maximum penalty for any single violation shall not exceed ten thousand dollars ($10,000) regardless of the number of days of such violation.

(4) Fines for violations for which no base fine is listed shall be determined by the Commission at its discretion subject to subparagraphs (1), (2), and (3) of this Rule 523.a.

b. **Voluntary disclosure.** Any operator who conducts a voluntary self-evaluation as defined in the 100 Series of the rules and makes a voluntary disclosure to the Director of a significant adverse impact on the environment or of a failure to obtain or comply with any necessary permits, shall enjoy a rebuttable presumption against the imposition of a fine for any violation relating to such impact or failure, under the following conditions:

(1) The disclosure is made promptly after the operator learns of the violation as a result of the voluntary self-evaluation;

(2) The operator making the disclosure cooperates with the Director regarding investigation of the issue identified in the disclosure; and

(3) The operator making the disclosure has achieved or commits to achieve compliance within a reasonable time and pursues compliance with due diligence.

The Commission shall deny the presumption against the imposition of fines only, if, after hearing, it finds that any of the preceding conditions have not been met, or that the use of this process was engaged in for fraudulent purposes.

c. Base fine schedule. The following table sets forth the base fine for violation of the rules listed.

RULE NUMBER	BASE FINE
205	$500
206	$500
207	$500
208	$500
209	$1000
210	$250

RULE NUMBER	BASE FINE
401	$500
403	$250
404	$1000
405	$250

RULE NUMBER	BASE FINE
602	$1000
603	$1000
604	$1000
605	$750
606A	$750
606B	$750
607	$750

RULE NUMBER	BASE FINE
703	$1000
704	$1000
705	$1000
706	$1000
707	$1000
708	$1000
709	$1000
711	$1000

RULE NUMBER	BASE FINE
301	$1000
302	$500
303	$1000
305	$1000
306	$1000
307	$250
308	$500
309	$500
310	$500
311	$250
312	$250
313	$250
314A	$250
315	$250
316A	$500
316B	$1000
317	$1000
317A	$1000
318	$1000
319	$1000
320	$1000
321	$500
322	$500
323	$1000
324	$1000
325	$1000
326	$1000
327	$1000
328	$500
329	$500
330	$500
331	$500

RULE NUMBER	BASE FINE
802	$1000
803	$250
804	$250

RULE NUMBER	BASE FINE
1002	$1000
1003	$1000
1004	$1000

RULE NUMBER	BASE FINE
1101	$1000
1102	$1000
1103	$1000

RULE NUMBER	BASE FINE
332	$500
333	$1000

RULE NUMBER	BASE FINE
901	$1000
902	$1000
903	$1000
904	$1000
905	$1000
906	$1000
907	$1000
908	$1000
909	$1000
910	$1000
911	$1000
912	$1000

d. **Adjustment.** The fine may be increased or decreased by application of the aggravating and mitigating factors set forth below.

Aggravating factors.

(1) The violation was intentional or reckless.

(2) The violation had a significant negative impact, or threat of significant negative impact on the environment or on public health, safety, or welfare.

(3) The violation resulted in significant waste of oil and gas resources.

(4) The violation had a significant negative impact on correlative rights of other parties.

(5) The violation resulted in or threatened to result in significant loss or damage to public or private property.

(6) The violation involved recalcitrance or recidivism upon the part of the violator.

(7) The violation involved intentional false reporting or recordkeeping.

(8) The violation resulted in economic benefit to the violator, including the economic benefit associated with noncompliance with the applicable rule, in which case the amount of such benefit may be taken into consideration.

Mitigating factors.

(1) The violator self-reported the violation.

(2) The violator demonstrated prompt, effective and prudent response to the violation, including assistance to any impacted parties.

(3) The violator cooperated with the Commission, or other agencies with respect to the violation.

(4) The cause(s) of the violation was outside of the violator's reasonable control and responsibility, or is customarily considered to be force majeure.

(5) The violator made a good faith effort to comply with applicable requirements prior to the Commission learning of the violation.

(6) The cost of correcting the violation reduced or eliminated any economic benefit to the operator.

(7) The operator has demonstrated a history of compliance with Commission rules, regulations and orders.

e. **Public projects.** In lieu of or in reduction of fine amounts, an AOC may provide for the initiation of or participation in operator projects which are beneficial to the environment or public health, safety and welfare, and the Commission encourages AOCs which so provide.

f. **Payment of fines.** An operator against whom the Commission enters an order to pay a fine must pay the amount due within thirty (30) days of the effective date of the order, unless the Commission grants a longer period or unless the operator files for judicial appeal, in which event payment of the penalty shall be stayed pending resolution of such appeal. An operator's obligations to comply with the provisions of a Commission order requiring compliance with the Act, a permit condition or these rules and regulations shall not be stayed pending resolution of an appeal unless the stay is ordered by the court.

524. DETERMINATION OF RESPONSIBLE PARTY

In all cases it shall be the burden of the Director to present sufficient evidence to the Commission to determine responsible party status.

a. A hearing may be initiated on the Commission's own motion, upon application, or at the request of the Director to decide responsible party status upon at least twenty (20) days notice to the potentially responsible parties.

b. Operators shall provide to the Director such information as the Director may reasonably require in making such determination.

c. The Commission shall make the determination under this section without regard to any contractual assignments of liability or other legal defenses between parties.

d. An operator shall enjoy a rebuttable presumption against mitigation liability under §34-60-124 (7), C.R.S., for ongoing significant adverse environmental impacts where the violation which led to such impacts was committed by a predecessor operator and where the operator has conducted an environmental investigation, with reasonable due diligence, of the environmental condition of the particular asset or activity and such investigation did not reveal such significant adverse environmental impacts. The failure to report any condition which is causing such impacts, upon subsequent knowledge by the operator, shall negate the rebuttable presumption against mitigation liability.

e. Where multiple persons are determined to be responsible parties, they shall share in the mitigation liability in proportion to their respective shares of production, respective periods of ownership or respective contributions to the problem, or any other factors as may serve the interests of fairness.

f. The determination of responsible party status and mitigation liability shall require a showing that the responsible party conducted operations that have resulted in or have threatened to cause a significant adverse environmental impact to any air, water, soil or biological resource based on the conduct of oil or gas operations in contravention of any then applicable historic provisions of the Act or rules, whether or not the Commission has entered an order finding violation.

525. PERMIT-RELATED PENALTIES

a. If the Commission determines, after a hearing, that an operator failed to perform any required corrective action/abatement or failed to comply with a cease and desist order issued by the Director or the Commission with regard to violation of a permit provision, the Commission may issue an order suspending, modifying or revoking the permit authorizing the operation. The order shall provide the condition(s) which must be met by the operator for reinstatement of the permit. An operator which is subject to an order that suspends, modifies or revokes a permit shall continue the affected operations only for the purpose of bringing them into compliance with the permit or modified permit and shall do so under the supervision of the Director. Once the condition for reinstatement has been met to the satisfaction of the Director and any fine not subject to judicial review or appeal has been paid, the Director shall inform the Commission, and the Commission, if in agreement, shall reinstate the permit.

b. Whenever the Commission or the Director has evidence that an operator is responsible for a pattern of violation of any provision of the Act, or of any rule, permit, or order of the Commission, the Commission or the Director shall issue a notice to such operator to appear for a hearing before the Commission. If the Commission finds, after such hearing, that a knowing and willful pattern of violation exists, it may issue an order which shall prohibit the issuance of any new permits to such operator. When such operator demonstrates to the satisfaction of the Commission that it has brought each of the violations into compliance and that any fine not subject to judicial review or appeal has been paid, such order denying new permits shall be vacated.

526. ADMINISTRATIVE HEARINGS IN UNCONTESTED MATTERS

a. As to applications where there has been no protest or intervention filed with the Commission in accordance with Rule 509., and where the Director has not recommended approval based on the content of the verified application and supporting exhibits, the application may be heard administratively prior to or on the date of the scheduled Commission hearing. The date and time of the administrative hearing shall be scheduled for the mutual convenience of the applicant and the Hearing Officer. The administrative hearing may be conducted prior to the protest or intervention date but no order shall be entered by the Commission until it has fully considered any timely and properly filed protest or intervention.

b. One or more duly appointed Hearing Officers may hear the application at the administrative hearing. Administrative hearings shall proceed informally in a meeting format. The applicant may present its case using exhibits and witnesses. All witnesses shall be sworn. At the conclusion of the administrative hearing, the Hearing Officer shall make a decision concerning approval or denial of the application and so inform the applicant. The Hearing Officer shall put such decision in a written report to the Commission containing findings of fact, conclusions of law, if any, and a recommended order. If the Hearing Officer recommends denial or qualified approval of the application, the applicant shall be entitled to a hearing de novo at the next scheduled hearing of the Commission.

c. The Commission may appoint Hearing Officers from the Commission staff for the purpose of hearing uncontested matters, presiding at local public forums or otherwise representing the Commission. The service of the Hearing Officers shall be at the Director's discretion.

527. PREHEARING PROCEDURES FOR CONTESTED ADJUDICATORY PROCEEDINGS BEFORE THE COMMISSION

a. The Commission encourages the use of prehearing conferences between parties to a contested matter in order to facilitate settlement, narrow the issues, identify any stipulated facts, resolve any other pertinent issues, and reduce the hearing time before the Commission. A prehearing conference shall be conducted at the direction of the Commission or the Director upon receipt of a protest or an intervention, or upon the request of the applicant or any person who has filed a protest or intervention. For matters in which a staff analysis has been prepared, the Director shall participate in the prehearing conference to advise the parties of the content of the preliminary staff analysis. The prehearing conference shall be conducted under the following general guidelines.

b. The Director, a Hearing Officer or Hearing Commissioner shall preside over any prehearing conference and rule on preliminary matters in any proceeding pending before the Commission.

c. The Secretary shall notify the applicant and any person who has filed a protest or intervention of the prehearing conference, and shall direct the attorneys for the parties, and pro se parties, to appear in order to expedite the hearing or settle issues, or both.

d. All parties shall be prepared to discuss all procedural and substantive issues, and shall be authorized to make binding commitments on all procedural matters.

e. Preparation should include advance study of all materials filed and materials obtained through discovery.

f. Failure of any person to attend the prehearing conference, after being notified of the date, time and place, shall be a waiver of any objection and shall be deemed to be a concurrence to any agreement reached, or to any order or ruling made at the prehearing conference.

g. A prehearing statement may be required of any party.

h. At any prehearing conference, the following matters may be considered:

(1) Offers of settlement or designation of issues;

(2) Simplification of and establishment of a list or summary of the issues;

(3) Bifurcation of issues for hearing purposes;

(4) Admissions as to, or stipulations of, facts not remaining in dispute or the authenticity of documents;

(5) Limitation of the number of fact and expert witnesses;

(6) Limitation on methods and extent of discovery, and a discovery schedule;

(7) Disposition of procedural motions; and

(8) Other matters raised by the parties, the Commission, or presiding officer.

i. At any prehearing conference, the following information may be required:

(1) An exchange and acceptance of service of exhibits proposed to be offered in evidence, and establishment of a list of exhibits to be offered;

(2) Establishment of a list of witnesses to be called and anticipated testimony times; and

(3) A timetable for the completion of discovery, if discovery is allowed.

j. The parties shall reduce to writing any agreement reached or orders issued at a prehearing conference which shall be filed with the presiding officer, who shall enter a decision approving or disapproving it, or recommend modification as a condition for approval. An agreement which is disapproved shall be privileged and inadmissible as evidence in any Commission proceeding.

j. It is the intent of this rule that a prehearing order shall be binding upon the participating parties.

k. Subsequent to the prehearing conference and prior to the hearing on a contested matter, the parties shall each prepare and submit to the Hearing Officer a recommended order for the Commission to consider for adoption at the time of hearing.

528. CONDUCT OF ADJUDICATORY HEARINGS.

a. **Contested applications.** Every party shall have the right to present its case by oral and/or documentary evidence. The following shall be the order of presentation unless otherwise established by the Commission at the hearing:

(1) Determination of whether any Commission members have a conflict of interest;

(2) Presentation of any prehearing order;

(3) Presentation of any motions and disposition of procedural matters;

(4) Presentation of the stipulation, if any;

(5) Opening statement by the applicant;

(6) Opening statements by the respondent (and intervener, if any);

(7) Presentation of the case-in-chief by the applicant;

(8) Presentations by respondent (and intervener, if any);

(9) Presentation of statements under Rule 510., if any;

(10) Presentation of staff analysis, if requested by the Commission.

(11) Rebuttal by the applicant;

(12) Rebuttal by the respondent (and intervenor, if any);

(13) Closing statement by the applicant;

(14) Closing statements by the respondent (and intervenor, if any).

(15) Rebuttal closing statement by the applicant.

(16) Upon motion and for good cause shown, the Commission may permit surrebuttal.

(17) Closing of the record.

b. **Uncontested applications not approved administratively.** For uncontested applications not approved administratively pursuant to Rule 526., the applicant may present evidence in support of its application to the Commission. The order of presentation shall be as follows, unless otherwise established by the Commission at the hearing:

(1) Determination of whether any Commission members have a conflict of interest;

(2) Presentation of staff analysis, if requested by the Commission. The Commission, at its discretion, or upon request of the Director may defer staff testimony until all of the evidence has been presented.

(3) Presentation of the case-in-chief by the applicant;

(4) Closing statement by the applicant.

(5) Closing of the record.

c. **Enforcement hearings.** In order to assure that all parties against whom a fine or penalty may be imposed are afforded due process of law, the Commission shall, at any hearing, permit the Director or the complainant pursuant to Rule 522.b.(4) to present evidence and argument and to conduct cross-examination required for a full disclosure of the facts. The enforcement matter shall be heard by the Commission de novo unless the operator waives its right to a de novo hearing prior to or at the Commission hearing. The order of presentation in a hearing for an enforcement matter shall be as follows, unless otherwise established by the Commission at the hearing:

(1) Determination of whether any Commission members have a conflict of interest;

(2) Opening statements by all parties;

(3) Presentation by the Director;

(4) Presentation by any complainant under Rule 522.b.(4).;

(5) Presentation by the operator;

(6) Rebuttal by the Director;

(7) Rebuttal by the respondent;

(8) Closing statements by the parties;

(9) Finding regarding existence of violation;

(10) If the Commission first determines by a preponderance of the evidence that a violation or violations exist, presentation by the Director of any recommended fine or permit-related penalty, and/or recommended corrective action/abatement to be taken by the operator;

(11) Response by any complainant under Rule 522.b.(4).;

(12) Presentation of statements under Rule 510., if any;

(13) Response by the operator;

(14) Rebuttal by the Director; and

(15) Closing statements by all parties;

(16) Closing of the record.

d. **Closing of record.** At the conclusion of closing statements, the record shall be closed to the presentation of any further evidence, testimony, or statements, except as such may occur in response to questions from the Commission.

e. **Witnesses.** Each witness shall take an oath or affirmation before testifying. After a witness has testified, the applicant, the protestant or participating intervenors and any Commissioner may cross-examine that witness in the order established by the chairperson of the Commission.

f. Where two or more protestants or intervenors have substantially similar interests and positions, the Commission may limit cross-examination or argument on motions and objections to fewer than all the intervenors. The Commission may also limit testimony to avoid undue delay, waste of time or needless presentation of cumulative evidence.

g. **Commission findings and order.** After due consideration of written and oral statements, the testimony, and the arguments presented at hearing, the Commission shall make its findings and order, based upon evidence in the record and, as appropriate, consistent with the Act and any rule, permit, or order made pursuant thereto.

529. PROCEDURES FOR RULEMAKING PROCEEDINGS

a. **Institution of rulemaking.** The Commission may institute rulemaking on its motion or in response to an application filed by any person.

b. **Applications for rulemaking.** Any person may petition the Commission to initiate rulemaking. All applications for rulemaking shall contain the following information:

(1) The name, address, and telephone number of the person requesting the rulemaking;

(2) A copy of the rule proposed in the application and a general statement of the reasons for the requested rule; and

(3) A proposed statement of the basis and purpose for the rule.

c. **Notice of proposed rulemaking.** All rulemaking hearings of the Commission shall be noticed by publication in the Colorado Register not less than twenty (20) days and not more than sixty (60) days prior to the hearing.

d. **Time for rulemaking.** The rulemaking hearing shall not be held until the expiration of six (6) months from the date of application unless the Commission, in its discretion, decides that an earlier hearing is appropriate.

e. **Development of proposed rules.** Prior to the notice of proposed rulemaking, the Commission or Director may use informal procedures to gather information, including, but not limited to, public forums, investigation by Commission staff, and formation of rulemaking teams. Commissioners may participate in such informal proceedings.

f. **Content of notice.** The notice shall state the time, date, place, and general subject matter of the hearing to be held. It may include a statement indicating whether an informal public meeting will be held, the time, date, place, and general purpose of the meeting, any special procedures the Commission deems appropriate for the particular rulemaking proceeding and a statement encouraging public participation. The notice shall state that the proposed regulations will be available upon request from the office of the Commission, the date of availability, and any fee. The notice shall include a short and plain statement which summarizes the intended action and states generally the basis and purpose of the rule.

g. **The rulemaking hearing.** The Commission shall hold a formal public hearing before promulgating any rules or regulations. At that hearing, the Commission shall afford any person an opportunity to submit data, views or arguments. The Commission may limit such testimony or presentation of evidence at its discretion and may prohibit repetitive, irrelevant or harassing testimony.

h. **Conduct of rulemaking hearings.**

(1) The Commission encourages any person to participate at rulemaking hearings. The times at which the public may participate will be determined at the discretion of the Commission. The Commission may, at its discretion, limit the amount of time a person may use to comment or make public statements. Oaths shall not be required for public participation.

(2) The Commission encourages witnesses to make plain, brief, and simple statements of their positions. It also encourages submittal of written statements prior to hearing, with only an oral summary of such a statement at the hearing.

(3) The order of presentation at a rulemaking hearing shall be as established by the Commission at the hearing.

(4) The Commission has the discretion to continue rulemaking hearings by announcement at the rulemaking hearing without republication of the proposed rule.

530. INVOLUNTARY POOLING PROCEEDINGS

a. An application for involuntary pooling pursuant to §34-60-116, C.R.S. may be filed at any time a nonconsenting owner within the drilling unit refuses to agree to bear his proportionate share of the costs and risks of drilling and operating the well. As used herein a nonconsenting owner shall mean an owner in the area to be pooled who, after at least thirty (30) days written notice of the following information does not elect in writing to consent to participate in the cost of the well concerning which the pooling order is sought:

(1) The location and objective depth of the well.

(2) The estimated drilling and completion cost of the well.

(3) The estimated spud date for the well or range of time within which spudding is to occur.

(4) An authority for expenditure prepared by the operator and containing the information required above, together with additional information deemed appropriate by the operator shall satisfy this obligation.

b. In determining whether a reasonable offer to lease has been tendered under §34-60-116(7)(d), C.R.S., the Commission shall consider the lease terms listed below for the drilling and spacing unit in the application and for all cornering and contiguous units that are under the proposed lease:

(1) Date of lease and primary term or offer with acreage in lease;

(2) Annual rental per acre;

(3) Bonus payment or evidence of its non-availability;

(4) Mineral interest royalty;

(5) Such other lease terms as may be relevant.

SAFETY REGULATIONS

601. INTRODUCTION

The rules and regulations in this section are promulgated to protect the health, safety and welfare of the general public during the drilling, completion and operation of oil and gas wells and producing facilities. They do not apply to parties or requirements regulated under the Federal Occupational Safety and Health Act of 1970 (See Rule 212.).

602. GENERAL

The training and action of employees, as well as proper location and operation of equipment is an important part of any safety program. While this section is general in nature, it is considered a basic part of the foundation of any safety program.

a. Employees shall be familiarized with these rules and regulations as provided herein as they relate to their function in their respective jobs. Each new employee should have their job outlined, explained and demonstrated.

b. Unsafe and potentially dangerous conditions as defined by these rules, should be reported immediately by employees to the supervisor in charge and shall be remedied as soon as practical. Any accident involving injury to wellsite personnel or to a member of the general public which requires hospitalization, or significant damage to equipment or the wellsite shall be reported to the Oil and Gas Conservation Commission as soon as practicable, but in no event later than twenty-four (24) hours after the accident.

Where unsafe or potentially dangerous conditions exist, the owner or operator shall respond as directed by an agency with demonstrated authority to do so (such as sheriff, fire district director, etc.).

c. Vehicles of persons not involved in drilling, production, servicing, or seismic operations shall be located a minimum distance of one hundred (100) feet from the wellbore, or a distance equal to the height of the derrick or mast, whichever is greater. Equivalent safety measures shall be taken where terrain, location or other conditions do not permit this minimum distance requirements.

d. Existing wells are exempt from the provisions of these regulations as they relate to the location of the well.

e. Existing producing facilities shall be exempt from the provisions of these regulations with respect to minimum distance requirements and setbacks unless they are found by the Director to be unsafe.

f. Self-contained sanitary facilities shall be provided during drilling operations and at any other similarly staffed oil and gas operations facility.

603. DRILLING AND WELL SERVICING OPERATIONS AND HIGH DENSITY AREA RULES

a. **Statewide setbacks**. Subparagraph (1) below shall apply to all areas of the state except as provided under subparagraphs b. and e. of this rule. Subparagraph (2) below shall apply to all areas of the state.

(1) At the time of initial drilling of the well, the wellhead shall be located a distance of one hundred fifty (150) feet or one and one-half (1-1/2) times the height of the derrick, whichever is greater, from any occupied building, public road, major above ground utility line or railroad.

(2) A well shall be a minimum distance of one hundred fifty (150) feet from a surface property line. An exception may be granted by the Director if it is not feasible for the operator to meet this minimum distance requirement and a waiver is obtained from the offset surface owner(s). An exception request letter stating the reasons for the exception shall be submitted to the Director and accompanied by a signed waiver(s) from the offset surface owner(s). Such waiver shall be written and filed in the county clerk and recorder's office and with the Director.

b. **High density area rules for building units**. A high density area shall be determined at the time the well is permitted on a well-by-well basis by calculating the number of occupied building units within the seventy-two (72) acre area defined by a one thousand (1000) foot radius from the wellhead or production facility. If thirty-six (36) or more actual or platted building units (as defined in the 100 Series rules) are within the one thousand (1000) foot radius or eighteen (18) or more building units are within any semi-circle of the one thousand (1000) foot radius (i.e., an average density of one (1) building unit per two (2) acres), it shall be deemed a high density area. If platted building units are used to determine the density, then fifty percent (50%) of said platted units shall have building units under construction or constructed.

c. **High density area rules for other facilities.** If an educational facility, assembly building, hospital, nursing home, board and care facility, or jail is located within one thousand (1000) feet of a wellhead or production facility, high density area rules shall apply.

d. **Designated outside activity area.** The Commission, upon application and hearing, shall determine the appropriate boundary and setbacks for a designated outside activity area as defined in the 100 Series rules. The minimum setback from the boundary of the designated outside activity area shall be three hundred fifty (350) feet.

e. The following rules shall apply in high density and designated outside activity areas:

(1) **Provisions for encroaching development**. If, by virtue of subsequent future surface development, an area becomes a high density area, subparagraphs (2), (3), (7) and (14) shall not apply to the operator.

(2) **Setbacks for wellheads**. At the time of initial drilling of the well, the wellhead location shall be not less than three hundred fifty (350) feet from any building unit, educational facility, assembly building, hospital, nursing home, board and care facility, or jail.

(3) **Setbacks for production equipment**. At the time of initial installation, production tanks and/or associated on-site production equipment shall be located not less than three hundred fifty (350) feet from any building unit, and, if requested by the local governmental designee, production tanks shall be located five hundred (500) feet from an educational facility, assembly building, hospital, nursing home, board and care facility, jail or designated outside activity area. However, such five hundred (500) foot setback shall be decreased to the maximum achievable setback if five hundred (500) feet would extend beyond the area on which the operator has a legal right to place or construct such facilities. Should the operator object to such five hundred (500) foot setback for any reason, a variance hearing shall be conducted at the next regularly scheduled meeting of the Commission, subject to the notice requirements of Rule 507.

(4) A. **Blowout preventer equipment ("BOPE") for high density area drilling operations**. Blowout prevention equipment for drilling operations shall consist of (at a minimum):

i. Rig with kelley double ram with blind ram and pipe ram;
annular preventer or a rotating head

ii. Rig without kelley double ram with blind ram and pipe ram

Mineral Management certification or Director approved training for blowout prevention shall be required for at least one (1) person at the wellsite during drilling operations.

B. **BOPE testing for high density area drilling operations**. Upon initial rig-up and at least once every thirty (30) days during drilling operations thereafter, pressure testing of the casing string and each component of the blowout prevention equipment including flange connections shall be performed to seventy percent (70%) of working pressure or seventy percent (70%) of the internal yield of casing, whichever is less. Pressure testing shall be conducted and the documented results shall be retained by the operator for inspection by the Director for a period of one (1) year. Activation of the pipe rams for function testing shall be conducted on a daily basis when practicable.

C. **Pit level indicators**. Pit level indicators shall be used.

D. **Drill stem tests**. Closed chamber drill stem tests shall be allowed in high density areas. All other drill stem tests shall require approval by the Director.

(5) A. **BOPE for well servicing operations**. Adequate blowout prevention equipment shall be used on all well servicing operations.

B. Backup stabbing valves shall be required on well servicing operations during reverse circulation. Valves shall be pressure tested before each well servicing operation using both low pressure air and high pressure fluid.

(6) **Location requirement exceptions and waivers**. Exceptions to the location requirements set out in subparagraphs (2) and (3) above shall be granted by the Director if the Director determines that Rule 318. has been complied with and that a copy of waivers from each person owning an occupied building or building permitted for construction within three hundred fifty (350) feet of the proposed location is submitted as part of

the Permit to Drill, Form 2, and that the proposed location complies with all other safety requirements of the rules and regulations.

(7) **Fencing requirements**. At the time of initial installation, if a wellsite falls within a high density area, all pumps, pits, wellheads and production facilities shall be adequately fenced to restrict access by unauthorized persons. For security purposes, all such facilities and equipment used in the operation of a completed well shall be surrounded by a fence six (6) feet in height, constructed in conformance with local written standards so long as the material is non-combustible and allows for adequate ventilation, and the gate(s) shall be locked.

(8) **Control of fire hazards**. Any material not in use that might constitute a fire hazard shall be removed a minimum of twenty-five (25) feet from the wellhead, tanks and separator. Any electrical equipment installations inside the bermed area shall comply with API RP 500 classifications and comply with the current national electrical code as adopted by the State of Colorado.

(9) **Loadlines**. In high density areas, all loadlines shall be bullplugged or capped.

(10) **Removal of surface trash**. All surface trash, debris, scrap or discarded material connected with the operations of the property shall be removed from the premises or disposed of in a legal manner.

(11) **Guy line anchors**. All guy line anchors left buried for future use shall be identified by a marker of bright color not less than four (4) feet in height and not greater than one (1) foot east of the guy line anchor.

(12) **Berm construction**. All newly installed or replaced berms in high density areas, in the absence of remote impounding, shall be constructed around crude oil and condensate storage tanks and shall enclose an area sufficient to contain one hundred fifty percent (150%) of the largest single tank. No more than two (2) crude oil and condensate storage tanks shall be located within a single berm. Berms shall be inspected at regular intervals and containment integrity maintained. Refer to American Petroleum Institute Recommended Practices - D16.

(13) **Tank specifications**. All newly installed or replaced crude oil and condensate storage tanks in high density areas shall be designed, constructed, and maintained in accordance with National Fire Protection Association's latest edition (NFPA 30). The operator shall maintain written records verifying proper design, construction, and maintenance, and shall make these records available for inspection by the Director.

(14) **Access roads**. If a wellsite falls within a high density area at the time of construction, all leasehold roads shall be constructed to accommodate local emergency vehicle access requirements, and shall be maintained in a reasonable condition.

(15) **Well site cleared**. Within ninety (90) days after a well is plugged and abandoned, the well site shall be cleared of all non-essential equipment, trash, and debris. For good cause shown, an extension of time may be granted by the Director.

(16) **Identification of plugged and abandoned wells in high density areas**. The operator shall identify the location of the wellbore with a permanent monument as specified in Rule 319.a.(5). The operator shall also inscribe or imbed the well number and date of plugging upon the permanent monument.

(17) **Development from existing well pads**. Where possible, operators shall provide for the development of multiple reservoirs by drilling on existing pads or by multiple completions or commingling in existing wellbores (see Rule 322.). If any operator asserts it is not possible to comply with, or requests relief from, this requirement, the matter shall be set for hearing by the Commission and relief granted as appropriate.

f. **Statewide rig floor safety valve requirements**. When drilling or well servicing operations are in progress on a well where there is any indication the well will flow hydrocarbons, either through prior records or present conditions, there shall be on the rig floor a safety valve with connections suitable for use with each size and type of tool joint or coupling being used on the job.

g. **Statewide static charge requirements**. Rig substructure, derrick, or mast shall be designed and operated to prevent accumulation of static charge.

h. **Statewide well servicing pressure check requirements**. Prior to initiating well servicing operations, the well shall be checked for pressure and steps taken to remove pressure or operate safely under pressure before commencing operations.

i. **Statewide well control equipment and other safety requirements**. Well control equipment and other safety requirements are:

(1) When there is any indication that a well will flow, either through prior records, present well conditions, or the planned well work, blowout prevention equipment shall be installed in accordance with Rule 317. or any special orders of the Commission.

(2) Blowout prevention equipment when required by Rule 317. shall be in accordance with API RP 53: Recommended Practices for Blowout Prevention Equipment Systems, or amendments thereto.

(3) While in service, blowout prevention equipment shall be inspected daily and a preventer operating test shall be performed on each round trip, but not more than once every twenty-four (24) hour period. Notation of operating tests shall be made on the daily report.

(4) All pipe fittings, valves and unions placed on or connected with blowout prevention equipment, well casing, casinghead, drill pipe, or tubing shall have a working pressure rating suitable for the maximum anticipated surface pressure and shall be in good working condition as per generally accepted industry standards.

(5) Blowout prevention equipment shall contain pipe rams that enable closure on the pipe being used. The choke line(s) and kill line(s) shall be anchored, tied or otherwise secured to prevent whipping resulting from pressure surges.

(6) Pressure testing of the casing string and each component of the blowout prevention equipment, if blowout prevention equipment is required, shall be conducted prior to drilling out any string of casing except conductor pipe. The minimum test pressure shall be five hundred (500) psi, and shall hold for fifteen (15) minutes without pressure loss in order for the casing string to be considered serviceable. Upon demand the operator shall provide to the commissioner the pressure test evidence. Drilling operations shall not proceed until blowout prevention equipment is tested and found to be serviceable.

(7) If the blind rams are closed for any purpose except operational testing, the valves on the choke lines or relief lines below the blind rams should be opened prior to opening the rams to bleed off any trapped pressure.

(8) All rig employees shall have adequate understanding of and be able to operate the blowout prevention equipment system. New employees shall be trained in the operations of blowout prevention equipment system as soon as practicable to do so.

(9) Drilling contractors shall place a sign or marker at the point of intersection of the public road and rig access road.

(10) The number of the public road to be used in accessing the rig along with all necessary emergency numbers shall be posted in a conspicuous place on the drilling rig.

j. **Statewide equipment, weeds, waste, and trash requirements**. All locations, including wells and surface production facilities, shall be kept free of the following: equipment, vehicles, and supplies not necessary for use on that lease; weeds; rubbish, and other waste material. The burning or burial of such material on the premises may be subject to other applicable laws. In addition, material may be burned or buried on the premises only with the prior written consent of the surface owner.

k. **Statewide equipment anchoring requirements**. All equipment at drilling and production sites in geological hazard and floodplain areas shall be anchored to the extent necessary to resist flotation, collapse, lateral movement or subsidence.

604. PRODUCTION FACILITIES

a. **Crude Oil Tanks**.

(1) Atmospheric tanks used for crude oil storage shall be built in accordance with the following standards as applicable:

A. Underwriters Laboratories, Inc., No. UL-142, "Standard for Steel Above Ground Tanks for Flammable and Combustible Liquids"

B. American Petroleum Institute Standard No. 650, "Welded Steel Tanks for Oil Storage"

C. American Petroleum Institute Standard No. 12B, "Bolted Tanks for Storage of Production Liquids"

D. American Petroleum Institute Standard No. 12D, "Field Welded Tanks for Storage of Production Liquids" or

E. American Petroleum Institute Standard No. 12F, "Shop Welded Tanks for Storage of Production Liquids".

(2) Tanks shall be located at least two (2) diameters or three hundred fifty (350) feet, whichever is smaller, from the boundary of the property on which it is built. Where the property line is a public way the tanks shall be two thirds (2/3) of the diameter from the nearest side of the public way or easement.

A. Tanks less than three thousand (3,000) barrels capacity shall be located at least three (3) feet apart.

B. Tanks three thousand (3,000) or more barrels capacity shall be located at least one-sixth (1/6) the sum of the diameters apart. When the diameter of one (1) tank is less than one-half (1/2) the diameter of the adjacent tank, the tanks shall be located at least one-half (1/2) the diameter of the smaller tank apart.

(3) At the time of installation, tanks shall be a minimum of two hundred (200) feet from residences, normally occupied buildings, or well defined normally occupied outside areas.

(4) Berms shall be constructed around tanks in the absence of remote impounding. Both methods shall enclose an area with sufficient volume to contain the entire contents of the largest tank in the enclosure. Berms shall be inspected at regular intervals and maintained in good condition. When a berm is provided around tanks no potential ignition sources shall be installed inside that area.

(5) Tanks shall be a minimum of seventy-five (75) feet from a fired vessel or heater-treater.

(6) Tanks shall be a minimum of fifty (50) feet from a separator, well test unit or other non-fired equipment.

(7) Tanks shall be a minimum of seventy-five (75) feet from a compressor with a rating of two hundred (200) horsepower, or more.

(8) Tanks shall be a minimum of seventy-five (75) feet from a wellhead.

(9) Gauge hatches on atmospheric tanks used for crude oil storage shall be closed at all times when not in use.

(10) Vent lines from individual tanks shall be joined and ultimate discharge shall be directed away from the loading racks and fired vessels in accord with API RP 12R-1.

(11) During hot oil treatments on tanks containing thirty-five (35) degree or higher API gravity oil, hot oil units shall be located a minimum of one hundred (100) feet from any tank being serviced.

b. **Fired Vessel, Heater-Treater**.

(1) Fired vessels (FV) including heater-treaters (HT) shall be minimum of fifty (50) feet from separators or well test units.

(2) FV-HT shall be a minimum of fifty (50) feet from a lease automatic custody transfer unit (LACT).

(3) FV-HT shall be a minimum of forty (40) feet from a pump.

(4) FV-HT shall be a minimum of seventy-five (75) feet from a well.

(5) At the time of installation, FV-HT shall be a minimum of two hundred (200) feet from residences occupied buildings, or well defined normally occupied outside areas.

(6) Vents on pressure safety devices shall terminate in a manner so as not to endanger the public or adjoining facilities. They shall be designed so as to be clear and free of debris and water at all times.

c. **Special Equipment**. Under unusual circumstances special equipment may be required to protect public safety. The Director shall determine if such equipment should be employed to protect public safety and if so, require the operator to employ same. If the operator or the affected party does not concur with the action taken, the Director shall bring the matter before the Commission at public hearing.

(1) All wells located within one hundred fifty (150) feet of a residence(s), normally occupied buildings, or well defined normally occupied outside area(s), shall be equipped with an automatic control valve that will shut the well in when a sudden change of pressure, either a rise or drop, occurs. Automatic control valves shall be designed so they fail safe.

(2) Pressure control valves required in subparagraph a. shall be activated by a secondary gas source supply, and shall be inspected at least every three (3) months to assure they are in good working order and the secondary gas supply has volume and pressure sufficient to activate the control valve.

(3) All pumps, pits, and producing facilities shall be adequately fenced to prevent access by unauthorized persons when the producing site or equipment is easily accessible to the public and poses a physical or health hazard.

(4) Sign(s) shall be posted at the boundary of the producing site where access exists, identifying the operator, lease name, location, and listing a phone number, including area code, where the operator may be reached at all times unless emergency numbers have been furnished to the county commission or it's designee.

d. **Mechanical Conditions**. All valves, pipes and fittings shall be securely fastened, inspected at regular intervals and maintained in good mechanical condition.

e. **Buried or partially buried tanks, vessels or structures.** Buried or partially buried tanks, vessels, or structures used for storage of E&P waste shall be properly designed, constructed and installed in a manner to contain materials safely. Such vessels shall be tested for leaks after installation and maintained, repaired or replaced to prevent spills or releases of E&P waste.

605. RESERVED

606A. FIRE PREVENTION AND PROTECTION

a. Gasoline-fueled engines shall be shut down during fueling operations if the fuel tank is an integral part of the engine.

b. Handling, connecting and transfer operations involving liquefied petroleum gas (LPG) shall conform to the requirements of the State Oil Inspector.

c. Flammable liquids storage areas within any building or shed shall:

(1) Be adequately vented to the outside air;

(2) Have two (2) unobstructed exits leading from the building in different directions if the building is in excess of five hundred (500) square feet.

(3) Be maintained with due regard to fire potential with respect to housekeeping and materials storage;

(4) Be identified as a hazard and appropriate warning signs posted;

d. Flammable liquids shall not be stored within fifty (50) feet of the wellbore, except for the fuel in the tanks of operating equipment or supply for injection pumps. Where terrain and location configuration do not permit maintaining this distance, equivalent safety measures should be taken.

e. Liquefied petroleum gas (LPG) tanks larger than two hundred fifty (250) gallons and used for heating purposes, shall be placed as far as practical from and parallel to the adjacent side of the rig or wellbore as terrain and location configuration permit. Installation shall be consistent with provisions of NFPA 58, "Standards for the Storage and Handling of Liquid Petroleum Gases".

f. Smoking shall be prohibited at or in the vicinity of operations which constitute a fire hazard and such locations shall be conspicuously posted with a sign, "No Smoking" or "Open Flame". Matches and all smoking equipment may not be carried into "No Smoking" areas.

g. No source of ignition shall be permitted in an area where smoking has been prohibited unless it is first determined to be safe to do so by the supervisor in charge or the designated representative.

h. Open fires, transformers, or other sources of ignition shall be permitted only in designated areas located at a safe distance from the wellhead or flammable liquid storage areas.

i. Only approved heaters for Class I Division 2 areas, as designated by API RB 500B, shall be permitted on or near the rig floor. The safety features of these heaters shall not be altered.

j. Combustible materials such as oily rags and waste shall be stored in covered metal containers.

k. Material used for cleaning shall have a flash point of not less than one hundred degrees fahrenheit (100°F). For limited special purposes, a lower flash point cleaner may be used when it is specifically required and should be handled with extreme care.

l. Firefighting equipment shall not be tampered with and shall not be removed for other than fire protection and firefighting purposes and services. A firefighting water system may be used for wash down and other utility purposes so long as its firefighting capability is not compromised. After use, water systems must be properly drained or properly protected from freezing.

m. An adequate amount of fire extinguishers and other firefighting equipment shall be suitably located, readily accessible, and plainly labeled as to their type and method of operation.

n. Fire protection equipment shall be periodically inspected and maintained in good operating condition at all times.

o. Firefighting equipment shall be readily available near all welding operations. When welding, cutting or other hot work is performed in locations where other than a minor fire might develop, a person shall be designated as a fire watch. The area surrounding the work shall be inspected at least one (1) hour after the hot work is completed.

p. Portable fire extinguishers shall be tagged showing the date of last inspection, maintenance or recharge. Inspection and maintenance procedures shall comply with the latest edition of the National Fire Protection Association's publication NFPA 10.

q. Personnel shall be familiarized with the location of fire control equipment such as drilling fluid guns, water hoses and fire extinguishers and trained in the use of such equipment. They shall also be familiar with the procedure for requesting emergency assistance as terrain and location configuration permit. Installation shall be consistent with provisions of NFPA 58, "Standards for the Storage and Handling of Liquefied Petroleum Gases".

606B. AIR AND GAS DRILLING

a. Drilling compressors (air or gas) shall be located at least one hundred twenty five (125) feet from the wellbore and in a direction away from the air or gas discharge line.

b. The air or gas discharge line shall be laid in as nearly as a straight line as possible from the wellbore and be a minimum of one hundred fifty (150) feet in length. The line shall be securely anchored.

c. A pilot flame shall be maintained at the end of the air or gas discharge line at all times when air, gas, mist drilling, or well testing is in progress.

d. All combustible material shall be kept at least one hundred (100) feet away from the air and gas discharge line and burn pit.

e. The air line from the compressors to the standpipe shall be of adequate strength to withstand at least the maximum discharge pressure of the compressors used, and shall be checked daily for any evidence of damage or weakness.

f. Smoking shall not be allowed within seventy-five (75) feet of the air and gas discharge line and burn pit.

g. All operations associated with the drilling, completion or production of a well shall be subject to the Colorado Air Quality Control Act, §25-7-101, C.R.S.

607. HYDROGEN SULFIDE GAS

a. When well servicing operations take place in zones known to contain at or above one hundred (100) ppm hydrogen sulfide gas, as measured in the gas stream, the operator shall file a hydrogen sulfide drilling operations plan (United States Department of the Interior, Bureau of Land Management, Onshore Order No. 6, November 23, 1990).

b. When proposing to drill a well in areas where hydrogen sulfide gas in excess of one hundred (100) ppm can reasonably be expected to be encountered, the operator shall submit as part of the Application for Permit to Drill, Form 2, a hydrogen sulfide drilling operations plan (United States Department of the Interior, Bureau of Land Management, Onshore Order No. 6, November 23, 1990).

c. Any gas analysis indicating the presence of hydrogen sulfide gas shall be reported to the Commission and the local governmental designee.

FINANCIAL ASSURANCE AND ENVIRONMENTAL RESPONSE FUND

701. SCOPE

The rules in this series pertain to the provision of financial assurance by operators to ensure the performance of certain obligations imposed by the Oil and Gas Conservation Act (the Act), §34-60-106 (3.5), (11), (12) and (17) C.R.S., as well as the use of the Environmental Response Fund (ERF), §34-60-124 C.R.S., as a mechanism to plug and abandon orphan wells, perform orphaned site reclamation, and remediation, and to conduct other authorized environmental activities.

702. GENERAL

Operators are required to provide financial assurance to the Commission to demonstrate that they are capable of fulfilling the obligations imposed by the Act, as described in this series. Except as otherwise specified herein, a surety bond, in a form and from a company acceptable to the Commission, is an approved method of providing financial assurance. Any other method of providing financial assurance identified in §34-60-106(B), C.R.S., shall be submitted to the Commission for approval, and shall be equivalent to the protection provided by a surety bond and may require detailed Commission review on an ongoing basis, including the use of third party consultants, the reasonable expense for which shall be charged to the operator proposing such alternative financial assurance.

a. When the Director has reasonable cause to believe that the Commission may become burdened with the costs of fulfilling the statutory obligations described herein because an operator has demonstrated a pattern of non-compliance with oil and gas regulations in this or other states, because special geologic, environmental, or operational circumstances exist which make the plugging and abandonment of particular wells more costly, or due to other special and unique circumstances, the Director may petition the Commission for an increase in any individual or blanket financial assurance required in this series.

b. The requirements of this series do not apply to situations where financial assurance has been provided to federal or Indian agencies for operations regulated solely by such agencies.

703. SURFACE OWNER PROTECTION

Operators shall provide financial assurance to the Commission, prior to commencing any operations with heavy equipment, to protect surface owners who are not parties to a lease, surface use or other relevant agreement with the operator from unreasonable crop loss or land damage caused by such operations. The determination that crop loss or land damage is unreasonable shall be made by the Commission after the affected surface owner has filed an application in accordance with the 500 Series rules. Financial assurance for the purpose of surface owner protection shall not be required for operations conducted on state lands when a bond has been filed with the State Board of Land Commissioners.

The financial assurance required by this section shall be in the amount of two thousand dollars ($2,000) per well for non-irrigated land, or five thousand dollars ($5,000) per well for irrigated land. In lieu of such individual amounts, operators may submit statewide, blanket financial assurance in the amount of twenty five thousand dollars ($25,000).

704. CENTRALIZED E&P WASTE MANAGEMENT FACILITIES

An operator which makes application for an offsite, centralized E&P waste management facility shall, upon approval and prior to commencing construction, provide to the Commission financial assurance in the amount of fifty thousand dollars ($50,000) to ensure the proper reclamation, closure and abandonment of such facility. This section does not apply to underground injection wells and multi-well pits covered under Rules 706. and 707.

705. SEISMIC OPERATIONS

Any operator submitting a Notice of Intent to Conduct Seismic Operations, Form 20, shall, prior to commencing such operations, provide financial assurance to the Commission in the amount of twenty five thousand dollars ($25,000) statewide blanket financial assurance to ensure the proper plugging and abandonment of any shot holes and any necessary surface reclamation.

706. SOIL PROTECTION AND PLUGGING AND ABANDONMENT

Prior to commencing the drilling of a well, an operator shall provide financial assurance to the Commission to ensure the protection of the soil and the proper plugging and abandonment of the well in accordance with the 300 Series of drilling regulations, the 900 Series of E&P waste management, the 1000 Series of reclamation regulations, and the 1100 Series of flowline regulations. The financial assurance required by this section shall be in the amount of five thousand dollars ($5,000) per well. In lieu of such individual amount, an operator may submit statewide blanket financial assurance in the amount of thirty thousand dollars ($30,000) for the drilling and operation of less than one hundred (100) wells, or one hundred thousand dollars ($100,000) for the drilling and operation of one hundred (100) or more wells.

707. INACTIVE WELLS

a. To the extent that an operator's inactive well count exceeds such operator's financial assurance amount divided by five thousand dollars ($5,000), such additional wells shall be considered "excess inactive wells". For each excess inactive well, an operator's required financial assurance amount under Rule 706. shall be increased by five thousand dollars ($5,000). This requirement shall be modified or waived if the Commission approves a plan submitted by the operator for reducing such additional financial assurance requirement, for returning wells to production in a timely manner, or for plugging and abandoning such wells on an acceptable schedule.

In determining whether such plan is acceptable, the Commission shall take into consideration such factors as: the number of excess inactive wells; the cost to plug and abandon such wells; the proportion of such wells to the total number of wells held by the operator; any business reason the operator may have for shutting-in or temporarily abandoning such wells; the extent to which such wells may cause or have caused a significant adverse environmental impact; the financial condition of the operator; the capability of the operator to manage such plan in an orderly fashion; and the availability of plugging and abandonment services. If an increase in financial assurance is ordered pursuant to this subsection, the operator may, at its option and in compliance with these 700 Series rules, submit new financial assurance or supplement its existing financial assurance.

b. Operators shall identify and list any shut-in or temporarily abandoned wells on their monthly production/injection report. In addition, when equipment is removed from a well so as to render it temporarily abandoned, operators shall file a Sundry Notice, Form 4, with the Commission within thirty (30) days describing such activity.

c. Any person, other than the operator, who causes equipment from a well to be removed so as to render it temporarily abandoned shall, prior to conducting such activity, file a notice of intent to remove equipment and receive the approval of the Director. The Director may condition such approval on concurrent plugging and abandonment of the well or on provision of the financial assurance required of operators in this series.

708. PUBLIC HEALTH, SAFETY AND WELFARE

All operators shall maintain general liability insurance coverage for property damage and bodily injury to third parties in the minimum amount of five hundred thousand dollars ($500,000) per occurrence. Operators with wells or production facilities located in "high density areas" as defined in Rule 603.b. shall maintain such coverage in the minimum amount of one million dollars ($1,000,000) per occurrence. Such policies shall include the Commission as a "certificate holder" so that the Commission may receive advance notice of cancellation.

709. FINANCIAL ASSURANCE

All financial assurance provided to the Commission pursuant to this Series shall remain in place until such time as the Director determines an operator has complied with the statutory obligations described herein, or until such time the Director determines a successor-in-interest has filed satisfactory replacement financial assurance, at which time the Director shall provide written approval for release of such financial assurance. Whenever an operator fails to fulfill any statutory obligation described herein, and the Commission undertakes to expend funds to remedy the situation, the Director shall make application to the Commission for an order calling or foreclosing the operator's financial assurance.

a. Operators and third party providers of financial assurance shall be served with a copy of such application pursuant to Rule 503. and shall be accorded an opportunity to be heard thereon. Any third party provider of financial assurance which subsequently fails to comply with a Commission order to make such financial assurance available shall be considered an unacceptable provider of any new financial assurance to operators in Colorado, until such time as it applies for and receives an order of reinstatement. This provision shall be stayed by the filing of a judicial appeal. In addition, the Commission may institute suit to recover such monies.

b. If an operator's financial assurance is called or foreclosed by the Commission, the called or foreclosed amount shall be deposited in the Environmental Response Fund to be expended by the Director for the purposes referenced in Rule 701., and an overhead recovery fee of ten percent (10%) of the funds expended by the Director as direct costs shall be charged against any excess of the financial assurance over such costs.

Any remainder of such financial assurance after such cost recovery shall be returned to its provider. In no circumstances will the liability of a third party provider of financial assurance exceed the face amount of such financial assurance.

c. If an operator's financial assurance is called or foreclosed by the Commission, such operator's Certificates of Clearance, Form 10, are forthwith suspended and no sales of gas or oil shall be allowed, except as may be allowed by the Commission order, until such time as the operator's financial assurance has been replaced or restored.

710. ENVIRONMENTAL RESPONSE FUND

It is the intent of the Commission that an Environmental Response Fund (ERF) "emergency reserve" of unobligated funds be maintained in the amount of one million dollars ($1,000,000), which may be used in accordance with the Act and Rule 701.

711. NATURAL GAS GATHERING, NATURAL GAS PROCESSING AND UNDERGROUND NATURAL GAS STORAGE FACILITIES

Operators of natural gas gathering, natural gas processing, or underground natural gas storage facilities shall be required to provide statewide blanket financial assurance to ensure compliance with the 900 Series rules in the amount of fifty thousand dollars ($50,000), or in an amount voluntarily agreed to with the Director, or in an amount to be determined by order of the Commission. Operators of small systems gathering or processing less than five (5) MMSCFD may provide individual financial assurance in the amount of five thousand dollars ($5,000).

AESTHETIC AND NOISE CONTROL REGULATIONS

801. INTRODUCTION

The rules and regulations in this section are promulgated to control aesthetics and noise impacts during the drilling, completion and operation of oil and gas wells and production facilities. Any Colorado county, home rule or statutory city, town, territorial charter city or city and county may, by application to the Commission, seek a determination that the rules and regulations in this section, or any individual rule or regulation, shall not apply to oil and gas activities occurring within the boundaries, or any part thereof, of any Colorado county, home rule or statutory city, town, territorial charter city or city and county, such determination to be based upon a showing by any Colorado county, home rule or statutory city, town, territorial charter city or city and county that, because of conditions existing therein, the enforcement of these rules and regulations is not necessary within the boundaries of any Colorado county, home rule or statutory city, town, territorial charter city or city and county for the protection of public health, safety and welfare.

802. NOISE ABATEMENT

a. Oil and gas operations, including gas facility operations, shall comply with the following maximum permissible noise levels for the predominant land use existing in the zone in which the operation occurs. Any operation involving pipeline or gas facility installation or maintenance, the use of a drilling rig, completion rig, workover rig, or stimulation is subject to the maximum permissible noise levels for industrial zones. In the hours between 7:00 a.m. and the next 7:00 p.m. the noise levels permitted below may be increased ten (10) db(A) for a period not to exceed fifteen (15) minutes in any one (1) hour period.

ZONE	7:00 am to next 7:00 pm	7:00 pm to next 7:00 am
Residential	55 db(A)	50 db(A)
Commercial	60 db(A)	55 db(A)
Light industrial	70 db(A)	65 db(A)
Industrial	80 db(A)	75 db(A)

The following provide guidance for the measurement of sound levels from oil and gas operations:

(1) If there are no occupied building units impacted, sound levels shall be measured at a distance of twenty-five (25) feet or more from the property line radiating the noise. Sound levels at occupied building units shall be measured as near as practicable to the exterior edge of the occupied building unit closest to the area radiating the noise.

(2) Sound level meters shall be equipped with wind screens, and readings taken when the wind velocity at the time and place of measurement is not more than five (5) miles per hour.

(3) Sound level measurements shall be taken four (4) feet above ground level.

(4) Sound levels shall be determined by averaging measurements made over a fifteen (15) minute sample duration.

(5) In all sound level measurements, the existing ambient noise level from all other sources in the encompassing environment at the time and place of such sound level measurement shall be considered to determine the contribution to the sound level by the oil and gas operation(s).

b. Exhaust from all engines, motors, coolers and other mechanized equipment shall be vented in a direction away from all occupied buildings to the extent practicable.

c. In high density areas all facilities within four hundred (400) feet of occupied buildings with engines or motors which are not electrically operated shall be equipped with quiet design mufflers or equivalent. All mufflers shall be properly installed and maintained in proper working order.

803. LIGHTING

To the extent practicable, site lighting shall be directed downward and internally so as to avoid glare on public roads and occupied buildings within seven hundred (700) feet.

804. VISUAL IMPACT MITIGATION

Production facilities constructed or substantially repainted after May 30, 1992 which are observable from any public highway shall be painted with uniform, non-contrasting, non-reflective color tones, (similar to the Munsell Soil Color Coding System) and with colors matched to but slightly darker than the surrounding landscape.

901. INTRODUCTION

a. **General.** The rules and regulations of this series establish the permitting, construction, operating and closure requirements for pits, methods of E&P waste management, procedures for spill/release response and reporting, and sampling and analysis for remediation activities. The 900 Series rules are applicable only to E&P waste, as defined in §34-60-103(4.5), C.R.S., or other solid waste where the Colorado Department Of Public Health And Environment ("CDPHE") has allowed remediation and oversight by the Commission.

b. **COGCC reporting forms.** The reporting required by the rules and regulations of this series shall be made on forms provided by the Director. Alternate forms may be used where equivalent information is supplied and the format has been approved by the Director.

c. **Additional requirements.** Whenever the Director has reasonable cause to believe that an operator, in the conduct of any oil or gas operation, is performing any act or practice which threatens to cause or causes a violation of Table 910-1 and with consideration of water quality standards or classifications established by the Water Quality Control Commission ("WQCC") for waters of the state, the Director may impose additional requirements, including but not limited to, sensitive area determination, sampling and analysis, remediation, monitoring, permitting and the establishment of points of compliance. Any action taken pursuant to this Rule shall comply with the provisions of Rules 324A. through D. and the 500 Series rules.

d. **Alternative compliance methods.** Operators may propose for prior approval by the Director alternative methods for determining the extent of contamination, sampling and analysis, or alternative cleanup goals using points of compliance or risk-based approaches.

e. **Sensitive area determination.** Operators shall make a sensitive area determination using the Sensitive Area Determination Decision Tree, Figure 901-1 to evaluate the potential for impact to ground water and submit data evaluated and analysis used in the determination to the Director for the following operations or remediation activities:

(1) Construction of drilling pits designed for use with fluids containing hydrocarbon concentrations exceeding 20,000 parts per million ("ppm") total petroleum hydrocarbon ("TPH") or chloride concentrations at total well depth exceeding 15,000 ppm.

(2) Construction of production and special purpose pits;

(3) Construction of centralized E&P waste management facilities;

(4) Management and remediation of spills/releases exceeding twenty (20) barrels net loss of E&P waste; or

(5) When the operator or Director has data that indicate an impact or threat of impact to ground water.

f. Sensitive area operations. **Operations in sensitive areas shall incorporate adequate measures and controls to prevent significant adverse environmental impacts and ensure compliance with the allowable concentrations and levels in Table 910-1, with consideration to WQCC standards and classifications. Unlined production and special purpose pits in sensitive areas are generally not approved.**

902. PITS - GENERAL AND SPECIAL RULES

a. Pits used for exploration and production of oil and gas shall be constructed and operated to protect the waters of the state from significant adverse environmental impacts from E&P waste, except as permitted by applicable laws and regulations.

b. Topsoil and subsoil removed in the construction of the pit shall be segregated and stockpiled in a manner described in Rule 1002. and used for reclamation of the site.

c. Pits shall be constructed and operated to provide for a minimum of two (2) feet of freeboard between the top of the pit wall and the fluid level of the pit.

d. Any accumulation of oil in a pit shall be removed within twenty-four (24) hours of discovery. This requirement is not applicable to properly permitted and properly fenced or netted skim pits.

e. Where necessary to protect public health, safety and welfare or to prevent significant adverse environmental impacts resulting from access to a pit by wildlife, migratory birds, domestic animals, or members of the general public, operators shall install appropriate netting or fencing.

f. **Multi-well pits.** Production and special purpose pits used for treatment or disposal of E&P waste generated from more than one well may be permitted in accordance with Rule 903. as a multi-well pit, subject to Director approval.

g. Unlined drilling pits shall not be constructed on fill material.

h. Produced water shall be treated in accordance with Rule 907. before being placed in a production pit.

903. PIT PERMITTING/REPORTING REQUIREMENTS

a. Drilling pits, production pits, and special purpose pits shall be permitted or reported as follows:

(1) Pit Construction Report/Permit, Form 15, shall be submitted for prior Director approval for the following:

A. Drilling pits designed for use with fluids containing hydrocarbon concentrations exceeding 20,000 ppm TPH or chloride concentrations at total well depth exceeding 15,000 ppm in sensitive areas or 50,000 ppm outside sensitive areas.

B. Production pits and unlined special purpose pits in sensitive areas.

C. Unlined production pits and special purpose pits outside sensitive areas, excluding those pits permitted in accordance with Rule 903.a.(2).B.

(2) Pit Construction Report/Permit, Form 15, shall be submitted within thirty (30) days after construction for the following:

A. Lined production pits outside sensitive areas.

B. Unlined production pits outside sensitive areas receiving produced water at an average daily rate of five (5) or less barrels per day calculated on a monthly basis for each month of operation.

C. Lined special purpose pits.

D. Flare pits where there is no risk of condensate accumulation.

(3) Pit Construction Report/Permit, Form 15, shall not be required for drilling pits using water-based bentonitic drilling fluids with concentrations of TPH and chloride below those referenced in Rule 903.a.(1).A.

b. The Pit Construction Report/Permit, Form 15, shall be completed in accordance with the instructions in Appendix I. Failure to complete the form in full may result in delay of approval or return of form.

c. The Director shall endeavor to review any properly completed Pit Construction Report/Permit, Form 15, within thirty (30) days after receipt. In order to allow adequate time for pit permit approval, operators should submit required Form 15 pit construction permit requests for approval with an Application for Permit to Drill, Form 2. The Director may condition permit approval upon compliance with additional terms, provisions or requirements necessary to protect the waters of the state, public health, or the environment.

904. PIT LINING REQUIREMENTS AND SPECIFICATIONS

a. Pit lining requirements. The following pits shall be lined:

(1) Drilling pits designed for use with fluids containing hydrocarbon concentrations exceeding 20,000 ppm TPH or chloride concentrations at total well depth exceeding 15,000 ppm in sensitive areas or 50,000 ppm outside sensitive areas.

(2) Production pits in sensitive areas.

(3) Special purpose pits, except emergency pits constructed during initial response to spills/releases, or flare pits where there is no risk of condensate accumulation.

(4) Skim pits.

b. The following specifications shall apply to pits that are required to be lined:

(1) Materials used in lining pits shall be impervious, weather resistant and resistant to deterioration when in contact with hydrocarbons, aqueous acids, alkali, fungi or other substances in the produced water.

(2) Soil liners shall have a minimum thickness of six (6) inches after compaction, shall cover the entire bottom and interior sides of the pit, and shall be constructed so that the hydraulic conductivity of the liner shall not exceed 1.0×10^{-6} cm/sec. Bentonite liners shall be constructed to provide equivalent protection. Operators shall perform post-construction tests either in a laboratory or in the field. All test results shall be filed with the Director.

(3) Synthetic or fabricated liners shall have a minimum thickness of twelve (12) mils and shall be resistant to deterioration by ultraviolet light, weathering, chemicals, punctures and tearing, and designed for the life of the well. The foundation for the liner shall be constructed to prevent punctures from soils or other materials beneath the liner. The synthetic or fabricated liner shall cover the bottom and interior sides of the pit with the edges secured with at least a twelve (12) inch deep anchor trench around the pit perimeter.

(4) In Sensitive Areas, the Director may require a leak detection system for the pit or other equivalent protective measures, including but not limited to, increased record-keeping requirements, monitoring systems and underlying gravel fill sumps and lateral systems. In making such determination, the Director shall consider the surface and subsurface geology, the use and quality of potentially-affected ground water, the quality of the produced water, and the hydraulic conductivity of the surrounding soils and the type of liner.

905. CLOSURE OF PITS, AND BURIED OR PARTIALLY BURIED PRODUCED WATER VESSELS.

a. Unlined production and special purpose pits, except emergency pits constructed during initial response to spills/releases, shall be closed in accordance with an approved Site Investigation and Remediation Workplan, Form 27. The workplan shall be submitted for prior Director approval and shall include a description of the proposed investigation and remediation activities in accordance with Rule 909.

b. Lined pits and buried or partially buried produced water vessels:

(1) Operators shall ensure that soils and ground water meet the allowable concentrations of Table 910-1.

(2) **Pit evacuation.** Prior to backfilling and site reclamation, E&P waste shall be treated or disposed in accordance with Rule 907.

(3) Liners shall be disposed as follows:

A. **Synthetic liner disposal.** On irrigated crop land, liner material shall be removed and disposed in accordance with applicable solid waste rules. On non-irrigated crop land and on non-crop land, liner material may be left in place with surface owner approval.

B. **Constructed soil liners.** Constructed soil liner material may be removed for treatment or disposal, or, where left in place, the material shall be ripped and mixed with native soils in a manner to alleviate compaction and prevent an impermeable barrier to infiltration and ground water flow.

c. **Discovery of a spill/release during closure**. When a spill/release is discovered during closure operations operators shall report the spill/release on the Spill/Release Report, Form 19, in accordance with Rule 906. Leaking pits and buried or partially buried produced water vessels shall be closed and remediated in accordance with Rules 909. and 910.

d. **Emergency pits**. Emergency pits constructed during initial response to contain and mitigate spills/releases shall not be subject to lining requirements. These pits shall be closed and remediated in accordance with Rule 906.

e. **Unlined drilling pits.** Unlined drilling pits shall be closed and reclaimed in accordance with the 1000 Series rules.

906. SPILLS AND RELEASES

a. **General.** Spills/releases of E&P waste, including produced fluids shall be controlled and contained immediately upon discovery. Impacts resulting from spills/releases shall be investigated and cleaned up as soon as practicable.

The Director may require additional activities to prevent or mitigate threatened or actual significant adverse environmental impacts on any air, water, soil or biological resource, or to the extent necessary to ensure compliance with the allowable concentrations and levels in Table 910-1, with consideration to WQCC ground water standards and classifications.

b. **Reporting.**

(1) Spills/releases of E&P waste or produced fluid exceeding five (5) barrels, including those contained within unlined berms, shall be reported on COGCC Spill/Release Report Form, 19. Such report shall include information relating to initial mitigation, site investigation and remediation, and shall be submitted to the Director within ten (10) days of discovery of the spill/release.

(2) In addition, spills/releases which exceed twenty (20) barrels of an E&P waste shall be verbally reported to the Director within twenty-four (24) hours of discovery.

(3) In addition, spill/releases of any size which impact or threaten to impact any waters of the state, residence or occupied structure, livestock or public byway, shall be verbally reported to the Director as soon as practicable after discovery.

c. **Surface owner notification and consultation.** The operator shall make good faith efforts to notify and consult with the surface owner prior to commencing operations to remediate E&P waste from a spill/release in an area not being utilized for oil and gas operations.

d. **Remediation of spills/releases**.

(1) **Remediation workplan.** When threatened or actual significant adverse environmental impacts on any air, water, soil or biological resource from a spill/release exists or when necessary to ensure compliance with the allowable concentrations and levels in Table 910-1, with consideration to WQCC ground water standards and classifications, the Director may require operators to submit a Site Investigation and Remediation Workplan, Form 27.

(2) **Remediation requirements.** Spills/releases shall be remediated to meet the allowable concentrations in Table 910-1. Spills/releases exceeding twenty (20) barrels net loss of E&P waste shall be remediated in accordance with Rules 909. and 910.

e. **Spill/release prevention.**

(1) **Secondary containment.** Secondary containment shall be constructed or installed around tanks containing crude oil, condensate or produced water with greater than 10,000 milligrams per liter (mg/l) total dissolved solids (TDS). Operators are also subject to crude oil tank and containment requirements under Rules 603. and 604. This requirement shall not apply to water tanks with a capacity of one hundred (100) barrels or less.

(2) **Spill/release evaluation.** Operators shall determine the cause of a spill/release, and to the extent practicable, shall implement measures to prevent spills/releases due to similar causes in the future. For reportable spills, operators shall submit this information to the Director on the Spill/Release Report, Form 19 within ten (10) days after discovery of the spill/release.

907. MANAGEMENT OF E&P WASTE

a. **General requirements.**

(1) **Operator obligations.** Operators shall ensure that E&P waste is properly stored, handled, transported, treated, recycled or disposed to prevent threatened or actual significant adverse environmental impacts to air, water, soil or biological resources or to the extent necessary to ensure compliance with the allowable concentrations and levels in Table 910-1, with consideration to WQCC ground water standards and classifications.

(2) E&P waste management activities shall be conducted, and facilities constructed and operated, to protect the waters of the state from significant adverse environmental impacts from E&P waste, except as permitted by applicable laws and regulations.

(3) **Reuse and recycling.** To encourage and promote waste minimization, operators may propose plans for managing E&P waste through beneficial use, reuse and recycling by submitting a written management plan to the Director for approval. Such plans shall describe the proposed use of the waste, method of waste treatment, product quality assurance, and shall include a copy of any certification or authorization that may be required by other laws.

b. **Waste transportation.**

(1) E&P waste, when transported off-site within Colorado for treatment or disposal, shall be transported to facilities authorized by the Director or waste disposal facilities approved to receive E&P waste by the CDPHE.

(2) **Waste generator requirements.** Generators of E&P waste shall maintain, for not less than three (3) years, copies of each invoice, bill or ticket and such other records as necessary to document the following information from a transporter or disposal site, describing the disposal of E&P waste from each location:

A. The date of the transport;

B. The identity of the waste generator;

C. The identity of the waste transporter;

D. The location of the waste pickup site;

E. The type and volume of waste; and

F. The name and location of the treatment or disposal site.

Such records shall be made available for inspection by the Director during normal business hours and copies thereof shall be furnished to the Director upon request.

c. **Produced water.**

(1) **Treatment of produced water.** Produced water shall be treated prior to placement in a production pit to prevent crude oil and condensate from entering the pit.

(2) **Produced water disposal.** Produced water may be disposed as follows:

A. Injection into a Class II well, permitted in accordance with Rule 325.;

B. Evaporation/percolation in a properly permitted lined or unlined pit;

C. Disposal at permitted commercial facilities; or

D. Disposal by roadspreading on lease roads outside sensitive areas for produced waters with less than 5,000 mg/l TDS when authorized by the surface owner. Roadspreading shall not result in pooling or runoff of produced waters and the adjacent soils shall meet the allowable concentrations in Table 910-1.

E. Discharging into state waters, in accordance with the Water Quality Control Act and the rules and regulations promulgated thereunder. Produced water discharged pursuant to this subsection (2)E. may be put to beneficial use in accordance with applicable state statutes and regulations governing the use and administration of water.

(3) **Produced water reuse and recycling.** Produced water may be reused for enhanced recovery, drilling, and other uses in a manner consistent with existing water rights and in consideration of water quality standards and classifications established by the WQCC for waters of the state, or any point of compliance established by the Director pursuant to Rule 324D.

(4) **Mitigation.** Water produced during operation of an oil or gas well may be used to provide an alternate domestic water supply to surface owners within the oil or gas field, in accordance with all applicable laws, including, but not limited to, obtaining the necessary approvals from the WQCD for constructing a new "waterworks," as defined by section 25-1-107(1)(X)(II)(A), C.R.S. Any produced water not so used shall be disposed of in accordance with subsection (2) or (3). Provision of produced water for domestic use within the meaning of this subsection (4) shall not constitute an admission by the operator that the well is dewatering or

impacting any existing water well. The water produced shall be to the benefit of the surface owner within the oil and gas field and may not be sold for profit or traded.

d. **Drilling fluids.**

(1) **Drilling pit fluid recycling.** Drilling pit contents may be recycled to another drilling pit consistent with Rule 903.

(2) **Drilling fluids treatment and disposal.** Drilling fluids may be treated or disposed as follows:

A. Injection into a Class II well permitted in accordance with Rule 325.;

B. Disposal at a commercial solid waste disposal facility; or

C. Land treatment or land application at a centralized E&P waste management facility permitted in accordance with Rule 908.

(3) **Additional authorized disposal of water-based bentonitic drilling fluids.** Water-based bentonitic drilling fluids may be disposed as follows:

A. Drying and burial in drilling pits on non-crop land; or

B. Land application as follows:

i. **Applicability.** Acceptable methods of land application include, but are not limited to, production facility construction and maintenance, lease and farm road maintenance, or lining of stock ponds and irrigation ditches.

ii. **Land application requirements**. The average thickness of water-based bentonitic drilling fluid waste applied shall be no more than three (3) inches prior to incorporation. The waste shall be applied to prevent ponding or erosion and shall be incorporated as a beneficial amendment into the native soils as soon as practicable. The resulting concentrations shall not exceed those in Table 910-1.

iii. **Surface owner approval.** Operators shall obtain written authorization from the surface owner prior to land application of water-based bentonitic drilling fluids.

iv. **Operator obligations**. Operators with control and authority over the wells from which the water-based bentonitic drilling fluid wastes are obtained retain responsibility for the land application operation, and shall diligently cooperate with the Director in responding to complaints regarding land application of water-based bentonitic drilling fluids.

v. **Approval.** Prior Director approval is not required for reuse of water-based bentonitic drilling fluids for land application as a soil amendment or lining material.

e. **Oily waste.** Oily waste includes those materials containing crude oil, condensate or other hydrocarbon-containing E&P waste, such as soil, frac sand, drilling fluids, workover fluids, pit sludge, tank bottoms, pipeline pigging wastes, and natural gas gathering, processing and storage wastes.

(1) Oily waste may be treated or disposed as follows:

A. Disposal at a commercial solid waste disposal facility;

B. Land treatment onsite or with prior written surface owner approval, offsite land treatment; or

C. Land treatment at a centralized E&P waste management facility permitted in accordance with Rule 908.

(2) Land treatment requirements:

A. Free oil shall be removed from the oily waste prior to land treatment.

B. Oily waste shall be spread evenly to prevent pooling, ponding or runoff.

C. Contamination of ground water or surface water shall be prevented.

D. Biodegradation shall be enhanced by disking, tilling, aerating, addition of nutrients, microbes, water or other amendments, as appropriate.

E. Land-treated oily waste incorporated in place shall not exceed the allowable concentrations in Table 910-1.

F. When a threatened or significant adverse environmental impact from onsite land treatment exists, the Director may require operators to submit a Site Investigation And Remediation Workplan, Form 27. Treatment shall thereafter be completed in accordance with the workplan and Rules 909. and 910.

G. When land treatment occurs in an area not being utilized for oil and gas operations, operators shall obtain prior written surface owner approval.

908. CENTRALIZED E&P WASTE MANAGEMENT FACILITIES

a. **Applicability.** Operators may establish non-commercial, centralized E&P waste management facilities for the treatment, disposal, recycling or beneficial reuse of E&P waste. This rule applies only to non-commercial facilities, which means the operator does not represent itself as providing E&P waste management services to third parties, except as part of a unitized area or joint operating agreement or in response to an emergency. Centralized facilities may include components such as land treatment or land application sites, pits and recycling equipment.

b. **Permit requirements.** An application for permit including the following information shall be submitted to the Director for prior approval along with a filing and service fee established by the Commission (Appendix III):

(1) The name, address, phone and fax number of the operator, and a designated contact person.

(2) The name, address and phone number of the surface owner of the site, if not the operator, and the written authorization of such surface owner.

(3) The legal description of the site.

(4) A general topographic, geologic and hydrologic description of the site, including immediately adjacent land uses, a topographic map of a scale no less than 1:24,000 showing the location, and the average annual precipitation and evaporation rates at the site.

(5) Centralized facility siting requirements.

A. A site plan showing drainage patterns and any diversion or containment structures, and facilities such as roads, fencing, tanks, pits, buildings, and other construction details.

B. Scaled drawings of entire sections containing the proposed facility. The field measured distances from the nearer north or south and nearer east or west section lines shall be measured at ninety (90) degrees from said section lines to facility boundaries and referenced on the drawing. A survey shall be provided including a complete description of established monuments or collateral evidence found and all aliquot corners.

C. Appropriate measures to limit access to the centralized facility by wildlife, domestic animals, and members of the general public shall be implemented.

D. Centralized facilities shall have a fire lane of at least ten (10) feet in width around the active treatment areas and within the perimeter fence. In addition, a buffer zone of at least ten (10) feet shall be maintained within the perimeter fire lane.

E. Surface water diversion structures, including, but not limited to, berms and ditches, shall be constructed to accommodate a one hundred (100) year, twenty four (24) hour event.

(6) **Waste profile.** For each type of waste, the amounts to be received and managed by the facility shall be estimated on a monthly average basis. For each waste type to be treated, a characteristic waste profile shall be completed.

(7) F**acility design and engineering.** Facility design and engineering data, including plans and elevations, design basis, calculations, and process description.

(8) **Operating plan.** An operating plan, including, but not limited to, a detailed description of the method of treatment, loading rates, application of nutrients and soil amendments, dust and moisture control, sampling, inspection and maintenance, emergency response, record-keeping, site security, hours of operation, and final disposition of waste. Where treated waste will be beneficially reused, a description of reuse and method of product quality assurance shall be included.

(9) **Ground water monitoring.**

A. The Director may require ground water monitoring for the purpose of preventing and mitigating threatened or actual significant adverse environmental impact or to ensure compliance with the allowable concentrations and levels in Table 910-1, with consideration to WQCC standards and classifications by establishing points of compliance.

B. Where monitoring is required, the direction of flow, ground water gradient and quality of water shall be established by the installation of a minimum of three (3) monitor wells, including an up-gradient well and two (2) down-gradient wells that will serve as points of compliance, or other methods authorized by the Director.

c. **Permit approval**. The Director shall endeavor to approve or deny the properly completed permit within thirty (30) days after receipt and may condition permit approval as necessary to prevent any threatened or actual significant adverse environmental impact on air, water, soil or biological resources or to the extent necessary to ensure compliance with the allowable concentrations and levels in Table 910-1, with consideration to WQCC ground water standards and classifications.

d. **Financial assurance.** The operator of a land treatment facility shall submit for the Director's approval such financial assurance as required by Rule 704.

e. **Facility modifications.** Throughout the life of the facility the operator shall submit proposed modifications to the facility design, operating plan, permit data, or permit conditions to the Director for prior approval.

f. **Annual permit review.** To ensure compliance with permit conditions and the 900 Series rules, the facility permit shall be subject to an annual review by the Director.

g. **Closure.** A preliminary plan for closure shall be submitted with the centralized facility permit. A Site Investigation and Remediation Workplan, Form 27 shall be submitted sixty (60) days prior to closure for approval by the Director. The workplan shall describe the final closure plan.

h. Operators may be subject to local requirements for zoning and construction of facilities and shall provide copies of notifications to local governments or other agencies to the Director.

909. SITE INVESTIGATION, REMEDIATION AND CLOSURE

a. **Applicability.** This section applies to the closure and remediation of pits other than drilling pits constructed pursuant to Rule 903.a.(3).; investigation, reporting and remediation of spills/releases; permitted waste management facilities including treatment facilities; plugged and abandoned wellsites; sites impacted by E&P waste management practices; or other sites as designated by the Director.

b. **General site investigation and remediation requirements.**

(1) **Sensitive Area Determination.** Operators shall complete a sensitive area determination in accordance with Rule 901.e.

(2) **Sampling and analyses.** Samples and analysis of soil and ground water shall be conducted in accordance with Rule 910. to determine the horizontal and vertical extent of any contamination in excess of the allowable concentrations in Table 910-1.

(3) **Management of E&P waste.** E&P waste shall be managed in accordance with Rule 907.

(4) **Pit evacuation**. Prior to backfilling and site reclamation, E&P waste shall be treated or disposed in accordance with Rule 907. and the 1000 Series rules.

(5) **Remediation.** Remediation shall be performed in a manner to mitigate, remove or reduce contamination that exceeds the allowable concentrations in Table 910-1 in order to ensure protection of public health, safety and welfare, and to prevent and mitigate significant adverse environmental impacts. Soil that does not meet allowable concentrations in Table 910-1 shall be remediated. Ground water that does not meet allowable concentrations in Table 910-1 shall be remediated in accordance with a Site Investigation and Remediation Workplan, Form 27.

(6) **Reclamation.** Remediation sites shall be reclaimed in accordance with the 1000 Series rules for reclamation.

c. **Site Investigation And Remediation Workplan, Form 27.** Operators shall prepare and submit for prior Director approval a Site Investigation and Remediation Workplan, Form 27 for the following operations and remediation activities:

(1) Unlined pit closure when required by Rule 905.

(2) Remediation of spills/releases in accordance with Rule 906.

(3) Land treatment of oily waste in accordance with Rule 907.e.(2).F.

(4) Closure of centralized E&P waste management facilities in accordance with Rule 908.g.

(5) Remediation of impacted ground water in accordance with Rule 910.b.(4).

d. **Multiple sites.** Remediation of multiple sites may be submitted on a single workplan with prior Director approval.

e. **Closure.**

(1) Remediation and reclamation shall be complete upon compliance with the allowable concentrations in Table 910-1, or upon compliance with an approved workplan.

(2) **Notification of completion.** Within thirty (30) days after conclusion of site remediation and reclamation activities operators shall provide the following notification of completion:

A. Operators conducting remediation operations in accordance with Rule 909.b. shall submit to the Director a Site Investigation and Remediation Workplan, Form 27, containing information sufficient to demonstrate compliance with these rules.

B. Operators conducting remediation under an approved workplan shall submit to the Director, by adding or attaching to the original workplan, information sufficient to demonstrate compliance with the workplan.

f. **Release of financial assurance.** Financial assurance required by Rule 706. may be held by the Director until the required remediation of ground water impacts is completed in accordance with the approved workplan, or until cleanup goals are met.

910. ALLOWABLE CONCENTRATIONS AND SAMPLING FOR SOIL AND GROUND WATER

a. **Soil and ground water allowable concentrations.** The allowable concentrations for soil and ground water are in Table 910-1. Ground water standards and analytical methods are derived from the ground water standards and classifications established by WQCC.

b. **Sampling and analysis.**

(1) **Existing workplans.** Sampling and analysis for sites subject to an approved workplan shall be conducted in accordance with the workplan and the sampling and analysis requirements described in this rule.

(2) **Methods for sampling and analysis.** Sampling and analysis for site investigation or confirmation of successful remediation shall be conducted to determine the nature and extent of impact and confirm compliance with appropriate allowable concentrations.

A. **Field analysis.** Field measurements and field tests shall be conducted using appropriate equipment, calibrated and operated according to manufacturer specifications, by personnel trained and familiar with the equipment.

B. **Sample collection.** Samples shall be collected, preserved, documented, and shipped using standard environmental sampling procedures in a manner to ensure accurate representation of site conditions.

C. **Laboratory analytical methods.** Laboratories shall analyze samples using standard methods (such as EPA SW-846 or API RP-45) appropriate for detecting the target analyte. The method selected shall have detection limits less than or equal to the allowable concentrations in Table 910-1.

D. **Background sampling.** Samples of comparable, nearby, non-impacted, native soil, ground water or other medium may be required by the Director for establishing background conditions.

(3) **Soil sampling and analysis.**

A. **Applicability.** If soil contamination is suspected or known to exist as a result of spills/releases or E&P waste management, representative samples of soil shall be collected and analyzed in accordance with this rule.

B. **Sample collection.** Samples shall be collected from areas most likely to have been impacted, and the horizontal and vertical extent of contamination shall be determined. The number and location of samples shall be appropriate to the impact.

C. **Sample analysis.** Soil samples shall be analyzed for contaminants listed in Table 910-1 as appropriate to assess the impact or confirm remediation.

D. **Reporting.** Soil Analysis Report, Form 24 shall be used when the Director requires results of soil analyses.

E. **Soil impacted by produced water.** For impacts to soil due to produced water, samples from comparable, nearby non-impacted, native soil shall be collected and analyzed for purposes of establishing background soil conditions including pH and electrical conductivity (EC). Where EC of the impacted soil exceeds the allowable level in Table 910-1, the sodium adsorption ratio (SAR) shall also be determined.

F. **Soil impacted by hydrocarbons.** For impacts to soil due to hydrocarbons, samples shall be analyzed for TPH.

(4) **Ground water sampling and analysis.**

A. **Applicability.** Operators shall collect and analyze representative samples of ground water in accordance with these rules under the following circumstances:

i. Where ground water contamination is suspected or known to exceed the allowable concentrations in Table 910-1;

ii. Where impacted soils are in contact with ground water; or

iii. Where impacts to soils extend down to the high water table.

B. **Sample collection.** Samples shall be collected from areas most likely to have been impacted, downgradient or in the middle of excavated areas. The number and location of samples shall be appropriate to determine the horizontal and vertical extent of the impact. If the concentrations in Table 910-1 are exceeded, the direction of flow and a ground water gradient shall be established, unless the extent of the contamination and migration can otherwise be adequately determined.

C. **Sample analysis.** Ground water samples shall be analyzed for benzene, toluene, ethylbenzene, xylene, and API RP-45 constituents, or other parameters appropriate for evaluating the impact.

D. **Reporting.** Water Analysis Report, Form 25 shall be used when the Director requires results of water analyses.

E. **Impacted ground water.** Where ground water contaminants exceed the allowable concentrations listed in Table 910-1, operators shall notify the Director, and submit to the Director for prior approval a Site Investigation and Remediation Workplan, Form 27, for the investigation, remediation, or monitoring of ground water to meet the required allowable concentrations.

911. PIT, BURIED OR PARTIALLY BURIED PRODUCED WATER VESSEL, BLOWDOWN PIT, AND BASIC SEDIMENT/TANK BOTTOM PIT MANAGEMENT REQUIREMENTS PRIOR TO DECEMBER 30, 1997.

a. **Applicability.** This rule applies to the management, operation, closure and remediation of drilling, production and special purpose pits, buried or partially buried produced water vessels, blowdown pits, and basic sediment/tank bottom pits put into service prior to December 30, 1997 and unlined skim pits put into service prior to July 1, 1995. For pits constructed after December 30, 1997 and skim pits constructed after July 1, 1995, operators shall comply with the requirements contained in Rules 901. through 910.

b. **Inventory.** Operators were required to submit to the Director no later than December 31, 1995, an inventory identifying production pits, buried or partially buried produced water vessels, blowdown pits, and basic sediment/tank bottom pits that existed on June 30, 1995. The inventory required operators to provide the facility name, a description of the location, type, capacity and use of pit/vessel, whether netted or fenced, lined or unlined, and where available, water quality data. Operators who have failed to submit the required inventory are in continuing violation of this rule.

c. **Sensitive area determination.**

(1) For unlined production and special purpose pits constructed prior to July 1, 1995 and not closed by December 30, 1997, operators were required to determine whether the pit was located within a sensitive area in accordance with the Sensitive Area Determination Decision Tree, Figure 901-1, (now Rule 901.e.), and submit data evaluated and analysis used in the determination to the Director on a Sundry Notice, Form 4.

(2) For steel, fiberglass, concrete, or other similar produced water vessels that were buried or partially buried and located in sensitive areas prior to December 30, 1997, operators were required to test such vessels for integrity, unless a monitoring or leak detection system was put in place.

d. The following permitting/reporting requirements applied to pits constructed prior to December 30, 1997:

(1) A Sundry Notice, Form 4, including the name, address, and phone number of the primary contact person operating the production pit for the operator, the facility name, a description of the location, type, capacity and use of pit, engineering design, installation features and water quality data, if available, was required for the following:

A. Lined production pits and lined special purpose pits constructed after July 1, 1995.

B. Unlined production pits constructed prior to July 1, 1995 which are lined in accordance with Rule 905. by December 30, 1997.

(2) An Application For Permit For Unlined Pit, Form 15 was required for the following:

A. Unlined production pits and special purpose pits in sensitive areas constructed prior to July 1, 1995, and not closed by December 30, 1997.

B. Unlined production pits outside sensitive areas constructed after July 1, 1995 and not closed by December 30, 1997.

(3) An Application For Permit For Unlined Pit, Form 15 and a variance under Rule 904.e.(1). (repealed, now Rule 502.b.) was required for unlined production pits and unlined special purpose pits in sensitive areas constructed after July 1, 1995.

(4) A Sundry Notice, Form 4 was required for unlined production pits outside sensitive areas receiving produced water at an average daily rate of five (5) or less barrels per day calculated on a monthly basis for each month of operation constructed prior to December 30, 1997.

e. The Director may have established points of compliance for unlined production pits and special purpose pits and for lined production pits in sensitive areas constructed after July 1, 1995.

f. **Closure requirements.**

(1) Operators of production or special purpose pits existing on July 1, 1995 which were closed before December 30, 1997, were required to submit a Sundry Notice, Form 4, within thirty (30) days of December 30, 1997. The Sundry Notice, Form 4 shall include a copy of the existing pit permit, if a permit was obtained and a description of the closure process.

(2) Pits closed prior to December 30, 1997 were required to be reclaimed in accordance with the 1000 Series rules. Pits closed after December 30, 1997 shall be closed in accordance with the 900 Series rules and reclaimed in accordance with the 1000 Series rules.

(3) Operators of steel, fiberglass, concrete or other similar produced water vessels buried or partially buried and located in sensitive areas were required to repair or replace vessels and tanks found to be leaking. Operators shall repair or replace vessels and tanks found to be leaking. Operators shall submit to the Director a Sundry Notice, Form 4, describing the integrity testing results and action taken within thirty (30) days of December 30, 1997.

(4) Closure of pits and steel, fiberglass, concrete or other similar produced water vessels, and associated remediation operations conducted prior to December 30, 1997 are not subject to Rules 905., 906., 907., 909. and 910.

912. VENTING OR FLARING NATURAL GAS

a. The unnecessary or excessive venting or flaring of natural gas produced from a well is prohibited.

b. Except for gas flared or vented during an upset condition, well maintenance, well stimulation flowback, purging operations, or a productivity test, gas from a well shall be flared or vented only after notice has been given and approval obtained from the Director on a Sundry Notice, Form 4, stating the estimated volume and content of the gas. The notice shall indicate whether the gas contains more than one (1) ppm of hydrogen sulfide. If necessary to protect the public health, safety or welfare, the Director may require the flaring of gas.

c. Gas flared, vented or used on the lease shall be estimated based on a gas-oil ratio test or other equivalent test approved by the Director, and reported on Operator's Monthly Production Report, Form 7.

d. Prior to flaring of any gas, operators shall construct a special purpose pit in compliance with Rule 903.

e. Operators shall notify the local emergency dispatch or the local governmental designee of any natural gas flaring. Notice shall be given prior to flaring when flaring can be reasonably anticipated, or as soon as possible but in no event more than two (2) hours after the flaring occurs.

Table 910-1
ALLOWABLE CONCENTRATIONS AND LEVELS

Contaminant of concern	Allowable concentrations
Organics in Soil: EPA Method 8015 (modified)	
TPH-Non-Sensitive Area	10,000 mg/kg
TPH-Sensitive Area	1,000 mg/kg
Organics in Ground Water: EPA Method 8020 [1]	
Benzene	5 µg/l [1]
Toluene	1,000 µg/l [1]
Ethylbenzene	680 µg/l [1]
Xylene	10,000 µg/l [1]
Inorganics in Soils[4]	
Electrical Conductivity (EC)	<4 mmhos/cm or 2x background
Sodium Adsorption Ratio (SAR)	<12
pH	6-9
Inorganics in Ground Water	
Total Dissolved Solids (TDS)	<1.25 x background [1]
Chlorides	<1.25 x background [1]
Sulfates	<1.25 x background [1]
Total Metals in Soils: EPA Method 3050[4]	
Arsenic	41 mg/kg [2]
Barium (LDNR True Total Barium)	180,000 mg/kg [2]
Boron (Hot Water Soluble)	2 mg/l [2]
Cadmium	26 mg/kg [2]
Chromium	1,500 mg/kg [2]
Copper	750 mg/kg [2]
Lead	300 mg/kg [2]
Mercury	17 mg/kg [2]
Molybdenum	[3]
Nickel	210 mg/kg [2]
Selenium	[3]
Silver	100 mg/kg [2]
Zinc	1,400 mg/kg [2]

1 Concentrations taken from CDPHE-WQCC
2 Concentrations taken from API Metals Guidance: Maximum Soil Concentrations
3 Concentrations are dependent on site-specific conditions
4 Consideration shall be given to background levels in native soils

Figure 901-1
SENSITIVE AREA DETERMINATION
Decision Tree

***BOX 1*:** Is discharge water or waste:
>1.25 x background ppm TDS
>250 ppm Chloride or
1.25 x background
>250 ppm Sulfate or
1.25 x background
> 5 ppb Benzene
> 1000 ppb Toluene
> 680 ppb Ethylbenzene
> 10,000 ppb Xylene

NO → OUTSIDE SENSITIVE AREAS
YES ↓

***BOX 2*:** Is the site underlain by an unconfined aquifer or recharge zone?

NO → OUTSIDE SENSITIVE AREAS
YES ↓

***BOX 3*:** is the hydraulic conductivity of the underlying soils and geologic material less than or equal to 10^{-6} cm/sec?

YES → OUTSIDE SENSITIVE AREAS
NO ↓

***BOX 4*:** Is the site within an area classified for domestic use by WQCC, or a local (water supply) wellhead protection area (WHPA)?

YES → INSIDE SENSITIVE AREAS
NO ↓

***BOX 5*:** Is the location within 1/8 mi. of a domestic water well, or 1/4 mi. of a public water supply well, using the same aquifer?

YES → INSIDE SENSITIVE AREAS
NO ↓

***BOX 6*:** Is the depth to the average high ground water table <20', from the deeper of the ground surface, pit bottom or from the point of spill/release? (**see footnote*)

NO → OUTSIDE SENSITIVE AREAS
YES → INSIDE SENSITIVE AREAS

OUTSIDE SENSITIVE AREAS

-New E&P waste management facilities shall be allowed outside Sensitive Areas. Points of Compliance shall be established as appropriate.

-Where complaints are made, Points of Compliance may be established for existing facilities.

INSIDE SENSITIVE AREAS

-E&P waste management facilities shall not be allowed unless the operator demonstrates no potential for significant adverse environmental impact.

-Facilities which are permitted may have Points of Compliance established.

** Additional requirements may be imposed by the Director in accordance with Rule 901.c.*

RECLAMATION REGULATIONS

1001. INTRODUCTION

a. **General.** The rules and regulations of this series establish the proper reclamation of the land and soil affected by oil and gas operations and ensure the protection of the topsoil of said land during such operations. The surface of the land shall be restored as nearly as practicable to its condition at the commencement of drilling operations.

b. **Additional requirements.** Notwithstanding the provisions of the 1000 Series rules, when the Director has reasonable cause to believe that a proposed oil and gas operation could result in a significant adverse environmental impact on any air, water, soil, or biological resource, the Director shall conduct an onsite inspection and may request an emergency meeting of the Commission to address the issue.

c. **Surface owner waiver of 1000 Series rules.** The Commission shall not require compliance with Rules 1002., 1003., 1004.a., b., or c.(1), (2), or (3), if the operator can demonstrate to the Director's or the Commission's satisfaction that compliance with such rules is not necessary to protect the public health, safety and welfare, including prevention of significant adverse environmental impacts, and that the operator has entered into an agreement with the surface owner regarding topsoil protection and reclamation of the land. Absent bad faith conduct by the operator, penalties may only be imposed for non-compliance with a Commission order issued after a determination that, notwithstanding such agreement, compliance is necessary to protect public health, safety and welfare. Prior to final reclamation approval as to a specific well, the operator shall either comply with the rules or obtain a variance under Rule 502.b. This rule shall not have the effect of relieving an operator from compliance with the 900 Series rules.

1002. SITE PREPARATION

a. Effective June 1, 1996:

(1) **Fencing of drill sites and access roads on crop lands.** During drilling operations on crop lands, when requested by the surface owner, the operator shall delineate each drillsite and access road on crop lands constructed after such date by berms, single strand fence or other equivalent method in order to discourage unnecessary surface disturbance.

(2) **Fencing of reserve pit when livestock is present.** During drilling operations where livestock is in the immediate area and is not fenced out by existing fences, the operator, at the request of the surface owner, will install a fence around the reserve pit.

(3) **Fencing of well sites.** Subsequent to drilling operations, where livestock is in the immediate area and is not fenced out by existing fences, the operator, at the request of the surface owner, will install a fence around the wellhead, pit and production equipment to prevent livestock entry.

b. **Soil removal and segregation.**

(1) **Soil removal and segregation on crop land.** As to all excavation operations undertaken after June 1, 1996 on crop land, the operator shall separate and store the various A, B, and C soil horizons separately from one another and mark or document stockpile locations to facilitate subsequent reclamation. When separating soil horizons, the operator shall segregate horizons based upon noted changes in physical characteristics such as color, texture, density or consistency. On crop land below the C horizon, the soil horizons shall also be segregated based on the above noted physical characteristics. Segregation will be performed to the extent practicable to a depth of six (6) feet or bedrock, whichever is shallower.

(2) **Soil removal and segregation on non crop land.** As to all excavation operations undertaken after July 1, 1997 on non crop land, the operator shall separate and store the A soil horizon or the top six (6) inches, whichever is deeper, and mark or document stockpile locations to facilitate subsequent reclamation. When separating the A soil horizon, the operator shall segregate the horizon based upon noted changes in physical characteristics such as color, texture, density or consistency.

(3) **Horizons too rocky or too thin.** When the soil horizons are too rocky or too thin for the operator to practicably segregate, then the topsoil shall be segregated to the extent possible and stored. Too rocky shall mean that the soil horizon consists of greater than thirty five percent (35%) by volume rock fragments larger than ten (10) inches in diameter. Too thin shall mean soil horizons that are less than six (6) inches in thickness. The operator shall segregate remaining soils on crop land to the extent practicable to a depth of three (3) feet below the ground surface or bedrock, whichever is shallower, based upon noted changes in

physical characteristics such as color, texture, density or consistency and such soils shall be stockpiled to avoid loss and mixing with other soils.

c. **Protection of soils.** All stockpiled soils shall be protected from degradation due to contamination, compaction and, to the extent practicable, from wind and water erosion during drilling and production operations.

d. **Drill pad location.** The drilling location shall be designed and constructed to provide a safe working area while reasonably minimizing the total surface area disturbed. Consistent with applicable spacing orders and well location orders and regulations, in locating drill pads, steep slopes shall be avoided when reasonably possible. The drill pad site shall be located on the most level location obtainable that will accommodate the intended use. Deep vertical cuts and steep long fill slopes shall be constructed to the least percent slope practical.

e. **Surface disturbance minimization.** In order to reasonably minimize land disturbances and facilitate future reclamation, well sites, production facilities and access roads shall be located, constructed and maintained so as to reasonably control dust, minimize erosion, alteration of natural features and removal of surface materials.

f. **Access roads.** Existing roads shall be used to the greatest extent practicable to avoid erosion and minimize the land area devoted to oil and gas operations. Where feasible and practicable, operators are encouraged to share access roads in developing a field. Where feasible and practicable, roads shall be routed to complement other land usage. To the greatest extent practicable, all vehicles used by the operator, contractors, and other parties associated with the well shall not travel outside of the original access road boundary. Repeated or flagrant instance(s) of failure to restrict lease access to lease roads which result in unreasonable land damage or crop losses shall be subject to a penalty under Rule 523.

1003. INTERIM RECLAMATION

a. General. Debris and waste materials other than de minimis amounts, including, but not limited to, concrete, sack bentonite and other drilling mud additives, sand, plastic, pipe and cable, as well as equipment associated with the drilling, re-entry or completion operations shall be removed. All E&P waste shall be handled according to the 900 Series rules. All pits, cellars, rat holes, and other bore holes unnecessary for further lease operations, excluding the drilling pit, will be backfilled as soon as possible after the drilling rig is released to conform with surrounding terrain. On crop land, if requested by the surface owner, temporary guy line anchors shall be removed as soon as reasonably possible after the completion rig is released. When permanent guy line anchors are installed, it shall not be mandatory to remove them. When permanent guy line anchors are installed on cropland, care shall be taken to minimize disruption of cultivation, irrigation, or harvesting operations. If requested by the surface owner or its representative, the anchors shall be specifically marked, in addition to the marking required below, so as to facilitate farming operations. All guy line anchors left buried for future use shall be identified by a marker of bright color not less than four (4) feet in height and not greater than one (1) foot east of the guy line anchor. Material may be burned or buried on the premises only with the prior written consent of the surface owner, and with prior written notice to the surface tenant. Such burning or burial may be prohibited by other applicable law.

b. **Interim reclamation of areas no longer in use.** All disturbed areas affected by drilling or subsequent operations, except areas reasonably needed for production operations, shall be reclaimed as early and as nearly as practicable to their original condition and shall be maintained to control dust and minimize erosion. As to crop lands, if subsidence occurs in such areas additional topsoil shall be added to the depression and the land shall be re-leveled as close to its original contour as practicable. Interim reclamation shall occur no later than three (3) months on crop land or twelve (12) months on non-crop land after such operations unless the Director extends the time period because of conditions outside the control of the operator.

c. **Compaction alleviation.** All areas compacted by drilling and subsequent oil and gas operations which are no longer needed following completion of such operations shall be cross-ripped. On crop land, such compaction alleviation operations shall be undertaken when the soil moisture at the time of ripping is below thirty-five percent (35%) of field capacity. Ripping shall be undertaken to a depth of eighteen (18) inches unless and to the extent bed rock is encountered at a shallower depth.

d. **Drilling pit closure.** As part of interim reclamation, drilling pits shall be closed in the following manner:

(1) Drilling pit closure on crop land. On crop land water-based bentonitic drilling fluids, except *de minimis* amounts, shall be removed from the drilling pit and disposed of in accordance with the 900 Series rules. Drilling pit reclamation, including the disposal of drilling fluids and cuttings, shall be performed in a manner so as to not result in the formation of an impermeable barrier. Any cuttings removed from the pit for drying shall be returned to the pit prior to backfilling, and no more than *de minimis* amounts may be incorporated into the

surface materials. After the drilling pit is sufficiently dry, the pit shall be backfilled. The backfilling of the drilling pit shall be done to return the soils to their original relative positions.

(2) **Drilling pit closure on non-crop land.** All drilling fluids shall be disposed of in accordance with the 900 Series rules. After the drilling pit is sufficiently dry, the pit shall be backfilled. Materials removed from the pit for drying shall be returned to the pit prior to the backfilling. No more than de minimis amounts may be incorporated into the surface materials. The backfilling of the drilling pit will be done to return the soils to their original relative positions so that the muds and associated solids will be confined to the pit and not squeezed out and incorporated in the surface materials.

(3) **Minimum cover.** On crop lands, a minimum of three (3) feet of backfill cover shall be applied over any remaining drilling pit contents. As to both crop lands and non-crop lands, during the two (2) year period following drilling pit closure, if subsidence occurs over the closed drilling pit location additional topsoil shall be added to the depression and the land shall be re-leveled as close to its original contour as practicable.

e. **Restoration and revegetation.** When a well is completed for production, all disturbed areas no longer needed will be restored and revegetated as soon as practicable.

(1) **Revegetation of crop lands.** All segregated soil horizons removed from crop lands shall be replaced to their original relative positions and contour, and shall be tilled adequately to re-establish a proper seedbed. The area shall be treated if necessary and practicable to prevent invasion of undesirable species and noxious weeds, and to control erosion. Any perennial forage crops that were present before disturbance shall be re-established.

(2) **Revegetation of non-crop lands.** All segregated soil horizons removed from non-crop lands shall be replaced to their original relative positions and contour as near as practicable to achieve erosion control and long-term stability, and shall be tilled adequately in order to establish a proper seedbed. The disturbed area then shall be reseeded in the first favorable season. Reseeding with species consistent with the adjacent plant community is encouraged. In the absence of an agreement between the operator and the affected surface owner as to what seed mix should be used, the operator shall consult with a representative of the local soil conservation district to determine the proper seed mix to use in revegetating the disturbed area. In an area where an operator has drilled or plans to drill multiple wells, in the absence of an agreement between the operator and the affected surface owner, the operator may rely upon previous advice given by the local soil conservation district in determining the proper seed mixes to be used in revegetating each type of terrain upon which operations are to be conducted.

f. **Weed control.** During drilling, production, and reclamation operations, all disturbed areas shall be kept reasonably free of noxious weeds and undesirable species as practicable.

1004. FINAL RECLAMATION OF WELL SITES AND ASSOCIATED PRODUCTION FACILITIES

a. Well sites and associated production facilities. Upon the plugging and abandonment of a well, all pits, mouse and rat holes and cellars shall be backfilled. All debris, abandoned gathering line risers and flowline risers, and surface equipment shall be removed within three (3) months of plugging a well. All access roads to plugged and abandoned wells and associated production facilities shall be closed, graded and recontoured. Culverts and any other obstructions that were part of the access road(s) shall be removed. Well locations, access roads and associated facilities shall be reclaimed. As applicable, compaction alleviation, restoration, and revegetation of well sites, associated production facilities, and access roads shall be performed to the same standards as established for interim reclamation under Rule 1003. Material may be burned or buried on the premises only with the prior written consent of the surface owner, and with prior written notice to the surface tenant. Such burning or burial shall be subject to applicable state and local law. All such reclamation work shall be completed within three (3) months on crop land and twelve (12) months on non-crop land after plugging a well or final closure of associated production facilities. The Director may grant an extension where unusual circumstances are encountered, but every reasonable effort shall be made to complete reclamation before the next local growing season.

b. **Production and special purpose pit closure.** The operator shall comply with the 900 Series rules for the removal or treatment of E&P waste remaining in a production or special purpose pit before the pit may be closed for final reclamation. After any remaining E&P waste is removed or treated, all such pits must be backfilled to return the soils to their original relative positions. As to both crop lands and non-crop lands, if subsidence occurs over closed pit locations, additional topsoil shall be added to the depression and the land shall be re-leveled as close to its original contour as practicable.

c. **Final reclamation threshold for release of financial assurance.** Successful reclamation of the well site and access road will be considered completed when:

(1) On crop land, reclamation has been performed as per Rules 1003. and 1004., and observation by the Director over two growing seasons has indicated no significant unrestored subsidence.

(2) On non-crop land, reclamation has been performed as per Rules 1003. and 1004., and the total cover of live perennial vegetation, excluding noxious weeds, provides sufficient soils erosion control as determined by the Director through a visual appraisal. The Director shall consider the total cover of live perennial vegetation of adjacent or nearby undisturbed land, not including overstory or tree canopy cover, having similar soils, slope and aspect of the reclaimed area.

(3) Disturbances resulting from flow line installations shall be deemed adequately reclaimed when the disturbed area is reasonably capable of supporting the pre-disturbance land use.

(4) A Sundry Notice, Form 4, has been submitted by the operator which describes the final reclamation procedures and any mitigation measures associated with final reclamation performed by the operator, and

(5) A final reclamation inspection has been completed by the Director, there are no outstanding compliance issues relating to Commission rules, regulations, orders, permit conditions or the act, and the Director has notified the operator that final reclamation has been approved.

1101. INSTALLATION AND RECLAMATION

a. **Material**.

(1) After June 1, 1996, materials for pipe and components shall be:

A. Able to maintain the structural integrity of the flowline under temperature, pressure, and other conditions that may be anticipated;

B. Compatible with the material to be transported.

C. A tracer line or location device will be placed adjacent to or in the trench of all buried nonmetallic flowlines to facilitate the location of such pipelines.

b. **Design**. Each component of a flowline shall be designed to prevent failure from corrosion and be able to withstand anticipated operating pressures and other loadings without impairment of its serviceability. The pipe shall have sufficient wall thickness or be installed with adequate protection to withstand anticipated external pressures and loads that will be imposed on the pipe after installation.

c. **Cover**.

(1) All installed flowlines shall have cover sufficient to protect them from damage. On crop land, all flowlines installed after June 1, 1996 shall have a minimum cover of three (3) feet.

(2) Where an underground structure, geologic, economic or other uncontrollable condition prevents flowlines from being installed with minimum cover, or when there is an agreement between the surface owner and the operator, the line may be installed with less than minimum cover or above ground.

d. **Excavation, backfill and reclamation**.

(1) When flowlines cross crop lands, unless waived by the surface owner, the operator shall segregate topsoil while trenching, and trenches shall be backfilled so that the soils will be returned to their original relative positions and contour. This requirement to segregate and backfill topsoil shall not apply to trenches which are twelve (12) inches or less in width. Reasonable efforts shall be made to run flowlines parallel to crop irrigation rows on flood irrigated land.

(2) On crop lands and non-crop lands, flowline trenches will be maintained in order to correct subsidence and reasonably minimize erosion. Interim and final reclamation, including revegetation, shall be performed in accordance with the applicable 1000 Series rules.

e. **Pressure testing**.

(1) Before operating a segment of flowline installed after June 1, 1996, it must be tested to maximum anticipated operating pressure. In conducting tests, each operator shall ensure that reasonable precautions are taken to protect its employees and the general public. The testing may be conducted using well head pressure sources and well bore fluids, including natural gas. Such pressure tests shall be repeated once each calendar year to maximum anticipated operating pressure, and operators shall maintain records of such testing for Commission inspection for at least three (3) years.

(2) Flowline segments operating at less than fifteen (15) psig are excepted from pressure testing requirements.

1102. OPERATIONS, MAINTENANCE, AND REPAIR

a. **Maintenance**.

(1) Each operator shall take reasonable precautions to prevent failures, leakage and corrosion of flowlines.

(2) Whenever an operator discovers any condition that could adversely affect the safe and proper operation of its flowline, it shall correct it within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator shall not operate the affected part of the system until it has corrected the unsafe condition.

b. **Flowline repair**.

(1) Each operator shall, in repairing its flowlines, ensure that the repairs are made in a safe manner and are made so as to prevent injury to persons and damage to property.

(2) No operator shall use any pipe, valve, or fitting in repairing flowline facilities unless the components meet the installation requirements of this section.

c. **Flowline marking**.

(1) In designated high density areas, and where crossing public rights-of-way or utility easement, a marker shall be installed and maintained to identify the location of flowlines installed after June 1, 1996.

(2) The following must be written legibly on a background of sharply contrasting color on each line marker:

"Warning", "Caution" or "Danger" followed by the words "gas (or name of natural gas or petroleum transported) pipeline" in letters at least one (1) inch high with one-quarter (1/4) inch stroke and the name of the operator and the telephone number where the operator can be reached at all times.

d. **One Call participation**. As to flowlines, and any other pipeline over which the Commission has jurisdiction, installed after June 1, 1996, each operator shall participate in Colorado's One Call notification system, the requirements of which are established by §9-1.5-101., C.R.S. et seq.

1103. ABANDONMENT

Each flowline abandoned in place must be disconnected from all sources and supplies of natural gas and petroleum, purged of liquid hydrocarbons, depleted to atmospheric pressure, and cut off three (3) feet below ground surface, or the depth of the flowline, whichever is less and sealed at the ends. This requirement shall also apply to compressor or gas plant feeder pipelines upon decommissioning or closure of a portion or all of a compressor station or gas plant.

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TITLE 19 NATURAL RESOURCES & WILDLIFE
CHAPTER 15 OIL AND GAS
PART 1 GENERAL PROVISIONS AND DEFINITIONS
TITLE 19 NATURAL RESOURCES & WILDLIFE
CHAPTER 15 OIL AND GAS
PART 1 GENERAL PROVISIONS AND DEFINITIONS

19.15.1.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department, Oil Conservation Division, 2040 S. Pacheco, Santa Fe, New Mexico 87505
[2-1-96; 19.15.1.1 NMAC - Rn, 19 NMAC 15.A.1, 5-15-01]

19.15.1.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico.
[2-1-96; 19.15.1.2 NMAC - Rn, 19 NMAC 15.A.2, 5-15-01]

19.15.1.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the Oil and Gas Act which grants the oil conservation division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights, and the disposition of wastes resulting from oil and gas operations.
[2-1-96; 19.15.1.3 NMAC - Rn, 19 NMAC 15.A.3, 5-15-01]

19.15.1.4 DURATION: Permanent
[2-1-96; 19.15.1.4 NMAC - Rn, 19 NMAC 15.A.4, 5-15-01]

19.15.1.5 EFFECTIVE DATE: February 1, 1996.
[2-1-96; 19.15.1.5 NMAC - Rn, 19 NMAC 15.A.5, 5-15-01]

19.15.1.6 OBJECTIVE: To set forth general provisions and definitions pertaining to the authority of the oil Conservation division and the oil conservation commission pursuant to the Oil and Gas Act, NMSA 1978, Sections 70-2-1 through 70-2-38.
[2-1-96; 19.15.1.6 NMAC - Rn, 19 NMAC 15.A.6, 5-15-01]

19.15.1.7 DEFINITIONS:
A. Definitions beginning with the letter “A”.
(1) Abate or abatement shall mean the investigation, containment, removal or other mitigation of water pollution.
(2) Abatement plan shall mean a description of any operational, monitoring, contingency and closure requirements and conditions for the prevention, investigation and abatement of water pollution.
(3) Adjoining spacing units are those existing or prospective spacing units in the same pool(s) that are touching at a point or line the spacing unit that is the subject of the application.
(4) Adjusted allowable shall mean the allowable production a well or proration unit receives after all adjustments are made.
(5) Allocated pool is one in which the total oil or natural gas production is restricted and allocated to various wells therein in accordance with proration schedules.
(6) Allowable production shall mean that number of barrels of oil or standard cubic feet of natural gas authorized by the division to be produced from an allocated pool.
(7) Aquifer shall mean a geological formation, group of formations, or a part of a formation that is capable of yielding a significant amount of water to a well or spring.
B. Definitions beginning with the letter “B”.
(1) Back allowable shall mean the authorization for production of any shortage or underproduction

resulting from pipeline proration.

(2) Background shall mean, for purposes of ground-water abatement plans only, the amount of ground-water contaminants naturally occurring from undisturbed geologic sources or water contaminants occurring from a source other than the responsible person's facility. This definition shall not prevent the director from requiring abatement of commingled plumes of pollution, shall not prevent responsible persons from seeking contribution or other legal or equitable relief from other persons, and shall not preclude the director from exercising enforcement authority under any applicable statute, regulation or common law.

(3) Barrel shall mean 42 United States gallons measured at 60 degrees fahrenheit and atmospheric pressure at the sea level.

(4) Barrel of oil shall mean 42 United States gallons of oil, after deductions for the full amount of basic sediment, water and other impurities present, ascertained by centrifugal or other recognized and customary test.

(5) Below-grade tank shall mean a vessel, excluding sumps and pressurized pipeline drip traps, where any portion of the sidewalls of the tank is below the surface of the ground and not visible.

(6) Berm shall mean an embankment or ridge constructed for the purpose of preventing the movement of liquids, sludge, solids, or other materials.

(7) Bottom hole or subsurface pressure shall mean the gauge pressure in pounds per square inch under conditions existing at or near the producing horizon.

(8) Bradenhead gas well shall mean any well producing gas through wellhead connections from a gas reservoir which has been successfully cased off from an underlying oil or gas reservoir.

C. Definitions beginning with the letter “C”.

(1) Carbon dioxide gas shall mean noncombustible gas composed chiefly of carbon dioxide occurring naturally in underground rocks.

(2) Casinghead gas shall mean any gas or vapor or both gas and vapor indigenous to and produced from a pool classified as an oil pool by the division. This also includes gas-cap gas produced from such an oil pool.

(3) Commission shall mean the oil conservation commission.

(4) Common purchaser for natural gas shall mean any person now or hereafter engaged in purchasing from one or more producers gas produced from gas wells within each common source of supply from which it purchases.

(5) Common purchaser for oil shall mean every person now engaged or hereafter engaging in the business of purchasing oil to be transported through pipelines.

(6) Common source of supply. See pool.

(7) Condensate shall mean the liquid recovered at the surface that results from condensation due to reduced pressure or temperature of petroleum hydrocarbons existing in a gaseous phase in the reservoir.

(8) Contiguous shall mean acreage joined by more than one common point, that is, the common boundary must be at least one side of a governmental quarter-quarter section.

(9) Conventional completion shall mean a well completion in which the production string of casing has an outside diameter in excess of 2.875 inches.

(10) Correlative rights shall mean the opportunity afforded, as far as it is practicable to do so, to the owner of each property in a pool to produce without waste his just and equitable share of the oil or gas, or both, in the pool, being an amount, so far as can be practically determined, and so far as can be practicably obtained without waste, substantially in the proportion that the quantity of recoverable oil or gas, or both, under such property bears to the total recoverable oil or gas, or both, in the pool, and for such purpose to use his just and equitable share of the reservoir energy.

(11) Cubic feet of gas or standard cubic foot of gas, for the purpose of these rules, shall mean that volume of gas contained in one cubic foot of space and computed at a base pressure of 10 ounces per square inch above the average barometric pressure of 14.4 pounds per square inch (15.025 psia), at a standard base temperature of 60 degrees fahrenheit.

D. Definitions beginning with the letter “D”.

(1) Deep pool shall mean a common source of supply which is situated 5000 feet or more below the surface.

(2) Depth bracket allowable shall mean the basic oil allowable assigned to a pool and based on its depth, unit size, or special pool rules, which, when multiplied by the market demand percentage factor in effect, will determine the top unit allowable for the pool.

(3) Director shall mean the director of the oil conservation division of the New Mexico energy, minerals and natural resources department.

(4) Division shall mean the oil conservation division of the New Mexico energy, minerals and natural resources department.

E. Definitions beginning with the letter "E".

(1) Exempted aquifer shall mean an aquifer that does not currently serve as a source of drinking water, and which cannot now and will not in the foreseeable future serve as a source of drinking water because: is hydrocarbon producing;

(a) it is hydrocarbon producing;

(b) it is situated at a depth or location which makes the recovery of water for drinking water purposes economically or technologically impractical; or,

(c) it is so contaminated that it would be economically or technologically impractical to render that water fit for human consumption.

(2) Existing spacing unit is a spacing unit containing a producing well.

F. Definitions beginning with the letter "F".

(1) Facility shall mean any structure, installation, operation, storage tank, transmission line, access road, motor vehicle, rolling stock, or activity of any kind, whether stationary or mobile.

(2) Field means the general area which is underlaid or appears to be underlaid by at least one pool; and field also includes the underground reservoir or reservoirs containing such crude petroleum oil or natural gas, or both. The words field and pool mean the same thing when only one underground reservoir is involved; however, field unlike pool may relate to two or more pools.

(3) Fresh water (to be protected) includes the water in lakes and playas, the surface waters of all streams regardless of the quality of the water within any given reach, and all underground waters containing 10,000 milligrams per liter (mg/1) or less of total dissolved solids (TDS) except for which, after notice and hearing, it is found there is no present or reasonably foreseeable beneficial use which would be impaired by contamination of such waters. The water in lakes and playas shall be protected from contamination even though it may contain more than 10,000 mg/1 of TDS unless it can be shown that hydrologically connected fresh ground water will not be adversely affected.

G. Definitions beginning with the letter "G".

(1) Gas lift shall mean any method of lifting liquid to the surface by injecting gas into a well from which oil production is obtained.

(2) Gas-oil ratio shall mean the ratio of the casinghead gas produced in standard cubic feet to the number of barrels of oil concurrently produced during any stated period.

(3) Gas-oil ratio adjustment shall mean the reduction in allowable of a high gas oil ratio unit to conform with the production permitted by the limiting gas-oil ratio for the particular pool during a particular proration period.

(4) Gas transportation facility shall mean a pipeline in operation serving gas wells for the transportation of natural gas, or some other device or equipment in like operation whereby natural gas produced from gas wells connected therewith can be transported or used for consumption.

(5) Gas well shall mean a well producing gas or natural gas from a gas pool, or a well with a gas-oil ratio in excess of 100,000 cubic feet of gas per barrel of oil producing from an oil pool.

(6) Ground water shall mean interstitial water which occurs in saturated earth material and which is capable of entering a well in sufficient amounts to be utilized as a water supply.

H. Definitions beginning with the letter "H".

(1) Hazard to public health exists when water which is used or is reasonably expected to be used in the future as a human drinking water supply exceeds at the time and place of such use, one or more of the numerical standards of Subsection A of 20.6.2.3103 NMAC, or the naturally occurring concentrations, whichever is higher, or if any toxic pollutant as defined at Subsection VV of 20.6.2.7 NMAC affecting human health is present in the water. In determining whether a release would cause a hazard to public health to exist, the director shall investigate and consider the purification and dilution reasonably expected to occur from the time and place of release to the time and place of withdrawal for use as human drinking water.

(2) High gas-oil ratio proration unit shall mean a unit with at least one producing oil well with a gas-oil ratio in excess of the limiting gas-oil ratio for the pool in which the unit is located.

I. Definitions beginning with the letter "I".

(1) Illegal gas shall mean natural gas produced from a gas well in excess of the allowable determined by the division.

(2) Illegal oil shall mean crude petroleum oil produced in excess of the allowable as fixed by the division.

(3) Illegal product shall mean any product of illegal gas or illegal oil.

(4) Inactive well shall be a well which is not being utilized for beneficial purposes such as production, injection or monitoring and which is not being drilled, completed, repaired or worked over.

(5) Injection or input well shall mean any well used for the injection of air, gas, water, or other fluids into any underground stratum.

J. Reserved.

K. Reserved.

L. Definitions beginning with the letter "L".

(1) Limiting gas-oil ratio shall mean the gas-oil ratio assigned by the division to a particular oil pool to limit the volumes of casinghead gas which may be produced from the various oil producing units within that particular pool.

(2) Load oil is any oil or liquid hydrocarbon which has been used in remedial operation in any oil or gas well.

(3) Log or well log shall mean a systematic detailed and correct record of formations encountered in the drilling of a well.

M. Definitions beginning with the letter "M".

(1) Marginal unit shall mean a proration unit which is incapable of producing top unit allowable for the pool in which it is located.

(2) Market demand percentage factor shall mean that percentage factor of 100 percent or less as determined by the division at an oil allowable hearing, which, when multiplied by the depth bracket allowable applicable to each pool, will determine the top unit allowable for that pool.

(3) Mineral estate is the most complete ownership of oil and gas recognized in law and includes all the mineral interests and all the royalty interests.

(4) Mineral interest owners are owners of an interest in the executive rights, which are the rights to explore and develop, including oil and gas lessees (i.e., "working interest owners") and mineral interest owners who have not signed an oil and gas lease.

(5) Minimum allowable shall mean the minimum amount of production from an oil or gas well which may be advisable from time to time to the end that production will repay reasonable lifting cost and thus prevent premature abandonment and resulting waste.

(6) Multiple completion (combination) shall mean a multiple completion in which two or more common sources of supply are produced through a combination of two or more conventional diameter casing strings cemented in a common well-bore, or a combination of small diameter and conventional diameter casing strings cemented in a common well-bore, the conventional diameter strings of which might or might not be a multiple completion (conventional).

(7) Multiple completion (conventional) shall mean a completion in which two or more common sources of supply are produced through one or more strings of tubing installed within a single casing string, with the production from each common source of supply completely segregated by means of packers.

(8) Multiple completion (tubingless) shall mean completion in which two or more common sources of supply are produced through an equal number of casing strings cemented in a common well-bore, each such string of casing having an outside diameter of 2.875 inches or less, with the production from each common source of supply completely segregated by use of cement.

N. Definitions beginning with the letter "N".

(1) Natural gas or gas shall mean any combustible vapor composed chiefly of hydrocarbons occurring naturally in a pool classified by the division as a gas pool.

(2) Non-aqueous phase liquid shall mean an interstitial body of liquid oil, petroleum product, petrochemical, or organic solvent, including an emulsion containing such material.

(3) Non-marginal unit shall mean a proration unit which is capable of producing top unit allowable for the pool in which it is located, and to which has been assigned a top unit allowable.

O. Definitions beginning with the letter "O".

(1) Official gas-oil ratio test shall mean the periodic gas-oil ratio test made by order of the division by such method and means and in such manner as prescribed by the division.

(2) Oil, crude oil, or crude petroleum oil shall mean any petroleum hydrocarbon produced from a well in the liquid phase and which existed in a liquid phase in the reservoir.

(3) Oil field wastes shall mean those wastes produced in conjunction with the exploration, production, refining, processing and transportation of crude oil and/or natural gas and commonly collected at field storage, processing, disposal, or service facilities, and waste collected at gas processing plants, refineries and other processing or transportation facilities.

(4) Oil well shall mean any well capable of producing oil and which is not a gas well as defined herein.

(5) Operator shall mean any person who, duly authorized, is in charge of the development of a lease or the operation of a producing property, or who is in charge of the operation or management of a facility.

(6) Overage or overproduction shall mean the amount of oil or the amount of natural gas produced during a proration period in excess of the amount authorized on the proration schedule.

(7) Owner means the person who has the right to drill into and to produce from any pool, and to appropriate the production either for himself or for himself and another.

P. Definitions beginning with the letter "P".

(1) Penalized unit shall mean a proration unit to which, because of an excessive gas-oil ratio, an allowable has been assigned which is less than top unit allowable for the pool in which it is located and also less than the ability of the well(s) on the unit to produce.

(2) Person shall mean an individual or any other entity including partnerships, corporation, associations, responsible business or association agents or officers, the state or a political subdivision of the state or any agency, department or instrumentality of the United States and any of its officers, agents or employees.

(3) Pit shall mean any surface or sub-surface impoundment, man-made or natural depression, or diked area on the surface. Excluded from this definition are berms constructed around tanks or other facilities solely for the purpose of safety and secondary containment.

(4) Playa lake shall mean a level or nearly level area that occupies the lowest part of a completely closed basin and that is covered with water at irregular intervals, forming a temporary lake.

(5) Pool means any underground reservoir containing a common accumulation of crude petroleum oil or natural gas or both. Each zone of a general structure, which zone is completely separated from any other zone in the structure, is covered by the word "pool" as used herein. "Pool" is synonymous with "common source of supply" and with "common reservoir."

(6) Potential shall mean the properly determined capacity of a well to produce oil, or gas, or both, under conditions prescribed by the division.

(7) Pressure maintenance shall mean the injection of gas or other fluid into a reservoir, either to maintain the existing pressure in such reservoir or to retard the natural decline in the reservoir pressure.

(8) Produced water shall mean those waters produced in conjunction with the production of crude oil and/or natural gas and commonly collected at field storage, processing, or disposal facilities including but not limited to: lease tanks, commingled tank batteries, burn pits, LACT units, and community or lease salt water disposal systems and which may be collected at gas processing plants, pipeline drips and other processing or transportation facilities.

(9) Producer shall mean the owner of a well or wells capable of producing oil or natural gas or both in paying quantities.

(10) Product means any commodity or thing made or manufactured from crude petroleum oil or natural gas, and all derivatives of crude petroleum oil or natural gas, including refined crude oil, crude tops, topped crude, processed crude petroleum, residue from crude petroleum, cracking stock, uncracked fuel oil, treated crude oil, fuel oil, residuum, gas oil, naphtha, distillate, gasoline, kerosene, benzene, wash oil, lubricating oil, and blends or mixtures of crude petroleum oil or natural gas or any derivative thereof.

(11) Proration day shall consist of 24 consecutive hours which shall begin at 7 a.m. and end at 7 a.m. on the following day. The language in this paragraph is different than that which was filed 02-28-97 (effective

(12) Proration month shall mean the calendar month which shall begin at 7 a.m. on the first day of such month and end at 7 a.m. on the first day of the next succeeding month.

(13) Proration period shall mean for oil the proration month and for gas the twelve-month period which shall begin at 7 a.m. on January 1 of each year and end at 7 a.m. on January 1 of the succeeding year or other period designated by general or special order of the division.

(14) Proration schedule shall mean the order of the division authorizing the production, purchase, and transportation of oil, casinghead gas, and natural gas from the various units of oil or of natural gas in allocated pools.

(15) Proration unit is the area in a pool that can be effectively and efficiently drained by one well as determined by the division or commission (See NMSA 1978 Section 70-2-17.B) as well as the area assigned to an individual well for the purposes of allocating allowable production pursuant to a prorationing order for the pool. A proration unit will be the same size and shape as a spacing unit. All proration units are spacing units but not all spacing units are proration units.

(16) Prospective spacing unit is a hypothetical spacing unit that does not yet have a producing well.

Q. Reserved.

R. Definitions beginning with the letter “R”.

(1) Recomplete shall mean the subsequent completion of a well in a different pool from the pool in which it was originally completed.

(2) Regulated naturally occurring radioactive material (regulated NORM) shall mean naturally occurring radioactive material (NORM) contained in any oil-field soils, equipment, sludges or any other materials related to oil-field operations or processes exceeding the radiation levels specified in 20.3.14.1403 NMAC.

(3) Release shall mean all breaks, leaks, spills, releases, fires or blowouts involving crude oil, produced water, condensate, drilling fluids, completion fluids or other chemical or contaminant or mixture thereof, including oil field wastes and natural gases to the environment.

(4) Remediation plan shall mean a written description of a program to address unauthorized releases. The plan may include appropriate information, including assessment data, health risk demonstrations, and corrective action(s). The plan may also include an alternative proposing no action beyond the submittal of a spill report.

(5) Responsible person shall mean the owner or operator who must complete division approved corrective action for pollution from releases.

(6) Royalty interest owners are owners of an interest in the non-executive rights including lessors, royalty interest owners and overriding royalty interest owners. Royalty interests are non-cost bearing.

S. Definitions beginning with the letter “S”.

(1) Secondary recovery shall mean a method of recovering quantities of oil or gas from a reservoir which quantities would not be recoverable by ordinary primary depletion methods.

(2) Shallow pool shall mean a pool which has a depth range from 0 to 5000 feet.

(3) Shortage or underproduction shall mean the amount of oil or the amount of natural gas during a proration period by which a given proration unit failed to produce an amount equal to that authorized in the proration schedule.

(4) Shut-in shall be the status of a production well or an injection well which is temporarily closed down, whether by closing a valve or disconnection or other physical means.

(5) Shut-in pressure shall mean the gauge pressure noted at the wellhead when the well is completely shut in, not to be confused with bottom hole pressure.

(6) Significant modification of an abatement plan shall mean a change in the abatement technology used excluding design and operational parameters, or relocation of 25% or more of the compliance sampling stations, for any single medium, as designated pursuant to Subsection E, Paragraph (4), Subparagraph (b), Subsubparagraph (iv) of Section 19.15.5.19 NMAC.

(7) Spacing unit is the area allocated to a well under a well spacing order or rule. Under the Oil & Gas Act, NMSA 1978, Section 70-2-12.B(10), the commission has the power to fix spacing units without first creating proration units. See *Rutter & Wilbanks Corp. v. Oil Conservation Comm'n*, 87 NM 286 (1975). This is the area designated on division form C-102.

(8) Subsurface water shall mean ground water and water in the vadose zone that may become ground water or surface water in the reasonably foreseeable future or may be utilized by vegetation.

T. Definitions beginning with the letter "T".

(1) Tank bottoms shall mean that accumulation of hydrocarbon material and other substances which settles naturally below crude oil in tanks and receptacles that are used in handling and storing of crude oil, and which accumulation contains in excess of two (2%) percent of basic sediment and water; provided, however, that with respect to lease production and for lease storage tanks, a tank bottom shall be limited to that volume of the tank in which it is contained that lies below the bottom of the pipeline outlet thereto.

(2) Temporary abandonment shall be the status of a well which is inactive and has been approved for temporary abandonment in accordance with the provisions of these rules.

(3) Top unit allowable for gas shall mean the maximum number of cubic feet of natural gas, for the proration period, allocated to a gas producing unit in an allocated gas pool.

(4) Top unit allowable for oil shall mean the maximum number of barrels for oil daily for each calendar month allocated on a proration unit basis in a pool to non-marginal units. The top unit allowable for a pool shall be determined by multiplying the applicable depth bracket allowable by the market demand percentage factor in effect.

(5) Treating plant shall mean any plant constructed for the purpose of wholly or partially or being used wholly or partially for reclaiming, treating, processing, or in any manner making tank bottoms or any other waste oil marketable.

(6) Tubingless completion shall mean a well completion in which the production string of casing has an outside diameter of 2.875 inches or less.

U. Definitions beginning with the letter "U".

(1) Underground source of drinking water shall mean an aquifer which supplies water for human consumption or which contains ground water having a total dissolved solids concentration of 10,000 mg/1 or less and which is not an exempted aquifer.

(2) Unit of proration for gas shall consist of such multiples of 40 acres as may be prescribed by special pool rules issued by the division.

(3) Unit of proration for oil shall consist of one 40-acre tract or such multiples of 40-acre tracts as may be prescribed by special pool rules issued by the division.

(4) Unorthodox well location shall mean a location which does not conform to the spacing requirements established by the rules and regulations of the division.

V. Definitions beginning with the letter "V". Vadose zone shall mean unsaturated earth material below the land surface and above ground water, or in between bodies of ground water.

W. Definitions beginning with the letter "W".

(1) Waste, in addition to its ordinary meaning, shall include:

(a) underground waste as those words are generally understood in the oil and gas business, and in any event to embrace the inefficient, excessive, or improper use or dissipation of the reservoir energy, including gas energy and water drive, of any pool, and the locating, spacing, drilling, equipping, operating, or producing, of any well or wells in a manner to reduce or tend to reduce the total quantity of crude petroleum oil or natural gas ultimately recovered from any pool, and the use of inefficient underground storage of natural gas;

(b) surface waste as those words are generally understood in the oil and gas business, and in any event to embrace the unnecessary or excessive surface loss or destruction without beneficial use, however caused, of natural gas of any type or in any form, or crude petroleum oil, or any product thereof, but including the loss or destruction, without beneficial use, resulting from evaporation, seepage, leakage, or fire, especially such loss or destruction incident to or resulting from the manner of spacing, equipping, operating or producing a well or wells, or incident to or resulting from the use of inefficient storage or from the production of crude petroleum oil or natural gas, in excess of the reasonable market demand;

(c) the production of crude petroleum oil in this state in excess of the reasonable market demand for such crude petroleum oil; such excess production causes or results in waste which is prohibited by the Oil and Gas Act; the words "reasonable market demand" as used herein with respect to crude petroleum oil, shall be construed to mean the demand for such crude petroleum oil, for reasonable current requirements for current consumption and use within or outside of the state, together with the demand of such amounts as are reasonably necessary for building up or maintaining reasonable storage reserves of crude petroleum oil or the products thereof, or both such crude petroleum oil and products;

(d) the non-ratable purchase or taking of crude petroleum oil in this state; such non-ratable taking and purchasing causes or results in waste, as defined in Subparagraphs (a), (b), and (c) of this definition and causes waste by violating Section 70-2-16 of the Oil and Gas Act;

(e) the production in this state of natural gas from any gas well or wells, or from any gas pool, in excess of the reasonable market demand from such source for natural gas of the type produced or in excess of the capacity of gas transportation facilities for such type of natural gas; the words "reasonable market demand," as used herein with respect to natural gas, shall be construed to mean the demand for natural gas for reasonable current requirements, for current consumption and for use within or outside the state, together with the demand for such amounts as are necessary for building up or maintaining reasonable storage reserves of natural gas or products thereof, or both such natural gas and products.

(2) Water shall mean all water including water situated wholly or partly within or bordering upon the state, whether surface or subsurface, public or private, except private waters that do not combine with other surface or subsurface water.

(3) Water contaminant shall mean any substance that could alter if released or spilled the physical, chemical, biological or radiological qualities of water. "Water contaminant" does not mean source, special nuclear or by-product material as defined by the Atomic Energy Act of 1954.

(4) Watercourse shall mean any lake bed, or gully, draw, stream bed, wash, arroyo, or natural or human-made channel through which water flows or has flowed.

(5) Water pollution shall mean introducing or permitting the introduction into water, either directly or indirectly, of one or more water contaminants in such quantity and of such duration as may with reasonable probability injure human health, animal or plant life or property, or to unreasonably interfere with the public welfare or the use of property.

(6) Well blowout shall mean a loss of control over and subsequent eruption of any drilling or workover well or the rupture of the casing, casinghead, or wellhead or any oil or gas well or injection or disposal well, whether active or inactive, accompanied by the sudden emission of fluids, gaseous or liquids, from the well.

(7) Wellhead protection area shall mean the area within 200 horizontal feet of any private, domestic fresh water well or spring used by less than five households for domestic or stock watering purposes or within1000 horizontal feet of any other fresh water well or spring. Wellhead protection areas shall not include areas around water wells drilled after an existing oil or natural gas waste storage, treatment, or disposal site was established.

(8) Wetlands shall mean those areas that are inundated or saturated by surface or groundwater at a frequency and duration sufficient to support, and under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil conditions in New Mexico. Constructed wetlands used for wastewater treatment purposes are not included in this definition.

(9) Working interest owners are the owners of the operating interest under an oil and gas lease who have the exclusive right to exploit the oil & gas minerals. Working interests are cost bearing.

[1-5-50…2-1-96; A, 7-15-96; Rn, 19 NMAC 15.A.7.1 through 7.84, 3-15-97; A, 7-15-99; 19.15.1.7 NMAC - Rn, 19 NMAC 15.A.7, 5-15-001; A, 3/31/04]

19.15.1.8-10 [RESERVED]

19.15.1.11 SCOPE OF RULES:

A. The following rules of statewide application have been adopted by the commission to conserve the natural resources of the state of New Mexico, to prevent waste, to protect correlative rights, to protect public health and the environment and to otherwise implement the Oil and Gas Act, NMSA 1978, Section 70-2-1 through 70-2-38.

B. Orders, including special pool orders (formerly referred to as "special pool rules and regulations"), of the division or the commission may be issued when required and shall prevail against rules if in conflict with them.

[1-1-50...2-1-96; A, 7-15-99; 19.15.1.11 NMAC - Rn, 19 NMAC 15.A.11, 5-15-01]

19.15.1.12 ENFORCEMENT OF STATUTES AND RULES:
The division is charged with the duty and obligation of enforcing all rules and statutes of the state of New Mexico relating to the conservation of oil and gas including the protection of public health and the environment. However, it shall be the responsibility of all the owners or operators to obtain information pertaining to the regulation of oil and gas before operations begin.

[1-1-50...2-1-96; A, 7-15-99; 19.15.1.12 NMAC - Rn, 19 NMAC 15.A.12, 5-15-01]

19.15.1.13 GENERAL OPERATIONS/WASTE PROHIBITED:

A. The production or handling of crude petroleum oil or natural gas of any type or in any form, or the handling of products thereof, in such a manner or under such conditions or in such amount as to constitute or result in waste is hereby prohibited.

B. All operators, contractors, drillers, carriers, gas distributors, service companies, pipe pulling and salvaging contractors, treating plant operators or other persons shall at all times conduct their operations in or related to the drilling, equipping, operating, producing, plugging and abandonment of oil, gas, injection, disposal, and storage wells or other facilities in a manner that will prevent waste of oil and gas, the contamination of fresh waters and shall not wastefully utilize oil or gas, or allow either to leak or escape from a natural reservoir, or from wells, tanks, containers, pipe or other storage, conduit or operating equipment.

[1-1-50...2-1-96; 19.15.1.13 NMAC - Rn, 19 NMAC 15.A.13, 5-15-01]

19.15.1.14 UNITED STATES GOVERNMENT LEASES:
Operator shall file or cause to be filed with the division copies of "application for permit to drill, deepen or plug back," (BLM form no. 3160-3), "sundry notices and reports on wells," (BLM form no. 3160-5), and "well completion or recompletion report and log," (BLM form no. 3160-4), as approved by the bureau of land management for wells on U.S. government land.

[1-1-50...2-1-96; 19.15.1.14 NMAC - Rn, 19 NMAC 15.A.14, 5-15-01]

19.15.1.15 CLASSIFYING AND DEFINING POOLS:
The division will determine whether a particular well or pool is a gas or oil well, or a gas or oil pool, as the case may be, and from time to time classify and reclassify wells and name pools accordingly, and will determine the limits of any pool or pools producing crude petroleum oil or natural gas and from time to time redetermine such limits.

[1-1-50...2-1-96; 19.15.1.15 NMAC - Rn, 19 NMAC 15.A.15, 5-15-01]

19.15.1.16 FORMS UPON REQUEST:
Forms for written notices, requests and reports required by the division will be furnished upon request.

[1-1-50...2-1-96; 19.15.1.16 NMAC - Rn, 19 NMAC 15.A.16, 5-15-01]

19.15.1.17 AUTHORITY TO COOPERATE WITH OTHER AGENCIES:
The division may from time to time enter into arrangements with state and federal governmental agencies, industry

committees and individuals, with respect to special projects, services and studies relating to conservation of oil and gas and the associated protection of fresh waters.
[1-1-50...2-1-96; 19.15.1.17 NMAC - Rn, 19 NMAC 15.A.17, 5-15-01]

19.15.1.18 [RESERVED.]
[9-23-85; 9-1-89...2-1-96; 19.15.1.18 NMAC - Rn, 19 NMAC 15.A.18, 5-15-01; Repealed, 5-28-04]

19.15.1.19 PREVENTION AND ABATEMENT OF WATER POLLUTION:

A. Purpose

(1) The purpose of this rule are to:

(a) Abate pollution of subsurface water so that all ground water of the state of New Mexico which has a background concentration of 10,000 mg/L or less TDS, is either remediated or protected for use as domestic, industrial and agricultural water supply, and to remediate or protect those segments of surface waters which are gaining because of subsurface-water inflow, for uses designated in the water quality standards for interstate and intrastate surface waters in New Mexico (20.6.4 NMAC); and

(b) Abate surface-water pollution so that all surface waters of the state of New Mexico are remediated or protected for designated or attainable uses as defined in the water quality standards for interstate and intrastate surface waters in New Mexico (20.6.4 NMAC).

(2) If the background concentration of any water contaminant exceeds the standard or requirement of Section 19.15.1.19 NMAC, Subsection B, Paragraphs (1), (2) or (3) pollution shall be abated by the responsible person to the background concentration.

(3) The standards and requirements set forth in of Section 19.15.1.19 NMAC, Subsection B, Paragraphs (1), (2) or (3) are not intended as maximum ranges and concentrations for use, and nothing herein contained shall be construed as limiting the use of waters containing higher ranges and concentrations.

B. Abatement standards and requirements

(1) The vadose zone shall be abated so that water contaminants in the vadose zone will not with reasonable probability contaminate ground water or surface water, in excess of the standards in Paragraphs (2) and (3) below, through leaching, percolation, or other transport mechanisms, or as the water table elevation fluctuates.

(2) Ground-water pollution at any place of withdrawal for present or reasonably foreseeable future use, where the TDS concentration is 10,000 mg/L or less, shall be abated to conform to the following standards:

(a) Toxic pollutant(s) as defined in 20.6.2.7 NMAC shall not be present; and

(b) The standards of 20.6.2.3103 NMAC shall be met.

(3) Surface-water pollution shall be abated to conform to the water quality standards for interstate and intrastate surface waters in New Mexico 20.6.4 NMAC.

(4) Subsurface-water and surface-water abatement shall not be considered complete until eight (8) consecutive quarterly samples, or an alternate lesser number of samples approved by the director, from all compliance sampling stations approved by the director meet the abatement standards of Paragraphs (1), (2) and (3) above. Abatement of water contaminants measured in solid-matrix samples of the vadose zone shall be considered complete after one-time sampling from compliance stations approved by the director.

(5) Technical infeasibility

(a) If any responsible person is unable to fully meet the abatement standards set forth in Paragraphs (1) and (2) above using commercially accepted abatement technology pursuant to an approved abatement plan, he may propose that abatement standards compliance is technically infeasible. Technical infeasibility proposals involving the use of experimental abatement technology shall be considered at the discretion of the director. Technical infeasibility may be demonstrated by a statistically valid extrapolation of the decrease in concentration(s) of any water contaminant(s) over the remainder of a twenty (20) year period, such that projected future reductions during that time would be less than 20% of the concentration(s) at the time technical infeasibility is proposed. A statistically valid decrease cannot be demonstrated by fewer than eight (8) consecutive quarters. The technical infeasibility proposal shall include a substitute abatement standard(s) for those contaminants that is/are technically feasible. Abatement standards for all other water contaminants not demonstrated to be technically infeasible shall be met.

(b) In no event shall a proposed technical infeasibility demonstration be approved by the director for any water contaminant if its concentration is greater than 200% of the abatement standard for the contaminant.

(c) If the director cannot approve any or all portions of a proposed technical infeasibility demonstration because the water contaminant concentration(s) is/are greater than 300% of the abatement standard(s) for each contaminant, the responsible person may further pursue the issue of technical infeasibility by filing a petition with the division seeking approval of alternate abatement standard(s) pursuant to Paragraph (6) below.

(6) Alternative abatement standards

(a) At any time during or after the submission of a stage 2 abatement plan, the responsible person may file a petition seeking approval of alternative abatement standard(s) for the standards set forth in Paragraphs (1) and (2) above. The division may approve alternative abatement standard(s) if the petitioner demonstrates that:

(i) either: compliance with the abatement standard(s) is/are not feasible, by the maximum use of technology within the economic capability of the responsible person; or there is no reasonable relationship between the economic and social costs and benefits (including attainment of the standard(s) set forth in Subsection B of Section 19.15.1.19 NMAC to be obtained, and

(ii) the proposed alternative abatement standard(s) is/are technically achievable and cost-benefit justifiable; and

(iii) compliance with the proposed alternative abatement standard(s) will not create a present or future hazard to public health or undue damage to property.

(b) The petition shall be in writing, filed with the division environmental bureau chief. The petition may include a transport, fate and risk assessment in accordance with accepted methods, and other information as the petitioner deems necessary to support the petition. The petition shall:

(i) state the petitioner's name and address;

(ii) state the date of the petition;

(iii) describe the facility or activity for which the alternate abatement standard(s) is sought;

(iv) state the address or description of the property upon which the facility is located;

(v) describe the water body or watercourse affected by the release;

(iv) identify the abatement standard from which petitioner wishes to vary;

(vii) state why the petitioner believes that compliance with the regulation will impose an unreasonable burden upon his activity;

(viii) identify the water contaminant(s) for which alternative standard(s) is/are proposed;

(ix) state the alternative standard(s) proposed;

(x) identify the three-dimensional body of water pollution for which approval is sought;

(xi) state the extent to which the abatement standard(s) set forth in Subsection B of 19.15.1.19 NMAC is/are now, and will in the future be, violated.

(c) The division environmental bureau chief shall review the petition and, within sixty (60) days after receiving the petition, shall submit a written recommendation to the director to approve, approve subject to conditions, or disapprove any or all of the proposed alternative abatement standard(s). The recommendation shall include the reasons for the division environmental bureau chief's recommendation. The division environmental bureau chief shall submit a copy of the recommendation to the petitioner by certified mail.

(d) If the division environmental bureau chief recommends approval, or approval subject to conditions, of any or all of the proposed alternative abatement standard(s), the division shall hold a public hearing on those standards. If the division environmental bureau chief recommends disapproval of any or all of the proposed alternative abatement standard(s), the petitioner may submit a request to the director, within fifteen (15) days after receipt of the recommendation, for a public hearing on those standards. If a timely request for hearing is not submitted, the recommended disapproval shall become a final decision of the director and shall not be subject to review.

(e) If the director grants a public hearing, the hearing shall be conducted in accordance with division hearing procedures.

(f) Based on the record of the public hearing, the division shall approve, approve subject to condition, or disapprove any or all of the proposed alternative abatement standard(s). The division shall notify the petitioner by certified mail of its decision and the reasons therefore.

(7) Modification of abatement standards. If applicable abatement standards are modified after abatement measures are approved, the abatement standards are modified after abatement measures are approved, the abatement standards that are in effect at the time that abatement measures are approved shall be the abatement standards for the duration of the abatement action, unless the director determines that compliance with those standards may with reasonable probability create a present or future hazard to public health or the environment. In any appeal of the director's determination that additional actions are necessary, the director shall have the burden of proof.

C. Abatement plan required

(1) Unless otherwise provided by Section 19.15.1.19 NMAC all responsible persons who are abating, or who are required to abate, water pollution in excess of the standards and requirements set forth in Subsection B of Section 19.15.1.19 NMAC shall do so pursuant to an abatement plan approved by the director. When an abatement plan has been approved, all actions leading to and including abatement shall be consistent with the terms and conditions of the abatement plan.

(2) In the event of a transfer of the ownership, control or possession of a facility for which an abatement plan is required or approved, where the transferor is a responsible person, the transferee also shall be considered a responsible person for the duration of the abatement plan, and may jointly share the responsibility to conduct the actions required by Section 19.15.1.19 NMAC with other responsible persons. The transferor shall notify the transferee in writing, at least thirty (30) days prior to the transfer, that abatement plan has been required or approved for the facility, and shall deliver or send by certified mail to the director a copy of such notification together with a certificate or other proof that such notification has in fact been received by the transferee. The transferor and transferee may agree to a designated responsible person who shall assume the responsibility to conduct the actions required by Section 19.15.1.19 NMAC. The responsible persons shall notify the director in writing if a designated responsible person is agreed upon. If the director determines that the designated responsible person has failed to conduct the actions required by Section 19.15.1.19 NMAC, the director shall notify all responsible persons of this failure in writing and allow them thirty (30) days, or longer for good cause shown, to conduct the required actions before setting a show cause hearing requiring those responsible persons to appear and show cause why they should not be ordered to comply, a penalty should not be assessed, a civil action should not be commenced in district court or any other appropriate action should not be taken by the division.

(3) If the source of the water pollution to be abated is a facility that operated under a discharge plan, the director may require the responsible person(s) to submit a financial assurance plan which covers the estimated costs to conduct the actions required by the abatement plan. Such a financial assurance plan shall be consistent with any financial assurance requirements adopted by the division.

D. Exemptions from abatement plan requirement

(1) Except a provided in Paragraph (2) below, Subsections C and E do not apply to a person who is abating water pollution:

(a) from an underground storage tank, under the authority of the underground storage tank regulations (Title 20, Chapter 5) adopted by the New Mexico environmental improvement board, or in accordance with the New Mexico Ground Water Protection Act;

(b) under the authority of the U.S. environmental protection agency pursuant to either the Federal Comprehensive Environmental Response, Compensation and Liability Act, and amendments, or the Resource Conservation and Recovery Act;

(c) pursuant to the hazardous waste management regulations (20.4.1 NMAC) adopted by the New Mexico environmental improvement board;

(d) under the authority of the U.S. nuclear regulatory commission or the U.S. department of energy pursuant to the Atomic Energy Act;

(e) under the authority of a ground-water discharge plan approved by the director, provided that such abatement is consistent with the requirements and provisions of Section 19.15.1.19 NMAC, Subsections A, B and E, Paragraphs (3) and (4), and Subsections F and K.

(f) under the authority of a letter of understanding, settlement agreement or administrative order on consent or other agreement signed by the director or his designee prior to **(insert effective date of rule),** 1997, provided that abatement is being performed in full compliance with the terms of the letter of understanding, settlement agreement or administrative order or other agreement on consent; and

(g) on an emergency basis, or while abatement plan approval is pending, or in a manner that will likely result in compliance with the standards and requirements set forth in Subsection B within one year after notice is required to be given pursuant to Subsection B of 19.15.3.116 NMAC provided that the division does not object to the abatement action.

(2) If the director determines that abatement of water pollution subject to Section 19.15.1.19 NMAC, Subsection D, Paragraph (1) will not met the standards of Section 19.15.1.19 NMAC, Subsection B, Paragraphs (2) and (3) or that additional action is necessary to protect health, welfare, environment or property, the director may notify a responsible person, by certified mail, to submit an abatement plan pursuant to Section 19.15.1.19 NMAC, Subsections C and E, Paragraph (1). The notification shall state the reasons for the director's determination. In any appeal of the director's determination under this Paragraph, the director shall have the burden of proof.

E. Abatement plan proposal

(1) Except as provided for in Subsection D of 19.15.1.19 NMAC a responsible person shall, within sixty (60) days of receipt of written notice from the director that an abatement plan is required, submit an abatement plan proposal to the director for approval. Stage 1 and stage 2 abatement plan proposals may be submitted together. For good cause shown, the director may allow for a total of one hundred and twenty (120) days to prepare and submit the abatement plan proposal.

(2) Voluntary abatement

(a) any person wishing to abate water pollution in excess of the standards and requirements set forth in Subsection B of Section 19.15.1.19 NMAC may submit a stage 1 abatement plan proposal to the director for approval. Following approval by the director of a final site investigation report prepared pursuant to stage 1 of an abatement plan, any person may submit a stage 2 abatement plan proposal to the director for approval.

(b) Following approval of a stage 1 or stage 2 abatement plan proposal under E(2)(a) above, the person submitting the approved plan shall be a responsible person under Section 19.15.1.19 NMAC for the purpose of performing the approved stage 1 or stage 2 abatement plan. Nothing in Section 19.15.1.19 NMAC shall preclude the director from applying Subsection D of 19.15.3.116 NMAC to a responsible person if applicable.

(3) Stage 1 abatement plan. The purpose of stage 1 of the abatement plan shall be to design and conduct a site investigation that will adequately define site conditions, and provide the data necessary to select and design an effective abatement option. Stage 1 of the abatement plan may include, but not necessarily be limited to, the following information depending on the media affected, and as needed to select and implement an expeditious abatement option:

(a) Descriptions of the site, including a site map, and of site history including the nature of the release that caused the water pollution, and a summary of previous investigations;

(b) Site investigation work plan to define:

(i) site geology and hydrogeology, the vertical and horizontal extent and magnitude of vadose-zone and ground-water contamination, subsurface hydraulic conductivity, transmissivity, storativity, and rate and direction of contaminant migration, inventory of water wells inside and within one (1) mile from the perimeter of the three-dimensional body where the standards set forth in Subsection B, Paragraph (2) are exceeded, and location and number of such wells actually or potentially affected by the pollution; and

(ii) surface-water hydrology, seasonal stream flow characteristics, groundwater/surface-water relationships, the vertical and horizontal extent and magnitude of contamination and impacts to surface water and stream sediments. The magnitude of contamination and impacts on surface water may be, in part, defined by conducting a biological assessment of fish, benthic macro invertebrates and other wildlife populations. Seasonal ariations should be accounted for when conducting these assessments.

(c) Monitoring program, including sampling stations and frequencies, for the duration of the abatement plan that may be modified, after approval by the director, as additional sampling stations are created;

(d) Quality assurance plan, consistent with the sampling and analytical techniques listed in Subsection B of 20.6.2.3107 NMAC and with 20.6.4.13 NMAC of the water quality standards for interstate and intrastate surface waters in New Mexico 20.6.4 NMAC, for all work to be conducted pursuant to the abatement plan;

(e) A schedule for all stage 1 abatement plan activities, including the submission of summary quarterly progress reports, and the submission, for approval by the director, of a detailed final site investigation report; and

(f) Any additional information that may be required to design and perform an adequate site investigation.

(4) Stage 2 abatement plan

(a) Any responsible person shall submit a stage 2 abatement plan proposal to the director for approval within sixty (60) days, or up to one hundred and twenty (120) days for good cause shown, after approval by the director of the final site investigation report prepared pursuant to stage 1 of the abatement plan. A stage 1 and 2 abatement plan proposal may be submitted together. The purpose of stage 2 of the abatement plan shall be to select and design, if necessary, an abatement option that, when implemented, will result in attainment of the abatement standards and requirements set forth in Section 19.15.1.19 NMAC, Subsection B including post-closure maintenance activities.

(b) Stage 2 of the abatement plan should include, at a minimum, the following information:

(i) brief description of the current situation at the site;

(ii) development and assessment of abatement options;

(iii) description, justification and design, if necessary, of preferred abatement option;

(iv) modification, if necessary, of the monitoring program approved pursuant to stage 1 of the abatement plan, including the designation of pre- and post-abatement-completion sampling stations and sampling frequencies to be used to demonstrate compliance with the standards and requirements set forth in Subsection B of Section 19.15.1.19 NMAC;

(v) site maintenance activities, if needed, proposed to be performed after termination of abatement activities;

(vi) a schedule for the duration of abatement activities, including the submission of summary quarterly progress reports;

(vii) a public notification proposal designed to satisfy the requirements of Section 19.15.1.19 NMAC, Subsection G, Paragraphs (2) and (3);

(viii) any additional information that may be reasonably required to select, describe, justify and design an effective abatement option.

F. Other requirements

(1) Any responsible person shall allow any authorized representative of the director, upon presentation of proper credentials and with reasonable prior notice, to:

(a) enter the facility at reasonable times;

(b) inspect and copy records required by an abatement plan;

(c) inspect any treatment works, monitoring and analytical equipment;

(d) sample any wastes, ground water, surface water, stream sediment, plants, animals, or vadose-zone material including vadose-zone vapor;

(e) use monitoring systems and wells under such responsible person's control in order to collect samples of any media listed in Subparagraph (d) above; and

(f) gain access to off-site property not owned or controlled by such responsible person, but accessible to such responsible person through a third-party access agreement, provided that it is allowed by the agreement.

(2) Any responsible person shall provide the director, or a representative of the director, with at least four (4) working days advance notice of any sampling to be performed pursuant to an abatement plan, or any well plugging, abandonment or destruction at any facility where an abatement plan has been required.

(3) Any responsible person wishing to plug, abandon or destroy a monitoring or water supply well within the perimeter of the 3-dimensional body where the standards set forth in Section 19.15.1.19 NMAC, Subsection B, Paragraph (2) of are exceeded, at any facility where an abatement plan has been required, shall propose such action by certified mail to the director for approval, unless such approval is required from the state engineer. The proposed action shall be designed to prevent water pollution that could result from water contaminants migrating through the well or borehole. The proposed action shall not take place without written approval from the director, unless written approval or disapproval is not received by the responsible person within thirty (30) days of the date of receipt of the proposal.

G. Public notice and participation

(1) Prior to public notice, the applicant shall give written notice, as approved by the division, of stage 1 and stage 2 abatement plans to the following persons:

(a) surface owners of record within one (1) mile of the perimeter of the geographic area where the standards and requirements set forth in Subsection B of Section 19.15.1.19 NMAC are exceeded;

(b) the county commission where the geographic area where the standards and requirements set forth in Subsection B of Section 19.15.1.19 NMAC are exceeded is located;

(c) the appropriate city official(s) if the geographic area where the standards and requirements set forth in Subsection B of Section 19.15.1.19 NMAC are exceeded is located or is partially located within city limits or within one (1) mile of the city limits;

(d) those persons, as identified by the director, who have requested notification, who shall be notified by mail;

(e) the New Mexico trustee for natural resources, and any other local, state or federal governmental agency affected, as identified by the director, which shall be notified by certified mail;

(f) the appropriate governor or president of any indian tribe, pueblo or nation if the geographic area where the standards and requirements set forth in Subsection B of Section 19.15.1.19 NMAC are exceeded is located or is partially located within tribal boundaries oar within one (1) mile of the tribal boundaries, who shall be notified by certified mail;

(g) the distance requirements for notice may be extended by the director is the director determines the proposed abatement plan has the potential to adversely impact public health or the environment at a distance greater than one (1) mile. The director may require additional notice as needed. A copy and proof of such notice will be furnished to the division.

(2) Within fifteen days after the division determines that a stage 1 abatement plan or a stage 2 abatement plan is administratively complete, the responsible person will issue public notice in a form approved by the division in a newspaper of general circulation in the county in which the release occurred, and in a newspaper of general circulation in the state. For the purposes of this paragraph, an administratively complete stage 1 abatement plan is a document that satisfies the requirements of Section 19.15.1.19 NMAC, Subsection E, Paragraph E (3) and an administratively complete stage 2 abatement plan is a document that satisfies the requirements of Section 19.15.1.19 NMAC, Subsection E, Paragraph (4), Subparagraph (b). The public notice shall include, as approved in advance by the director:

(a) name and address of the responsible person;

(b) location of the proposed abatement;

(c) brief description of the source extent, and estimated volume of release, whether the release occurred into the vadose zone, ground water or surface water; and a description of the proposed stage 1 or stage 2 abatement plan;

(d) brief description of the procedures followed by the director in making a final determination;

(e) statement that a copy of the abatement plan can be viewed by the public at the division's main office or at the division's district office for the area in which the release occurred, and a statement describing how the abatement plan can be accessed by the public electronically from a division-maintained site if such access is available;

(f) statement that the following comments and requests will be accepted for consideration if received by the director within thirty (30) days after the date of publication of the public notice:

(i) written comments on the abatement plan; and

(ii) for a stage 2 abatement plan, written requests for a public hearing that include reasons why a hearing should be held.

(g) address and phone number at which interested persons may obtain further information.

(3) Any person seeking to comment on a stage 1 abatement plan, or to comment or request a public hearing on a stage 2 abatement plan, must file written comments or hearing requests with the division within thirty (30) days of the date of public notice, or within thirty (30) days of receipt by the director of a proposed significant modification of a stage 2 abatement plan. Requests for a public hearing must set forth the reasons why a hearing should be held. A public hearing shall be held if the director determines that there is significant public interest or that the request has technical merit.

(4) The division will distribute notice of the filing of an abatement plan with the next division and commission hearing docket following receipt of the plan.

H. Director approval or notice of deficiency of submittals

(1) The director shall, within sixty (60) days of receiving an administratively complete stage 1 abatement plan a site investigation report, a technical infeasibility demonstration, or an abatement completion report, approve the document, or notify the responsible person of the document's deficiency, based upon the information available.

(2) If no public hearing is held pursuant to Section 19.15.1.19 NMAC, Subsection G, Paragraph (3) then the director shall, within ninety (90) days of receiving a stage 2 abatement plan proposal, approve the plan, or notify the responsible person of the plan's deficiency, based upon the information available.

(3) If a public hearing is held pursuant to Section 19.15.1.19 NMAC, Subsection G, Paragraph (3) then the director shall, within sixty (60) days of receipt of all required information, approve stage 2 of the abatement plan proposal, or notify the responsible person of the plan's deficiency, based upon the information contained in the plan and information submitted at the hearing.

(4) If the director notifies a responsible person of any deficiencies in a site investigation report, or in a stage 1 or stage 2 abatement plan proposal, the responsible person shall submit a modified document to cure the deficiencies specified by the director within thirty (30) days of receipt of the notice of deficiency. The responsible person shall be in violation of Section 19.15.1.19 NMAC if he fails to submit a modified document within the required time, or if the modified document does not make a good faith effort to cure the deficiencies specified by the director.

(5) Provided that the other requirements of Section 19.15.1.19 NMAC are met and provided further that stage 2 of the abatement plan, if implemented, will result in the standards and requirements set forth in Subsection B of Section 19.15.1.19 NMAC being met within a schedule that is reasonable given the particular circumstances of the site, the director shall approve the plan.

I. Investigation and abatement - Any responsible person who receives approval for stage 1 and/or stage 2 of an abatement plan shall conduct all investigation, abatement, monitoring and reporting activity in full compliance with Section 19.15.1.19 NMAC and according to the terms and schedules contained in the approved abatement plans.

J. Abatement plan modification

(1) Any approved abatement plan may be modified, at the written request of the responsible person, in accordance with Section 19.15.1.19 NMAC, and with written approval of the director.

(2) If data submitted pursuant to any monitoring requirements specified in the approved abatement plan or other information available to the director indicates that the abatement action is ineffective, or is creating unreasonable injury to or interference with health, welfare, environment or property, the director may require a responsible person to modify an abatement plan within the shortest reasonable time so as to effectively abate water pollution which exceeds the standards and requirements set forth in Subsection B of Section 19.15.1.19 NMAC, and to abate and prevent unreasonable injury to or interference with health, welfare, environment or property.

K. Completion and termination

(1) Abatement shall be considered complete when the standards and requirements set forth in Subsection B of Section 19.15.1.19 NMAC are met. At that time, the responsible person shall submit an abatement completion report, documenting compliance with the standards and requirements set forth in Subsection B of Section

19.15.1.19 NMAC, to the director for approval. The abatement completion report also shall propose any changes to long-term monitoring and site maintenance activities, if needed, to be performed after termination of the abatement plan.

(2) Provided that the other requirements of Section 19.15.1.19 NMAC are met and provided further that the standards and requirements set forth in Subsection B of Section 19.15.1.19 NMAC have been met, the director shall approve the abatement completion report. When the director approves the abatement completion report, he shall also notify the responsible person in writing that the abatement plan is terminated.

L. Dispute resolution - In the event of any technical dispute regarding the requirements of Section 19.15.3.116 NMAC, Subsections B, D, E, J, or K (above), including notices of deficiency, the responsible person may notify the director by certified mail that a dispute has arisen, and desires to invoke the dispute resolution provisions of this Paragraph, provided that such notification must be made within thirty (30) days after receipt by the responsible person of the decision of the director that causes the dispute. Upon such notification, all deadlines affected by the technical dispute shall be extended for a thirty (30) day negotiation period, or for a maximum of sixty (60) days if approved by the director for good cause shown. During this negotiation period, the director or his/her designee and the responsible person shall meet at least once. Such meeting(s) may be facilitated by a mutually agreed upon third party, but the third party shall assume no power or authority granted or delegated to the director by the Oil and Gas Act or by the division or commission. If the dispute remains unresolved after the negotiation period, the decision of director shall be final.

M. Appeals from director's and division's decisions

(1) If the director determines that (i) an abatement plan is required pursuant to Subsection D of 19.15.3.116 NMAC, (ii) approves or provides notice of deficiency of a proposed abatement plan, technical infeasibility demonstration or abatement completion report, or (iii) modifies or terminates an approved abatement plan, he shall provide written notice of such action by certified mail to the responsible person and any person who participated in the action.

(2) Any person who participated in the action before the director and who is adversely affected by the action listed in Paragraph (1) above may file a petition requesting a hearing before a division examiner.

(3) The petition shall be made in writing to the division and shall be filed with the division within thirty (30) days after receiving notice of the director's action. The petition shall specify the portions of the action to which the petitioner objects, certify that a copy of the petition has been mailed or hand-delivered to the director, and to the applicant or permittee if the petitioner is not the applicant or permittee, and attach a copy of the action for which review is sought. Unless a timely petition for hearing is made, the director's action is final.

(4) The hearing before the division shall be conducted in the same manner as other division hearings.

(5) The cost of the court reporter for the hearing shall be paid by the petitioner.

(6) Any party adversely affected by any order by the division pursuant to any hearing held by an Examiner, shall have a right to have such matter heard ***de novo*** before the commission.

(7) The appeal provisions do not relieve the owner, operator or responsible person of their obligations to comply with any federal or state laws or regulations.

[3-15-97; 6-30-97; 19.15.1.19 NMAC - Rn, 19 NMAC 15.A.19, 5-15-01; A, 3-15-02]

19.15.1.20 MEETINGS BY TELECONFERENCE:

Pursuant to Section 10-15-1 NMSA 1978, commission members may participate in commission meetings and hearings by means of a conference telephone or other similar communications equipment when it is otherwise difficult or impossible for members to attend the meeting or hearing in person. Each member participating by conference telephone or other similar communications equipment must be identified when speaking. All participants must be able to hear each other at the same time. Members of the public hearing attending the meetings or hearing must be able to hear commission members who speak during the meeting or hearing.

[12-31-96; 19.15.1.20 NMAC - Rn, 19 NMAC 15.A.20, 5-15-01]

19.15.1.21 SPECIAL PROVISIONS FOR SELECTED AREAS OF SIERRA AND OTERO COUNTIES:

A. The selected areas comprise:

(1) all of Sierra county except the area west of Range 8West NMPM and north of Township 18 South, NMPM; and

(2) all of Otero county except the area included in the following townships and ranges:

(a) township 11 south, range 9 1/2 east and range 10 east NMPM;

(b) township 12 south, range 10 east and ranges 13 east through 16 east, NMPM;

(c) township 13 south, ranges 11 east through 16 east, NMPM;

(d) township 14 south, ranges 11 east through 16 east, NMPM;

(e) township 15 south, ranges 11 east through 16 east, NMPM;

(f) township 16 south, ranges 11 east through 15 east, NMPM;

(g) township 17 south, range 11 east (surveyed) and ranges 12 east through 15 east, NMPM;

(h) township 18 south, ranges 11 east through 15 East, NMPM;

(i) township 20 1/2 south, range 20 east, NMPM;

(j) township 21 south, range 19 east and range 20 east, NMPM; and

(k) township 22 south, range 20 east, NMPM; and also excepting also the unsurveyed area bounded as follows:

(i) beginning at the most northerly northeast corner of Otero county, said point lying in the west line of range 13 east (surveyed);

(ii) thence west along the north boundary line of Otero county to the point of intersection of such line with the east line of range 10 east NMPM (surveyed);

(iii) thence south along the east line of range 10 east NMPM (surveyed) to the southeast corner of township 11 south, range 10 east NMPM (surveyed);

(iv) thence west along the south line of township 11 south, range 10 east NMPM (surveyed) to the more southerly northeast corner of township 12 south, range 10 east NMPM (surveyed);

(v) thence south along the east line of range 10 east NMPM (surveyed) to the inward corner of township 13 south, range 10 east NMPM (surveyed) (said inward corner formed by the east line running south from the more northerly northeast corner and the north line running west from the more southerly northeast corner of said township and range);

(vi) thence east along the north line of township 13 south NMPM (surveyed) to the southwest corner of township 12 south, range 13 east, NMPM (surveyed);

(vii) thence north along the west line of range 13 east, NMPM (surveyed) to the point of beginning.

B. The division shall not issue permits under 19.15.2.50 NMAC or 19.15.9.711 NMAC for pits located in the selected areas.

C. Produced water injection wells located in the selected areas are subject to the following requirements in addition to those set out in 19.15.9.701 NMAC through 19.15.9.710 NMAC.

(1) Permits shall be issued under 19.15.9.701 NMAC only after notice and hearing.

(2) The radius of the area of review shall be the greater of:

(a) one-half mile; or

(b) one and one-third times the radius of the zone of endangering influence, as calculated under environmental protection agency regulation 40 CFR Part 146.6(a) or by any other method acceptable to the division; but in no case shall the radius of the area of review exceed one and one-third miles.

(3) Operators shall demonstrate the vertical extent of any fresh water aquifer(s) prior to using a new or existing well for injection.

(4) All fresh water aquifers shall be isolated throughout their vertical extent with at least two cemented casing strings. In addition,

(a) existing wells converted to injection shall have continuous, adequate cement from casing shoe to surface on the smallest diameter casing, and

(b) wells drilled for the purpose of injection shall have cement circulated continuously to surface on all casing strings, except the smallest diameter casing shall have cement to at least 100 feet above the casing shoe of the next larger diameter casing.

(5) Operators shall run cement bond logs acceptable to the division after each casing string is cemented, and file the logs with the appropriate district office of the division. For existing wells the casing and cementing program shall comply with 19.15.9.702 NMAC.

(6) Produced water transportation lines shall be constructed of corrosion-resistant materials acceptable to the division, and shall be pressure tested to one and one-half times the maximum operating pressure prior to operation, and annually thereafter.

(7) All tanks shall be placed on impermeable pads and surrounded by lined berms or other impermeable secondary containment device having a capacity at least equal to one and one-third times the capacity of the largest tank, or, if the tanks are interconnected, of all interconnected tanks.

(8) Operators shall record injection pressures and volumes daily or in a manner acceptable to the division, and make the record available to the division upon request.

(9) Operators shall perform a mechanical integrity tests as described in Paragraph 2, Subsection A of 19.15.9.704 NMAC annually, shall advise the appropriate district office of the division of the date and time each such test is to be commenced in order that the test may be witnessed, and shall file the pressure chart with the appropriate district office of the division.

[19.15.1.21 NMAC - N, 08-13-04]

19.15.1.22-29 [RESERVED]

19.15.1.30 ENHANCED OIL RECOVERY PROJECT TAX INCENTIVE:

A. General - Applications for qualification of enhanced oil recovery projects or expansions of existing enhanced oil recovery projects for the recovered oil tax rate pursuant to the New Mexico "Enhanced Oil Recovery Act" (Sections 7-29A-1 through 7-29A-5 NMSA 1978) will be accepted by the division after March 6, 1992.

B. Applicability - These rules apply to:

(1) enhanced oil recovery (EOR) projects;

(2) expansions of existing EOR projects;

(3) the expanded use of enhanced oil recovery technology in existing EOR projects; and

(4) the change from a secondary recovery project to a tertiary recovery project.

C. Definitions

(1) Crude oil means oil and other liquid hydrocarbons removed from natural gas at or near the wellhead.

(2) Enhanced oil recovery (EOR) project means the use or the expanded use of any process for the displacement of crude oil from an oil well or division-designated pool other than a primary recovery process, including but not limited to the use of a pressure maintenance process, a waterflooding process, an immiscible, miscible, chemical, thermal or biological process or any other related process.

(3) Expansion or expanded use means a significant change or modification as determined by the Division in (a) the technology or process used for the displacement of crude oil from an oil well or division-designated pool; or (b) the expansion, extension or increase in size of the geologic area or adjacent geologic area that could reasonably be determined to represent a new or unique area of activity.

(4) Operator means the person responsible for the actual physical operation of an enhanced recovery project.

(5) Positive production response means that the rate of oil production from the wells or pools affected by an enhanced recovery project is greater than the rate that would have occurred without the project.

(6) Project area means a pool or a portion of a pool that is directly affected by EOR operations.

(7) Primary recovery means the displacement of crude oil from an oil well or division-designated pool into the well bore by means of the natural pressure of the oil well or pool, including but not limited to artificial lift.

(8) Recovered oil tax rate means the tax rate set forth in Section 7-29-4 NMSA 1978, on crude oil produced from an enhanced recovery project.

(9) Secondary recovery project means an enhanced oil recovery project that: (a) occurs subsequent to the completion of primary recovery and is not a tertiary recovery project; (b) involves the application, in accordance with sound engineering principles of carbon dioxide miscible fluid displacement, pressure maintenance, waterflooding or any other secondary recovery method accepted and approved by the division that can reasonably be expected to result in an increase, determined in light of all facts and circumstances, in the amount of crude oil that may ultimately be recovered; and (c) encompasses a pool or portion of a pool the boundaries of which can be adequately defined and controlled.

(10) Termination means the discontinuance of an enhanced recovery project by the operator.

(11) Tertiary recovery project means an enhanced recovery project that: (a) occurs subsequent to the completion of a secondary recovery project; (b) involves the application, in accordance with sound engineering principles, of carbon dioxide miscible fluid displacement, pressure maintenance, water flooding or any other tertiary recovery method accepted and approved by the division that can reasonably be expected to result in an increase, determined in light of all facts and circumstances, in the amount of crude oil that may ultimately be recovered; and (c) encompasses a pool or portion of a pool the boundaries of which can be adequately defined and controlled.

D. Procedure

(1) The division’s general rules of procedure shall apply unless altered or amended by these rules.

(2) To be eligible for the tax rate the operator must apply for and receive division approval. No project or expansion approved by the division prior to March 6, 1992 shall qualify.

(3) All applications shall be filed in triplicate with the division’s Santa Fe office. One copy of the application and all attachments shall also be filed with the appropriate division district office.

(4) All applications shall be executed and certified by the operator or its authorized representative having knowledge of the facts therein and shall contain:

(a) operator’s name and address;

(b) description of the project area including:

(i) a plat outlining the project area;

(ii) description of the project area by section, township and range; total acres; and

(iii) name of the subject pool and formation;

(c) status of operations in the project area:

(i) if unitized, the name of the unit and the date and number of the division order approving the unit plan of operation;

(ii) if an application for approval of a unit plan has been made, the date the application was filed with the Division; and

(iii) if not unitized, identify each lease in the project area by lessor, lessee and legal description;

(d) method of recovery to be used:

(i) identify fluids to be injected;

(ii) if the division has approved the project, provide the date and number of the division order; and

(iii) if the project has not been approved by the division, provide the date the application for approval was filed with the division on form C-108;

(e) description of the project:

(i) a list of producing wells;

(ii) a list of injection wells;

(iii) capital costs of additional facilities;

(iv) total project cost;

(v) estimated total value of the additional production that will be recovered as a result of the project;

(vi) anticipated date for commencement of injection;

(vii) the type of fluid to be injected and the anticipated volumes; and if application is made for an expansion of an existing project, explain what changes in technology will be used or what additional geographic area will be added to the project area; and

(f) production data: provide graphs, charts and other supporting data to show the production history and production forecast of oil, gas, casinghead gas and water from the project area.

E. Approval and certification

(1) Project approval: An EOR project will be approved and the project area designated for the recovered oil tax rate when the operator proves that:

(a) the application of the proposed enhanced recovery techniques to the reservoir should result in an increase in the amount of crude oil that may be ultimately recovered;

(b) the project area has been so depleted that it is prudent to apply enhanced recovery techniques to maximize the ultimate recovery of crude oil; and

(c) the application is economically and technically reasonable and has not been prematurely filed.

(2) Positive production response certification:

(a) for the recovered oil tax rate to apply to oil produced from an approved qualified EOR project, the operator must demonstrate a positive production response to the division. Applications for certification of a positive production response shall be filed with the division's Santa Fe office and shall include:

(i) a copy of the division's approval of the enhanced recovery project or expansion;

(ii) a plat of the affected area showing all injection and producing wells with completion dates; and

(iii) production graphs and supporting data demonstrating a positive production response and showing the volumes of water or other substances that have been injected on the lease or unit since initiation of the enhanced recovery project;

(b) the division director shall have authority to administratively approve an application and certify a positive production response or, at the director's discretion or at the request of the applicant, may set the application for hearing; and

(c) the division shall certify that a positive production response occurred and notify the secretary of taxation and revenue. This certification and notice shall set forth the date the certification was made and the date the positive production response occurred provided however:

(i) for a secondary recovery project, the application for certification of a positive production response must occur not later than five (5) years from the date the division issued the certification of approval for the enhanced oil recovery project or expansion; and

(ii) for a tertiary recovery project, the application for certification of a positive production response must occur not later than seven (7) years from the date the division issues the certification of approval for the enhanced recovery project or expansion.

F. Reporting requirements

(1) The operator of an approved EOR project shall report annually on the status of the project and confirm that the project is still a viable EOR project as approved. The report will be for the year ending May 31 and shall be filed with the division's Santa Fe office. The report shall contain:

(a) the date and number of the division's certification order for the project;

(b) production graphs showing oil, gas and water production;

(c) a graph showing the volumes of fluid injected and the average injection pressures; and

(d) any additional data the director deems necessary for continued approval;

(2) the director may set for hearing the continued approval of any EOR project.

G. Termination - When active operation of an approved enhanced recovery project or expansion is terminated, the operator shall notify the division and the secretary of taxation and revenue in writing not later than the thirtieth (30) day after the termination of the enhanced recovery project or expansion.

[6-15-9; 19.15.1.30 NMAC - Rn, 19 NMAC 15.A.30, 5-15-01]

19.15.1.31 PRODUCTION RESTORATION PROJECT TAX INCENTIVE:

A. General - Applications for qualification of production restoration projects for the production restoration incentive tax exemption pursuant to the "Natural Gas and Crude Oil Production Incentive Act" (Sections 7-29B-1 through 7-29B-6 NMSA 1978) shall be accepted by the division after November 9, 1995.

B. Applicability - These rules apply to any natural gas or oil well division records show had thirty (30) days or less production in any period of twenty-four consecutive months beginning on or after January 1, 1993 upon which the operator commenced operations to restore production after June 16, 1995.

C. Definitions

(1) Operator means the person responsible for the actual physical operation of a natural gas or oil well;

(2) Production restoration incentive tax exemption means the severance tax exemption for natural gas and/or oil produced from an approved production restoration project found in Section 7-29-4 NMSA 1978.

(3) Production restoration project means returning to production any natural gas or oil well, including but not limited to any injection well which has previously produced, which had no more than (30) days of production in any period of twenty-four consecutive months beginning on or after January 1, 1993 as approved and certified by the division;

(4) Well means a wellbore with single or multiple completions, including all horizons and producing formations from the surface to total depth.

D. Procedure

(1) The division's general rules of procedure shall apply unless altered or amended by these rules.

(2) To be eligible for the exemption, the operator must apply for and receive division approval. No production restoration project commenced prior to June 16, 1995 shall qualify.

(3) An application must be filed with the division within twelve (12) months of the production restoration.

(4) Applications shall be filed by the operator on behalf of all interest owners in the project.

(5) Applications shall be filed in triplicate with the division at its appropriate district office on division form C-139 and shall contain:

(a) operator's name and address; and

(b) description of the production restoration project including:

(i) name and footage location of the well;

(ii) name of the pool from which the well previously produced;

(iii) a description of the process used, or to be used, by the operator for returning the well to production;

(iv) identification of the division records which show that the well had thirty (30) days or less production in any period of twenty-four consecutive months beginning on or after January 1, 1993;

(v) date the project was commenced and date the well was returned to production; and

(vi) a statement under oath by the operator or its authorized representative having knowledge of the facts contained in the application that: the application is complete and correct; production from the well has been reported to the division and division records establish the well had thirty (30) days or less production in any period of twenty-four consecutive months beginning on or after January 1, 1993.

E. Approval, certification, notification and hearing

(1) Project approval and certification

(a) A project shall be approved and a certification of approval issued to the operator designating the natural gas or oil well as a production restoration project when the operator proves that:

(i) after June 16, 1995, the operator has commenced any process to return the well to production; and

(ii) division records show the well had thirty (30) days or less of production in any period of twenty-four consecutive months beginning on or after January 1, 1993.

(b) The exemption will apply beginning the first day of the month following the date the well was returned to production as certified by the division.

(2) Notification to the secretary of taxation and revenue - The division shall notify the secretary of taxation and revenue of the approval. This notice shall identify the natural gas or oil well as a production restoration project and certify the date production was restored.

(3) Hearing - The division shall consider applications without a hearing. If the division district office

denies an application, the division upon the applicant's request shall set the application for hearing. Any application not acted upon by the division district office within thirty (30) days from the date it is filed shall be deemed denied.
[Rn, 19 NMAC 15.I.712.A through E, 6-15-99; A, 6-15-99; 19.15.1.31 NMAC - Rn, 19 NMAC 15.A.31, 5-15-01]

19.15.1.32 WELL WORKOVER PROJECT TAX INCENTIVE:

A. General - Applications for qualification of well workover projects for the well workover incentive tax rate pursuant to the "Natural Gas and Crude Oil Production Incentive Act" (Sections 7-29B-1 through 7-29B-6 NMSA 1978) shall be accepted by the division after November 9, 1995.

B. Applicability - These rules apply to any natural gas or oil well upon which the operator has commenced a workover after June 16, 1995 that is intended to increase production from the well.

C. Definitions

(1) Routine maintenance means repair or like-for-like replacement of downhole equipment or any other procedure performed by an operator to maintain the well's current production;

(2) Well means a wellbore with single or multiple completions, including all horizons and producing formations from the surface to total depth.

(3) Well workover incentive tax rate means the tax rate imposed by Section 7-29-4 NMSA 1978 on natural gas and/or oil produced from a well workover project;

(4) Well workover project means any procedure undertaken by the operator of a natural gas or oil well that is intended to increase production from the well and that has been approved and certified by the division;

(5) Workover means any procedure undertaken by the operator of the well intended to increase production but is not routine maintenance and includes, but is not limited to:

(a) re-entry into the well to drill deeper, to sidetrack to a different location, to recomplete for production or to restore production from a zone which has been temporarily abandoned;

(b) recompletion by re-perforation of a zone from which natural gas or oil has been produced or by perforation of a different zone;

(c) repair or replacement of faulty or damaged casing or related downhole equipment;

(d) fracturing, acidizing or installing compression equipment; and

(e) squeezing, cementing or installing equipment necessary for removal of excessive water, brine or condensate from the well bore in order to establish, continue or increase production from the well.

D. Procedure

(1) The division's general rules of procedure shall apply unless altered or amended by these rules.

(2) To be eligible for the incentive tax rate, the operator must apply for and receive division approval. No well workover project commenced by the operator prior to June 16, 1995 shall qualify.

(3) Applications must be filed with the division within twelve (12) months of completion of the workover.

(4) An application shall be filed by the operator on behalf of all interest owners in the project.

(5) The data utilized in the application shall be retained by the operator in its files during the period of time the well qualifies for and receives the well workover incentive tax rate and for such time thereafter as the department requires.

(6) Applications shall be filed in triplicate with the division at its appropriate district office on division form C-140 and shall contain:

(a) operator's name and address; and

(b) description of well workover project including:

(i) name and footage location of the well;

(ii) name of the pool from which the well previously produced;

(iii) the dates workover procedures commenced and were completed;

(iv) a description of the procedures undertaken by operator of the well intended to increase production;

(v) evidence of a positive production increase over the production rate of the well prior to the workover. The operator must submit a production curve or data tabulation made up of at least twelve months' production prior to the workover and at least three months' production following the workover that reflects a positive production increase;

(vi) other documentation the applicant determines may be applicable to this filing, such as division forms or division orders; and

(vii) a statement under oath by the operator or its authorized representative having knowledge of the facts contained in the application that he/she has made or caused to be made a diligent search of all production records which are reasonably available and contain information relevant to the production history of the well.

E. Approval, certification, notification and hearing

(1) Project approval and certification

(a) A workover shall be approved and a certification of approval issued to the operator designating the natural gas or oil well as a well workover project when the operator proves that:

(i) approved workover procedures have been undertaken on the well which are intended to increase production; and

(ii) the production curve or data tabulation from production data reflects a positive production increase from the workover.

(b) The incentive tax rate will apply beginning the first day of the month following the date the workover was completed as certified by the division.

(2) Notification to the secretary of taxation and revenue - The division shall notify the secretary of taxation and revenue of the approval by identifying the natural gas or oil well as a well workover project and certifying the date the project was completed.

(3) Hearings and requests for additional information

(a) The division shall consider applications without a hearing. If the division district office denies an application, the division upon the applicant's request shall set the application for hearing. Any application not acted upon by the division district office within thirty (30) days from the date it is filed is deemed denied.

(b) The division may request additional information from the operator to support an application. When additional information is requested, the 30-day approval period shall begin to run on the date the requested data is provided.

F. Certifications prior to July 1, 1999 - Well workover projects certified prior to July 1, 1999 shall be deemed to be approved and certified in accordance with the provisions of the 1999 act and natural gas or oil produced from those projects shall be eligible for the well workover incentive tax rate effective beginning July 1, 1999.

[6-15-99, Rn, 19. NMAC 15.I.713.A through E, 7-1-99; A, 7-1-99; 19.15.1.32 NMAC - Rn, 19 NMAC 15.A.32, 5-15-01]

19.15.1.33 STRIPPER WELL TAX INCENTIVE:

A. General - Qualification of stripper well properties for the stripper well incentive tax rates in Sections 7-29-4 and 7-31-4 NMSA 1978, requires certification by the division. The division shall certify stripper well properties for calendar year 1998 no later than June 30, 1999 and no later than June 1 of each succeeding year for the preceding calendar year.

B. Applicability - These rules apply to any property that the division certifies as a stripper well property after June 30, 1999.

C. Definitions

(1) Average daily production means the number derived by dividing the total volume of crude oil or natural gas production from the stripper well property reported to the division during a calendar year by the sum of the number of days each eligible well within the property produced or injected during that calendar year;

(2) Eligible well means a crude oil or natural gas well that produces, or an injection well that injects and is integral to production, for any period of time during the preceding calendar year.

(3) Stripper well property means a crude oil or natural gas producing property that is assigned a single production unit number (PUN) by the taxation and revenue department and:

(a) (if a crude oil producing property) produced a daily average of less than ten barrels of oil per eligible well per day for the preceding calendar year;

(b) (if a natural gas producing property) produced a daily average of less than sixty thousand cubic feet of natural gas per eligible well per day during the preceding calendar year; or

(c) (if a property with wells that produce both crude oil and natural gas) produced a daily average of less than ten barrels of oil per eligible well per day for the preceding calendar year, as determined by converting the volume of natural gas produced by the well to barrels of oil by using a ratio of six thousand cubic feet to one barrel of oil; and

(4) Stripper well incentive tax rates means the tax rates set for stripper well properties by Sections 7-29-4 and 7-31-4 NMSA 1978.

D. Certification, notification and hearing

(1) The division shall determine which wells qualify as stripper well properties.

(2) Upon certification of properties as stripper well properties, the division shall notify the operator and the secretary of taxation and revenue of that certification.

(3) The operator shall notify all the interest owners of the certification of the property as a stripper well property.

(4) An operator may make a written request that the division reevaluate a property for stripper well status.

(5) If the division denies stripper well certification to a property, the division upon the operator's request shall set the matter for hearing.

[6-15-99; 19.15.1.33 NMAC - Rn, 19 NMAC 15.A.33, 5-15-01]

19.15.1.34 NEW WELL TAX INCENTIVE:

A. Applicability - These rules apply to any new natural gas or oil well for which drilling commenced after January 1, 1999 and before July 1, 2000.

B. Definitions - New well means a crude oil or natural gas producing well for which drilling commenced after January 1, 1999 and before July 1, 2000, or a horizontal crude oil or natural gas well that was recompleted from a vertical well by drilling operations that commenced after January 1, 1999 and before July 1, 2000, that has been approved and certified as such by the division.

C. Procedure

(1) The division's general rules of procedure shall apply unless altered or amended by these rules.

(2) The operator must apply for and be granted division approval of the "new well". A new well shall qualify if the division certifies that:

(a) the operator applying for the tax credit commenced drilling the new well after January 1, 1999 and before July 1, 2000;

(b) the new well was completed as a producer; and

(c) the application is for one of the first six hundred new wells commenced after January 1, 1999 and before July 1, 2000.

(3) An application must be filed with the division: (a) within sixty (60) days of completion of the well as a producer, or (b) by Oct 1, 1999 for a well commenced after January 1, 1999 and before July 1, 1999.

(4) All applications shall be filed in triplicate with the division's Santa Fe office on form C-142 and shall contain:

(a) operator's name and address;

(b) description of the well:

(i) name and footage location;

(ii) date and time spudded; and

(iii) completion date and production test results;

(c) copies of division form C-103 or federal form 3160-5 showing spud date and time and form C-105 or federal form 3160-4 showing the well was completed as a producer;

(d) a list of all working interest owners in the well along with their percentage interests; and

(e) a statement under oath by the operator or its authorized representative having knowledge of the facts contained in the application that the application is complete and correct.

D. Certification, notification and hearing

(1) Upon approval of the application, the division shall certify that approval by sending a copy of the approved application to the operator and the secretary of taxation and revenue.

(2) The division shall consider applications without a hearing. The division may request additional information from an operator to support the application. If the division denies an application, the division upon the applicant's request shall set the application for hearing.

(3) The operator shall notify all working interest owners of the approval and certification of the well as a new well.

[6-15-99, A, 10-29-99; 19.15.1.34 NMAC - Rn, 19 NMAC 15.A.34, 5-15-01]

19.15.1.35 COMPULSORY POOLING. CHARGE FOR RISK

A. General rule - Compulsory pooling orders entered by the division pursuant to NMSA 1978 Section 70-2-17, as amended, may provide for the recovery, out of the share of production allocable to the working interest of any party that elects not to pay its proportionate share of well costs in advance, in addition to reasonable well costs and costs of supervision and management, of a charge for risk associated with the drilling, completion, or working over and recompletion of each unit well for which provision is made in the order. Unless otherwise ordered pursuant to Subsection B of 19.15.1.35 NMAC, the charge for risk shall be 200% of well costs.

(1) "Well costs" shall mean all reasonable costs of drilling, reworking, diverting, deepening, plugging back and testing the well; completing the well in any formation pooled by the order; and equipping the well for production. If, however, any well was previously completed in another formation or bottom-hole location, or was previously abandoned without completion, well costs as to such well shall mean only the reasonable costs of re-entering, reworking, diverting, deepening, plugging back or testing the well; completion in the pooled formation or formations and; if necessary, reequipping the well for production, unless the division determines that allowance of all or some portion of historical costs of drilling is just and reasonable due to particular circumstances. If a well is completed in two or more formations having diverse ownership or a different risk charge percentage, the order shall provide for allocation of well costs between the formations. As to any interest owner who elects not to pay its share of well costs associated with a specific well in advance, as provided in the applicable order, "well costs" shall include costs of any subsequent operation undertaken to secure or enhance production from any formation pooled by the order prior to the time that the entire amount of such non-consenting owner's share of well costs and applicable risk charge have been recovered from such non-consenting owner's share of production from such well. Such costs shall include expenses for reworking, diverting, deepening, plugging back, testing, completion or recompletion and equipping for production, but not ordinary operating expenses.

(2) Well costs shall also include reasonable costs of drilling, testing, completing, and equipping a substitute well if, in the drilling of a well pursuant to a compulsory pooling order, the operator loses the hole or encounters mechanical difficulties rendering it impracticable to drill to the objective depth, and the substitute well is located within 330 feet of the original well and drilling thereof is commenced within ten (10) days of the abandonment of the original well.

(3) An applicant for compulsory pooling shall not be required to present technical evidence justifying the risk charge provided in Subsection A of 19.15.1.35 NMAC.

B. Exceptions - Any person responding to a compulsory pooling application who seeks a different risk charge than that provided in Subsection A shall so state in a timely pre-hearing statement filed with the division and served on the applicant in accordance with Subsection B of 19.15.14.1208 NMAC, and shall have the burden to prove the justification for the risk charge sought by relevant geologic or technical evidence. The hearing officer shall have discretion to allow a responding party who has not filed a pre-hearing statement, but who appears in person or by attorney at the hearing, to offer evidence in support of a different risk charge than that provided in Subsection A of 19.15.1.35, but in such cases a continuance of the hearing shall be allowed, if requested, to enable the applicant to present rebuttal evidence.

[N, 8-15-03]

HISTORY of 19.15.5 NMAC:
Pre-NMAC History: Material in this part was derived from that previously filed with the commission of public records – state records center and archives as: Rule 0.1, Definitions, filed 1-8-82; Rule 0.1, Definitions, filed 11-6-86; Rule 0.1, Definitions, filed 10-11-89; Rule 0.1, Definitions, filed 7-10-90; Rule 0.1, Definitions, filed 2-5-91; Rule 1, Scope of Rules and Regulations, filed 1-8-82; Rule 1, Scope of Rules and Regulations, filed 9-16-85; Rule 1, Scope of Rules and Regulations, filed 2-5-91; Rule 2, Enforcement of Laws, Rules and Regulations Dealing with Conservation of Oil and Gas, filed 1-8-82; Rule 2, Enforcement of Laws, Rules and Regulations Dealing with Conservation of Oil and Gas; 9-16-85; Rule 2, Enforcement of Laws, Rules and Regulations Dealing with Conservation of Oil and Gas; 2-5-91; Rule 3, Waste Prohibited, filed 1-8-82; Rule 3, General Operations/Waste Prohibited, filed 9-16-85; Rule 3, General Operations/Waste Prohibited, filed 2-5-91; Rule 4, United States Government Leases, filed 1-8-82; Rule 4, United States Government Leases, filed 2-5-91; Rule 5, Classifying and Defining Pools, filed 1-8-82; Rule 5, Classifying and Defining Pools, filed 2-5-91; Rule 6, Forms Upon Request, filed 1-8-82; Rule 6, Forms upon Request, filed 2-5-91; Rule 7, Authority to Cooperate with Other Agencies, filed 9-16-85; Rule 7, Authority to Cooperate with Other Agencies, filed 9-16-85; Rule 7, Authority to Cooperate with Other Agencies, filed 2-5-91; Rule 8, Lined Pits/Below Grade Tanks, filed 9-12-85; Rule 8, Exposed Pits/Lined Pits/Below Grade Tanks, filed 8-17-89; Rule 8, Lined Pits/Below Grade Tanks, filed 2-5-91.

History of Repealed Material: [Reserved]

Other History: Rule 0.1, Definitions, filed 2-5-91; Rule 1, Scope of Rules and Regulations, filed 2-5-91; Rule 2, Enforcement of Laws, Rules and Regulations Dealing with Conservation of Oil and Gas; 2-5-91; Rule 3, General Operations/Waste Prohibited, filed 2-5-91; Rule 4, United States Government Leases, filed 2-5-91; Rule 5, Classifying and Defining Pools, filed 2-5-91; Rule 6, Forms upon Request, filed 2-5-91; Rule 7, Authority to Cooperate with Other Agencies, filed 2-5-91; and Rule 8, Lined Pits/Below Grade Tanks, filed 2-5-91 **renumbered, reformatted and amended to** 19 NMAC 15.A, General Provisions and Definitions, filed 01-18-96.
19 NMAC 15.A, General Provisions and Definitions, filed 01-18-96 **renumbered and reformatted to 19.15.1 NMAC**, General Provisions, effective 5-15-01.

TITLE 19 NATURAL RESOURCES and WILDLIFE
CHAPTER 15 OIL AND GAS
PART 2 GENERAL OPERATING PRACTICES, WASTES ARISING FROM EXPLORATION AND PRODUCTION

19.15.2.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department, Oil Conservation Division, 1220 S. St. Francis Drive, Santa Fe, New Mexico 87505, (505) 476-3440.
[19.15.2.1 NMAC - N, 2/13/04]

19.15.3.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico.
[19.15.2.2 NMAC - N, 02/13/04]

19.15.3.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the Oil and Gas Act which grants the oil conservation division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights, and the disposition of wastes resulting from oil and gas operations.
[19.15.2.3 NMAC - N, 02/13/04]

19.15.2.4 DURATION: Permanent.
[19.15.2.4 NMAC - N, 02/13/04]

19.15.2.5 EFFECTIVE DATE: February 13, 2004, unless a later date is cited at the end of a section.
[19.15.2.5 NMAC - N, 02/13/04]

19.15.2.6 OBJECTIVE: To regulate the drilling of oil and gas wells within the state of New Mexico to enable the oil conservation division to fulfill its statutory mandates under the Oil and Gas Act.
[19.15.2.6 NMAC - N, 02/13/04]

19.15.2.7 DEFINITIONS:
A. Alluvium shall mean detrital material that has been transported by water or other erosional forces and deposited at points along the flood plain of a watercourse. It typically is composed of sands, silts, and gravels, exhibits high porosity and permeability and generally carries fresh water.
B. Sump shall mean any impermeable single wall vessel with a capacity less than 500 gallons, where any portion of the sidewalls of the reservoir is below the surface of the ground and not visible which vessel remains predominantly empty, serves as a drain or receptacle for spilled or leaked liquids on an intermittent basis, and is not used to store, treat, dispose of, or evaporate products or wastes.
[19.15.2.7 NMAC - N, 02/13/04]

19.15.2.8 through 19.15.2.49 [RESERVED]

19.15.2.50 PITS AND BELOW-GRADE TANKS:
A. Permit required. Discharge into, or construction of, any pit or below-grade tank is prohibited absent possession of a permit issued by the division, unless otherwise herein provided or unless the division grants an exemption pursuant to Subsection G of 19.15.2.50 NMAC. Facilities permitted by the division pursuant to Section 711 of 19.15.9 NMAC or water quality control commission regulations are exempt from Section 50 of 19.15.2 NMAC.
B. Application.
(1) Where filed; application form.
(a) Downstream facilities. An operator shall apply to the division's environmental bureau for a permit to construct or use a pit or below-grade tank at a downstream facility such as a refinery, gas plant, compressor station, brine facility, service company, or surface waste management facility that is not permitted pursuant to Section 711 of 19.15.9 NMAC or water quality control commission regulations. The operator shall use a form C-144, application to discharge into a pit or below-grade tank. The operator may submit the form separately or as an attachment to an application for a discharge permit, best management practices permit, surface waste management facility permit, or other permit.
(b) Drilling or production. An operator shall apply to the appropriate district office for a permit for use of a pit or below-grade tank in drilling, production, or operations not otherwise identified in Subparagraph (a), Paragraph (1),

Subsection B of 19.15.2.50 NMAC. The operator shall apply for the permit on the application for permit to drill or on the sundry notices and reports on wells, or electronically as otherwise provided in this chapter. Approval of such form constitutes a permit for all pits and below-grade tanks annotated on the form. A separate Corm C-144 is not required.

(2) General permit; individual permit. An operator may apply for a permit to use an individual pit or below-grade tank, or may apply for a general permit applicable to a class of like facilities.

(3) When filed.

(a) New pits or new below-grade tanks. After April 15, 2004, operators shall obtain a permit before constructing a pit or below-grade tank.

(b) Existing pits or new below-grade tanks. For each pit or below-grade tank in existence on April 15, 2004 that has not received an exemption after hearing as allowed by OCC Order R-3221 through R-3221D inclusive, the operator shall submit a notice not later than April 15, 2004 indicating either that use of the pit or below-grade tank will continue or that such pit or below grade tank will be closed. If use of a pit or below-grade tank is to be discontinued, discharge into the pit or use of the below-grade tank shall cease not later than June 30, 2005. If use of a pit or below-grade tank will continue, the operator shall file a permit application not later than September 30, 2004. If an operator files a timely, administratively complete application for continued use, use of the pit or below-grade tank may continue until the division acts upon the permit application.

C. Design, construction, and operational standards.

(1) In general. Pits, sumps and below-grade tanks shall be designed, constructed and operated so as to contain liquids and solids to prevent contamination of fresh water and protect public health and the environment.

(2) Special requirements for pits.

(a) Location. No pit shall be located in any watercourse, lakebed, sinkhole, or playa lake. Pits adjacent to any such watercourse or depression shall be located safely above the ordinary high-water mark of such watercourse or depression. No pit shall be located in any wetland. The division may require additional protective measures for pits located in groundwater sensitive areas or wellhead protection areas.

(b) Liners.

(i) Drilling pits, workover pits. Each drilling pit or workover pit shall contain, at a minimum, a single liner appropriate for conditions at the site. The liner shall be designed, constructed, and maintained so as to prevent the contamination of fresh water, and protect public health and the environment. Pits used to vent or flare gas during drilling or workover operations that are designed to allow liquids to drain to a separate pit do not require a liner.

(ii) Disposal or storage pits. Each disposal pit (including, but not limited to, any separator pit, tank drain pit, evaporation pit, blowdown pit used in production activities, pipeline drip pit, or production pit) and each storage pit (including any brine pit, salt water pit, fluid storage pit for an LPG system, or production pit) shall contain, at a minimum, a primary and a secondary liner appropriate to the conditions at the site. Liners shall be designed, constructed, and maintained so as to prevent the contamination of fresh water, and protect public health and the environment.

(iii) Alternative liner media. The division may approve liners that are not constructed in accordance with division guidelines only if the operator demonstrates to the division's satisfaction that the alternative liner protects fresh water, public health, and the environment as effectively as those prescribed in division guidelines.

(c) Leak detection. A leak detection system shall be installed between the primary and secondary liner in each disposal or storage pit. The leak detection system shall be designed, installed, and operated so as to prevent the contamination of fresh water, and protect public health and the environment. The operator shall notify the division at least twenty-four hours prior to installation of the primary liner so a division representative may inspect the leak detection system before it is covered.

(d) Drilling and workover pits. Each drilling or workover pit shall be of an adequate size to assure that a supply of fluid is available and sufficient to confine oil, natural gas, or water within its native strata. Hydrocarbon-based drilling fluids shall be contained in tanks made of steel or other division-approved material.

(e) Disposal or storage pits. No measurable or visible layer of oil may be allowed to accumulate or remain anywhere on the surface of any pit. Spray evaporation systems shall be operated such that all spray-borne suspended or dissolved solids remain within the perimeter of the pond's lined portion.

(f) Fencing and netting. All pits shall be fenced or enclosed to prevent access by livestock, and fences shall be maintained in good repair. Active drilling or workover pits may have a portion of the pit unfenced to facilitate operations. In issuing a permit, the division may impose additional fencing requirements for protection of wildlife in particular areas. All tanks exceeding 16 feet in diameter, exposed pits, and ponds shall be screened, netted, covered, or otherwise rendered non-hazardous to migratory birds. Drilling and workover pits are exempt from the netting requirement. Immediately after cessation of these operations such pits shall have any visible or measurable layer of oil removed from the surface. Upon written application, the division may grant an exception to screening, netting, or covering requirements upon a showing that an alternative method will adequately protect migratory birds or that the tank or pit is not hazardous to migratory birds.

(g) Unlined pits.

(i) General prohibition. After June 30, 2005 use of, or discharge into, any unlined pit that has not been previously permitted pursuant to Section 711of 19.15.9 NMAC or water quality control commission regulations is prohibited, except as otherwise provided in Section 50 of 19.15.2 NMAC. After April 15, 2004, construction of unlined pits is prohibited unless otherwise provided in Section 50 of 19.15.2 NMAC.

(ii) Unlined pits exempted by previous order. An operator of an unlined pit existing on April 15, 2004 for which a previous exemption was received after hearing as allowed pursuant to commission Orders No. R-3221 through R-3221D inclusive, shall not be required to reapply for an exemption pursuant to Subparagraph (g), Paragraph (2), Subsection C of 19.15.2.50 NMAC provided the operator notifies the division, no later than April 15, 2004, of the existence of each unlined pit it believes is exempted by order, the location of the pit, and the nature and amount of any discharge into the pit. Such order shall constitute a permit for the purpose of Subparagraph (g), Paragraph (2), Subsection C of 19.15.2.50 NMAC. The division may terminate any such permit in accordance with Paragraph (2), Subsection C of 19.15.2.50 NMAC. Any pit constructed after April 15,2004 shall comply with the permitting, lining and other requirements of Section 50 of 19.15.2 NMAC, notwithstanding any previous order to the contrary.

(iii) Unlined pits shall be allowed in the following areas provided that the operator has submitted, and the division has approved, an application for permit as provided in Section 50 of 19.15.2 NMAC, and provided that the pit site is not located in fresh water-bearing alluvium or in a wellhead protection area:

TOWNSHIP 19 SOUTH, RANGE 30 EAST, NMPM Sections 8 through 36;
TOWNSHIP 20 SOUTH, RANGE 30 EAST, NMPM Sections 1 through 36;
TOWNSHIP 20 SOUTH, RANGE 31 EAST, NMPM Sections 1 through 36;
TOWNSHIP 20 SOUTH, RANGE 32 EAST, NMPM Sections 4 through 9, Sections 16 through 21; and Sections 28 through 33;
TOWNSHIP 21 SOUTH, RANGE 29 EAST, NMPM Sections 1 through 36;
TOWNSHIP 21 SOUTH, RANGE 30 EAST, NMPM Sections 1 through 36;
TOWNSHIP 21 SOUTH, RANGE 31 EAST, NMPM Sections 1 through 36;
TOWNSHIP 22 SOUTH, RANGE 29 EAST, NMPM Sections 1 through 36;
TOWNSHIP 22 SOUTH, RANGE 30 EAST, NMPM Sections 1 through 36;
TOWNSHIP 23 SOUTH, RANGE 29 EAST, NMPM Sections 1 through 3, Sections 10 through 15, Sections 22 through 27, and Sections 34 through 36;
TOWNSHIP 23 SOUTH, RANGE 30 EAST, NMPM Sections 1 through 19; and that area within San Juan, Rio Arriba, Sandoval, and McKinley Counties that is outside the valleys of the San Juan, Animas, Rio Grande, and La Plata Rivers, which are bounded by the topographic lines on either side of the rivers that are 100 vertical feet above the river channels, measured perpendicularly to the river channels, andis outside those areas that lie within 50 vertical feet, measured perpendicularly to the drainage channel, of all perennial and ephemeral creeks, canyons, washes, arroyos, and draws, and is outside the areas between the above-named rivers and the Highland Park Ditch, Hillside Thomas Ditch, Cunningham Ditch, Farmers Ditch, Halford Independent Ditch, Citizens Ditch, or Hammond Ditch, provided that no protectable ground water is present or if present, will not be adversely affected; or any area where the discharge into the pit meets New Mexico Water Quality Control Commission ground water standards.

(3) Special requirements for below-grade tanks. All below-grade tanks constructed after April 15, 2004 shall be constructed with secondary containment and leak detection. The operator of any below-grade tank constructed prior to April 15, 2004 shall test its integrity annually and shall promptly repair or replace any below-grade tank that does not demonstrate integrity. Any such below-grade tank shall be equipped with leak detection at the time of any major repair.

(4) Sumps. Operators shall test the integrity of all sumps annually, and shall promptly repair or replace any sump that does not demonstrate integrity. Sumps that can be removed from their emplacements may be tested by visual inspection. Other sumps shall be tested by appropriate mechanical means.

D. Emergency actions.

(1) Permit not required. In an emergency an operator may construct a pit without a permit to contain fluids, solids, or wastes if an immediate danger to fresh water, public health, or the environment exists.

(2) Construction standards. A pit constructed in an emergency shall be constructed, to the extent possible given the emergency, in a manner that is consistent with the requirements of Section 50 of 19.15.2 NMAC and that prevents the contamination of fresh water, and protects public health and the environment.

(3) Notice. The operator shall notify the appropriate district office as soon as possible (if possible before construction begins) of the need for construction of such a pit.

(4) Use and duration. The pit may be used only for the duration of the emergency. If the emergency lasts more than forty-eight (48) hours, the operator must seek approval from the division for continued use of the pit. All fluids, solids or wastes must be removed within 24 hours after cessation of use unless the division extends that time period.

(5) "Emergency pits." Subsection D, of 19.15.2.50 NMAC shall not be construed to allow construction or use of so-called "emergency pits," which are pits constructed as a precautionary matter to contain a spill in the event of a release. Construction or use of any such pit shall require a permit issued pursuant to Section 50 of 19.15.2 NMAC unless the pit is described in a spill prevention, control and countermeasure (SPCC) plan required by the United States environmental protection agency, all fluids are removed from the pit within 24 hours, and the operator has filed a notice of the location of the pit with the division.

E. Drilling fluids and drill cuttings. Drilling fluids and drill cuttings shall either be recycled or be disposed of as approved by the division and in a manner to prevent the contamination of fresh water and protect public health and the environment. The operator shall describe the proposed disposal method in the application for permit to drill or the sundry notices and reports on wells.

F. Closure and restoration.

(1) Closure. Except as otherwise specified in Section 50 of 19.15.2 NMAC, a pit or below-grade tank shall be properly closed within six months after cessation of use. As a condition of a permit, the division may require the operator to file a detailed closure plan before closure may commence. The division for good cause shown may grant a six-month extension of time to accomplish closure. Upon completion of closure a closure report (form C- 144), or sundry notices and reports on wells shall be submitted to the division. Where the pit's contents will likely migrate and cause ground water or surface water to exceed water quality control commission standards, the pit's contents and the liner shall be removed and disposed of in a manner approved by the division.

(2) Surface restoration. Within one year of the completion of closure of a pit, the operator shall contour the surface where the pit was located to prevent erosion and ponding of rainwater.

G. Exemptions; additional conditions.

(1) The division may attach additional conditions to any permit upon a finding that such conditions are necessary to prevent the contamination of fresh water, or to protect public health or the environment.

(2) The division may grant an exemption from any requirement if the operator demonstrates that the granting of such exemption will not endanger fresh water, public health or the environment. The division may revoke any such exemption after notice to the operator of the pit and opportunity for a hearing if the division determines that such action is necessary to prevent the contamination of fresh water, or to protect public health or the environment.

(3) Exemptions may be granted administratively without hearing provided that the operator gives notice to the surface owner of record where the pit is to be located and to such other persons as the division may direct and (a) written waivers are obtained from all persons to whom notice is required, or (b) no objection is received by the division within 30 days of the time notice is given. If any objection is received and the director determines that the objection has technical merit or that there is significant public interest the director shall set the application for hearing. The director, however, may set any application for hearing.

[19.15.2.50 NMAC - N, 02/13/04]

HISTORY OF 19.15.2 NMAC:

Pre-NMAC History: The material in this part was derived from that previously filed with the state records center and archives:
OCC 67-10, Commission Order No. R-3221, Case No. 3551, filed 5/2/67.
OCC 67-10, Amendment No. 1, Commission Order No. R-3221-A, Case No. 3644, filed 8/31/67.
OCC 67-10, Amendment No. 2, Commission Order No. R-3221-B, Case No. 3806, filed 7/31/68.
OCC 67-10, Amendment No. 2, Commission Order No. R-3221-B-1, Case No. 3806, filed 8/20/68.
Order No. R-7940-C, Special Rules and Regulations for the Disposal of Oil and Natural Gas Wastes in the Vulnerable Area in San Juan, McKinley, Rio Arriba and Sandoval Counties, New Mexico, filed 2/10/93.

History of Repealed Material:
OCC 67-10, Commission Order No. R-3221, Case No. 3551 (filed 5/2/67), repealed 02/13/04.
Order No. R-7940-C, Special Rules and Regulations for the Disposal of Oil and Natural Gas Wastes in the Vulnerable Area in San Juan, McKinley, Rio Arriba and Sandoval Counties, New Mexico (filed 2/10/93), repealed 02/13/04.

Other History:
OCC 67-10, Commission Order No. R-3221, Case No. 3551 (filed 5/2/67) and Order No. R-7940-C, Special Rules and Regulations for the Disposal of Oil and Natural Gas Wastes in the Vulnerable Area in San Juan, McKinley, Rio Arriba and Sandoval Counties, New Mexico, (filed 2/10/93) replaced by 19.15.2 NMAC, General Operating Practices, Wastes Arising from Exploration and Production, effective 02/13/04.

TITLE 19 NATURAL RESOURCES & WILDLIFE
CHAPTER 15 OIL AND GAS
PART 3 DRILLING

19.15.3.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department, Oil Conservation Division, 2040 S. Pacheco, Santa Fe, New Mexico 87505, (505) 827-7131.
[2-1-96; 19.15.3.1 NMAC - Rn, 19 NMAC 15.C.1, 11-15-01]

19.15.3.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico.
[2-1-96; 19.15.3.2 NMAC - Rn, 19 NMAC 15.C.2, 11-15-01]

19.15.3.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the Oil and Gas Act which grants the Oil Conservation Division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights, and the disposition of wastes resulting from oil and gas operations.
[2-1-96; 19.15.3.3 NMAC - Rn, 19 NMAC 15.C.3, 11-15-01]

19.15.3.4 DURATION: Permanent.
[2-1-96; 19.15.3.4 NMAC - Rn, 19 NMAC 15.C.4, 11-15-01]

19.15.3.5 EFFECTIVE DATE: February 1, 1996.
[2-1-96; 19.15.3.5 NMAC - Rn, 19 NMAC 15.C.5, 11-15-01]

19.15.3.6 OBJECTIVE: To regulate the drilling of oil and gas wells within the State of New Mexico to enable the Oil Conservation Division to fulfill its statutory mandates under the Oil & Gas Act.
[2-1-96; 19.15.3.6 NMAC - Rn, 19 NMAC 15.C.6, 11-15-01]

19.15.3.7 DEFINITIONS: [Reserved].

19.15.3.8-100 [RESERVED].

19.15.3.101 PLUGGING BOND:

A. Any person, firm, corporation, or association who has drilled or acquired, is drilling, or proposes to drill or acquire any oil, gas, or service well on privately owned or state owned lands within this state shall furnish to the division, and obtain approval thereof, a surety bond running to the State of New Mexico, in a form prescribed by the division, and conditioned that the well be plugged and abandoned in compliance with the rules and regulations of the division. Such bond may be a one-well plugging bond or a blanket plugging bond. All bonds shall be executed by a responsible surety company authorized to do business in the State of New Mexico.

B. Blanket plugging bonds shall be in the amount of fifty thousand dollars ($50,000) conditioned as above provided, covering all oil, gas, or service wells drilled, acquired or operated in this state by the principal on the bond.

C. One-well plugging bonds shall be in the amounts stated below in accordance with the depth and location of the well:

(1) Chaves, Eddy, Lea, McKinley, Rio Arriba, Roosevelt, Sandoval, and San Juan Counties, New Mexico:

Projected Depth of Proposed Well or Actual Depth of Existing Well	Amount of Bond
Less than 5,000 feet	$ 5,000
5,000 feet to 10,000 feet	$ 7,500

More than 10,000 feet	$ 10,000

(2) All other Counties in the State:

Projected Depth of Proposed Well or Actual Depth of Existing Well	Amount of Bond
Less than 5,000 feet	$ 7,500
5,000 feet to 10,000 feet	$ 10,000
More than 10,000 feet	$ 12,500

D. Revised plans for an actively drilling well may be approved by the appropriate District Office of the division for drilling as much as 500 feet deeper than the normal maximum depth allowed on the well's bond. Any well to be drilled more than 500 feet deeper than the normal depth bracket must be covered by a new bond in the amount prescribed for the deeper depth bracket.

E. The bond requirement for any intentionally deviated well shall be determined by the well's measured depth, and not its true vertical depth.

F. A cash bond may be accepted by the division pursuant to the conditions set forth hereinafter. Cash representing the full amount of the bond shall be deposited by the operator in an account in a federally-insured financial institution located within the State of New Mexico, such account to be held in trust for the division. Both one well and blanket cash bonds shall be in the amount specified for surety bonds. A document, approved by the division, evidencing the terms and conditions of the cash bond shall be executed by an authorized representative of the operator and the depository institution and filed with the division prior to the effective date of the bond. No cash bond will be authorized by the Director and no wells may be drilled or acquired under a blanket cash bond unless the operator/applicant is in good standing with the division. If the financial status or reliability of the applicant is unknown to the Director he may require the filing of a financial statement or such other information as may be necessary to evaluate the ability of the applicant/operator to fulfill the conditions of the bond.

G. From time to time any accrued interest over and above the face amount of the bond may be paid to the operator. Upon satisfactory plugging by the operator of any well(s) covered by a cash bond, the Director shall issue an order authorizing the release of said bond.

H. Any bond required by Section 101 of 19.15.3 NMAC is a plugging bond, not a drilling bond, and shall endure until any well drilled or acquired under such bond has been plugged and abandoned and such plugging and abandonment has been approved by the division, or has been covered by another bond approved by the division.

I. Transfer of a property does not of itself release a bond. In the event of transfer of ownership of a well, the appropriate form, C-103 or C-104, properly executed, shall be filed with the District Office of the division in accordance with Rule 1103 or Rule 1104 by the new owner of the well. The District Office may approve the transfer providing that a new one-well bond covering the well or a blanket bond in the name of the new owner has been approved by the Santa Fe office of the division.

J. Upon approval of the bond and the Form C-103 or C-104, the transferror is released of plugging responsibility for the well, and upon request, the original bond will be released. No blanket bond will be released, however, until all wells covered by the bond have been plugged and abandoned or transferred in accordance with the provisions of Section 101 of 19.15.3 NMAC.

K. All bonds shall be filed with the Santa Fe office of the division, and approval of such bonds, as well as releases thereof, obtained from said office.

L. All bonds required by these rules shall be conditioned for well plugging and location cleanup only, and not to secure payment for damages to livestock, range, water, crops, tangible improvements, nor any other purpose.

M. Upon failure of the operator to properly plug and abandon the well(s) covered by a bond, the division shall give notice to the operator and surety, if applicable, and hold a hearing as to whether the well(s) should be plugged in accordance with a division-approved plugging program. If, at the hearing, it is determined that the operator has failed to plug the well as provided for in the bond conditions and division rules, the Division director shall issue an order directing the well(s) to be plugged in a time certain. Such an order may also direct the forfeiture of the bond upon the failure or refusal of the operator, surety, or other responsible party to properly plug the well(s). If the proceeds of the bond(s) are not sufficient to cover all of the costs incurred by the division in plugging the

well(s) covered by the bond, the division shall take such legal action as is necessary to recover such additional costs. Any monies recovered through bond forfeiture or legal actions shall be placed in the Oil & Gas Reclamation Fund.
[1-1-50, 6-17-77, 6-5-86, 2-1-96; 19.15.3.101 NMAC - Rn, 19 NMAC 15.C.101, 11-15-01]

19.15.3.102 NOTICE OF INTENTION TO DRILL:

A. Prior to the commencement of operations, notice shall be delivered to the division of intention to drill any well for oil or gas or for injection purposes and approval obtained on Form C-101. A copy of the approved Form C-101 must be kept at the well site during drilling operations.

B. No permit shall be approved for the drilling of any well within the corporate limits of any city, town, or village of this state unless notice of intention to drill such well has been given to the duly constituted governing body of such city, town or village or its duly authorized agent. Evidence of such notification shall accompany the application for a permit to drill (Form C-101).

C. When filing a permit to drill in any quarter-quarter section containing an existing well or wells, the applicant shall concurrently file a plat or other acceptable document locating and identifying such well(s) and a statement that the operator(s) of such well(s) have been furnished a copy of the permit.
[1-1-50, 5-22-73…2-1-96; 19.15.3.102 NMAC - Rn, 19 NMAC 15.C.102, 11-15-01]

19.15.3.103 SIGN ON WELLS:

A. All wells and related facilities regulated by the division shall be identified by a sign, which sign shall remain in place until the well is plugged and abandoned and the related facilities are closed.

B. For drilling wells, the sign shall be posted on the derrick or not more than 20 feet from the well. C. The sign shall be of durable construction and the lettering shall be legible and large enough to be read under normal conditions at a distance of 50 feet.

D. The wells on each lease or property shall be numbered in non-repetitive, logical and distinctive sequence.

E. An operator will have 90 days from the effective date of an operator name change to change the operator name on the well sign unless an extension of time, for good cause shown along with a schedule for making the changes, is granted.

F. Each sign shall show the:

(1) number of well;

(2) name of property;

(3) name of operator;

(4) location by footage, quarter-quarter section, township and range (or Unit Letter can be substituted for the quarter-quarter section); and

(5) API number.

[1-1-50, 2-1-96, 6-30-97, 3-31-00; 19.15.3.103 NMAC - Rn, 19 NMAC 15.C.103, 11-15-01; A, 01-31-03]

19.15.3.104 WELL SPACING AND LOCATION:

A. Classification Of Wells: Wildcat And Development Wells

(1) Wildcat Well

(a) In San Juan, Rio Arriba, Sandoval, and McKinley Counties a wildcat well is any well to be drilled the spacing unit of which is a distance of two miles or more from:

(i) the outer boundary of any defined pool that has produced oil or gas from the formation to which the well is projected to be drilled; and

(ii) any well that has produced oil or gas from the formation to which the proposed well is projected to be drilled.

(b) In all counties except San Juan, Rio Arriba, Sandoval, and McKinley, a wildcat well is any well to be drilled the spacing unit of which is a distance of one mile or more from:

(i) the outer boundary of any defined pool that has produced oil or gas from the formation to which the well is projected to be drilled; and

(ii) any well that has produced oil or gas from the formation to which the proposed well is projected.

(2) Development Well

(a) Any well that is not a wildcat well shall be classified as a development well for the nearest pool that has produced oil or gas from the formation to which the well is projected to be drilled. Such development well shall be spaced, drilled, operated, and produced in accordance with the rules in effect for that pool, provided the well is completed in that pool.

(b) Any well classified as a development well for a pool but completed in a producing formation not included in the vertical limits of that pool shall be operated and produced in accordance with the rules in effect for the nearest pool that is producing from that formation within the two miles in San Juan, Rio Arriba, Sandoval, and McKinley Counties or within one mile everywhere else. If there is no designated pool for that producing formation within the two miles in San Juan, Rio Arriba, Sandoval, and McKinley Counties or within one mile everywhere else, the well shall be re-classified as a wildcat well.

B. Oil Well Acreage And Well Location Requirements

(1) Any wildcat well that is projected to be drilled as an oil well to a formation and in an area that in the opinion of the division may reasonably be presumed to be productive of oil rather than gas and each development well for a defined oil pool, unless otherwise provided in special pool orders, shall be located on a spacing unit consisting of approximately 40 contiguous surface acres substantially in the form of a square which is a legal subdivision of the U.S. Public Land Surveys, which is a governmental quarter-quarter section or lot, and shall be located no closer than 330 feet to any boundary of such unit. Only those 40-acre spacing units committed to active secondary recovery projects shall be permitted more than four wells.

(2) If a well drilled as an oil well is completed as a gas well but does not conform to the applicable gas well location rules, the operator must apply for administrative approval for a non-standard location before the well can produce. The Director may set any such application for hearing.

C. Gas Wells Acreage And Well Location Requirements. Any wildcat well that is projected to be drilled as a gas well to a formation and in an area that in the opinion of the division may reasonably be presumed to be productive of gas rather than oil and each development well for a defined gas pool, unless otherwise provided in special pool orders, shall be spaced and located as follows:

(1) 640-Acre Spacing applies to any deep gas well in Rio Arriba, San Juan, Sandoval or McKinley County that is projected to be drilled to a gas producing formation older than the Dakota formation or is a development well within a gas pool created and defined by the division after June 1, 1997 in a formation older than the Dakota formation, which formation or pool is located within the surface outcrop of the Pictured Cliffs formation (i.e., the San Juan Basin). Such well shall be located on a spacing unit consisting of 640 contiguous surface acres, more or less, substantially in the form of a square which is a section and legal subdivision of the U.S. Public Land Surveys and shall be located no closer than: 1200 feet to any outer boundary of the spacing unit, 130 feet to any quarter section line, and 10 feet to any quarter-quarter section line or subdivision inner boundary.

(2) 320-Acre Spacing applies to any deep gas well in Lea, Chaves, Eddy or Roosevelt County, defined as a well that is projected to be drilled to a gas producing formation or is within a defined gas pool in the Wolfcamp or an older formation. Such well shall be located on a spacing unit consisting of 320 surface contiguous acres, more or less, comprising any two contiguous quarter sections of a single section that is a legal subdivision of the U.S. Public Land Surveys provided that:

(a) the initial well on a 320-acre unit is located no closer than 660 feet to the outer boundary of the quarter section on which the well is located and no closer than 10 feet to any quarter-quarter section line or subdivision inner boundary;

(b) only one infill well on a 320-acre unit shall be allowed provided that the well is located in the quarter section of the 320-acre unit not containing the initial well and is no closer than 660 feet to the outer boundary of the quarter section and no closer than 10 feet to any quarter-quarter section line or subdivision inner boundary; and

(c) the division-designated operator for the infill well is the same operator currently designated by the division for the initial well.

(3) 160-Acre Spacing applies to any other gas well not covered above. Such well shall be located in a spacing unit consisting of 160 surface contiguous acres, more or less, substantially in the form of a square which is a quarter section and a legal subdivision of the U.S. Public Land Surveys and shall be located no closer than 660 feet to any outer boundary of such unit and no closer than 10 feet to any quarter-quarter section or subdivision inner boundary.

D. Acreage Assignment

(1) Well Tests and Classification. It is the responsibility of the operator of any wildcat or development gas well to which more than 40 acres has been dedicated to conduct a potential test within 30 days following completion of the well and to file the test with the division within 10 days following completion of the test. (See Rule 401)

(a) The date of completion for a gas well is the date of the conclusion of active completion work on the well.

(b) If the division determines that a well should not be classified as a gas well, the division will reduce the acreage dedicated to the well to the standard acreage for an oil well.

Failure of the operator to file the test within the specified time will also subject the well to such acreage reduction.

(2) Non-Standard Spacing Units. Any well that does not have the required amount of acreage dedicated to it for the pool or formation in which it is completed may not be produced until a standard spacing unit for the well has been formed and dedicated or until a non-standard spacing unit has been approved.

(a) Division District Offices have the authority to approve non-standard spacing units without notice when the unorthodox size or shape is necessitated by a variation in the legal subdivision of the U. S. Public Land Surveys and/or consists of an entire governmental section and the non-standard spacing unit is not less than 70% or more than 130% of a standard spacing unit. The operator must obtain division approval of division Form C-102 showing the proposed non-standard spacing unit and the acreage contained therein.

(b) The Director may grant administrative approval to non-standard spacing units after notice and opportunity for hearing when an application has been filed and the unorthodox size or shape is necessitated by a variation in the legal subdivision of the U.S. Public Land Surveys or the following facts exist:

(i) the non-standard spacing unit consists of: (A) a single quarter-quarter section or lot or (B) quarter-quarter sections or lots joined by a common side; and

(ii) the non-standard spacing unit lies wholly within: a single quarter section if the well is completed in a pool or formation for which 40, 80, or 160 acres is the standard spacing unit size; a single half section if the well is completed in a pool or formation for which 320 acres is the standard spacing unit size; or a single section if the well is completed in a pool or formation for which 640 acres is the standard spacing unit size.

(c) Applications for administrative approval of non-standard spacing units pursuant to Subsection D, Paragraph (2), Subparagraph (b) of 19.15.3.104 NMAC shall be submitted to the division's Santa Fe Office and accompanied by: (i) a plat showing the spacing unit and an applicable standard spacing unit for that pool or formation, the proposed well dedications and all adjoining spacing units; (ii) a list of affected persons as defined in Rule 1207.A(2); and (iii) a statement discussing the reasons for the formation of the non-standard spacing unit.

(d) The applicant shall submit a statement attesting that the applicant, on or before the date the application was submitted to the division, sent notification to the affected persons by submitting a copy of the application, including a copy of the plat described in Subparagraph (c) above, by certified mail, return receipt requested, advising them that if they have an objection it must be filed in writing within 20 days from the date the division receives the application. The Director may approve the application upon receipt of waivers from all the notified persons or if no person has filed an objection within the 20-day period.

(e) The Director may set for hearing any application for administrative approval.

(3) Number of Wells Per Spacing Unit. Exceptions to the provisions of statewide rules or special pool orders concerning the number of wells allowed per spacing unit may be permitted by the Director only after notice and opportunity for hearing. Notice shall be given to those affected persons defined in Rule 1207.A.(2).

E. Forms - Form C-102 "Well Location and Acreage Dedication Plat" for any well shall designate the exact legal subdivision dedicated to the well. Form C-101 "Application for Permit to Drill, Deepen, or Plug Back" will not be approved without an acreage designation on Form C-102.

F. Unorthodox Locations

(1) Well locations for producing wells and/or injection wells that are unorthodox based on the requirements of Subsection B above and are necessary for an efficient production and injection pattern within a secondary recovery, tertiary recovery, or pressure maintenance project are hereby authorized, provided that the unorthodox location within the project is no closer than the required minimum distance to the outer boundary of the lease or unitized area, and no closer than 10 feet to any quarter-quarter section line or subdivision inner boundary. These locations shall only require such prior approvals as are necessary for an unorthodox location.

(2) The Director may grant an exception to the well location requirements of Subsections B and C above or special pool orders after notice and opportunity for hearing when the exception is necessary to prevent waste or protect correlative rights.

(3) Applications for administrative approval pursuant to Subsection F, Paragraph (2) above shall be submitted to the division's Santa Fe Office accompanied by (a) a plat showing the spacing unit, the proposed unorthodox well location and the adjoining spacing units and wells; (b) a list of affected persons as defined in Rule 1207.A(2); and (c) information evidencing the need for the exception. Notice shall be given as required in Rule 1207.A(2).

(4) The applicant shall submit a statement attesting that applicant, on or before the date that the application was submitted to the division, sent notification to the affected persons by submitting a copy of the application, including a copy of the plat described in Subsection F, Paragraph (3) above, by certified mail, return receipt requested, advising them that if they have an objection it must be filed in writing within 20 days from the date the division receives the application. The Director may approve the unorthodox location upon receipt of waivers from all the affected persons or if no affected person has filed an objection within the 20-day period.

(5) The Director may set for hearing any application for administrative approval of an unorthodox location.

(6) Whenever an unorthodox location is approved, the division may order any action necessary to offset any advantage of the unorthodox location.

G. Effect On Allowables

(1) If the drilling tract is within a prorated/allocated oil pool or is subsequently placed within such pool and the drilling tract consists of less than 39½ acres or more than 40½ acres, the top unit allowable for the well shall be increased or decreased in the proportion that the number of acres in the drilling tract bears to 40.

(2) If the drilling tract is within a prorated/allocated gas pool or is subsequently placed within such pool and the drilling tract consists of less than 158 acres or more than 162 acres in 160-acre pools, or less than 316 acres or more than 324 acres in 320-acre pools, or less than 632 acres or more than 648 acres in 640-acre pools, the top allowable for the well shall be decreased or increased in the proportion that the number of acres in the drilling tract bears to a standard spacing unit for the pool.

(3) In computing acreage under Paragraphs (1) and (2) above, less than ½ acre shall not be counted but ½ acre or more shall count as one acre.

(4) The provisions of Paragraphs (1) and (2) above shall apply only to wells completed after January 1, 1950.

H. Division-Initiated Exceptions - In order to prevent waste, the division may, after hearing, set different spacing requirements and require different acreage for drilling tracts in any defined oil or gas pool.

I. Pooling Or Communitization Of Small Oil Lots

(1) The division may approve the pooling or communitization of fractional oil lots of 20.49 acres or less with a contiguous oil spacing unit when the ownership is common and the tracts are part of the same lease with the same royalty interests if the following requirements are satisfied:

(a) Applications for administrative approval shall be submitted to the division's Santa Fe Office and accompanied by: (i) a plat showing the dimensions and acreage involved, the ownership of such acreage, the location of all existing and proposed wells and all adjoining spacing units; (ii) a list of affected persons as defined in Rule 1207.A(2); and (iii) a statement discussing the reasons for the pooling or communitization.

(b) The applicant shall submit a statement attesting that the applicant, on or before the date the application was submitted to the division, sent notification to the affected persons by submitting a copy of the application, including a copy of the plat described in (a) above, by certified mail, return receipt requested, advising them that if they have an objection it must be filed in writing within 20 days from the date the division receives the application. The Director may approve the application upon receipt of waivers from all the notified persons or if no person has filed an objection within the 20-day period.

(c) The Director may set for hearing any application for administrative approval.

(2) The division may consider the common ownership and common lease requirements met if the applicant furnishes with the application a copy of an executed pooling agreement communitizing the tracts involved.
[1-1-50…2-1-96; A, 6-30-97; A, 8-31-99; 19.15.3.104 NMAC - Rn, 19 NMAC 15.C.104, 11-15-01]

19.15.3.105 [RESERVED].
[1-1-50, 9-1-89…2-1-96; 19.15.3.105 NMAC - Rn, 19 NMAC 15.C.105, 11-15-01; Repealed, 5-28-04]

19.15.3.106 SEALING OFF STRATA:

A. During the drilling of any oil well, injection well or any other service well, all oil, gas, and water strata above the producing and/or injection horizon shall be sealed or separated in order to prevent their contents from passing into other strata.

B. All fresh waters and waters of present or probable value for domestic, commercial, or stock purposes shall be confined to their respective strata and shall be adequately protected by methods approved by the division. Special precautions by methods satisfactory to the division shall be taken in drilling and abandoning wells to guard against any loss of artesian water from the strata in which it occurs, and the contamination of artesian water by objectionable water, oil, or gas.

C. All water shall be shut off and excluded from the various oil- and gas-bearing strata which are penetrated. Water shut-offs shall ordinarily be made by cementing casing.
[1-1-50, 3-1-91…2-1-96; 19.15.3.106 NMAC - Rn, 19 NMAC 15.C.106, 11-15-01]

19.15.3.107 CASING AND TUBING REQUIREMENTS:

A. Any well drilled for oil or natural gas shall be equipped with such surface and intermediate casing strings and cement as may be necessary to effectively seal off and isolate all water-, oil-, and gas-bearing strata and other strata encountered in the well down to the casing point. In addition thereto, any well completed for the production of oil or natural gas shall be equipped with a string of properly cemented production casing at sufficient depth to ensure protection of oil- and gas-bearing strata encountered in the well, including the one(s) to be produced.

B. Sufficient cement shall be used on surface casing to fill the annular space behind the casing to the top of the hole, provided however, that authorized field personnel of the division may, at their discretion, allow exceptions to the foregoing requirement when known conditions in a given area render compliance impracticable.

C. All cementing shall be by pump and plug method unless some other method is expressly authorized by the division.

D. All cementing shall be with conventional-type hard-setting cements to which such additives (lighteners, densifiers, extenders, accelerators, retarders, etc.) have been added to suit conditions in the well.

E. Authorized field personnel of the division may, when conditions warrant, allow exceptions to the above paragraph and permit the use of oil-base casing packing material in lieu of hard-setting cements on intermediate and production casing strings; provided however, that when such materials are used on the intermediate casing string, conventional-type hard-setting cements shall be placed throughout all oil- and gas-bearing zones and throughout at least the lowermost 300 feet of the intermediate casing string. When such materials are used on the production casing string, conventional-type hard-setting cements shall be placed throughout all oil- and gas-bearing zones and shall extend upward a minimum of 500 feet above the uppermost perforation or, in the case of an open-hole completion, 500 feet above the production casing shoe.

F. All casing strings shall be tested and proved satisfactory as provided in Subsection I. below.

G. After cementing, but before commencing tests required in Subsection I. below, all casing strings shall stand cemented in accordance with Option 1 <u>or</u> 2 below. Regardless of which option is taken, the casing shall remain stationary and under pressure for at least eight hours after the cement has been placed. Casing shall be "under pressure" if some acceptable means of holding pressure is used or if one or more float valves are employed to hold the cement in place.

(1) Option 1 Allow all casing strings to stand cemented a minimum of eighteen (18) hours prior to commencing tests. Operators using this option shall report on Form C-103 the actual time the cement was in place before initiating tests.

(2) Option 2 (May be used in the counties of San Juan, Rio Arriba, McKinley, Sandoval, Lea, Eddy, Chaves, and Roosevelt only.) Allow all casing strings to stand cemented until the cement has reached a compressive strength of at least 500 pounds per square inch in the "zone of interest" before commencing tests, provided however, that no tests shall be commenced until the cement has been in place for at least eight (8) hours.

(a) The "zone of interest" for surface and intermediate casing strings shall be the bottom 20 percent of the casing string, but shall be no more than 1000 feet nor less than 300 feet of the bottom-part of the casing unless the casing is set at less than 300 feet. The "zone of interest" for production casing strings shall include the interval or intervals where immediate completion is contemplated.

(b) To determine that a minimum compressive strength of 500 pounds per square inch has been attained, operators shall use the typical performance data for the particular cement mix used in the well, at the minimum temperature indicated for the zone of interest by Figure 107-A, Temperature Gradient Curves. Typical performance data used shall be that data furnished by the cement manufacturer or by a competent materials testing agency, as determined in accordance with the latest edition of API Code RP 10 B "Recommended Practice for Testing Oil-Well Cements."

(See Temperature Gradient - Page 17A)

H. Operators using the compressive strength criterion (Option 2) shall report the following information on Form C-103:

(1) Volume of cement slurry (cubic feet) and brand name of cement and additives, percent additives used, and sequence of placement if more than one type cement slurry is used.

(2) Approximate temperature of cement slurry when mixed.

(3) Estimated minimum formation temperature in zone of interest.

(4) Estimate of cement strength at time of casing test.

(5) Actual time cement in place prior to starting test.

I. All casing strings except conductor pipe shall be tested after cementing and before commencing any other operations on the well. Form C-103 shall be filed for each casing string reporting the grade and weight of pipe used. In the case of combination strings utilizing pipe of varied grades or weights, the footage of each grade and weight used shall be reported. The results of the casing test, including actual pressure held on pipe and the pressure drop observed shall also be reported on the same Form C-103.

(1) Casing strings in wells drilled with rotary tools shall be pressure tested. Minimum casing test pressure shall be approximately one-third of the manufacturer's rated internal yield pressure except that the test pressure shall not be less than 600 pounds per square inch and need not be greater than 1500 pounds per square inch. In cases where combination strings are involved, the above test pressure shall apply to the lowest pressure rated casing used. Test pressures shall be applied for a period of 30 minutes. If a drop of more than 10 percent of the test pressure should occur, the casing shall be considered defective and corrective measures shall be applied.

(2) Casing strings in wells drilled with cable tools may be tested as outlined in Subsection I, Paragraph (1) above, or by bailing the well dry in which case the hole must remain satisfactorily dry for a period of at least one (1) hour before commencing any further operations on the well.

J. Well Tubing Requirements

(1) All flowing oil wells equipped with casing larger in size than 2 7/8-inch OD shall be tubed.

(2) All gas wells equipped with casing larger in size than 3 ½-inch OD shall be tubed.

(3) Tubing shall be set as near the bottom as practical and tubing perforations shall not be more than 250 feet above top of pay zone.

(4) The supervisor of the appropriate division district office, upon application, may grant exceptions to these requirements, provided waste will not be caused.

(5) The supervisor may request that an application be reviewed by the Director. The operator shall

submit information and give notice as requested by the Director. Unprotested applications may be approved after 20 days of receipt of the application and supporting information. If the application is protested, or the Director so decides, the application shall be set for hearing.

K. Repealed.

[1-1-50, 5-5-58, 6-26-59, 2-29-64, 2-1-96, 2-26-99; 19.15.3.107 NMAC - Rn, 19 NMAC 15.C.107, 11-15-01]

19.15.3.108 DEFECTIVE CASING OR CEMENTING:

If any well appears to have a defective casing program or faultily cemented or corroded casing which will permit or may create underground waste or contamination of fresh waters, the operator shall give written notice to the division within five (5) working days and proceed with diligence to use the appropriate method and means to eliminate such hazard. If such hazard of waste or contamination of fresh water cannot be eliminated, the well shall be properly plugged and abandoned.

[1-1-50...2-1-96; 19.15.3.108 NMAC - Rn, 19 NMAC 15.C.108, 11-15-01]

19.15.3.109 BLOWOUT PREVENTION: (See Section 114, Subsection B of 19.15.3 NMAC also)

A. Blowout preventers shall be installed and maintained in good working order on all drilling rigs operating in areas of known high pressures at or above the projected depth of the well and in all areas where pressures which will be encountered are unknown, and on all workover rigs working on wells in which high pressures are known to exist.

B. Blowout preventers shall be installed and maintained in good working order on all drilling rigs and workover rigs operating within the corporate limits of any city, town, or village, or within 1320 feet of habitation, school, or church, wherever located.

C. All operators, when filing Form C-101, Application for Permit to Drill, Deepen, or Plug Back, or Form C-103, Sundry Notices, for any operation requiring blowout prevention equipment in accordance with Subsections A and B above, shall submit a proposed blowout prevention program for the well. The program as submitted may be modified by the district supervisor if, in his judgement, such modification is necessary.

[10-22-74...2-1-96; 19.15.3.109 NMAC - Rn, 19 NMAC 15.C.109, 11-15-01]

19.15.3.110 PULLING OUTSIDE STRINGS OF CASING:

In pulling outside strings of casing from any oil or gas well, the space outside the casing left in the hole shall be kept and left full of mud-laden fluid or cement of adequate specific gravity to seal off all fresh and salt water strata and any strata bearing oil or gas not producing.

[1-1-50...2-1-96; 19.15.3.110 NMAC - Rn, 19 NMAC 15.C.110, 11-15-01]

19.15.3.111 DEVIATION TESTS AND DIRECTIONAL WELLS:

A. Definitions - the following definitions shall apply to Section 111 of 19.15.3 NMAC only:

(1) Azimuth - the deviation in the horizontal plane of a wellbore expressed in terms of compass degrees.

(2) Deviated Well - any wellbore which is intentionally deviated from vertical but not with an intentional azimuth. Any deviated well is subject to Section 111, Subsection B of 19.15.3 NMAC.

(3) Directional Well - a wellbore which is intentionally deviated from vertical with an intentional azimuth. Any directional well is subject to Section 111, Subsection C of 19.15.3 NMAC.

(4) Kick-off Point - the point at which the wellbore is intentionally deviated from vertical.

(5) Lateral - any portion of a wellbore past the point where the wellbore has been intentionally departed from the vertical.

(6) Penetration Point - the point where the wellbore penetrates the top of the pool from which it is intended to produce.

(7) Producing Area - the area that lies within a window formed by plotting the measured distance from the North, South, East and West boundaries of a project area, inside of which a vertical wellbore can be drilled and produced in conformity with the setback requirements from the outer boundary of a standard spacing unit for the

applicable pool(s).

(8) Producing Interval - that portion of the wellbore drilled inside the vertical limits of a pool, between its penetration point and its terminus.

(9) Project Area - an area designated on Form C-102 that is enclosed by the outer boundaries of a spacing unit, a combination of complete spacing units, or an approved secondary, secondary, tertiary or pressure maintenance project.

(10) Project Well - any well drilled, completed, produced or injected into as either a vertical well, deviated well or directional well.

(11) Spacing Unit - the acreage that is dedicated or a well in accordance with Rule 104. Included in this definition is a "unit of proration for oil or gas" as defined by the division and all non-standard such units previously approved by the division.

(12) Terminus - the farthest point attained along the wellbore.

(13) Unorthodox - any part of the producing interval which is located outside of the producing area.

(14) Vertical Well - a well that does not have an intentional departure or course deviation from the vertical.

(15) Wellbore - the interior surface of a cased or open hole through which drilling, production, or injection operations are conducted.

B. Deviated Wellbores

(1) Deviation Tests Required. Any vertical or deviated well which is drilled or deepened shall be tested at reasonably frequent intervals to determine the deviation from the vertical. Such tests shall be made at least once each 500 feet or at the first bit change succeeding 500 feet. A tabulation of all deviation tests run, sworn to and notarized, shall be filed with Form C-104, Request for Allowable and Authorization to Transport Oil and Natural Gas.

(2) Excessive Deviation. When the deviation averages more than five degrees in any 500-foot interval, the operator shall include the calculations of the maximum possible horizontal displacement of the hole. When the maximum possible horizontal displacement exceeds the distance to the nearest outer boundary line of the appropriate unit, the operator shall run a directional survey to establish the location of the producing interval(s).

(3) Unorthodox Locations. If the results of the directional survey indicate that the producing interval is more than 50 feet from the approved surface location and closer than the minimum setback requirements to the outer boundaries of the applicable unit, then the well shall be considered unorthodox. To obtain authority to produce such well, the operator shall file an application with the Division director, copy to the appropriate division district office, and shall otherwise follow the normal process outlined in Section 104, Subsection F, Paragraph (3) of 19.15.3 NMAC to obtain approval of the unorthodox location.

(4) Directional Survey Requirements. Upon request from the Division director, any vertical or deviated well shall be directionally surveyed. The appropriate division district office shall be notified of the approximate time any directional surveys are to be conducted. All directional surveys run on any well in any manner for any reason must be filed with the division upon completion of the well. The division shall not assign an allowable to the well until all such directional surveys have been filed.

C. Directional Wellbores

(1) Directional Drilling Within a Project Area. A permit to directionally drill a wellbore may be granted by the appropriate division district office if the producing interval is entirely within the producing area or at an unorthodox location previously approved by the division. Additionally, if the project area consists of a combination of drilling units and includes any State or Federal acreage, a copy of the OCD Form C-102 shall be sent to the State Land Office or the Bureau of Land Management.

(2) Unorthodox Wellbores. If all or part of the producing interval of any directional wellbore is projected to be outside of the producing area, the wellbore shall be considered unorthodox. To obtain approval for such wellbore, the applicant shall file a written application in duplicate with the Division director, copy to the appropriate division district office, and shall otherwise follow the normal process outlined in Section 104, Subsection F, Paragraph (3) of 19.15.3 NMAC.

(3) Allowables for Project Areas With Multiple Proration Units. The maximum allowable assigned to

the project area within a prorated pool shall be based upon the number of standard spacing units (or approved non-standard spacing units) that are developed or traversed by the producing interval of the directional wellbore or wellbores. Such maximum allowable shall be applicable to all production from the project area, including any vertical wellbores on standard spacing units inside the project area.

(4) Directional Surveys Required. A directional survey shall be required on each well drilled under the provisions of this section. The appropriate division district office shall be notified of the approximate time all directional surveys are to be conducted. All directional surveys run on any well in any manner for any reason must be filed with the division upon completion of the well. The division shall not assign an allowable to the well until all such directional surveys have been filed. If the directional survey indicates that any part of the producing interval is outside of the producing area, or, in the case of an approved unorthodox location, less than the approved setback requirements from the outer boundary of the applicable unit, then the operator shall file an application with the Division director, copy to the appropriate division district office, and shall otherwise follow the normal process outlined in Section 104, Subsection F, Paragraph (3) of 19.15.3 NMAC to obtain approval of the unorthodox location.

(5) Re-entry of Vertical or Deviated Wellbores for Directional Drilling Projects. These wellbores shall be considered orthodox provided the surface location is orthodox and the location of producing interval is within the tolerance allowed for deviated wellbores under Section 111, Subsection B, Paragraph (3) of 19.15.3 NMAC.

D. Additional Matters

(1) Directional surveys required under the provisions of Section 111 of 19.15.3 NMAC shall have shot points no more than 200 feet apart and shall be run by competent surveying companies that are approved by the Division director. Exceptions to the minimum shot point spacing will be allowed provided the accuracy of the survey is still within acceptable limits.

(2) The Division director, may, at his discretion, set any application for administrative approval whereby the operator shall submit appropriate information and give notice as requested by the Division director. Unprotested applications may be approved administratively within 20 days of receipt of the application and supporting information. If the application is protested, or the Division director decides that a public hearing is appropriate, the application may be set for public hearing.

(3) Permission to deviate or directionally drill any wellbore for any reason or in any manner not provided for in Section 111 of 19.15.3 NMAC shall be granted only after notice and opportunity for hearing.

E. Reserved.

(1) Reserved.

(2) Reserved.

F. Reserved.

(1) Reserved.

(2) Reserved.

(3) Reserved.

[1-1-50; 8-28-62; 3-2-84; 7-26-95; 2-1-96; A, 7-31-97; 19.15.3.111 NMAC - Rn, 19 NMAC 15.C.111, 11-15-01]

19.15.3.112 [MULTIPLE COMPLETIONS; BRADENHEAD GAS WELLS]

A. Multiple Completions

(1) Filing. Operators intending to multiple complete must file Form C-101 and/or C-103 for approval before completing and C-104 after completing along with any information required by the form instructions.

(2) Operation and Testing

(a) Wells shall be completed and produced so that no commingling of hydrocarbons from separate pools occurs.

(b) The operator shall commence a segregation and/or packer leakage test within 20 days after the multiple completion. Segregation tests and/or packer leakage tests shall also be made any time the packer is disturbed. The operator shall also conduct any other tests and determinations required by the division. The appropriate district office shall be notified 48 hours in advance of tests so the district office may schedule personnel to witness the tests. Offset operators may witness such tests and shall advise the operator in writing if they desire to be notified of the tests. Test results shall be filed with the division within 20 days of test completion. In the event a segregation and/or packer leakage test indicates communication between separate pools, the operator shall immediately notify the division and commence corrective action on the well.

(c) Wells shall be equipped so that (i) reservoir pressure may be determined for each of the separate pools, and (ii) meters may be installed so that the gas and/or oil produced from each of the separate pools may be accurately measured.

(d) No multiple completion shall produce in a manner unnecessarily wasting reservoir energy.

(e) The division may require the proper plugging of any zone of a multiple-completed well if the plugging appears necessary to prevent waste, protect correlative rights or protect groundwater, public health or the environment.

B. Bradenhead Gas Wells

(1) The production of gas from a bradenhead gas well may be permitted only by order of the division upon hearing, except as noted by the provisions of Subsection C of 19.15.3.112 NMAC.

(2) The application for such hearings shall be submitted in triplicate and shall include an exhibit showing the location of all wells on applicant's lease and all offset wells on offset leases, together with a diagrammatic sketch showing the casing program, formation tops, estimated top of cement on each casing string run and any other pertinent data, including drill stem tests.

(3) The Division director shall have authority to grant an exception to the requirements of paragraph A. above without notice and hearing where application has been filed in due form, and when the lowermost producing zone involved in the completion is an oil or gas producing zone within the defined limits of an oil or gas pool and the producing zone to be produced through the bradenhead connection is a gas producing zone within the defined limits of a gas pool.

(4) Applicants shall furnish all operators who offset the lease upon which the subject well is located a copy of the application to the division, and applicant shall include with his application a written stipulation that all offset operators have been properly notified. The Division director shall wait at least 10 days before approving the production of gas from the bradenhead gas well, and shall approve such production only in the absence of objection from any offset operator. In the event an operator objects to the completion the Division director shall consider the matter only after proper notice and hearing.

(5) The division may waive the 10-day waiting period requirement if the applicant furnishes the division with the written consent to the production of gas from the bradenhead connection by all offset operators involved.

(6) Section 112-2 of 19.15.3 NMAC shall apply only to wells hereinafter completed as bradenhead gas wells.

(7) (1), (2), (3), (4) Repealed.

(8) (1); (1).(a); (1).(b); (2) Repealed.

(9) (1), (2) Repealed.

(10) (1).(a), (b), (c), (d), (e), (f), (g) Reserved.

[4-3-53; 7-3-58…2-1-82; 2-1-96; 19.15.3.112 NMAC - Rn, 19 NMAC 15.C.112-A and 112-B, 11-15-01]

19.15.3.113 SHOOTING AND CHEMICAL TREATMENT OF WELLS:
If injury results to the producing formation, injection interval, casing or casing seat from shooting, fracturing, or treating a well and which injury may create underground waste or contamination of fresh water, the operator shall give written notice to the division within five (5) working days and proceed with diligence to use the appropriate method and means for rectifying such damage. If shooting, fracturing, or chemical treating results in irreparable injury to the well the division may require the operator to properly plug and abandon the well.
[1-1-50...2-1-96; 19.15.3.113 NMAC - Rn, 19 NMAC 15.C.113, 11-15-01]

19.15.3.114 SAFETY REGULATIONS:

A. All oil wells shall be cleaned into a pit or tank, not less than 40 feet from the derrick floor and 150 feet from any fire hazard. All flowing oil wells must be produced through an oil and gas separator of ample capacity and in good working order. No boiler or portable electric lighting generator shall be placed or remain nearer than 150 feet to any producing well or oil tank. Any rubbish or debris that might constitute a fire hazard shall be removed to a distance of at least 150 feet from the vicinity of wells and tanks. All waste shall be burned or disposed of in such manner as to avoid creating a fire hazard.

B. When coming out of the hole with drill pipe, drilling fluid shall be circulated until equalized and subsequently drilling fluid level shall be maintained at a height sufficient to control subsurface pressures. During course of drilling blowout preventers shall be tested at least once each 24-hour period.

[1-1-50...2-1-96; 19.15.3.114 NMAC - Rn, 19 NMAC 15.C.114, 11-15-01]

19.15.3.115 WELL AND LEASE EQUIPMENT:

A. Christmas tree fittings or wellhead connections shall be installed and maintained in first class condition so that all necessary pressure tests may easily be made on flowing wells. On oil wells the Christmas tree fittings shall have a test pressure rating at least equivalent to the calculated or known pressure in the reservoir from which production is expected. On gas wells the Christmas tree fittings shall have a test pressure equivalent to at least 150 percent of the calculated or known pressure in the reservoir from which production is expected.

B. Valves shall be installed and maintained in good working order to permit pressures to be obtained on both casing and tubing. Each flowing well shall be equipped to control properly the flowing of each well, and in case of an oil well, shall be produced into an oil and gas separator of a type generally used in the industry.

[1-1-50...2-1-96; 19.15.3.115 NMAC - Rn, 19 NMAC 15.C.115, 11-15-01]

19.15.3.116 RELEASE NOTIFICATION AND CORRECTIVE ACTION:

A. Notification

(1) The division shall be notified of any unauthorized release occurring during the drilling, producing, storing, disposing, injecting, transporting, servicing or processing of crude oil, natural gases, produced water, condensate or oil field waste including Regulated NORM, or other oil field related chemicals, contaminants or mixture thereof, in the State of New Mexico in accordance with the requirements of Section 116 of 19.15.3 NMAC.

(2) The division shall be notified in accordance with Section 116 of 19.15.3 NMAC with respect to any release from any facility of oil or other water contaminant, in such quantity as may with reasonable probability be detrimental to water or cause an exceedance of the standards in Section 19, Subsection B, Paragraphs (1) and (2) or (3) of 19.15.1 NMAC.

B. Reporting Requirements. Notification of the above releases shall be made by the person operating or controlling either the release or the location of the release in accordance with the following requirements:

(1) A Major Release shall be reported by giving both immediate verbal notice and timely written notice pursuant to Subsection C, Paragraphs (1) and (2) of 19.15.3.116 NMAC. A Major Release is:

(a) an unauthorized release of a volume, excluding natural gases, in excess of 25 barrels;

(b) an unauthorized release of any volume which:

(i) results in a fire;

(ii) will reach a water course;

(iii) may with reasonable probability endanger public health; or

(iv) results in substantial damage to property or the environment;

(c) an unauthorized release of natural gases in excess of 500 mcf; or

(d) a release of any volume which may with reasonable probability be detrimental to water or cause an exceedance of the standards in Section 19, Subsection B, Paragraphs (1) and (2) or (3) of 19.15.1 NMAC.

(2) A Minor Release shall be reported by giving timely written notice pursuant to Subsection C, Paragraph (2) of 19.15.3.116 NMAC. A Minor Release is an unauthorized release of a volume, greater than 5 barrels but not more than 25 barrels; or greater than 50 mcf but less than 500 mcf of natural gases.

C. Contents Of Notification

(1) Immediate verbal notification required pursuant to Subsection B of 19.15.3.116 NMAC shall be reported within twenty-four (24) hours of discovery to the division district office for the area within which the

release takes place. In addition, immediate verbal notification pursuant to Subsection B, Paragraph (1), Subparagraph (d) of 19.15.3.116 NMAC shall be reported to the division's Environmental Bureau Chief. This notification shall provide the information required on division Form C-141.

(2) Timely written notification is required to be reported pursuant to Subsection B of 19.15.3.116 NMAC within fifteen (15) days to the division district office for the area within which the release takes place by completing and filing division Form C-141. In addition, timely written notification required pursuant to Subsection B, Paragraph (1), Subparagraph (d) of 19.15.3.116 NMAC shall also be reported to the division's Environmental Bureau Chief within fifteen (15) days after the release is discovered. The written notification shall verify the prior verbal notification and provide any appropriate additions or corrections to the information contained in the prior verbal notification.

D. Corrective Action. The responsible person must complete division approved corrective action for releases which endanger public health or the environment. Releases will be addressed in accordance with a remediation plan submitted to and approved by the division or with an abatement plan submitted in accordance with Section 19 of 19.15.1 NMAC.

[1-1-50…5-22-73…2-1-96; A, 3-15-97; 19.15.3.116 NMAC - Rn, 19 NMAC 15.C.116, 11-15-01]

19.15.3.117 WELL LOG, COMPLETION AND WORKOVER REPORTS:
Within 20 days after the completion of a well drilled for oil or gas, or the recompletion of a well into a different common source of supply, a completion report shall be filed with the division on Form C-105. For the purpose of Section 117 of 19.15.3 NMAC, any hole drilled or cored below fresh water or which penetrates oil- or gas-bearing formations or which is drilled by an "owner" as defined herein shall be presumed to be a well drilled for oil or gas.

[1-1-50...2-1-96; 19.15.3.117 NMAC - Rn, 19 NMAC 15.C.117, 11-15-01]

19.15.3.118 HYDROGEN SULFIDE GAS (HYDROGEN SULFIDE):

A. Applicability. This section applies to any person, operator or facility subject to the jurisdiction of the division, including, but not limited to, any person, operator or facility engaged in drilling, stimulating, injecting into, completing, working over or producing any oil, natural gas or carbon dioxide well or any person, operator or facility engaged in gathering, transporting, storing, processing or refining of crude oil, natural gas or carbon dioxide (referred to herein as "person, operator or facility" or "well, facility or operation"). This section shall not act to exempt or otherwise excuse surface waste management facilities permitted by the division pursuant to 19.15.9.711 NMAC from more stringent conditions on the handling of hydrogen sulfide required of such facilities by 19.15.9.711 NMAC or more stringent conditions in permits issued thereunder, nor shall such facilities be exempt or otherwise excused from the requirements set forth in this section by virtue of permitting under 19.15.9.711 NMAC.

B. Definitions (specific to this section).

(1) ANSI. The acronym "ANSI" means the American national standards institute.

(2) API. The acronym "API" means the American petroleum institute.

(3) Area of Exposure. The phrase "area of exposure" means the area within a circle constructed with a point of escape at its center and the radius of exposure as its radius.

(4) ASTM. The acronym "ASTM" means the American society for testing and materials.

(5) Dispersion Technique. A "dispersion technique" is a mathematical representation of the physical and chemical transportation characteristics, dilution characteristics and transformation characteristics of hydrogen sulfide gas in the atmosphere.

(6) Escape Rate. The "escape rate" is the maximum volume (Q) that is used to designate the possible rate of escape of a gaseous mixture containing hydrogen sulfide, as set forth herein.

(a) For existing gas facilities or operations, the escape rate shall be calculated using the maximum daily rate of the gaseous mixture produced or handled or the best estimate thereof. For an existing gas well, the escape rate shall be calculated using the current daily absolute open flow rate against atmospheric pressure or the best estimate of that rate.

(b) For new gas operations or facilities, the escape rate shall be calculated as the maximum anticipated flow rate through the system. For a new gas well, the escape rate shall be calculated using the maximum open-flow rate of offset wells in the pool or reservoir, or the pool or reservoir average of maximum open-flow rates.

(c) For existing oil wells, the escape rate shall be calculated by multiplying the producing gas/oil ratio by the maximum daily production rate or the best estimate thereof.

(d) For new oil wells, the escape rate shall be calculated by multiplying the producing gas/oil ratio by the maximum daily production rate of offset wells in the pool or reservoir, or the pool or reservoir average of the producing gas/oil ratio multiplied by the maximum daily production rate.

(e) For facilities or operations not mentioned, the escape rate shall be calculated using the actual flow of the gaseous mixture through the system or the best estimate thereof.

(7) GPA. The acronym "GPA" means the gas processors association.

(8) LEPC. The acronym "LEPC" means the local emergency planning committee established pursuant to the emergency planning and community right-to-know act, 42 U.S.C. Section 11001.

(9) NACE. The acronym "NACE" refers to the national association of corrosion engineers.

(10) PPM. The acronym "ppm" means "parts per million" by volume.

(11) Potentially Hazardous Volume means the volume of hydrogen sulfide gas of such concentration that:

(a) the 100-ppm radius of exposure includes any public area;

(b) the 500-ppm radius of exposure includes any public road; or

(c) the 100-ppm radius of exposure exceeds 3,000 feet.

(12) Public Area. A "public area" is any building or structure that is not associated with the well, facility or operation for which the radius of exposure is being calculated and that is used as a dwelling, office, place of business, church, school, hospital, or government building, or any portion of a park, city, town, village or designated school bus stop or other similar area where members of the public may reasonably be expected to be present.

(13) Public Road. A "public road" is any federal, state, municipal or county road or highway.

(14) Radius of Exposure. The radius of exposure is that radius constructed with the point of escape as its starting point and its length calculated using the following Pasquill-Gifford derived equation, or by such other method as may be approved by the division:

(a) For determining the 100-ppm radius of exposure: $X= [(1.589)(\text{hydrogen sulfide concentration})(Q)]^{(0.6258)}$, where "X" is the radius of exposure in feet, the "hydrogen sulfide concentration" is the decimal equivalent of the mole or volume fraction of hydrogen sulfide in the gaseous mixture, and "Q" is the escape rate expressed in cubic feet per day (corrected for standard conditions of 14.73 psia and 60 degrees F).

(b) For determining the 500-ppm radius of exposure: $X=[(0.4546)(\text{hydrogen sulfide concentration})(Q)]^{(0.6258)}$, where "X" is the radius of exposure in feet, the "hydrogen sulfide concentration" is the decimal equivalent of the mole or volume fraction of hydrogen sulfide in the gaseous mixture, and "Q" is the escape rate expressed in cubic feet per day (corrected for standard conditions of 14.73 psia and 60 degrees F).

(c) For a well being drilled, completed, recompleted, worked over or serviced in an area where insufficient data exists to calculate a radius of exposure but where hydrogen sulfide could reasonably be expected to be present in concentrations in excess of 100 ppm in the gaseous mixture, a 100-ppm radius of exposure equal to 3,000 feet shall be assumed.

C. Regulatory Threshold.

(1) Determination of Hydrogen Sulfide Concentration.

(a) Each person, operator or facility shall determine the hydrogen sulfide concentration in the gaseous mixture within each of its wells, facilities or operations either by testing (using a sample from each well, facility or operation), testing a representative sample, or using process knowledge in lieu of testing. If a representative sample or process knowledge is used, the concentration derived from the representative sample or process knowledge must be reasonably representative of the hydrogen sulfide concentration within the well, facility or operation.

(b) The tests used to make the determination referred to in the previous subparagraph shall be conducted in accordance with applicable ASTM or GPA standards or by another method approved by the division.

(c) If a test was conducted prior to the effective date of this section that otherwise meets the requirements of the previous subparagraphs, new testing shall not be required.

(d) If any change or alteration may materially increase the concentration of hydrogen sulfide in a well, facility or operation, a new determination shall be required in accordance with this section.

(2) Concentrations Determined to be Below 100 ppm. If the concentration of hydrogen sulfide in a given well, facility or operation is less than 100 ppm, no further actions shall be required pursuant to this section.

(3) Concentrations Determined to be Above 100 ppm.

(a) If the concentration of hydrogen sulfide in a given well, facility or operation is determined to be 100 ppm or greater, then the person, operator or facility must calculate the radius of exposure and comply with applicable requirements of this section.

(b) If calculation of the radius of exposure reveals that a potentially hazardous volume is present, the results of the determination of the hydrogen sulfide concentration and the calculation of the radius of exposure shall be provided to the division. For a well, facility or operation existing on the effective date of this section, the determination, calculation and submission required herein shall be accomplished within 180 days of the effective date of this section; for any well, facility or operation that commences operations after the effective date of this section, the determination, calculation and submission required herein shall be accomplished before operations begin.

(4) Recalculation. The person, operator or facility shall calculate the radius of exposure if the hydrogen sulfide concentration in a well, facility or operation increases to 100 ppm or greater. The person, operator or facility shall also recalculate the radius of exposure if the actual volume fraction of hydrogen sulfide increases by a factor of twenty-five percent in a well, facility or operation that previously had a hydrogen sulfide concentration of 100 ppm or greater. If calculation or recalculation of the radius of exposure reveals that a potentially hazardous volume is present, the results shall be provided to the division within sixty (60) days.

D. Hydrogen Sulfide Contingency Plan.

(1) When Required. If a well, facility or operation involves a potentially hazardous volume of hydrogen sulfide, a hydrogen sulfide contingency plan that will be used to alert and protect the public must be developed in accordance with the following paragraphs.

(2) Plan Contents.

(a) API Guidelines. The hydrogen sulfide contingency plan shall be developed with due consideration of paragraph 7.6 of the guidelines published by the API in its publication entitled “Recommended Practices for Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide," RP-55, most recent edition, or with due consideration to another standard approved by the division.

(b) Required Contents. The hydrogen sulfide contingency plan shall contain, but shall not be limited to, information on the following subjects, as appropriate to the well, facility or operation to which it applies:

(i) Emergency procedures. The hydrogen sulfide contingency plan shall contain information on emergency procedures to be followed in the event of a release and shall include, at a minimum, information concerning the responsibilities and duties of personnel during the emergency, an immediate action plan as described in the API document referenced in the previous subsubparagraph, and telephone numbers of emergency responders, public agencies, local government and other appropriate public authorities. The plan shall also include the locations of potentially affected public areas and public roads and shall describe proposed evacuation routes, locations of any road blocks and procedures for notifying the public, either through direct telephone notification using telephone number lists or by means of mass notification and reaction plans. The plan shall include information on the availability and location of necessary safety equipment and supplies.

(ii) Characteristics of hydrogen sulfide and sulfur dioxide. The hydrogen sulfide contingency plan shall include a discussion of the characteristics of hydrogen sulfide and sulfur dioxide.

(iii) Maps and drawings. The hydrogen sulfide contingency plan shall include maps and drawings that depict the area of exposure and public areas and public roads within the area of exposure.

(iv) Training and Drills. The hydrogen sulfide contingency plan shall provide for training and drills, including training in the responsibilities and duties of essential personnel and periodic on-site or classroom drills or exercises that simulate a release, and shall describe how the training, drills and attendance will be documented. The hydrogen sulfide contingency plan shall also provide for training of residents as appropriate on the proper protective measures to be taken in the event of a release, and shall provide for briefing of public officials on issues such as evacuation or shelter-in-place plans.

(v) Coordination with State Emergency Plans. The hydrogen sulfide contingency plan shall describe how emergency response actions under the plan will be coordinated with the division and with the New Mexico state police consistent with the New Mexico hazardous materials emergency response plan (HMER).

(vi) Activation Levels. The hydrogen sulfide contingency plan shall include the activation level and a description of events that could lead to a release of hydrogen sulfide sufficient to create a concentration in excess of the activation level.

(3) Plan Activation. The hydrogen sulfide contingency plan shall be activated when a release creates a concentration of hydrogen sulfide greater than the activation level set forth in the hydrogen sulfide contingency plan. At a minimum, the plan must be activated whenever a release may create a concentration of hydrogen sulfide of more than 100 ppm in any public area, 500 ppm at any public road or 100 ppm 3,000 feet from the site of release.

(4) Submission.

(a) Where Submitted. The hydrogen sulfide contingency plan shall be submitted to the division.

(b) When Submitted. A hydrogen sulfide contingency plan for a well, facility or operation existing on the effective date of this section shall be submitted within one year of the effective date of this section. A hydrogen sulfide contingency plan for a new well, facility or operation shall be submitted before operations commence. The hydrogen sulfide contingency plan for a drilling, completion, workover or well servicing operation must be on file with the division before operations commence and may be submitted separately or along with the application for permit to drill (APD) or may be on file from a previous submission. A hydrogen sulfide contingency plan shall also be submitted within 180 days after the person, operator or facility becomes aware or should have become aware that a public area or public road is established that creates a potentially hazardous volume where none previously existed.

(c) Electronic Submission. Any filer who operates more than one hundred wells or who operates a crude oil pump station, compressor station, refinery or gas plant must submit each hydrogen sulfide contingency plan in electronic format. The hydrogen sulfide contingency plan may be submitted through electronic mail, through an Internet filing or by delivering electronic media to the division, so long as the electronic submission is compatible with the division's systems.

(5) Failure to Submit Plan. Failure to submit a hydrogen sulfide contingency plan when required may result in denial of an application for permit to drill, cancellation of an allowable for the subject well or other enforcement action appropriate to the well, facility or operation.

(6) Review, Amendment. The person, operator or facility shall review the hydrogen sulfide contingency plan any time a subject addressed in the plan materially changes and make appropriate amendments. If the division determines that a hydrogen sulfide contingency plan is inadequate to protect public safety, the division may require the person, operator or facility to add provisions to the plan or amend the plan as necessary to protect public safety.

(7) Retention and Inspection. The hydrogen sulfide contingency plan shall be reasonably accessible in the event of a release, maintained on file at all times, and available for inspection by the division.

(8) Annual Inventory of Contingency Plans. On an annual basis, each person, operator or facility required to prepare one or more hydrogen sulfide contingency plans pursuant to this section shall file with the appropriate local emergency planning committee and the state emergency response commission an inventory of the wells, facilities and operations for which plans are on file with the division and the name, address and telephone number of a point of contact.

(9) Plans Required by Other Jurisdictions. A hydrogen sulfide contingency plan required by the Bureau of Land Management or other jurisdiction that meets the requirements of this subsection may be submitted to the division in satisfaction of this subsection.

E. Signage, Markers. For each well, facility or operation involving a concentration of hydrogen sulfide of 100 ppm or greater, signs and/or markers shall be installed and maintained. Each sign or marker shall conform with the current ANSI standard Z535.1-2002 (“Safety Color Code”), or some other standard approved by the division, shall be readily readable, and shall contain the words "poison gas" and other information sufficient to warn the public that a potential danger exists. Signs or markers shall be prominently posted at locations, including but not limited to entrance points and road crossings, sufficient to alert the public that a potential danger exists. Signs and/or markers that conform with this subsection shall be installed no later than one year from the effective date of this section.

F. Protection from Hydrogen Sulfide During Drilling, Completion, Workover, and Well Servicing Operations.

(1) API Standards. All drilling, completion, workover and well servicing operations involving a hydrogen sulfide concentration of 100 ppm or greater shall be conducted with due consideration to the guidelines published by the API entitled “Recommended Practice for Oil and Gas Well Servicing and Workover Operations Involving Hydrogen Sulfide," RP-68, and “Recommended Practices for Drilling and Well Servicing Operations Involving Wells Containing Hydrogen Sulfide,” RP-49, most recent editions, or some other standard approved by the division.

(2) Detection and Monitoring Equipment. Drilling, completion, workover and well servicing operations involving a hydrogen sulfide concentration of 100 ppm or greater shall include hydrogen sulfide detection and monitoring equipment as follows:

(a) Each drilling and completion site shall have an accurate and precise hydrogen sulfide detection and monitoring system that will automatically activate visible and audible alarms when the ambient air concentration of hydrogen sulfide reaches a predetermined value set by the operator, not to exceed 20 ppm. There shall be a sensing point located at the shale shaker, rig floor and bell nipple for a drilling site and the cellar, rig floor and circulating tanks or shale shaker for a completion site.

(b) For workover and well servicing operations, one operational sensing point shall be located as close to the well bore as practical. Additional sensing points may be necessary for large or long-term operations.

(c) Hydrogen sulfide detection and monitoring equipment must be provided and must be made operational during drilling when drilling is within 500 feet of a zone anticipated to contain hydrogen sulfide and continuously thereafter through all subsequent drilling.

(3) Wind Indicators. All drilling, completion, workover and well servicing operations involving a hydrogen sulfide concentration of 100 ppm or greater shall include wind indicators. Equipment to indicate wind direction shall be present and visible at all times. At least two devices to indicate wind direction shall be installed at separate elevations and visible from all principal working areas at all times. When a sustained concentration of hydrogen sulfide is detected in excess of 20 ppm at any detection point, red flags shall be displayed.

(4) Flare System. For drilling and completion operations in an area where it is reasonably expected that a potentially hazardous volume of hydrogen sulfide will be encountered, the person, operator or facility shall install a flare system to safely gather and burn hydrogen-sulfide-bearing gas. Flare outlets shall be located at least 150 feet from the well bore. Flare lines shall be as straight as practical. The flare system shall be equipped with a suitable and safe means of ignition. Where noncombustible gas is to be flared, the system shall provide supplemental fuel to maintain ignition.

(5) Well Control Equipment. When the 100 ppm radius of exposure includes a public area, the following well control equipment shall be required:

(a) Drilling. A remote-controlled well control system shall be installed and operational at all times beginning when drilling is within 500 feet of the formation believed to contain hydrogen sulfide and continuously thereafter during drilling. The well control system must include, at a minimum, a pressure and hydrogen-sulfide-rated well control choke and kill system including manifold and blowout preventer that meets or exceeds the specifications API-16C and API-RP 53 or other specifications approved by the division. Mud-gas separators shall be used. These systems shall be tested and maintained pursuant to the specifications referenced, according to the requirements of this part, or otherwise as approved by the division.

(b) Completion, Workover and Well Servicing. A remote controlled pressure and hydrogen-sulfide-rated well control system that meets or exceeds API specifications or other specifications approved by the division shall be installed and shall be operational at all times during completion, workover and servicing of a well.

(6) Mud Program. All drilling, completion, workover and well servicing operations involving a

hydrogen sulfide concentration of 100 ppm or greater shall use a hydrogen sulfide mud program capable of handling hydrogen sulfide conditions and well control, including de-gassing.

(7) Well Testing. Except with prior approval of the division, drill-stem testing of a zone that contains hydrogen sulfide in a concentration of 100 ppm or greater shall be conducted only during daylight hours and formation fluids shall not be permitted to flow to the surface.

(8) If Hydrogen Sulfide Encountered During Operations. If hydrogen sulfide was not anticipated at the time the division issued a permit to drill but is encountered during drilling in a concentration of 100 ppm or greater, the operator must satisfy the requirements of this section before continuing drilling operations. The operator shall notify the division of the event and the mitigating steps that have been or are being taken as soon as possible, but no later than 24 hours following discovery. The division may grant verbal approval to continue drilling operations pending preparation of any required hydrogen sulfide contingency plan.

G. Protection from Hydrogen Sulfide at Crude Oil Pump Stations, Producing Wells, Tank Batteries and Associated Production Facilities, Pipelines, Refineries, Gas Plants and Compressor Stations.

(1) API Standards. Operations at crude oil pump stations and producing wells, tank batteries and associated production facilities, refineries, gas plants and compressor stations involving a concentration of hydrogen sulfide of 100 ppm or greater shall be conducted with due consideration to the guidelines published by the API in its publication entitled “Recommended Practices for Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide," RP-55, latest edition or some other standard approved by the division.

(2) Security. Well sites and other unattended, fixed surface facilities involving a concentration of hydrogen sulfide of 100 ppm or greater shall be protected from public access by fencing with locking gates when the location is within 1/4 mile of a public area. A surface pipeline shall not be considered a fixed surface facility for purposes of this paragraph.

(3) Wind Direction Indicators. All crude oil pump stations, producing wells, tank batteries and associated production facilities, pipelines, refineries, gas plants and compressor stations involving a concentration of hydrogen sulfide of 100 ppm or greater shall have equipment to indicate wind direction. The wind direction equipment shall be installed and visible from all principal working areas at all times.

(4) Control Equipment. When the 100 ppm radius of exposure includes a public area, the following additional measures are required:

(a) Safety devices, such as automatic shut-down devices, shall be installed and maintained in good operating condition to prevent the escape of hydrogen sulfide. Alternatively, safety procedures shall be established to achieve the same purpose.

(b) Any well shall possess a secondary means of immediate well control through the use of an appropriate christmas tree or downhole completion equipment. Such equipment shall allow downhole accessibility (reentry) under pressure for permanent well control.

(5) Tanks or vessels. Each stair or ladder leading to the top of any tank or vessel containing 300 ppm or more of hydrogen sulfide in the gaseous mixture shall be chained or marked to restrict entry.

(6) Compliance Schedule. Each existing crude oil pump station, producing well, tank battery and associated production facility, pipeline, refinery, gas plant and compressor station not currently meeting the requirements of this subsection shall be brought into compliance within one year of the effective date of this section.

H. Personnel Protection and Training. All persons responsible for the implementation of any hydrogen sulfide contingency plan shall be provided training in hydrogen sulfide hazards, detection, personal protection and contingency procedures.

I. Standards for Equipment That May Be Exposed to Hydrogen Sulfide. Whenever a well, facility or operation involves a potentially hazardous volume of hydrogen sulfide, equipment shall be selected with consideration for both the hydrogen sulfide working environment and anticipated stresses and NACE Standard MR0175 (latest edition) or some other standard approved by the division shall be used for selection of metallic equipment or, if applicable, adequate protection by chemical inhibition or other methods that control or limit the corrosive effects of hydrogen sulfide shall be used.

J. Exemptions. Any person, operator or facility may petition the director or the director's designee for an exemption to any requirement of this section. Any such petition shall provide specific information as to the circumstances that warrant approval of the exemption requested and how the public safety will be protected. The director or the director's designee, after considering all relevant factors, may approve an exemption if the circumstances warrant and so long as the public safety will be protected.

K. Notification of the Division. The person, operator or facility shall notify the division upon a release of hydrogen sulfide requiring activation of the hydrogen sulfide contingency plan as soon as possible, but no more than four hours after plan activation, recognizing that a prompt response should supercede notification. The person, operator or facility shall submit a full report of the incident to the division on Form C-141 no later than fifteen (15) days following the release.

[5-22-73…1-1-87...2-1-96; A 3-15-97; 19.15.3.118 NMAC - Rn, 19 NMAC 15.C.118, 11-15-2001; A, 01-31-03]

History of 19.15.3 NMAC:
Pre-NMAC History:
Material in this part was derived from that previously filed with the commission of public records - state records center and archives as:
Rule 101, Plugging Bond, filed 06-04-86;
Rule 101, Plugging Bond, filed 01-06-88;
Rule 101, Plugging Bond, filed 02-05-91;
Rule 102, Notice of Intention to Drill, filed 01-08-82;
Rule 102, Notice of Intention to Drill, filed 11-25-85;
Rule 102, Notice of Intention to Drill, filed 02-05-91;
Rule 103, Sign on Wells, filed 01-08-82;
Rule 103, Sign on Wells, filed 02-05-91;
Rule 104, Well Spacing: Acreage Requirements for Drilling Tracts, filed 01-08-82;
Rule 104, Well Spacing: Acreage Requirements for Drilling Tracts, filed 02-05-91;
Rule 105, Pit for Clay, Shale, and Drill Cutting, filed 01-08-82;
Rule 105, Pit for Clay, Shale, and Drill Cutting, filed 08-17-89;
Rule 105, Pit for Clay, Shale, and Drill Cutting, filed 02-05-91;
Rule 106, Sealing Off Strata, filed 01-08-82;
Rule 106, Sealing Off Strata, filed 10-11-89;
Rule 106, Sealing Off Strata, filed 02-05-91;
Rule 107, Casing and Tubing Requirements, filed 01-08-82;
Rule 107, Casing and Tubing Requirements, filed 02-05-91;
Rule 108, Defective Casing or Cementing, filed 01-08-82;
Rule 108, Defective Casing or Cementing, filed 09-16-85;
Rule 108, Defective Casing or Cementing, filed 02-05-91;
Rule 109, Blowout Prevention, filed 01-27-82;
Rule 109, Blowout Prevention, filed 02-05-91;
Rule 110, Pulling Outside Strings of Casing, filed 01-27-82;
Rule 110, Pulling Outside Strings of Casing, filed 02-05-91;
Rule 111, Deviation Tests and Directional Drilling, filed 01-08-82;
Rule 111, Deviation Tests and Directional Drilling, filed 09-16-85;
Rule 111, Deviation Tests and Directional Drilling, filed 10-11-89;
Rule 111, Deviation Tests and Directional Drilling, filed 02-05-91;
Rule 111, Deviation Tests/Deviated Wells and Directional Drilling, filed 07-27-95;
Rule 112-A, Multiple Completions, filed 01-08-82;
Rule 112-A, Multiple Completions, filed 02-05-91;
Rule 112-B, Brandenhead Gas Wells, filed 01-08-82;
Rule 112-B, Brandenhead Gas Wells, filed 02-05-91;
Rule 113, Shooting and Chemical Treatment of Wells, filed 01-08-82;
Rule 113, Shooting and Chemical Treatment of Wells, filed 09-16-85.

Rule 113, Shooting and Chemical Treatment of Wells, filed 02-05-91.
Rule 114, Safety Regulations, filed 01-08-82;
Rule 114, Safety Regulations, filed 02-05-91.
Rule 115, Well and Lease Equipment, filed 01-08-82;
Rule 115, Well and Lease Equipment, filed 02-05-91.
Rule 116, Notification of Fire, Breaks, Leaks, Spills, and Blowouts, filed 01-08-82;
Rule 116, Notification of Fire, Breaks, Leaks, Spills, and Blowouts, filed 02-05-91;
Rule 117, Well Log, Completion and Workover Reports, filed 01-08-82;
Rule 117, Well Log, Completion and Workover Reports, filed 10-11-89;
Rule 117, Well Log, Completion and Workover Reports, filed 02-05-91;
Rule 118, Hydrogen Sulfide Gas - Public Safety, filed 12-30-86;
Rule 118, Hydrogen Sulfide Gas - Public Safety, filed 10-11-89;
Rule 118, Hydrogen Sulfide Gas - Public Safety, filed 02-05-91.

History of Repealed Material: [Reserved]

Other History:
Rule 101, filed 02-05-91; Rule 102, filed 02-05-91; Rule 103, filed 02-05-91; Rule 104, filed 02-05-91; Rule 105, filed 02-05-91; Rule 106, filed 02-05-91; Rule 107, filed 02-05-91; Rule 108, filed 02-05-91; Rule 109, filed 02-05-91; Rule 110, filed 02-05-91; Rule 111, filed 07-27-95; Rule 112-A, filed 02-05-91; Rule 112-B, filed 02-05-91; Rule 113, filed 02-05-91; Rule 114, filed 02-05-91; Rule 115, filed 02-05-91; Rule 116, filed 02-05-91; Rule 117, filed 02-05-91; Rule 118, filed 02-05-91; all renumbered, reformatted **to and replaced by** 19 NMAC 15.C, Drilling, filed 01-18-96.
19 NMAC 15.C, Drilling, filed 01-18-96; **renumbered, reformatted and replaced by** 19.15.3 NMAC, effective 11-15-01.

TITLE 19 NATURAL RESOURCES & WILDLIFE
CHAPTER 15 OIL AND GAS
PART 4 PLUGGING AND ABANDONMENT OF WELLS

19.15.4.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department, Oil Conservation Division, 2040 S. Pacheco, Santa Fe, New Mexico 87505 (505) 827-7131.
[2-1-96; 19.15.4.1 NMAC - Rn, 19 NMAC 15.D.1, 12-14-01]

19.15.4.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico.
[2-1-96; 19.15.4.2 NMAC - Rn, 19 NMAC 15.D.2, 12-14-01]

19.15.4.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the Oil and Gas Act which grants the Oil Conservation Division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights, and the disposition of wastes resulting from oil and gas operations.
[2-1-96; 19.15.4.3 NMAC - Rn, 19 NMAC 15.D.3, 12-14-01]

19.15.4.4 DURATION: Permanent.
[2-1-96; 19.15.4.4 NMAC - Rn, 19 NMAC 15.D.4, 12-14-01]

19.15.4.5 EFFECTIVE DATE: February 1, 1996.
[2-1-96; 19.15.4.5 NMAC - Rn, 19 NMAC 15.D.5, 12-14-01]

19.15.4.6 OBJECTIVE: To provide for the proper plugging and abandonment of wells to protect fresh water and public health and environment pursuant to the Oil and Gas Act.
[2-1-96; 19.15.4.6 NMAC - Rn, 19 NMAC 15.D.6, 12-14-01]

19.15.4.7 DEFINITIONS: [Reserved].

19.15.4.8-200 [RESERVED].

19.15.4.201 WELLS TO BE PROPERLY ABANDONED

A. The operator of any well drilled for oil, gas or injection; for seismic, core or other exploration, or for a service well, whether cased or uncased, shall be responsible for the plugging thereof.

B. A well shall be either properly plugged and abandoned or temporarily abandoned in accordance with these rules within ninety (90) days after:

(1) a sixty (60) day period following suspension of drilling operations, or
(2) a determination that a well is no longer usable for beneficial purposes, or
(3) a period of one (1) year in which a well has been continuously inactive.

[7-12-90…2-1-96; 19.15.4.201 NMAC - Rn, 19 NMAC 15.D.201, 12-14-01]

19.15.4.202 PLUGGING AND PERMANENT ABANDONMENT

A. Notice of Plugging

(1) Notice of intention to plug must be filed with the Division on Form C-103, Sundry Notices and Reports on Wells, by the operator prior to the commencement of plugging operations, which notice must provide all of the information required by Rule 1103 including operator and well identification and proposed procedures for plugging said well, and in addition the operator shall provide a well-bore diagram showing the proposed plugging procedure. Twenty-four hours notice shall be given prior to commencing any plugging operations. In the case of a newly drilled dry hole, the operator may obtain verbal approval from the appropriate District Supervisor or his representative of the method of plugging and time operations are to begin. Written notice in accordance with this rule shall be filed with the Division ten (10) days after such verbal approval has been given.

B. Plugging

(1) Before any well is abandoned, it shall be plugged in a manner which will permanently confine all oil, gas and water in the separate strata in which they are originally found. This may be accomplished by using mud-laden fluid, cement and plugs singly or in combination as approved by the Division on the notice of intention to plug.

(2) The operator shall mark the exact location of plugged and abandoned wells with a steel marker not less than four inches (4") in diameter set in cement and extending at least four feet (4') above mean ground level. The operator name, lease name and well number and location, including unit letter, section, township and range, shall be welded, stamped or otherwise permanently engraved into the metal of the marker. No permanent structures preventing access to the wellhead shall be built over a plugged and abandoned well without written approval of the OCD. No plugged and abandonment marker shall be removed without the written permission of the OCD.

(3) As soon as practical but no later than one year after the completion of plugging operations, the operator shall:

(a) fill all pits;

(b) level the location;

(c) remove deadmen and all other junk; and

(d) take such other measures as are necessary or required by the Division to restore the location to a safe and clean condition.

(4) Upon completion of plugging and clean up restoration operations as required, the operator shall contact the appropriate district office to arrange for an inspection of the well and location.

(5) Below-ground plugged and abandonment markers can be used only with written permission of the OCD when an above-ground marker would interfere with agricultural endeavors. The below-ground marker shall have a steel plate welded onto the surface or conductor pipe of the abandoned well and shall be at least 3 feet below the ground surface and of sufficient size so that all the information required by Section 103 of 19.15.3 NMAC can be stenciled into the steel or welded onto the surface of the steel plate. The OCD may require a re-survey of the well location.

C. Reports

(1) The operator shall file Form C-105, Well Completion or Recompletion Report and Log as provided in Rule 1105.

(2) Within thirty (30) days after completing all required restoration work, the operator shall file with the Division, in triplicate, a record of the work done on Form C-103 as provided in Rule 1103.

(3) The Division shall not approve the record of plugging or release any bonds until all necessary reports have been file and the location has been inspected and approved by the Division.

[1-1-50, 7-12-90…2-1-96; A, 3-31-00; 19.15.4.202 NMAC - Rn, 19 NMAC 15.D.202, 12-14-01]

19.15.4.203 TEMPORARY ABANDONMENT

A. Wells Which May Be Temporarily Abandoned

(1) The Division may permit any well which is required to be properly abandoned under these rules but which has potential for future beneficial use for enhanced recovery or injection, and any other well for which an operator requests temporary abandonment, to be temporarily abandoned for a period of up to five (5) years. Prior to the expiration of any approved temporary abandonment the operator shall return the well to beneficial use under a plan approved by the Division, permanently plug and abandon said well or apply for a new approval to temporarily abandon the well.

B. Request For Approval And Permit

(1) Any operator seeking approval for temporary abandonment shall submit on Form C-103, Sundry Notices and Reports on Wells, a notice of intent to temporarily abandon the well describing the proposed temporary abandonment procedure to be used. No work shall be commenced until approved by the Division and the operator shall give 24 hours notice to the appropriate District office of the Division before work actually begins.

(2) No temporary abandonment shall be approved unless evidence is furnished to show that the casing of such well is mechanically sound and in such condition as to prevent:

(a) damage to the producing zone;

(b) migration of hydrocarbons or water;

(c) the contamination of fresh water or other natural resources; and

(d) the leakage of any substance at the surface.

(3) If the well fails the mechanical integrity test required herein, the well shall be plugged and abandoned in accordance with these rules or the casing problem corrected and the casing retested within ninety (90) days.

(4) Upon successful completion of the work on the temporarily abandoned well, the operator will submit a request for Temporary Abandonment to the appropriate district office on Form C-103 together with such other information as is required by Rule 1103 E.(1).

(5) The Division may require the operator to post with the Division a one-well plugging bond for the well in an amount to be determined by the Division to be satisfactory to meet the particular requirements of the well.

(6) The Division shall specify the expiration date of the permit, which shall be not more than five (5) years from the date of approval.

C. Tests Required

(1) The following methods of demonstrating casing integrity may be approved for temporarily abandoning a well:

(a) a cast iron bridge plug will be set within one hundred (100) feet of uppermost perforations or production casing shoe and the casing loaded with inert fluid and pressure tested to 500 pounds per square inch with a pressure drop of not more than 10% for thirty (30) minutes; or

(b) a retrievable bridge plug or packer will be run to within one hundred (100) feet of uppermost perforations or production casing shoe and the well tested to 500 pounds per square inch for thirty minutes with a pressure drop of not greater than 10% for thirty (30) minutes; or

(c) for a gas well in southeast New Mexico completed above the San Andres formation, if the operator can demonstrate that the fluid level is below the base of the salt and that a Bradenhead test shows no casing leaks, the Division may exempt the well from the requirement for a bridge plug or packer; or

(d) a casing inspection log confirming the mechanical integrity of the production casing may be submitted.

(2) Any such test which is submitted must have been conducted within the previous twelve (12) months.

(3) The Division may approve other casing tests submitted on Form C-103 on an individual basis.

[7-12-90...7-12-90, 2-1-96; 19.15.4.203 NMAC - Rn, 19 NMAC 15.D.203, 12-14-01]

19.15.4.204 WELLS TO BE USED FOR FRESH WATER

A. When a well to be plugged may safely be used as a fresh water well and the landowner agrees to take over said well for such purpose, the well need not be plugged above the sealing plug set below the fresh water formation.

B. The operator must comply with all other requirements contained in Section 202 of 19.15.3 NMAC regarding plugging, including surface restoration and reporting requirements.

C. Upon completion of plugging operations, the operator must file with the Division a written agreement signed by the landowner whereby the landowner agrees to assume responsibility for such well. Upon the filing of this agreement and approval by the Division of well abandonment operations, the operator shall no longer be responsible for such well, and any bonds thereon may be released.

[1-1-50…7-12-1-96; 19.15.4.204 NMAC - Rn, 19 NMAC 15.D.204, 12-14-01]

HISTORY of 19.15.4 NMAC:

Pre-NMAC History:

Material in this part was derived from that previously filed with the commission of public records - state records center and archives as:

Rule 201, Notice, file 1-8-82;
Rule 201, Wells to be Properly Abandoned, filed 7-10-90;
Rule 201, Wells to be Properly Abandoned, filed 2-5-91;
Rule 202, Plugging and Abandonment, 1-8-82;
Rule 202, Plugging and Permanent Abandonment, filed 7-10-90;
Rule 202, Plugging and Permanent Abandonment, filed 2-5-91;
Rule 203, Wells to be used for Fresh Water, filed 1-8-82;
Rule 203, Temporary Abandonment, filed 7-10-90;
Rule 203. Temporary Abandonment, filed 2-5-91;
Rule 204, Liability, filed 1-8-82;
Rule 204, Wells to be Used for Fresh Water, filed 7-10-90;
Rule 204, Wells to be Used for Fresh Water, filed 2-5-91.

History of the Repealed Material: [RESERVED].

Other History:

Rule 201, Wells to be Properly Abandoned, filed 2-5-91; Rule 202, Plugging and Permanent Abandonment, filed 2-5-91; Rule 203, Temporary Abandonment, filed 2-5-91; Rule 204, Wells to be Used For Fresh Water, filed 2-5-91; all renumbered, reformatted **to and replaced by** 19 NMAC 15.D, Plugging and Abandonment of Wells, filed 01-18-96.

19 NMAC 15.D, Plugging and Abandonment of Wells, filed 01-18-96; **renumbered, reformatted and replaced by** 19.15.4 NMAC, effective 12-14-01.

TITLE 19 NATURAL RESOURCES & WILDLIFE
CHAPTER 15 OIL AND GAS
PART 5 OIL PRODUCTION OPERATING PRACTICES

19.15.5.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department.
[2-1-96; 19.15.5.1 NMAC - Rn, 19 NMAC 15.E.1, 5-15-00]

19.15.5.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico.
[2-1-96; 19.15.5.2 NMAC - Rn, 19 NMAC 15.E.2, 5-15-00]

19.15.5.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the Oil and Gas Act which grants the Oil Conservation Division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights, and the disposition of wastes resulting from oil and gas operations.
[2-1-96; 19.15.5.3 NMAC - Rn, 19 NMAC 15.E.3, 5-15-00]

19.15.5.4 DURATION: Permanent
[2-1-96; 19.15.5.4 NMAC - Rn, 19 NMAC 15.E.4, 5-15-00]

19.15.5.5 EFFECTIVE DATE: February 1, 1996, unless a later date is cited at the of a section.
[2-1-96; 19.15.5.5 NMAC - Rn, 19 NMAC 15.E.5, 5-15-00]

19.15.5.6 OBJECTIVE: To regulate the production of oil to enable the oil conservation division to fulfill its statutory mandates under the Oil and Gas Act.
[2-1-96; 19.15.5.6 NMAC - Rn, 19 NMAC 15.E.6, 5-15-00]

19.15.5.7 DEFINITIONS: [RESERVED]. See 19.15.1.7 NMAC.

19.15.5.8-300 [RESERVED]

19.15.5.301 GAS-OIL RATIO AND PRODUCTION TESTS:

A. Each operator shall take a gas-oil ratio test no sooner than 20 days nor later than 30 days following the completion or recompletion of each oil well, if:

(1) the well is a wildcat, or

(2) the well is located in a pool which is not exempt from the requirements of this rule. Wells completed within one mile of the outer boundary of a defined oil pool producing from the same formation shall be governed by the provisions of this rule which are applicable to the pool. The results of the test shall be reported to the division on form C-116 within 10 days following completion of the test. The gas-oil ratio thus reported shall become effective for proration purposes on the first day of the calendar month following the date they are reported.

(3) Each operator shall also take an annual gas-oil ratio test of each producing oil well, located within a pool not exempted from the requirements of this rule, during a period prescribed by the division. A gas-oil ratio survey schedule shall be established by the division setting forth the period in which gas-oil ratio tests are to be taken for each pool wherein a test is required. The gas-oil ratio test shall be such test designated by the division, made by such method and means, and in such manner as the division in its discretion may prescribe from time to time.

B. The results of gas-oil ratio tests taken during survey periods shall be filed with the division on form C-116 not later than the 10^{th} of the month following the close of the survey period for the pool in which the well is located. The gas-oil ratios thus reported shall become effective for proration purposes on the first day of the second month following the close of the survey period. Unless form C-116 is filed within the required time limit, no further allowable will be assigned the affected well until form C-116 is filed.

C. In the case of special tests taken between regular gas-oil ratio surveys, the gas-oil ratio shall become effective for proration purposes upon the date form C-116, reporting the results of such test, is received by the division. A special test does not exempt any well from the regular survey.

D. During gas-oil ratio test, no well shall be produced at a rate exceeding top unit allowable for the pool in which it is located by more than 25 percent.

E. The director shall have the authority to exempt such pools as he may deem proper from the gas-oil ratio test requirements of this rule. Such exemption shall be by executive order directed to all operators in the pool being exempted.

F. The director shall have the authority to require annual productivity tests of all oil wells in pools exempt from gas-oil ratio tests, during a period prescribed by the division. An oil well productivity survey schedule shall be established by the division setting forth the period in which productivity tests are to be taken for each pool wherein such tests are required.

G. The results of productivity tests taken during survey periods shall be filed with the division on form C-116 (with the word "Exempt" inserted in the column normally used for reporting gas production) not later than the 10^{th} of the month following the close of the survey period for the pool in which the well is located. Unless form C-116 is filed within the required time limit, no further allowable will be assigned the affected well until form C-116 is filed.

H. In the case of special productivity tests taken between regular test survey periods, which result in a change of allowable assigned to the well, the allowable change shall become effective upon the date the form C-116 is received by the proration department. A special test does not exempt any well from the regular survey.

I. During the productivity test, no well shall be produced at a rate exceeding top unit allowable for the pool in which it is located by more than 25 percent.

[1-1-50…2-1-96; 19.15.5.301 NMAC - Rn, 19 NMAC 15.E.301, 5-15-00]

19.15.5.302 SUBSURFACE PRESSURE TESTS:

The operator shall make a subsurface pressure test on the discovery well of any new pool hereafter discovered, and shall report the results thereof to the division within 30 days after the completion of such discovery well. On or before December 1 of each calendar year the division shall designate the months in which subsurface pressure tests shall be taken in designated pools. Included in the designated list shall be listed the required shut-in pressure time and datum of tests to be taken in each pool. In the event a newly discovered pool is not included in the division's list, the division shall issue a supplementary bottom hole pressure schedule. Tests as designated by the division shall only apply to flowing wells in each pool. This test shall be made by a person qualified by both training and experience to make such test, and with an approved subsurface pressure instrument which shall be calibrated against an approved dead-weight tester at intervals frequent enough to ensure its accuracy within one percent. Unless otherwise designated by the division all wells shall remain completely shut in for at least 24 hours prior to the test. In the event a definite datum is not established by the division the subsurface determination shall be obtained as close as possible to the mid-point of the productive sand of the reservoir. The report shall be on form C-124 and shall state the name of the pool, the pool datum (if established), the name of the operator and lease, the well number, the wellhead elevation above sea level, the date of the test, the total time the well was shut in prior to the test, the subsurface temperature in degrees fahrenheit at the test depth, the depth in feet at which the subsurface pressure test was made, the observed pressure in pounds per square inch gauge (corrected for calibration and temperature), the corrected pressure computed from applying to the observed pressure the appropriate correction for difference in test depth and reservoir datum plane and any other information as required by form C-124.

[1-1-50...2-1-96; 19.15.5.302 NMAC - Rn, 19 NMAC 15.E.302, 5-15-00]

19.15.5.303 SEGREGATION OF PRODUCTION FROM DIFFERENT POOLS OR LEASES:

A. In general

(1) Pool segregation required - Each pool shall be produced as a single common source of supply and wells therein shall be completed, cased, maintained, and operated so as to prevent communication within the wellbore with any other pool. Oil, gas, or oil or gas produced from each pool shall at all times be segregated, and the combination commingling of production, before marketing, with production from any other pool without division approval is prohibited.

(2) Lease segregation required - Oil, gas, or oil and gas shall not be transported from a lease until it has been accurately measured or determined by other methods acceptable to the division. The production from each lease shall at all times be segregated, and the combination or commingling of production, before marketing, with production from any other lease without division approval is prohibited.

(3) Exceptions. Exceptions to Paragraphs (1) and (2) of Subsection A of 19.15.5.303 NMAC may be permitted for surface commingling, downhole commingling and off-lease storage and/or measurement pursuant to Subsections B, C and D of 19.15.5.303 NMAC, respectively. Exceptions granted by previous orders of the division remain in effect in accordance with their terms and conditions.

B. Surface commingling - oil gas or oil and gas

(1) Introduction - To prevent waste, to promote conservation and to protect correlative rights, the division shall have the authority to grant exceptions to permit the surface commingling of oil, gas or oil and gas in common facilities from two or more pools, two or more leases or combinations of pools and leases provided that:

(a) the method used to allocate the production to the various leases or pools to be commingled is approved by the division;

(b) if federal, Indian or state lands are involved, the United States bureau of land management or the commissioner of public lands for the state of New Mexico (as applicable) has been notified of the proposed commingling; and

(c) all other applicable requirements set out in Subsection B of 19.15.5.303 NMAC are met.

(2) Definitions - For purposes of Section 303 of 19.15.5 NMAC only, the following definitions shall apply:

(a) Lease. "Lease" means a contiguous geographical area of identical ownership overlying a pool or portion of a pool. An area pooled, unitized or communitized, either by agreement or by division order, or a participating area shall constitute a lease. If there is any diversity of ownership between different pools, or between different zones or strata, then each such pool, zone or stratum having such diverse ownership shall be considered a separate lease.

(b) Diverse ownership. "Diverse Ownership" exists if leases or pools have any different working, royalty or overriding royalty interest owners or any different ownership percentages of the same working, royalty or overriding royalty interest owners.

(c) Identical ownership. "Identical Ownership" exists if leases or pools have all the same working, royalty and overriding royalty owners in exactly the same percentages.

(3) Specific requirements and provisions for commingling of leases, pools or leases and pools with identical ownership.

(a) Measurement and allocation methods.

(i) Well test method - If all wells or units to be commingled are marginal and are physically incapable of producing the top unit allowable for their respective pools, or if all affected pools are unprorated, commingling shall be permitted without separately measuring the production from each pool or lease. Instead, the production from each well and from each pool or lease may be determined from well tests conducted periodically, but no less than annually. The well test method shall not apply to wells or units that can produce an amount of oil equal to the top unit allowable for the pool but are restricted because of high gas-oil ratios. The operator of any such marginal commingling installation shall notify the division at any time any well or unit so commingled under this subsection becomes capable of producing the top unit allowable for its pool, at which time the division shall require separate measurement.

(ii) Metering method - Production from each pool or lease may be determined by separately metering before commingling.

(iii) Subtraction method - If production from all except one of the pools or leases to be commingled is separately measured, the production from the remaining pool or lease may be determined by the subtraction method as follows: For oil, the net production from the unmetered pool or lease shall be the difference between the net pipeline runs with the beginning and ending stock adjustments and the sum of the net production of all metered pools or leases. For gas, the net production from the unmetered pool or lease shall be the difference between the volume recorded at the sales meter and the sum of the volumes recorded at the individual pool or lease meters.

(iv) Top allowable producers - If any well or unit in a prorated pool to be commingled can physically be produced at top unit allowable rates (even if restricted because of high gas-oil ratios), commingling may be permitted only if the production from such unit is metered prior to commingling, or determined by the subtraction method.

(v) Alternative methods - Production from each pool or lease to be commingled may also be determined by any other method specifically approved by the division prior to commingling. The division shall determine what evidence is necessary to support any request to use an alternative method.

(b) Approval process. Prior to commingling, the applicant shall notify the division by filing form C-103 (sundry notices and reports on wells) in the Santa Fe office with the following information set forth therein or attached thereto:

(i) Identification of each of the leases, pools or leases and pools to be commingled;

(ii) The method of allocation to be used. If the well test method is proposed for production from a prorated pool, the notification to the division shall be accompanied by a tabulation of production showing that the average daily production of any affected proration unit over a 60-day period has been below the top unit allowable for the subject pool (or for any newly drilled well without a 60-day production history, a tabulation of the available production) or other evidence acceptable to the division to establish that the well or wells on such unit are not capable of producing the top unit allowable. If the proposed method of allocation is other than an approved method provided in this section, the operator shall submit evidence of the reliability of such method;

(iii) A certification by a licensed attorney or qualified petroleum landman that the ownership in all pools and leases to be commingled is identical as defined in this section; and

(iv) Evidence of notice to the state land office and/or the United States bureau of land management, if required. Commingling may be authorized without any notice or hearing and may be commenced upon approval of form C-103 by the division, subject to compliance with any conditions of such approval noted by the division; provided however that commingling involving any state, federal or tribal leases shall not be commenced unless or until approved by the state land office or the United States bureau of land management, as applicable.

(4) Specific requirements and provisions for commingling of leases, pools or leases and pools with diverse ownership.

(a) Measurement and allocation methods. Where there is diversity of ownership between two or more leases, two or more pools, or between different pools and leases, the surface commingling of production therefrom shall be permitted only if production from each of such pools or leases is accurately metered, or determined by other methods specifically approved by the division, prior to such commingling.

(b) Meter proving and calibration frequencies.

(i) Oil. Each meter used in oil production accounting shall be tested for accuracy as follows: monthly, if more than 100,000 barrels of oil per month are measured through the meter; quarterly, if between 10,000 and 100,000 barrels of oil per month are measured through the meter; and semi-annually, if less than 10,000 barrels of oil per month are measured through the meter.

(ii) Gas. For each gas sales and allocation meter, the accuracy of the metering equipment at the point of delivery or allocation shall be tested following the initial installation and following repair and retested: quarterly, if 100 thousand cubic feet of gas per day ("Mcfgpd") or more are measured through the meter; and semi-annually, if less than 100 Mcfgpd are measured through the meter.

(iii) Correction and adjustment. If a meter proving and calibration test reveals inaccuracy in the metering equipment of more than two percent (2%), the volume measured shall be corrected and the meter adjusted to zero error. The operator shall submit a corrected report adjusting the volume of oil or gas measured and showing all calculations made in correcting the volumes. The volumes shall be corrected back to the time the inaccuracy occurred, if known. If the time is unknown, the volumes shall be corrected for the last half of the period elapsed since the date of the last calibration. If a test reveals an inaccuracy of less than 2%, the meter shall be adjusted, but correction of prior production shall not be required.

(c) Low production gas wells. For gas wells producing less than 15 Mcfgpd, estimation of production is an acceptable alternative to individual well measurement provided that commingling of production from different pools or leases does not take place unless otherwise authorized pursuant to Section 303 of 19.15.5 NMAC.

(d) Approval process.

(i) In general. Where there is diversity of ownership, the division may grant an exception to the requirements of Subsection A of 19.15.5.303 NMAC to permit surface commingling of production from different leases, pools or leases and pools only after notice and an opportunity for hearing as provided in Subparagraph (d) of Paragraph (4) of Subsection B of 19.15.5.303 NMAC.

(ii) Application. An application for administrative approval shall be submitted to the division's Santa Fe office on form C-107-B and shall contain a list of all parties (hereinafter called "interest owners") owning any interest in any of the production to be commingled (including owners of royalty and overriding royalty interests whether or not they have a right or option to take their interests in kind) and a method of allocating production to ensure the protection of correlative rights.

(iii) Notice. Notice shall be given to all interest owners in accordance with Subsection A of 19.15.14.1207 NMAC. The applicant shall submit a statement attesting that applicant, on or before the date the application was submitted to the division, sent notification to each of the interest owners by submitting a copy of the application and all attachments thereto, by certified mail, return receipt requested, and advising them that any objection must be filed in writing with the Santa Fe office of the division within 20 days from the date the division received the application. The division may approve the application administratively, without hearing, upon receipt of written waivers from all interest owners, or if no such owner has filed an objection within the 20-day period. If any objection is received, the application shall be set for hearing. Notice of the hearing shall be given to the applicant, to any party who has filed an objection, and to such other parties as the division shall direct.

(iv) Hearing ordered by the division. The division may set for hearing any application for administrative approval of surface commingling, and, in such case, notice of such hearing shall be given in such manner as the division shall direct.

(v) Notice by publication. When an applicant has been unable to locate all interest owners after exercising reasonable diligence, notice shall be provided by publication, and proof of publication shall be submitted with the application. Such proof shall consist of a copy of the legal advertisement that was published in a newspaper of general circulation in the county or counties in which the commingled production is located. The contents of such advertisement shall include (a) the name, address, telephone number, and contact party for the applicant, (b) the location by section, township and range of the leases from which production will be commingled and the location of the commingling facility; (c) the source of all commingled production by pool name, and (d) a notation that interested parties must file objections or requests for hearing in writing with the oil conservation division's Santa Fe office, within 20 days after publication, or the division may approve the application.

(vi) Effect of protest. All protests and requests for hearing received by the division shall be included in the case file; provided however, the protest will not be considered by the division as evidence. If the protesting party does not appear at the hearing, the application may be granted without the division receiving additional evidence in support thereof.

(vii) Additions. A surface commingling order may authorize, prospectively, the inclusion therein of additional pools and/or leases within defined parameters set forth in the order, provided that (a) the notice to the interest owners has included a statement that authorization for subsequent additions is being sought and of the parameters for such additions proposed by the applicant, and (b) the division finds that subsequent additions within defined parameters will not, in reasonable probability, reduce the value of the commingled production or otherwise adversely affect the interest owners. A subsequent application to amend an order to add to the commingled production other leases, pools or leases and pools that are within the defined parameters shall require notice only to the owners of interests in the production to be added, unless the division otherwise directs.

(viii) State, federal or tribal lands. Notwithstanding the issuance of an exception under Subsection B of 19.15.5.303 NMAC, no commingling involving any state, federal or tribal leases shall be commenced unless or until approved by the state land office or the United States bureau of land management, as applicable.

C. Downhole commingling

(1) The director may grant an exception to Subsection A of 19.15.303 NMAC to permit the commingling of multiple producing pools in existing or proposed wellbores when the following conditions are met:

(a) the fluids from each pool are compatible and combining the fluids will not result in damage to any of the pools;

(b) the commingling will not jeopardize the efficiency of present or future secondary recovery operations in any of the pools to be commingled;

(c) the bottom perforation of the lower zone is within 150% of the depth of the top perforation in the upper zone and the lower zone is at or below normal pressure with normal pressure assumed to be 0.433 psi per foot of depth. If the pools to be commingled are not within this vertical interval, then evidence will be required to demonstrate that commingling will not result in shut-in or flowing wellbore pressures in excess of the fracture parting pressure of any commingled pool. The fracture parting pressure shall be assumed to be 0.65 psi per foot of depth unless the applicant submits other measured or calculated pressure data acceptable to the division;

(d) the commingling will not result in the permanent loss of reserves due to cross-flow in the wellbore;

(e) fluid-sensitive formations that may be subject to damage from water or other produced liquids shall be protected from contact with such liquids produced from other pools in the well;

(f) if any of the pools being commingled is prorated, or the well's production has been restricted by division order in any manner, the allocated production from each producing pool in the commingled wellbore shall not exceed the top oil or gas allowable rate for a well in that pool or rate restriction applicable to such well;

(g) the commingling will not reduce the value of the total remaining production; and

(h) correlative rights will not be violated.

(2) The director may rescind authority to commingle production in a wellbore and require the pools to be produced separately if, in the director’s opinion, waste or reservoir damage is resulting, correlative rights are being impaired or the efficiency of any secondary recovery project is being impaired, or any changes or conditions render the installation no longer eligible for downhole commingling.

(3) When the conditions set forth in Paragraph (1) of Subsection C of 19.15.5.303 NMAC are satisfied, the director may approve a request to downhole commingle production in one of the following ways:

(a) **Individual exceptions:** Applications to downhole commingle in wellbores located outside of an area subject to a downhole commingling order issued in a "reference case" and not within a pre-approved pool or area shall be filed on division form C-107-A with the division.

(i) The director may administratively approve a form C-107-A application in the absence of a valid objection filed within 20-days after receipt of the application by the division if, in the director's opinion, waste will not occur and correlative rights will not be impaired.

(ii) In those instances where the ownership or percentages between the pools to be commingled is not identical, applicant shall send a copy of form C-107-A to all interest owners in the spacing unit by certified mail (return receipt).

(iii) Applicant shall send copies of form C-107-A to the commissioner of public lands for the state of New Mexico for wells in spacing units containing state lands or the bureau of land management for wells in spacing units containing federal lands.

(iv) The director may set any administratively filed form C-107-A application for hearing.

(b) **Exceptions for wells located in pre-approved pools or areas**: Applications to downhole commingle in wellbores within pools or areas that have been established by the division as "pre-approved pools or areas" pursuant to Subparagraph (b) of Paragraph (4) of Subsection C of 19.15.5.303 NMAC shall be filed on form C-103 (sundry notice of intent) at the appropriate division district office. The supervisor of the appropriate division district office may approve the proposed downhole commingling following receipt of form C-103. In addition to the information required by form C-103, the applicant shall include:

(i) number of division order that established pre-approved pool or area;

(ii) names of pools to be commingled;

(iii) perforated intervals;

(iv) allocation method and supporting data;

(v) a statement that the commingling will not reduce the value of the total remaining production;

(vi) in those instances where the ownership or percentages between the pools to be commingled is not identical, a statement attesting that applicant sent notice to all interest owners in the spacing unit by certified mail (return receipt) of its intent to apply for downhole commingling and no objection was received within 20 days of sending this notice; and

(vii) a statement attesting that applicant sent a copy of the division form C-103 to the commissioner of public lands for the state of New Mexico for wells in spacing units containing state lands or the bureau of land management for wells in spacing units containing federal lands using sundry notice form 3160-5.

(c) Exceptions for wells located in areas subject to a downhole commingling order issued in a "reference case": Applications to downhole commingle in wellbores within an area subject to a division order that excepted any of the criteria required by Subsection C of 19.15.5.303 NMAC or division form C-107-A shall be filed with the supervisor of the appropriate division district office and, except for the place of filing, shall meet the requirements of the applicable order issued in that "reference case".

(4) Applications for establishing a "reference case" or for pre-approval of downhole commingling on an area-wide or pool-wide basis:

(a) Reference cases: If sufficient data exists for a lease, pool, formation, or geographical area to render it unnecessary to repeatedly provide such data on form C-107-A, an operator may except any of the various criteria required under Subsection C of 19.15.5.303 NMAC or set forth in form C-107-A by establishing a "reference case." The division, upon its own motion or application from an operator, may establish "reference cases" either administratively or by hearing. Upon division approval of such "reference cases" for specific criteria, subsequent form C-107-A applications to downhole commingle will be required only to cite the division order number that established such exceptions and shall not be required to submit data for those criteria. Cases involving exceptions to the specific criteria required by Subsection C of 19.15.5.303 NMAC or by division form C-107-A may be approved by the division after notice sent to all interest owners in the affected spacing units by certified mail (return receipt) and based on evidence that such approval would adequately satisfy the conditions of Paragraph (1) of Subsection C of 19.15.5.303 NMAC.

(b) Pre-approval of downhole commingling on a pool-wide or area-wide basis: If sufficient data exists for multiple formations or pools that have previously been commingled or are proposed to be commingled, the division, upon its own motion or application from an operator, may establish downhole commingling on a pool-wide or area-wide basis either administratively or by hearing:

(i) Applications for pre-approval shall include all of the data required by division form C-107-A, a list of the names and address of all operators in the pools, all previous orders authorizing downhole commingling for the pools or area, and a map showing the location of all wells in the pools or area and indicating those wells approved for downhole commingling.

(ii) Applications for pre-approval of downhole commingling on a pool-wide or area-wide basis may be approved by the director after notice sent to operators in the affected pools or area by certified mail (return receipt) and based on evidence that such approval would adequately satisfy the conditions of Subsection C of 19.15.5.303 NMAC.

(iii) Upon approval of certain pools or areas for downhole commingling, subsequent applications for approval to downhole commingle wells within those pools or areas may be obtained by filing a division sundry notice (form C-103) in accordance with the procedure set forth in Subparagraph (b) of Paragraph (3) of Subsection C of 19.15.5.303 NMAC.

(c) The division will maintain and continually update a list of pre-approved pools or areas as set forth in Paragraph (5) of Subsection C of 19.15.5.303 NMAC.

(5) Pre-approved pools and areas: Downhole commingling is hereby approved within the described pool combinations or geographical areas set forth in Exhibit "A," provided, however, that the operator shall file form C-103 (sundry notice of intent) with the appropriate division district office in accordance with the procedure set forth in Subparagraph (b) of Paragraph (3) of Subsection C of 19.15.5.303 NMAC.

Pre-approved pools or geographic areas for downhole commingling, permian basin

All Blinebry, Tubb, Drinkard, Blinebry-Tubb, Blinebry-Drinkard & Tubb-Drinkard pool combinations within the following described geographic area in Lea County:

Township 18 South, Ranges 37, 38 and 39 East;
Township 19 South, Ranges 36, 37, 38 and 39 East;
Township 20 South, Ranges 36, 37, 38 and 39 East;
Township 21 South, Ranges 36, 37 and 38 East;
Township 22 South, Ranges 36, 37 and 38 East;
Township 23 South, Ranges 36, 37 and 38 East;
Township 24 South, Ranges 36, 37 and 38 East;
Township 25 South, Ranges 36, 37 and 38 East;
Township 26 South, Ranges 36, 37 and 38 East;

Blinebry Pools

6660 Blinebry Oil & Gas Pool (Oil)
72480 Blinebry Oil & Gas Pool (Pro Gas)
6670 West Blinebry Pool
12411 Cline Lower Paddock-Blinebry Pool
29710 Hardy-Blinebry Pool
31700 East Hobbs-Blinebry Pool
31680 Hobbs Upper-Blinebry Pool
31650 Hobbs Lower-Blinebry Pool
33230 House-Blinebry Pool
33225 South House-Blinebry Pool
34200 Justis-Blinebry Pool
46990 Monument-Blinebry Pool
47395 Nadine-Blinebry Pool
47400 West Nadine Paddock-Blinebry Pool
47960 Oil Center-Blinebry Pool
96314 North Teague Lower Paddock-Blinebry Assoc.
58300 Teague Paddock-Blinebry Pool
59310 East Terry-Blinebry Pool
63780 Weir-Blinebry Pool
63800 East Weir-Blinebry Pool

Tubb Pools

12440 Cline-Tubb Pool
77120 Fowler-Tubb Pool
26635 South Fowler-Tubb Pool
78760 House-Tubb Pool
33460 East House-Tubb Pool
33470 North House-Tubb Pool
47090 Monument-Tubb Pool
47525 Nadine-Tubb Pool
47530 West Nadine-Tubb Pool
58910 Teague-Tubb Pool
96315 North Teague-Tubb Associated Pool
60240 Tubb Oil & Gas Pool (Oil)
86440 Tubb Oil & Gas Pool (Pro Gas)
87080 Warren-Tubb Pool
87085 East Warren-Tubb Pool

Drinkard Pools

7900 South Brunson Drinkard-Abo Pool
12430 Cline Drinkard-Abo Pool
15390 D-K Drinkard Pool
19190 Drinkard Pool
19380 South Drinkard Pool
26220 Fowler-Drinkard Pool
28390 Goodwin-Drinkard Pool
31730 Hobbs-Drinkard Pool
33250 House-Drinkard Pool
47503 East Nadine-Drinkard Pool
47505 West Nadine-Drinkard Pool
47510 Nadine Drinkard-Abo Pool
57000 Skaggs-Drinkard Pool
96768 Northwest Skaggs-Drinkard Pool
58380 Teague-Drinkard Pool
96313 North Teague Drinkard-Abo Pool
63080 Warren-Drinkard Pool
63120 East Warren-Drinkard Pool
63840 Weir-Drinkard Pool

Blinebry-Tubb Pools

62965 Warren Blinebry-Tubb Oil & Gas Pool

Tubb-Drinkard Pools

18830 Dollarhide Tubb-Drinkard Pool
29760 Hardy Tubb-Drinkard Pool
96356 North Hardy Tubb-Drinkard Pool
33600 Imperial Tubb-Drinkard Pool
35280 Justis Tubb-Drinkard Pool

Pool-Combinations, Lea County

Airstrip-Bone Spring (960) & Airstrip-Wolfcamp (970) Pools
Baish-Wolfcamp (4480) & Maljamar-Abo (43250) Pools
Blinebry Oil & Gas & Wantz-Abo (62700) Pools

Blinebry Oil & Gas & South Brunson-Ellenburger (8000) Pools
Blinebry Oil & Gas & Paddock (49210) Pools
Cerca Lower-Wolfcamp (11800) & Cerca Upper-Pennsylvanian (11810) Pools
Drinkard (19190) & Paddock (49210) Pools
Drinkard (19190) & Wantz-Abo (62700) Pools
Drinkard (19190) & Wantz-Granite Wash (62730) Pools
Lazy J Penn (37430) & South Baum-Wolfcamp (4967) Pools
Mesa Verde-Delaware (96191) & Mesa Verde-Bone Spring (96229) Pools
West Red Tank-Delaware (51689) & Red Tank-Bone Spring (51683) Pools
South Shoe Bar-Wolfcamp (56300) & South Shoe Bar Upper-Penn (56285) Pools
Skaggs-Glorieta (57190) & Skaggs-Drinkard (57000) Pools
West Triste Draw-Delaware (59945) & South Sand Dunes Bone Spring (53805) Pools
Triste Draw-Delaware (59930) & Triste Draw-Bone Spring (96603) Pools
Tubb Oil & Gas & Paddock (49210) Pools
North Vacuum-Abo (61760) & Vacuum-Wolfcamp (62340) Pools
Vacuum-Blinebry (61850) & Vacuum-Glorieta (62160) Pools
Vacuum-Blinebry (61850) & Vacuum-Drinkard (62110) Pools
Vacuum Upper-Penn (62320) & Vacuum-Wolfcamp (62340) Pools
Wantz-Abo (62700) & Wantz-Granite Wash (62730) Pools
Pool Combinations, Eddy County
Red Lake Queen-Grayburg-San Andres (51300) & Northeast Red Lake-Glorieta Yeso (96836) Pools
Pool Combination, San Juan Basin
Basin-Dakota (71599) & Angels Peak-Gallup Associated (2170) Pools
Basin-Dakota (71599) & Armenta-Gallup (2290) Pools
Basin-Dakota (71599) & Baca-Gallup (3745) Pools
Basin-Dakota (71599) & Bisti Lower-Gallup (5890) Pools
Basin-Dakota (71599) & BS Mesa-Gallup (72920) Pools
Basin-Dakota (71599) & Calloway-Gallup (73700) Pools
Basin-Dakota (71599) & Devils Fork-Gallup Associated (17610) Pools
Basin-Dakota (71599) & Ensenada-Gallup (96321) Pools
Basin-Dakota (71599) & Flora Vista-Gallup (76640) Pools
Basin-Dakota (71599) & Gallegos-Gallup Associated (26980) Pools
Basin-Dakota (71599) & Ice Canyon-Gallup (93235) Pools
Basin-Dakota (71599) & Kutz-Gallup (36550) Pools
Basin-Dakota (71599) & Largo-Gallup (80000) Pools
Basin-Dakota (71599) & Otero-Gallup (48450) Pools
Basin-Dakota (71599) & Tapacito-Gallup Associated (58090) Pools
Basin-Dakota (71599) & Wild Horse-Gallup (87360) Pools
Basin-Dakota (71599) & Aztec-Pictured Cliffs (71280) Pools
Basin-Dakota (71599) & Ballard-Pictured Cliffs (71439) Pools
Basin-Dakota (71599) & Blanco-Pictured Cliffs (72359) Pools
Basin-Dakota (71599) & South Blanco-Pictured Cliffs (72439) Pools
Basin-Dakota (71599) & Fulcher Kutz-Pictured Cliffs (77200) Pools
Basin-Dakota (71599) & West Kutz-Pictured Cliffs (79680) Pools
Basin-Dakota (71599) & Tapacito-Pictured Cliffs (85920) Pools
Basin-Fruitland Coal (71629) & Aztec-Pictured Cliffs (71280) Pools
Basin-Fruitland Coal (71629) & Ballard-Pictured Cliffs (71439) Pools
Basin-Fruitland Coal (71629) & Blanco-Pictured Cliffs (72359) Pools
Basin-Fruitland Coal (71629) & East Blanco-Pictured Cliffs (72400) Pools
Basin-Fruitland Coal (71629) & South Blanco-Pictured Cliffs (72439) Pools

Basin-Fruitland Coal (71629) & Carracas-Pictured Cliffs (96154) Pools
Basin-Fruitland Coal (71629) & Choza Mesa-Pictured Cliffs (74960) Pools
Basin-Fruitland Coal (71629) & Fulcher Kutz-Pictured Cliffs (77200) Pools
Basin-Fruitland Coal (71629) & West Kutz-Pictured Cliffs (79680) Pools
Basin-Fruitland Coal (71629) & Gavilan-Pictured Cliffs (77360) Pools
Basin-Fruitland Coal (71629) & Gobernador-Pictured Cliffs (77440) Pools
Basin-Fruitland Coal (71629) & Huerfano-Pictured Cliffs (78840) Pools
Basin-Fruitland Coal (71629) & Potwin-Pictured Cliffs (83000) Pools
Basin-Fruitland Coal (71629) & Tapacito-Pictured Cliffs (85920) Pools
Basin-Fruitland Coal (71629) & Twin Mounds Fruitland Sand-Pictured Cliffs (86620) Pools
Basin-Fruitland Coal (71629) & W. A. W. Fruitland Sand-Pictured Cliffs (87190)
Blanco-Mesaverde (72319) & Basin-Dakota (71599) Pools
Blanco-Mesaverde (72319) & Blanco-Pictured Cliffs (72359) Pools
Blanco-Mesaverde (72319) & South Blanco-Pictured Cliffs (72439) Pools
Blanco-Mesaverde (72319) & Gobernador-Pictured Cliffs (77440) Pools
Blanco-Mesaverde (72319) & West Lindrith Gallup-Dakota (39189) Pools
Blanco-Mesaverde (72319) & Tapacito-Pictured Cliffs (85920) Pools
Blanco-Mesaverde (72319) & Armenta-Gallup (2290) Pools
Blanco-Mesaverde (72319) & BS Mesa-Gallup (72920) Pools
Blanco-Mesaverde (72319) & Calloway-Gallup (73700) Pools
Blanco-Mesaverde (72319) & Ensenada-Gallup (96321) Pools
Blanco-Mesaverde (72319) & Flora Vista-Gallup (76640) Pools
Blanco-Mesaverde (72319) & Largo-Gallup (80000) Pools
Blanco-Mesaverde (72319) & West Lindrith Gallup-Dakota (39189) Pools
Blanco-Mesaverde (72319) & McDermott Gallup (81050) Pools
Blanco-Mesaverde (72319) & Potter-Gallup (50387) Pools
Blanco-Mesaverde (72319) & Tapacito-Gallup Associated (58090) Pools
Blanco-Mesaverde (72319) & Wild Horse-Gallup (87360) Pools
Otero-Chacra (82329) & Aztec-Pictured Cliffs (71280) Pools
Otero-Chacra (82329) & Basin-Dakota (71599) Pools
Otero-Chacra (82329) & Blanco-Mesaverde (72319) Pools
Otero-Chacra (82329) & South Blanco-Pictured Cliffs (72439) Pools
Otero-Chacra (82329) & Fulcher Kutz-Pictured Cliffs (77200) Pools

D. Off-lease transportation or storage prior to measurement**.** The division may grant exceptions to the requirements of Subsection A of 19.15.5.303 NMAC, administratively, without hearing, to permit production from one lease to be transported prior to measurement to another lease for storage thereon when:

(1) an application for off-lease transportation or storage prior to measurement has been filed on division form C-107-B with the Santa Fe office of the division with one copy to the appropriate district office of the division;

(2) all such production is from the same common source of supply;

(3) commingling of production from different leases will not result;

(4) there will be no intercommunication of the handling, separating, treating or storage facilities designated to each lease;

(5) all parties owning working interests in any of the production to be transported off lease prior to measurement have been notified of the application in accordance with the provisions of 19.15.N.1207.A NMAC and have consented in writing ;

(6) in lieu of Paragraph (5), Subsection D of 19.15.5.303 NMAC, the applicant furnishes proof that said parties were notified by registered or certified mail of its intent to transport the production from one lease to another lease for storage prior to measurement, and after a period of twenty (20) days following receipt of the application, no party has filed objection to the application; and

(7) if state, federal or Indian lands are involved, the commissioner of public lands for the state of New Mexico or the United States bureau of land management (as applicable) has been notified. The division may set for hearing any application for approval of off-lease transportation or storage prior to measurement, in which event notice of hearing shall be given, pursuant to 19.15.N.1207.A NMAC, to all owners of working interests in any of the production to be transported off lease prior to measurement, and to such other owners as the division may direct.
[1-1-50…2-1-96; 19.15.5.303 NMAC - Rn, 19 NMAC 15.E.303 & A, 5-15-00; A, 3-31-03]

19.15.5.304 CONTROL OF MULTIPLE COMPLETED WELLS:
Multiple completed wells which have been authorized by the division shall at all times be operated, produced, and maintained in a manner to ensure the complete segregation of the various common sources of supply. The division may require such tests as it deems necessary to determine the effectiveness of segregation of the different common sources of supply.
[1-1-50...2-1-96; 19.15.5.304 NMAC - Rn, 19 NMAC 15.E.304, 5-15-00]

19.15.5.305 METERED CASINGHEAD GAS:
The owner of a lease shall not be required to measure the exact amount of casinghead gas produced and used by him for fuel purposes in the development and normal operation of the lease. All casinghead gas produced and sold or transported away from a lease, except small amounts of flare gas, shall be metered and reported in standard cubic feet monthly to the division. The amount of casinghead gas sold in small quantities for use in the field may be calculated upon a basis generally acceptable in the industry, or upon a basis approved by the division in lieu of meter measurements.
[1-1-50...2-1-96; 19.15.5.305 NMAC - Rn, 19 NMAC 15.E.305, 5-15-00]

19.15.5.306 CASINGHEAD GAS:

A. No casinghead gas produced from any well in this state shall be flared or vented after 60 days following completion of the well.

B. Any operator seeking an exception to the foregoing shall file an application therefor on division form C-129, application for exception to no-flare rule 306. Form C-129 shall be filed in triplicate with the appropriate district office of the division. The district supervisor may grant an exception when the same appears reasonably necessary to protect correlative rights, prevent waste, or prevent undue hardships on the applicant. The district supervisor shall either grant the exception within ten days after receipt of the application or refer it to the division director who will advertise the matter for public hearing if a hearing is desired by the applicant.

C. The flaring or venting by an operator of gas from any well in violation of this rule will result in suspension of the allowable assigned to the well.

D. No extraction plant processing gas in the state of New Mexico shall flare or vent such gas unless such flaring or venting is made necessary by mechanical difficulty of a very limited temporary nature or unless the gas flared or vented is of no commercial value.

E. In the event of a more prolonged mechanical difficulty or in the event of plant shut-downs or curtailment because of scheduled or non-scheduled maintenance or testing operations or other reasons, or in the event a plant is unable to accept, process, and market all of the casinghead gas produced by wells connected to its system, the plant operator shall notify the division as soon as possible of the full details of such shut-down or curtailment, following which the division shall take such action as is necessary to reduce the total flow of gas to such plant.

F. Pending connection of a well to a gas-gathering facility, or when a well has been excepted from the provisions of Paragraph A. of this rule, all gas produced and not utilized shall be burned, and the estimated volume reported on the monthly production report, form C-115.

G. The provisions of Paragraph A. of this rule shall not be applicable to wells completed prior to January 1, 1971, in pools which had no gas-gathering facilities on that date, provided however, said provisions shall be applicable to all wells in such a pool 60 days after the date of first casinghead gas connection in the pool.
[9-1-72...2-1-96; 19.15.5.306 NMAC - Rn, 19 NMAC 15.E.306, 5-15-00]

19.15.5.307 OPERATION AT BELOW ATMOSPHERIC PRESSURE:

A. A well operator may use vacuum pumps, gathering system compressors or other devices to operate a well or gathering system at below atmospheric pressure only if that operator has:

(1) executed a written agreement with the operator of the downstream gathering system or pipeline to which the well or gathering system so operated is immediately connected allowing operation of the well or gathering system at below atmospheric pressure; and

(**2)** filed a sundry notice in the appropriate district office of the division for each well operated at below atmospheric pressure or served by a gathering system operated at below atmospheric pressure, within ninety (90) days before beginning operation at below atmospheric pressure, notifying the division that the well or gathering system serving the well is being operated at below atmospheric pressure.

B. A gathering system operator may use vacuum pumps, gathering system compressors or other devices to operate a gathering system at below atmospheric pressure, or may accept gas originating from a well operated at below atmospheric pressure or that has been carried by any upstream gathering system operated at below atmospheric pressure, only if that operator has executed a written agreement with the operator of the downstream gathering system or pipeline to which the gathering system is immediately connected allowing delivery of gas from a well or gathering system that has been operated at below atmospheric pressure into the downstream gathering system or pipeline.

[1-1-50...2-1-96; 19.15.5.307 NMAC - Rn, 19 NMAC 15.E.307, 5-15-00; Repealed, 08/31/04; N, 08/31/04]

19.15.5.308 SALT OR SULPHUR WATER:

Operators shall report monthly on form C-115 the amount of water produced with the oil and gas from each well.

[1-1-50...2-1-96; 19.15.5.308 NMAC - Rn, 19 NMAC 15.E.308, 5-15-00]

19.15.5.309 AUTOMATIC CUSTODY TRANSFER EQUIPMENT:

A. Oil shall be received and measured in a facility of an approved design. Such facilities shall permit the testing of each well at reasonable intervals and may be comprised of manually gauged, closed stock tanks for which proper strapping tables have been prepared, or of automatic custody transfer (ACT) equipment. The use of such automatic custody transfer equipment shall be permitted only after compliance with the following: The operator shall file with the division form C-106, notice of intention to utilize automatic custody transfer equipment, and shall receive approval thereof prior to transferring oil through the ACT system. The carrier shall not accept delivery of oil through the ACT system until form C-106 has been approved.

B. Form C-106 shall be submitted in quadruplicate to the appropriate district office of the division and shall be accompanied (in quadruplicate) by the following:

(1) Plat of the lease showing thereon all wells which will be produced into the ACT system.

(2) Schematic diagram of the ACT equipment, showing thereon all major components such as surge tanks and their capacity, extra storage tanks and their capacity, transfer pumps, monitors, reroute valves, treaters, samplers, strainers, air and gas eliminators, back pressure valves, metering devices, (indicating type and capacity, i.e. whether automatic measuring tank, positive volume metering chamber, weir-type measuring vessel, or positive displacement meter). Schematic diagram shall also show means employed to prove accuracy of measuring device.

(3) Letter from transporter agreeing to utilization of ACT system as shown on schematic diagram.

C. Form C-106 will not be approved by the division unless the ACT system is to be installed and operated in compliance with the following:

(1) Provision must be made for accurate determination and recording of uncorrected volume and applicable temperature, or of temperature corrected volume. The overall accuracy of the system shall equal or surpass manual methods.

(2) Provision must be made for representative sampling of the oil transferred for determination of API gravity and BS&W content.

(3) Provision must be made if required by either the producer or the transporter of the oil to give adequate assurance that only merchantable oil is run by the ACT system.

(4) Provision must be made for set-stop counters to stop the flow of oil through the ACT system at or prior to the time the allowable has been run. All counters shall provide non-reset totalizers which shall be visible for inspection at all times.

(5) All necessary controls and equipment must be enclosed and sealed, or otherwise be so arranged as to provide assurance against, or evidence of, accidental or purposeful mismeasurement resulting from tampering.

(6) All components of the ACT system shall be properly sized to ensure operation within the range of their established ratings. All components of the system which require periodic calibration and/or inspection for proof of continued accuracy must be readily accessible. The frequency and methods of such calibration and/or inspection shall be set forth in Paragraph (12) of Subsection C of 19.15.5 NMAC.

(7) The control and recording system must include adequate fail-safe features which will provide assurance against mismeasurement in the event of power failure, or the failure of the ACT system's component parts.

(8) The ACT system and allied facilities shall include such fail-safe equipment as may be necessary, including high level switches in the surge tank or overflow storage tank which, in the event of power failure or malfunction of the ACT or other equipment, will shut down all artificially lifted wells connected to the ACT system and will shut in all flowing wells at the well-head or at the header manifold, in which latter case all flowlines shall be pressure-tested to at least 1 ½ times the maximum well-head shut-in pressure prior to initial use of the ACT system and each two years thereafter.

(9) As an alternative to the requirements of, Paragraph (8) of Subsection C of 19.15.5 NMAC the producer shall provide and shall at all times maintain a minimum of available storage capacity above the normal high working level of the surge tank to receive and hold the amount of oil which may be produced during maximum unattended time of lease operation.

(10) In all ACT systems employing automatic measuring tanks, weir-type measuring vessels, positive volume metering chambers, or any other volume measuring container, the container and allied components shall be properly calibrated prior to initial use and shall be operated, maintained, and inspected as necessary to ensure against incrustation, changes in clingage factors, valve leakage or other leakage, and improper action of floats, level detectors, etc.

(11) In all ACT systems employing positive displacement meters, the meter(s) and allied components shall be properly calibrated prior to initial use and shall be operated, maintained, and inspected as necessary to ensure against mismeasurement of oil.

(12) The measuring and recording devices of all ACT systems shall be checked for accuracy at least once each month unless exception to such determination has been obtained from the division director. API standard 1101, "measurement of petroleum liquid hydrocarbons by positive displacement meter," shall be used where applicable. Meters may be proved against master meters, portable prover tanks, or prover tanks permanently installed on the lease. If permanently installed prover tanks are used, the distance between the opening and closing levels and the provision for determining the opening and closing readings shall be sufficient to detect variations of 5/100 of one percent. Reports of determination shall be filed on the division form entitled "meter test report," or on another acceptable form and shall be submitted in duplicate to the appropriate district office of the division.

(13) To obtain exception to the requirement of Paragraph (12) of Subsection C of 19.15.5 NMAC that all measuring and recording devices be checked for accuracy once each month, either the producer or transporter may file such a request with the division director setting forth all facts pertinent to such exception. The application shall include a history of the average factors previously obtained, both tabulated and plotted on a graph of factors versus time, showing that the particular installation has experienced no erratic drift. The applicant shall also furnish evidence that the other interested party has agreed to such exception. The division director may then set the frequency for determination of the system's accuracy at the interval which he deems prudent.

D. Failure to operate an automatic custody transfer system in compliance with this rule shall subject the approval thereof to revocation by the division.

[5-1-61…2-1-96; 19.15.5.309 NMAC - Rn, 19 NMAC 15.E.309, 5-15-00, A, 3-31-03]

19.15.5.310 TANKS, OIL TANKS, FIRE WALLS, AND TANK IDENTIFICATION:

A. Oil shall not be stored or retained in earthen reservoirs, or in open receptacles. Dikes or fire walls shall not be required except such fire walls must be erected and kept around all permanent oil tanks, or battery of tanks that are within the corporate limits of any city, town or village, or where such tanks are closer than 150 feet to any producing oil or gas well or 500 feet to any highway or inhabited dwelling or closer than 1000 feet to any school or church, or where such tanks are so located as to be deemed an objectional hazard within the discretion of the division. Where fire walls are required, fire walls shall form a reservoir having a capacity one-third larger than the capacity of the enclosed tank or tanks.

B. After August 1, 1982, all oil tanks, tank batteries, automatic custody transfer systems, tanks used for salt water collection or disposal, and tanks used for sediment oil treatment or storage shall be identified by a sign posted on or not more than 50 feet from the tank, tank battery, or system. Such signs shall be of durable construction and the lettering thereon shall be kept in a legible condition and shall be large enough to be legible under normal conditions at a distance of 50 feet and shall identify the name of the operator, the name of the lease(s) being served by the tank(s) or system, if any, and the location of such tank(s) or system by unit letter, section, township, and range.

[1-1-50...2-1-96; 19.15.5.310 NMAC - Rn, 19 NMAC 15.E.310, 5-15-00]

19.15.5.311 SEDIMENT OIL, TANK CLEANING, AND TRANSPORTATION OF MISCELLANEOUS HYDROCARBONS:

A. "Sediment oil" is defined as tank bottoms and any other accumulations of liquid hydrocarbons on an oil and gas lease, which hydrocarbons are not merchantable through normal channels.

B. No tank shall be cleaned of sediment oil nor shall sediment oil be removed from any lease without prior approval of the appropriate division district office. Authorization for tank cleaning may be received by the operator of the lease or by the company contracted or otherwise authorized to perform the tank cleaning by obtaining approval on form C-117-A (tank cleaning, sediment oil removal, transportation of miscellaneous hydrocarbons and disposal permit). No operator, contractor, or other party shall engage in the cleaning of any tank of sediment oil or the removal of sediment oil from any lease without an approved copy of form C-117-A at the site.

C. No sediment oil shall be destroyed unless and until the appropriate division district office has approved an application to destroy the same on form C-117-A (tank cleaning, sediment oil removal, transportation of miscellaneous hydrocarbons and disposal permit). Unless the authorization to destroy sediment oil is utilized within ten (10) days after approval of the form C-117-A such authorization is automatically revoked. However, the district supervisor may approve one ten (10) day extension for good cause shown.

D. Any operator, contractor, or party, other than a treating plant operator, who cleans any tank of sediment oil and removes sediment oil from any lease shall file form C-117-B (monthly sediment oil disposal statement) setting out all information required thereon.

E. A representative sample of sediment oil from any source shall be tested in a manner designed to accurately estimate the percentage of good oil expected to be recovered therefrom. Such test shall be performed prior to transport and prior to commingling with sediment oil from other leases or sources and the results recorded on the appropriate form C-117-A. The division recommends the standard centrifugal tests prescribed by API Manual of Petroleum Measurement Standards, Chapter 10, Section 4. Other test procedures may be used if such procedures reliably predict the percentage of good oil to be recovered from sediment oil.

F. All sediment oil removed from storage shall be reported on form C-115 (operator's monthly report) together with the form C-117-A (tank cleaning, sediment oil removal, transportation of miscellaneous hydrocarbons and disposal permit) permit number.

G. "Miscellaneous hydrocarbons" are defined as tank bottoms occurring at pipeline stations, crude oil storage terminals, or refineries, pipeline break oil, catchings collected in traps, drips, or scrubbers by operators of gasoline plants in such plants or in the gathering lines serving such plants, the catchings collected in private, community, or commercial salt water disposal systems, or any other liquid hydrocarbon which is not lease crude or condensate.

H. Except in case of emergency, no miscellaneous hydrocarbons shall be delivered to a treating plant or other facility until division approval is obtained on form C-117-A (tank cleaning, sediment oil removal, transportation of miscellaneous hydrocarbons and disposal permit).

I. Whenever an emergency exists which requires delivery of miscellaneous hydrocarbons to a treating plant or other facilities prior to approval of form C-117-A, the transporter of such hydrocarbons shall notify the supervisor of the appropriate division district office of the nature and extent of such emergency on the first working day following the emergency and shall file form C-117-A within two working days following the emergency. For prolonged emergencies, the district supervisor may authorize the extended movement of miscellaneous hydrocarbons to a treating plant or other facilities during the period of the emergency and shall approve a form C-117-A filed subsequent to the conclusion of such emergency covering the entire volume of miscellaneous hydrocarbons transported.
[1-1-50…2-1-96; 19.15.5.311 NMAC - Rn, 19 NMAC 15.E.311, 5-15-00]

19.15.5.312 RESERVED: [Formerly "Treating Plants". Repealed 7-26-95]

19.15.5.313 EMULSION, BASIC SEDIMENTS, AND TANK BOTTOMS: Wells producing oil shall be operated in such a manner as will reduce as much as practicable the formation of emulsion and basic sediments. These substances and tank bottoms shall not be allowed to pollute fresh waters or cause surface damage.
[1-1-50...2-1-96; 19.15.5.313 NMAC - Rn, 19 NMAC 15.E.313, 5-15-00; A, 03/31/04]

19.15.5.314 GATHERING, TRANSPORTING AND SALE OF DRIP:

A. "Drip" is defined as any liquid hydrocarbon incidentally accumulating in a gas gathering or transportation system.

B. The waste of drip is hereby prohibited when it is economically feasible to salvage the same.

C. The movement and sale of drip is hereby authorized, provided the provisions of this Rule are complied with.

D. No drip shall be transported nor sold until the gas transporter has filed division form C-104 designating the drip transporter authorized to remove the drip from its gas gathering or transportation system.

E. Every person transporting drip within the state of New Mexico shall file division form C-112 each month, showing the amount, source, and disposition of all drip handled during the reporting period, and such other reports as may hereafter be required by the division.

F. Prior to commencement of operations, every person transporting drip directly from a gas gathering or transportation system shall file with the division plats drawn to scale, locating and identifying each drip trap which he is authorized to service.

G. Every person transporting drip directly from a gas gathering or transportation system shall keep a record of daily acquisitions from each drip trap which he is authorized to service, which records shall be made available at all reasonable times for inspection by the division or its authorized representatives.

H. Every gas transporter in the state of New Mexico shall, on or before the first day of November of each year, file with the division maps of its entire gas gathering and transportation systems within the state of New Mexico, locating and identifying thereon each drip trap in said systems, said maps to be accompanied by a report, on a form prescribed by the division, showing the disposition being made of the drip from each of said drip traps.
[8-26-57…2-1-96; 19.15.5.314 NMAC - Rn, 19 NMAC 15.E.314, 5-15-00]

History of 19.15.5 NMAC:
Pre-NMAC History:
Rule 301, Gas-Oil Ratio and Production Tests, filed 1-8-82;
Rule 301, Gas-Oil Ratio and Production Tests, filed 10-11-89;
Rule 301, Gas-Oil Ratio and Production Tests, filed 2-5-91;
Rule 302, Subsurface Pressure Tests, filed 1-8-82;
Rule 302, Subsurface Pressure Tests, filed 2-5-91;
Rule 303, Segregation of Production from Pools, filed 1-8-82;
Rule 303, Amendment No. 1, Segregation of Production from Pools, filed 1-27-82;

Rule 303, Segregation of Production from Pools, filed 10-11-89;
Rule 303, Segregation of Production from Pools, filed 2-5-91;
Rule 304, Control of Multiple Completed Wells, filed 1-8-82;
Rule 304, Control of Multiple Completed Wells, filed 2-5-91;
Rule 305, Metered Casinghead Gas, filed 1-8-82;
Rule 305, Metered Casinghead Gas, filed 2-5-91;
Rule 306, Casinghead Gas, filed 1-8-82;
Rule 306, Amendment No. 1, Casinghead Gas, filed 2-23-84;
Rule 306, Casinghead Gas, filed 2-5-91;
Rule 307, Use of Vacuum Pumps, filed 1-8-82;
Rule 307, Use of Vacuum Pumps, filed 2-5-91;
Rule 308, Salt or Sulfur Water, filed 1-8-82;
Rule 308, Produced Water, filed 9-16-85;
Rule 308, Salt or Sulfur Water, filed 2-5-91;
Rule 309-A, Central Tank Batteries - Automatic Custody Transfer Equipment, filed 1-8-82;
Rule 309-A, Central Tank Batteries - Automatic Custody Transfer Equipment, filed 2-5-91;
Rule 309-B, Administrative Approval, Lease Commingling, filed 1-8-82;
Rule 309-B, Administrative Approval, Lease Commingling, filed 2-5-91;
Rule 309-C, Administrative Approval, Off-Lease Storage, filed 1-8-82;
Rule 309-C, Administrative Approval, Off-Lease Storage, filed 10-11-89;
Rule 309-C, Administrative Approval, Off-Lease Storage, filed 2-5-91;
Rule 310, Tanks, Oil Tanks, Fire Walls, and Tank Identification, filed 1-8-82;
Rule 310, Amendment No. 1, Tanks, Oil Tanks, Fire Walls, and Tank Identification, filed 1-27-82;
Rule 310, Tanks, Oil Tanks, Fire Walls, and Tank Identification, filed 2-5-91;
Rule 311, Sediment Oil, Tank Cleaning, and Transportation of Miscellaneous Hydrocarbons, filed 1-8-82;
Rule 311, Amendment No. 1, Sediment Oil, Tank Cleaning, and Transportation of Miscellaneous Hydrocarbons, filed 1-27-82;
Rule 311, Sediment Oil, Tank Cleaning, and Transportation of Miscellaneous Hydrocarbons, filed 2-5-91;
Rule 312, Treating Plants, filed 1-8-82
Rule 312, Amendment No. 1, Treating Plants, filed 1-27-82
Rule 312, Treating Plants, filed 8-20-86
Rule 312, Treating Plants, filed 8-17-89
Rule 312, Treating Plants, filed 10-11-89
Rule 312, Treating Plants, filed 7-26-95
Rule 312, Treating Plants, filed 2-5-91
Rule 313, Emulsion, Basic Sediments, and Tank Bottoms, filed 1-8-82;
Rule 313, Emulsion, Basic Sediments, and Tank Bottoms, filed 10-18-85;
Rule 313, Emulsion, Basic Sediments, and Tank Bottoms, filed 8-17-89;
Rule 313, Emulsion, Basic Sediments, and Tank Bottoms, filed 2-5-91;
Rule 314, Gathering, Transportation and Sale of Drip, filed 1-8-82;
Rule 314, Gathering, Transportation and Sale of Drip, filed 2-5-91.

History of Repealed Material: Rule 312, Treating Plants, filed 7-26-95.

Other History:
Rule 301, Gas-Oil Ratio and Production Tests, filed 2-5-91; Rule 302, Subsurface Pressure Tests, filed 2-5-91; Rule 303, Segregation of Production from Pools, filed 2-5-91; Rule 304, Control of Multiple Completed Wells, filed 2-5-91; Rule 305, Metered Casinghead Gas, filed 2-5-91; Rule 306, Casinghead Gas, filed 2-5-91; Rule 307, Use of Vacuum Pumps, filed 2-5-91; Rule 308, Salt or Sulfur Water, filed 2-5-91; Rule 309-A, Central Tank Batteries - Automatic Custody Transfer Equipment, filed 2-5-91; Rule 309-B, Administrative Approval, Lease Commingling,

filed 2-5-91; Rule 309-C, Administrative Approval, Off-Lease Storage, filed 2-5-91; Rule 310, Tanks, Oil Tanks, Fire Walls, and Tank Identification, filed 2-5-91; Rule 311, Sediment Oil, Tank Cleaning, and Transportation of Miscellaneous Hydrocarbons, filed 2-5-91; Rule 313, Emulsion, Basic Sediments, and Tank Bottoms, filed 2-5-91; Rule 314, Gathering, Transportation and Sale of Drip, filed 2-5-91; all renumbered, reformatted **to and replaced by** 19 NMAC 15.E, Oil Production Operating Practices, filed 01-18-96.
19 NMAC 15.E, Oil Production Operating Practices, filed 01-18-96 renumbered, reformatted **to and replaced by** 19.15.5 NMAC, effective 5-15-00.

TITLE 19 NATURAL RESOURCES & WILDLIFE
CHAPTER 15 OIL AND GAS
PART 6 NATURAL GAS PRODUCTION OPERATING PRACTICE

19.15.6.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department, Oil Conservation Division, 2040 South Pacheco, Santa Fe, New Mexico 87505, (505) 827-7131.
[2-1-96; 19.15.6.1 NMAC - Rn, 19 NMAC 15.F.1, 12-14-01]

19.15.6.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico.
[2-1-96; 19.15.6.1 NMAC - Rn, 19 NMAC 15.F.2, 12-14-01]

19.15.6.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the Oil and Gas Act which grants the Oil Conservation Division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights, and the disposition of wastes resulting from oil and gas operations.
[2-1-96; 19.15.6.3 NMAC - Rn, 19 NMAC 15.F.3, 12-14-01]

19.15.6.4 DURATION: Permanent.
[2-1-96; 19.15.6.4 NMAC - Rn, 19 NMAC 15.F.4, 12-14-01]

19.15.6.5 EFFECTIVE DATE: February 1, 1996.
[2-1-96; 19.15.6.5 NMAC - Rn, 19 NMAC 15.F.5, 12-14-01]

19.15.6.6 OBJECTIVE: To regulate the production of natural gas to enable the Oil Conservation Division to fulfill its statutory mandates under the Oil and Gas Act.
[2-1-96; 19.15.6.6 NMAC - Rn, 19 NMAC 15.F.6, 12-14-01]

19.15.6.7 DEFINITIONS: [RESERVED].

19.15.6.8-400 [RESERVED].

19.15.6.401 METHOD OF DETERMINING NATURAL GAS WELL POTENTIAL:

A. All operators shall conduct tests to determine the daily open flow potential volumes of all natural gas wells from which gas is being used or marketed. Such tests shall be reported on forms prescribed by the division within 60 days after:

(1) the date of initial connection of the well to a gas transportation facility; and

(2) the date of reconnection following workover.

B. To establish comparable open flow capacity, wells shall be tested in accordance with the Oil Conservation Division "Manual for Back-Pressure Testing of Natural Gas Wells." In the event the division approves the alternate method for testing, all wells producing from a common source of supply shall be tested in a uniform and comparable manner.

C. All gas wells which are not connected to a gas gathering facility shall be tested within 30 days following the installation of a christmas tree. Tests shall be taken in accordance with the Rules of Procedure for Testing Unconnected Gas Well contained in the Oil Conservation Division "Manual for Back-Pressure Testing of Natural Gas Wells." Tests shall be reported on Form C-122 in compliance with Rule 1122 and shall be filed within 10 days following completion of the test.
[5-25-64...2-1-96; 19.15.6.401 NMAC - Rn, 19 NMAC 15.F.401, 12-14-01]

19.15.6.402 [RESERVED].

[7-15-63...2-1-96; 19.15.6.402 NMAC - Rn, 19 NMAC 15.F.402, 12-14-01; 19.15.6.402 NMAC - Repealed, 02-17-03]

19.15.6.403 NATURAL GAS FROM GAS WELLS TO BE MEASURED:

A. All natural gas produced shall be accounted for by metering or other method approved by the division and reported to the division by the transporter of the gas. Gas produced from a gas well and delivered to a gas transportation facility shall be reported by the owner or operator of the gas transportation facility. Gas produced from a gas well and required to be reported under this rule, which is not delivered to and reported by a gas transportation facility shall be reported by the operator of the well.

B. An operator may apply to the OCD District Supervisor, using Form C-136, for approval of one of the following procedures for measuring gas:

(1) In the event a well is not capable of producing more than 15 MCFD, a measurement method agreed upon by the operator and transporter whereby the parties establish by annual test the producing rate of said well under normal operating conditions and apply that rate to the period of time the well is in a producing status. If such well is capable of producing greater than 5 MCFD, a device shall be attached to the line which will determine the actual time period that the well is flowing.

(2) Any well which has a producing capacity of 100 MCFD or less and which is on a multi-well lease may be produced without being separately metered when the gas is measured using a lease meter at a Central Point Delivery (CPD). The ownership of the lease must be common throughout including working interest, royalty and overriding royalty ownership.

(3) If normal operating conditions change, either party may request a new well test, the cost of which will be borne by the party so requesting unless otherwise agreed upon.

C. Operators and transporters shall report the well volumes on Forms C-115 and C-111 based upon the approved method of measurement and, in the case of a CPD, upon the method of allocation of production to individual wells approved by the district supervisor.

[1-1-50, 12-23-91...2-1-96; 19.15.6.403 NMAC - Rn, 19 NMAC 15.F.403, 12-14-01]

19.15.6.404 NATURAL GAS UTILIZATION:

A. After the completion of a natural gas well, no gas from such well shall be:

(1) permitted to escape to the air;

(2) used expansively in engines or pumps and then vented, or

(3) used to gas-lift wells unless all gas produced is processed in a gasoline plant, used in the manufacture of carbon black, or beneficially used thereafter without waste.

B. Carbon black plants may utilize natural gas only in those instances in which all casinghead gas and residue gas produced in the vicinity of or which may reasonably be reached from the carbon black plant, is being used beneficially.

C. Any carbon black plant constructed after June 10, 1954, or any then existing carbon black plant which enlarges or expands its facilities for the manufacture of carbon black, may utilize natural gas in the manufacture of carbon black only after permission of the division is obtained upon due notice and hearing.

[1-1-50, 6-10-54...2-1-96; 19.15.6.404 NMAC - Rn, 19 NMAC 15.F.404, 12-14-01]

19.15.6.405 STORAGE GAS:

With the exception of the requirement to meter and report monthly the amount of gas injected and the amount of gas withdrawn from storage, in the absence of waste these rules and regulations shall not apply to gas being injected into or removed from storage. (See Rule 1131.)

[1-1-50...2-1-96; 19.15.6.405 NMAC - Rn, 19 NMAC 15.F.405, 12-14-01]

19.15.6.406 CARBON DIOXIDE:

The statewide regulations relating to gas and natural gas, gas wells, and gas reservoirs including, but not limited to, those provisions relating to well locations, acreage dedication requirements, casing and cementing requirements, and measuring and reporting of production shall also apply to carbon dioxide gas, carbon dioxide wells, and carbon dioxide reservoirs.

[1-1-50...2-1-96; 19.15.6.406 NMAC - Rn, 19 NMAC 15.F.406, 12-14-01]

19.15.6.407 DISCONNECTION OF GAS WELLS:

All gas wells which are disconnected from intrastate gas transportation facilities shall be reported to the division by the operator of the well or wells within 30 days of the date of disconnection. Such notice must be filed on Form C-130 in compliance with Rule 1130.

[8-23-77...2-1-96; 19.15.6.407 NMAC - Rn, 19 NMAC 15.F.407, 12-14-01]

19.15.6.408 HARDSHIP GAS WELL:

A. Hardship gas well is defined as a gas well wherein "underground waste" will occur if the well should be shut-in or curtailed below its minimum sustainable flow rate.

B. No well shall be classified as a hardship gas well except after notice and hearing or upon appropriate administrative action of the division.

C. Wells approved as hardship gas wells under Sections 409 and/or 410 of 19.15.6 NMAC shall be given priority access (over other gas wells) to the current available gas market to the extent that they might otherwise be restricted below the approved minimum flow rate.

[3-2-84...2-1-96; 19.15.6.408 NMAC - Rn, 19 NMAC 15.F.408, 12-14-01]

19.15.6.409 APPLICATION FOR HARDSHIP GAS WELL CLASSIFICATION:

A. Application for hardship gas well classification shall be made in the form prescribed by the division and shall include the following:

(1) a narrative description of the problem(s) which leads the applicant to believe that underground waste will occur if the well is shut-in or curtailed below its ability to produce;

(2) documentation that the applicant has made all reasonable and economic attempts to eliminate or correct the problem(s) or an explanation and justification as to why such attempts were not made;

(3) a wellbore sketch;

(4) historical data such as permanent loss of productivity after shut-in, frequency and actual costs of swabbing after shut-in or curtailment including length of swab time required, actual cost figures showing the inability to continue operations without special relief, or any other data which would show that shut-in or curtailment would cause underground waste;

(5) if failure to obtain a hardship gas well classification would result in premature abandonment of the well, a calculation of the reserves which would be lost thereby;

(6) the minimum sustainable producing rate as determined by a minimum flow or "log-off" test or documentation of well production history;

(7) a plat and/or map showing the proration unit dedicated to the well and the ownership of the offsetting acreage;

(8) the name of the authorized transporter (and purchaser if different) of gas; and

(9) any other data the applicant considers relevant.

B. Applications for hardship gas well classification shall be made in duplicate with the original copy being filed at Santa Fe and a copy being filed with the appropriate division district office.

C. In addition, the applicant will notify the transporter and purchaser of gas from the well and all offset operators of the application and the requested minimum producing rate and shall so certify to the division in his application.

[3-2-84...2-1-96; 19.15.6.409 NMAC - Rn, 19 NMAC 15.F.409, 12-14-01]

19.15.6.410 PROCESSING OF APPLICATIONS FOR HARDSHIP GAS WELLS:

A. The director of the division may administratively approve any application for hardship gas well classification or he may set such matter for notice and hearing.

B. Applications which are to be approved administratively shall be listed in the dockets of division or commission hearings which are issued from time to time.

(1) If no affected party has filed written objection to any such proposed administrative action within 20 days following the date of the hearing for which the docket is issued, the application may be approved. If any such party shall file an objection before or within such 20 day period, the application will be set for hearing unless withdrawn by the applicant.

(2) The director of the division, on his own or upon the request of an affected party, may require a minimum flow (log-off) test on the well for which the hardship classification is being sought. The applicant shall give notice to the division, the gas transporter and purchaser and the requesting affected party of any minimum flow test conducted following such a request, in order that such test may, at the option of the division or said parties, be witnessed. Notice of any minimum flow test conducted prior to submitting a hardship gas well application shall be given to the appropriate division district office, the gas transporter and purchaser, and offset operators in order that such test may, at the option of said parties, be witnessed.

[3-2-84...2-1-96; 19.15.6.410 NMAC - Rn, 19 NMAC 15.F.410, 12-14-01]

19.15.6.411 EMERGENCY HARDSHIP GAS WELL CLASSIFICATION:

A. The supervisor of the appropriate division district office may grant emergency approval of a hardship gas well classification upon receipt of a copy of the application form and attachments and a request by the applicant.

B. Approval of such emergency classification shall be made in writing to the director of the division, the applicant, and the purchaser. Emergency approval shall be given for 90 days and on a one time only basis.

[3-2-84...2-1-96; 19.15.6.411 NMAC - Rn, 19 NMAC 15.F.411, 12-14-01]

19.15.6.412 LIMITS ON HARDSHIP GAS WELL CLASSIFICATION:

A. No hardship gas well classification shall be retained for a period in excess of one year unless the applicant shall annually request an extension thereof and certify that the condition of the well has not substantially changed.

B. The division on its own motion may require that the applicant show cause why approval of the hardship gas well classification should not be rescinded in cases of suspected abuse, changed market conditions, or for any other reason.

C. Any well classified as a hardship gas well located in a prorated gas pool shall accumulate over or under production. No well which is classified as a hardship gas well shall be shut in for reason of over production.

D. Affected parties may petition the division for hearing for the purpose of offsetting any ratable take advantage which might be gained by the operator of a hardship gas well.
[3-2-84...2-1-96; 19.15.6.412 NMAC - Rn, 19 NMAC 15.F.412, 12-14-01]

19.15.6.413 [RESERVED].

19.15.6.414 GAS SALES BY LESS THAN ONE HUNDRED PERCENT OF THE OWNERS IN A WELL: When there are separate owners in a well and where any such owner's gas is not being sold with current production from such well, such owner may, if necessary to protect his correlative rights, petition the division for a hearing seeking appropriate relief.
[1-1-84...2-1-96; 19.15.6.414 NMAC - Rn, 19 NMAC 15.F.414, 12-14-01]

History of 19.15.6 NMAC:
Pre-NMAC History:
Material in this part was derived from that previously filed with the commission of public records - state records center and archives as:
Rule 401, Method of Determining Natural Gas Well Potential, filed 1-8-82;
Rule 401, Method of Determining Natural Gas Well Potential, filed 2-5-91;
Rule 402, Method and Time of Shut-in Pressure Tests, filed 1-8-82;
Rule 402, Method and Time of Shut-in Pressure Tests, filed 11-6-86;
Rule 402, Method and Time of Shut-in Pressure Tests, filed 2-5-91;
Rule 403, Natural Gas from Gas Well to be Measured, filed 1-8-82;
Rule 403, Natural Gas from Gas Well to be Measured, filed 3-17-86;
Rule 403, Natural Gas from Gas Well to be Measured, filed 2-5-91;
Rule 404, Natural Gas Utilization, filed 1-8-82;
Rule 404, Natural Gas Utilization, filed 2-5-91;
Rule 405, Storage Gas, filed 1-8-82;
Rule 405, Storage Gas, filed 2-5-91;
Rule 406, Carbon Dioxide, filed 1-8-82;
Rule 406, Carbon Dioxide, filed 2-5-91;
Rule 407, Disconnection of Gas Wells, filed 1-8-82;
Rule 407, Disconnection of Gas Wells, filed 2-5-91;
Rule 408, Hardship Gas Well, filed 2-23-84;
Rule 408, Hardship Gas Well, filed 2-5-91;
Rule 409, Application for Hardship Gas Well Classification, filed 2-23-84;
Rule 409, Application for Hardship Gas Well Classification, filed 2-5-91;
Rule 410, Processing of Applications for Hardship Gas Wells, filed 2-23-84;
Rule 410, Processing of Applications for Hardship Gas Wells, filed 2-5-91;
Rule 411, Emergency Hardship Gas Well Classification, filed 2-23-84;
Rule 411, Emergency Hardship Gas Well Classification, filed 2-5-91;
Rule 412, Limits On Hardship Gas Well Classification, filed 2-23-84;
Rule 412, Limits On Hardship Gas Well Classification, filed 2-5-91;
Rule 414, Gas Sales By Less than One Hundred Percent of the Owners in a Well, filed 12-30-86;
Rule 414, Gas Sales By Less than One Hundred Percent of the Owners in a Well, filed 2-5-91;

History of Repealed Material: [RESERVED].

Other History:
Rule 401, Method of Determining Natural Gas Well Potential, filed -5-91; Rule 402, Method and Time of Shut-In Pressure Tests, filed 2-5-91; Rule 403, Natural Gas From Gas Wells to be Measured, filed 2-5-91; Rule 404, Natural Gas Utilization, filed2-5-91; Rule 405, Storage Gas, filed 2-5-91; Rule 406, Carbon Dioxide, filed 2-5-91; Rule 407, Disconnection of Gas Wells, filed 2-5-91; Rule 408, Hardship Gas Well, filed 2-5-91; Rule 409, Application for Hardship Gas Well Classification, filed 2-5-91; Rule 410, Processing of Applications for Hardship Gas Wells, filed 2-5-91; Rule 411, Emergency Hardship Gas Well Classification, filed 2-5-91; Rule 412, Limits on Hardship Gas Well Classification, filed, 2-5-91; Rule 414, Gas Sales By Less Than One Hundred Percent of the owners in a Well, filed 2-5-91; all renumbered, reformatted **to and replaced by** 19 NMAC 15.F, Natural

Gas Production Operating Practice**,** filed 01-18-96.
19 NMAC 15.F, Natural Gas Production Operating Practice, filed 01-18-96; **renumbered, reformatted and replaced by** 19.15.6 NMAC, effective 12-14-01.

TITLE 19 NATURAL RESOURCES & WILDLIFE
CHAPTER 15 OIL AND GAS
PART 7 OIL PRORATION AND ALLOCATION

19.15.7.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department, Oil Conservation Division, 2040 S. Pacheco, Santa Fe, New Mexico 87505, (505) 827-7131.
[2-1-96; 19.15.7.1 NMAC – Rn, 19 NMAC 15.G.1, 6-14-02]

19.15.7.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico.
[2-1-96; 19.15.7.2 NMAC – Rn, 19 NMAC 15.G.2, 6-14-02]

19.15.7.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the Oil and Gas Act which grants the Oil Conservation Division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights, and the disposition of wastes resulting from oil and gas operations.
[2-1-96; 19.15.7.3 NMAC – Rn, 19 NMAC 15.G.3, 6-14-02]

19.15.7.4 DURATION: Permanent.
[2-1-96; 19.15.7.3 NMAC – Rn, 19 NMAC 15.G.4, 6-14-02]

19.15.7.5 EFFECTIVE DATE: February 1, 1996.
[2-1-96; 19.15.7.5 NMAC – Rn, 19 NMAC 15.G.5, 6-14-02]

19.15.7.6 OBJECTIVE: To regulate oil proration and allocation to prevent waste and protect correlative rights pursuant to the Oil and Gas Act.
[2-1-96; 19.15.7.6 NMAC – Rn, 19 NMAC 15.G.6, 6-14-02]

19.15.7.7 DEFINITIONS: [RESERVED].

19.15.7.8-500 [RESERVED].

19.15.7.501 REGULATION OF OIL POOLS:

A. To prevent waste, the division shall prorate and distribute the allowable production among the producers in a pool upon a reasonable basis and recognizing correlative rights.

B. After notice and hearing, the division, in order to prevent waste and protect correlative rights, may promulgate special rules, regulations, or orders pertaining to any pool.
[1-1-50...2-1-96; 19.15.7.501 NMAC – Rn, 19 NMAC 15.G.501, 6-14-02]

19.15.7.502 RATE OF PRODUCING WELLS:

A. Daily Tolerance

(1) It is recognized that oil wells located on units capable of producing their allowables may overproduce one day and underproduce another. No unit capable of producing its allowable, except for the purpose of testing, in the process of completing or recompleting a well or for tests made for the purpose of obtaining scientific data, shall produce any day more than 125% of the daily top unit allowable for the pool in which the same is located. (Subject to the foregoing, any underproduction may be made up by production from the same unit within the same month, and in like manner any overproduction shall be adjusted or balanced by underproduction from the same unit, within the same proration period).

(2) It is also recognized that certain wells must, as a matter of practicality, be produced at daily rates in excess of 125% of the daily top unit allowable for the pool in which such wells are located. The division director is hereby given authority to grant exceptions to the provisions of Paragraph (1) of Subsection A of 19.15.7.502 NMAC, without formal hearing, where application is filed in due form setting out the reasons for such requested exception; applicants for such exceptions shall, at the time of filing, also furnish each operator in the pool in which the subject well is located, a copy of such application. Included in any application for exception or attached thereto, filed under authority hereof, shall be a formal written statement by the applicant that every operator in the pool in which the subject well is located has been served with a copy of such application. The division director shall wait at least ten (10) days after receipt before approving any such application, and shall approve the same only in absence of objection from any operator or interested party, or in his discretion. In the event the Director for any reason fails to

approve such application, the division after notice will hear and determine the matter.

B. Monthly Tolerance - No unit shall produce during any one proration period more than the allowable production of such unit for the proration period plus a tolerance of not to exceed five (5) days allowable production. This permissive tolerance of overproduction from a unit shall be subject to all other provisions of 19.15.7.502 NMAC and particularly to the provisions of Subsection D of 19.15.7.502 NMAC. This permissive tolerance of overproduction from a unit shall be adjusted or balanced by subsequent corresponding underproduction from the same unit. Overproduction within the permitted tolerance shall be considered as oil produced against the allowable production assigned to the unit for the proration period during which such overproduction is adjusted or balanced by underproduction.

C. Production in Excess of Monthly Allowable, Plus Tolerance

(1) Oil produced from any unit in excess of the assigned monthly allowable plus the permissive proration period tolerance shall be "illegal oil" as defined in the Oil and Gas Act, unless:

(a) such excess oil be produced as a result of mistake or error;

(b) mechanical failure beyond the immediate control of the operator; or,

(c) resulting from essential tests of the unit within the purview of Oil Conservation Rules.

(2) Whenever production from any unit for a proration period is in excess of the assigned allowable, plus the permitted tolerance authorized herein and the cause of such excess reasonably falls within Subparagraphs (a), (b), or (c) of Paragraph (1) of Subsection C of 19.15.7.502 NMAC, the producer or operator shall briefly set forth the cause of such excess production together with a proposed plan of adjustment thereof, upon all copies of the operator's monthly report (Form C-115) for the month in which such excess production occurs. Such excess production shall be considered as oil produced against the allowable assigned to the unit for the following proration period, and it may be transported from the lease tanks only as and when the unit accrues daily allowable to offset such excess production.

D. General

(1) The tolerance permitted on a daily or monthly basis as provided hereinabove shall not be construed to increase the allowable of a producing unit or to grant authority to any operator to market or to any transporter to transport any quantity of oil in excess of the unit's allowable.

(2) The possession of a quantity of oil in lease storage at the end of any proration period in excess of five days allowable plus any rerun allowable oil shall be construed as violation of this Rule, unless reported in the manner and within the time provided for filing Form C-115 provided by Subsection C of 19.15.7.502 NMAC above.

E. Storage Records - All producers and all transporters of oil are required to maintain adequate records showing unrun allowable oil in storage at the end of each proration period. Such storage oil shall be the amount of oil in tanks from which oil is measured and delivered to the transporter.

[8-28-53...2-1-96; 19.15.7.502 NMAC – Rn, 19 NMAC 15.G.502, 6-14-02]

19.15.7.503 AUTHORIZATION FOR PRODUCTION OF OIL:

A. Except as provided below, the daily top unit allowable for any oil pool shall be 100 percent of the depth bracket allowable for the pool determined pursuant to the provisions of 19.15.7.505 NMAC.

B. The division shall have the option, within five days prior to the end of the month, to make a determination as to the likelihood of the total producing capacity of all oil wells in the state being in excess of anticipated reasonable market demand for crude petroleum oil from this state. If the division determines that such capacity may be in excess of the anticipated reasonable market demand, and that a market demand factor of less than 100 percent may be necessary to prevent waste, it shall immediately institute proper proceedings for a hearing to be held before the 20th day of the following month to determine actual reasonable market demand up to a maximum of 6 months.

C. At said hearing the division shall consider all evidence of market demand for crude petroleum oil from this state, and if it is determined that the market demand percentage factor should be less than 100 percent, an order shall be issued establishing the market demand factor and setting a date for the next market demand hearing.

D. The market demand factor thus established shall be multiplied by the applicable depth bracket allowable for each well and each pool to determine its unit allowable. Any fraction of a barrel shall be regarded as a full barrel in determining top unit allowable. Upon initial establishment of a market demand factor, and from time to time thereafter, the division shall issue a proration schedule authorizing the production of oil from the various proration units in the various pools in the state. Any well completed or recompleted after the issuance of said schedule and for which Form C-104 has been approved, shall, by supplement to the schedule, be authorized a daily allowable equal to the top unit allowable in effect. The allowable for such well shall become effective at 7:00 a.m. on the date of the completion, provided Form C-104 is submitted and approved within ten days following date of completion; otherwise the allowable shall be effective on the date the C-104 is approved. (As provided in Rule 1104, "date of completion" is the date when new oil is delivered into the stock tanks.)

E. A non-marginal unit is defined as being a proration unit which is capable of producing top unit allowable for the pool in which it is located and to which has been assigned a top unit allowable. Any such non-marginal unit shall be permitted to produce said top unit allowable without waste and subject to the provisions of 19.15.5.301 NMAC, 19.15.7.502 NMAC and 19.15.7.506 NMAC and all other applicable rules.

F. A marginal unit is defined as being a proration unit which is incapable of producing top unit allowable for the pool in which it is located as evidenced by well test, production history, or other report or form filed by the operator with the division. Any such marginal unit shall be permitted to produce any amount of oil which it is capable of producing without waste up to top unit allowable for the pool, subject to the provisions of 19.15.5.301 NMAC, 19.15.7.502 NMAC and 19.15.7.506 NMAC, and all other applicable rules, provided that an allowable has been assigned to the unit to authorize such production.

G. A penalized non-marginal unit is defined as being a proration unit to which, because of an excessive gas-oil ratio, an allowable has been assigned which shall be determined in accordance with the procedure set forth in 19.15.7.506 NMAC. In calculating a penalized allowable, any fraction of a barrel shall be regarded as a full barrel.

H. A periodic tabulation of all supplements to the current proration schedule shall be made and distributed by the division.

I. The provisions of Subsection H of 19.15.3.104 NMAC shall be adhered to in fixing top unit allowables.

J. In the event it becomes necessary for any transporter of crude petroleum to resort to pipeline proration in New Mexico, such transporter shall, as soon as possible and not later than 24 hours after the effective date thereof, notify the division of its decision to so prorate; upon receipt of such notice from such transporter, the division may take such emergency action, as may be deemed proper, and/or upon its own motion, after notice, hold a hearing for the purpose of considering any action within its authority, to preserve and protect correlative rights.

K. In case of pipeline proration any operator affected thereby has the right to make application to the division for authorization to have any shortage or underproduction resulting therefrom included in subsequent proration schedules. Such applications shall be made upon a form hereby authorized to be prescribed by the division and filed therewith within thirty days after the close of the first proration period in which such pipeline proration shortage occurred, and such authorization shall be limited in any event to wells capable of producing the daily top unit allowable for such period.

L. In approving any such application the division shall determine the period of time during which such shortage shall be made up without injury to the well or pool, and shall include the same in the regularly approved proration schedules following the conclusion of pipeline proration.

[9-1-72...2-1-96; 19.15.7.503 NMAC – Rn, 19 NMAC 15.G.503, 6-14-02]

19.15.7.504 AUTHORIZATION FOR PRODUCTION OF OIL WHILE COMPLETING, RECOMPLETING, OR TESTING AN OIL WELL:

A. In the event an operator does not have sufficient lease storage to hold oil produced from a well during the process of its drilling, completing, recompleting, or testing, the operator of said well shall be permitted to produce and sell from said well an amount of oil as may be necessary to drill, complete, recomplete or test said well; provided however, that the operator of said well shall file with the division a written application stating the circumstances at said well and setting forth therein the estimated amount of oil to be produced during the aforementioned process of operations, and provided further that said application is approved by the division. Oil produced during the process of drilling, completion or recompletion, or testing a well shall be charged against the allowable production of said well.

B. No well shall be placed on the proration schedule until Form C-104 has been filed with and approved by the division.

[7-1-52...2-1-96; 19.15.7.504 NMAC – Rn, 19 NMAC 15.G.504, 6-14-02]

19.15.7.505 DEPTH BRACKET ALLOWABLES:

A. Subject to the market demand percentage factor determined pursuant to the provisions of 19.15.7.503 NMAC, the daily oil allowable for each oil pool in the state shall be equal to the appropriate depth bracket allowable below. The depth of the casing shoe or the top perforation in the casing, whichever is higher, in the first well completed in the pool shall determine the depth classification for the pool. Daily oil allowables for each of the several ranges of depth and spacing patterns shall be as follows:

POOL DEPTH RANGE	DEPTH BRACKET ALLOWABLE		
	40 Acres	80 Acres	160 Acres
0 to 4,999 feet	80 bbls.	160 bbls.	
5,000 to 5,999 "	107 "	187 "	347 bbls.
6,000 to 6,999 "	142 "	222 "	382 "
7,000 to 7,999 "	187 "	267 "	427 "
8,000 to 8,999 "	230 "	310 "	470 "

9,000 to 9,999 "	275 "	355 "	515 "
10,000 to 10,999 "	320 "	400 "	560 "
11,000 to 11,999 "	365 "	445 "	605 "
12,000 to 12,999 "	410 "	490 "	650 "
13,000 to 13,999 "	455 "	535 "	695 "
14,000 to 14,999 "	500 "	580 "	740 "
15,000 to 15,999 "	545 "	625 "	785 "
16,000 to 16,999 "	590 "	670 "	830 "
17,000 to	635 "	715 "	875 "

B. The 40-acre depth bracket allowables shall apply to all undesignated wells not governed by special pool rules and to all pools developed on the normal 40-acre statewide spacing unit.

C. The 80-acre and 160-acre depth bracket allowables shall apply to wells governed by applicable special pool rules promulgated by the division as an exception to the normal 40-acre statewide spacing unit.

D. The division may, where the same is deemed appropriate, assign to a given pool a special depth bracket allowable at variance to the depth bracket allowable normally assigned to a pool of similar depth and spacing. Such special allowable may be more or less than the regular depth bracket allowable and shall be assigned only after notice and hearing.

E. In assigning a lesser than regular depth bracket allowable, the division may consider, among other pertinent factors, reservoir damage, casinghead gas production and disposition, water production and disposition, transportation facilities, the prevention of surface or underground waste, and the protection of correlative rights.

F. Assignment of a greater than regular depth bracket allowable shall be made only after sufficient reservoir information is available to ensure that said allowable can be produced without damage to the reservoir and without causing surface or underground waste. The division shall also consider the availability of crude oil transportation and marketing facilities, casinghead gas transportation, processing, and marketing facilities, water disposal facilities, the protection of correlative rights, and other pertinent factors.

[9-1-72...2-1-96; 19.15.7.505 NMAC – Rn, 19 NMAC 15.G.505, 6-14-02]

19.15.7.506 GAS-OIL RATIO LIMITATION:

A. In allocated pools containing a well or wells producing from a reservoir which contains both oil and gas, each proration unit shall be permitted to produce only that volume of gas equivalent to the applicable limiting gas-oil ratio multiplied by the top unit oil allowable for the pool. In the event the division has not set a gas-oil ratio limit for a particular oil pool, the limiting gas-oil ratio shall be 2,000 cubic feet of gas for each barrel of oil produced. In allocated oil pools all producing wells, whether oil or casinghead gas, shall be placed on the oil proration schedule.

B. Unless heretofore or hereafter specifically exempted by order of the division issued after hearing, a gas-oil ratio limitation shall be placed on all allocated oil pools, and all proration units having a gas-oil ratio exceeding the limit for the pool shall be penalized in accordance with the following procedure:

(1) Any proration unit which, on the basis of the latest official gas-oil ratio test, has a gas-oil ratio in excess of the limiting gas-oil ratio and has the capacity to produce above the top casinghead gas volume calculated by Subsection A of 19.15.7.506 NMAC for the pool in which it is located shall be permitted to produce daily that number of barrels of oil which shall be determined by multiplying the current top unit allowable by a fraction, the numerator of which shall be the limiting gas-oil ratio for the pool and the denominator of which shall be the official test gas-oil ratio of the well, and the proration unit will be designated non-marginal.

(2) Any unit containing a well or wells producing from a reservoir which contains both oil and gas shall be permitted to produce only that volume of gas equivalent to the applicable limiting gas-oil ratio multiplied by the top unit allowable currently assigned to the pool.

(3) A marginal unit shall be permitted to produce the same volume of gas which it would be permitted to produce if it were a non-marginal unit.

C. All non-marginal proration units to which gas-oil ratio adjustments are applied shall be so indicated in the proration schedule with adjusted allowables stated.

D. In cases of new pools, the limit shall be 2,000 cubic feet per barrel until such time as changed by order of the division issued after a hearing. Upon petition and after notice and hearing according to law, the division will determine or redetermine the specific gas-oil ratio limit which is applicable to a particular allocated oil pool.

[1-1-50...2-1-96; 19.15.7.506 NMAC – Rn, 19 NMAC 15.G.506, 6-14-02]

19.15.7.507 UNITIZED AREAS:

After petition and notice and hearing, the division may grant approval for the combining of contiguous developed proration units

into a unitized area.
[1-1-50...2-1-96; 19.15.7.507 NMAC – Rn, 19 NMAC 15.G.507, 6-14-02]

19.15.7.508 RECOVERED LOAD OIL:

A. Recovered load oil may be run from the lease on which it is recovered, provided division approval is obtained by means of Form C-126. Form C-126 must be filed in QUADRUPLICATE with the appropriate district office of the division. Upon approval, one copy will be returned to the operator and one copy will be sent to the designated transporter as authority to transport the oil.

B. 19.15.7.508 NMAC applies only to oil which has been obtained from a source other than the lease on which it is used.

C. Recovered load oil as used herein is any oil or liquid hydrocarbon which has been used in any operation in an oil or gas well, and which has been recovered as a merchantable product.
[4-15-54...2-1-96; 19.15.7.508 NMAC – Rn, 19 NMAC 15.G.508, 6-14-02]

19.15.7.509 OIL DISCOVERY ALLOWABLE:

A. In addition to the normally assigned allowable, an oil discovery allowable may be assigned to a well completed as a bona fide discovery well in a new common source of supply. Said oil discovery allowable shall be in the amount of 5 barrels for each foot of depth of said well from the surface of the ground to the top of the perforations in the new pool or the depth of the casing shoe, whichever is higher. In counties where there is no other current oil production, and in any county when the discovery is the deepest oil production in the county, the oil discovery allowable shall be 10 barrels per foot of depth.

B. Date of discovery to determine the well which should properly receive the oil discovery allowable for any new pool shall be the date the well is completed and new oil is run into stock tanks, provided however, any operator drilling through and discovering a new oil pool in the course of drilling to a lower horizon may file an affidavit of such discovery within seven days after drill stem tests were made of said pool, accompanying said affidavit with all available pool data. If, prior to completion of said well, another operator claims discovery of a similar pool and there are reasonable grounds to believe the pools are one and the same, no discovery allowable will be assigned to either well until after the initial well for which the affidavit was filed has been completed. If at that time the operator of the initial well makes formal application for the discovery allowable in said pool, it will be determined after hearing which well shall receive the discovery allowable.

C. To obtain an oil discovery allowable, the owner of a discovery well shall file two copies of division Form C-109, Application for Discovery Allowable and Creation of a New Pool, with the appropriate district office of the division and one with the Santa Fe office. Each copy of said form shall be accompanied by the following:

(1) A map depicting all wells within a two-mile radius of the discovery well. All producing oil and gas wells and the formations from which they are producing or have produced are to be clearly shown as well as all dry holes and the depths to which they were drilled. Maps shall be on a scale one inch equals 1,000 feet and shall also indicate the names of all lessees of record in the depicted area.

(2) A complete electrical log of the subject well with the tops and bottoms of producing formations in the subject well and in nearby wells identified thereon.

(3) If application is based on horizontal separation, a sub-surface structural map of the producing formation(s) for which the discovery allowable is sought, showing seismic or geological interpretation of the subject structure and any troughs, faults, pinch-outs, etc., which separate the subject well from nearby wells producing from the same formation(s).

(4) A geological cross-section prepared from electrical logs of the subject well and nearby wells establishing horizontal as well as vertical separation from other wells depicted on the plat which are producing or have produced from the discovery formation(s).

(5) A summary of all available reservoir data including bottom hole pressure data, fluid levels, core analyses, reservoir liquid characteristics and any other pertinent data on the subject reservoir as well as other nearby reservoirs which may help establish whether the subject well is in fact a discovery.

D. If, in the opinion of the division staff, good cause exists to bring the pool on for hearing as a discovery, and no objection has been received from any other operator, the pool will be placed on the first available hearing docket for inclusion by the staff in its regular pool nomenclature case. If the staff is not in agreement with the applicant's contention that a new pool has been discovered, or if, within ten days after receiving a copy of the application another operator files with the division an objection to the creation of a new pool and the assignment of a discovery allowable, the applicant will be so notified, and he will be expected to present the evidence supporting his case. Or, if the applicant so desires, the application may be set for separate hearing on other than the nomenclature docket for presentation of evidence by the applicant.

E. Effective date of a well's discovery allowable will be 7:00 a.m. on the first day of the month next succeeding the month in which the division approves the discovery.

F. The total discovery allowable attributable to each zone in the well shall be produced over a two-year period commencing with the time of authorization. The well's daily allowable for each pool receiving the discovery allowable shall not exceed the daily top unit allowable for the pool plus the total pool discovery allowable divided by 730 days (731 days if a leap year is included).

G. A discovery well shall be permitted to produce only that volume of gas equivalent to the applicable limiting gas-oil ratio for the pool multiplied by the top unit allowable for the pool plus the daily oil discovery allowable. In addition to all other statewide rules not specifically excepted herein, the provisions of 19.15.7.502 NMAC relating to daily tolerance, monthly tolerance, and underproduction and overproduction, shall apply to oil discovery allowables as well as to regular allowables for discovery wells.

H. Nothing herein contained shall be construed as prohibiting the division from curtailing the discovery allowables of wells during times of depressed market demand, provided however, such discovery allowables shall be reinstated for production at the earliest possible date. Further, when it appears reservoir damage or waste might result from production of the oil discovery allowable within the normal two-year period, the division may, after notice and hearing, extend said period.

[9-1-66...2-1-96; 19.15.7.509 NMAC – Rn, 19 NMAC 15.G.509, 6-14-02]

History of 19.15.7 NMAC:
Pre-NMAC History:
Rule 501, Regulation of Oil Pools, filed 1-8-82;
Rule 501, Regulations of Oil Pools, filed 2-5-91;
Rule 502, Rate of Producing Wells, filed 1-8-82;
Rule 502, Rate of Producing Wells, filed 2-5-91;
Rule 503, Authorization for Production of Oil, filed 1-8-82;
Rule 503, Authorization for Production of Oil, filed 10-11-89;
Rule 503, Authorization for Production of Oil, filed 2-5-91;
Rule 504, Authorization for Production of Oil While Completing, Recompleting, or Testing an Oil Well, filed 1-8-82;
Rule 504, Authorization for Production of Oil While Completing, Recompleting, or Testing an Oil Well, filed 2-5-91;
Rule 505, Depth Bracket Allowable, filed 1-8-82;
Rule 505, Depth Bracket Allowable, filed 10-11-89;
Rule 505, Depth Bracket Allowable, filed 2-5-91;
Rule 506, Gas-Oil Ratio Limitation, filed 1-8-82;
Rule 506, Gas-Oil Ratio Limitation, filed 10-11-89;
Rule 506, Gas-Oil Ratio Limitation, filed 2-5-91;
Rule 507, Unitized Areas, filed 1-8-82;
Rule 507, Unitized Areas, filed 2-5-91;
Rule 508, Recovered Load Oil, filed 1-8-82;
Rule 508, Recovered Load Oil, filed 2-5-91;
Rule 509, Oil Discovery Allowable, filed 1-8-82;
Rule 509, Oil Discovery Allowable, filed 10-11-89;
Rule 509, Oil Discovery Allowable, filed 2-5-91.

History of Repealed Material: [Reserved]

Other History:
Rule 501, Regulation of Oil Pools, filed 2-5-91; Rule 502, Rate of Producing Wells, filed 2-5-91; Rule 503, Authorization for Production of Oil, filed 2-5-91; Rule 504, Authorization for Production of Oil While Completing, Recompleting, or Testing an Oil Well, filed 2-5-91; Rule 505, Depth Bracket Allowables, filed 2-5-91; Rule 506, Gas-Oil Ratio Limitation, filed 2-5-91; Rule 507, Unitized Areas, filed 2-5-91; Rule 508, Recovered Load Oil, filed 2-5-91; Rule 509, Oil Discovery Allowable, filed 2-5-91 all renumbered, reformatted **to and replaced by** 19 NMAC 15.G, Oil Proration and Allocation, filed 01-18-96.
19 NMAC 15.G, Oil Proration and Allocation, filed 01-18-96 renumbered, reformatted **to and replaced by** 19.15.7 NMAC, effective 6-14-02.

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 8 GAS PRORATION AND ALLOCATION

19.15.8.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department, Oil Conservation Division, 2040 S. Pacheco, Santa Fe, New Mexico 87505, (505) 827-7131.
[2-1-96; 19.15.8.1 NMAC – Rn, 19 NMAC 15.H.1, 04-30-03]

19.15.8.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico.
[2-1-96; 19.15.8.2 NMAC - Rn, 19 NMAC 15.H.2, 04-30-03]

19.15.8.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the Oil and Gas Act which grants the oil conservation division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights, and the disposition of wastes resulting from oil and gas operations.
[2-1-96; 19.15.8.3 NMAC - Rn, 19 NMAC 15.H.3, 04-30-03]

19.15.8.4 DURATION: Permanent.
[2-1-96; 19.15.8.4 NMAC - Rn, 19 NMAC 15.H.4, 04-30-03]

19.15.8.5 EFFECTIVE DATE: February 1, 1996.
[2-1-96; 19.15.8.5 NMAC - Rn, 19 NMAC 15.H.5, 04-30-03]

19.15.8.6 OBJECTIVE: To regulate gas proration and allocation to prevent waste and protect correlative rights pursuant to the Oil and Gas Act.
[2-1-96; 19.15.6. NMAC - Rn, 19 NMAC 15.H.6, 04-30-03]

19.15.8.7 DEFINITIONS:

A. Acreage factor: A GPU's acreage factor shall be determined to the nearest hundredth of a unit by dividing the acreage assigned to the GPU by a number equal to the number of acres in a standard GPU for such pool. However, the acreage tolerance provided in Subparagraph (b), of Paragraph (2) of Subsection A, of 19.15.8.605 NMAC, shall apply.

B. Ad factor: An acreage times deliverability factor is calculated in pools in which acreage and deliverability are proration factors. The product obtained by multiplying the acreage factor by the calculated deliverability (expressed as MCF per day) for that GPU shall be known as the AD factor for that GPU. The AD Factor shall be computed to the nearest whole unit.

C. Allocation hearing: A hearing held by the division twice each year to determine pool allocations for the ensuing allocation period.

D. Allocation period: A six-month period beginning at 7:00 A.M. April 1 and October 1 of each year.

E. Balancing date: The date 7:00 A.M. April 1 of each year shall be known as the balancing date, and the twelve months following this date shall be known as the gas proration period.

F. Broker: A third party who negotiates contracts for purchase and resale.

G. Classification period: A three month period beginning at 7:00 A.M. April 1, July 1, October 1, and January 1 of each year.

H. Gas pool: Any pool which has been designated as a gas pool by the division after notice and hearing.

I. Gas proration unit (GPU): The acreage allocated to a well, or in the case of an infill well or wells to a group of wells, for purposes of spacing and proration. GPU's may be either of a standard or nonstandard size as provided in these rules. (GPU's means plural GPU).

J. Gas transporter: Any taker of gas, the party servicing the well meter, or the party responsible for measurement of gas sold from the well or beneficially used off-lease. This could be at the wellhead, at any other point on the lease, or at any other point authorized by the division where connection is made for gas transportation or utilization (other than is necessary for maintaining the producing ability of the well). The gas transporter can be the gatherer, transporter, producer, or a delegate of one of those parties. The gas transporter shall be identified on form C-104 and will be responsible for filing form C-111 as required under the provisions of 19.15.13.1111 NMAC.

K. Gas purchaser: The purchaser (where ownership of the gas is first exchanged by the producer to the purchaser for an agreed value) of the gas from a gas well or GPU.

L. Hardship gas well: A gas well wherein underground waste will occur if the well is shut-in or curtailed below its minimum sustainable flow rate. No well shall be classified as a hardship gas well except after notice and hearing or upon appropriate administrative action of the division.

M. Infill well: An additional producing well on a GPU which serves as a companion well to an existing well on the GPU.

N. Marginal GPU: A proration unit which is incapable of producing or has not produced the non-marginal allowable based on pool allocation factors. Marginal GPU's do not accrue over or underproduction.

O. Non-marginal GPU: A proration unit receiving an allowable based upon pool allocation factors. Non-marginal proration units accrue over or underproduction.

P. Overproduction: The volume of gas produced on a GPU in any month greater than the assigned non-marginal allowable (does not include gas used in maintaining the producing ability of the well(s) of the GPU). Overproduction accumulates month to month during the proration period.

Q. Prorated gas pool: A prorated gas pool is a gas pool in which, after notice and hearing, the production is allocated by the division according to these rules and any applicable special pool rules.

R. Proration period: The twelve-month period beginning April 1 of each year shall be the gas proration period.

S. Shadow allowable: The gas volume calculated for a marginal GPU that is equal to the allowable assigned to a non-marginal GPU in the same pool of the same A (acreage) or A and AD (acreage deliverability) factors as the marginal GPU.

T. Underproduction: The volume of assigned non-marginal allowable not produced on a GPU. Underproduction accumulates month to month during the proration period.

[5-30-98; 19.15.8.7 NMAC - Rn, 19 NMAC 15.H.7, 04-30-03]

19.15.8.8-600 [RESERVED]

19.15.8.601 ALLOCATION OF GAS PRODUCTION:

When the division determines that allocation of gas production in a designated gas pool is necessary to prevent waste, the division, after notice and hearing, shall consider the nominations of purchasers from that gas pool and other relevant data, and shall fix the allowable production of that pool, and shall allocate production among the gas wells in the pool delivering to a gas transportation facility upon a reasonable basis and recognizing correlative rights. The division shall include in the proration schedule of such pool any gas well which it finds is being unreasonably discriminated against through denial of access to a gas transportation facility which is reasonably capable of handling the type of gas produced by such well.

[1-1-50...2-1-96; 19.15.8.601 NMAC - Rn, 19 NMAC 15.H.601, 04-30-03]

19.15.8.602 PRORATION PERIOD:

The proration period shall be at least six months and the pool allowable and allocations thereof shall be made at least 30 days prior to each proration period.

[1-1-50...2-1-96; 19.15.8.602 NMAC - Rn, 19 NMAC 15.H.602, 04-30-03]

19.15.8.603 ADJUSTMENT OF ALLOWABLES:

When the actual market demand from any allocated gas pool during a proration period is more than or less than the allowable set by the division for the pool for the period, the division shall adjust the gas proration unit allowables for the pool for the next proration period so that each gas proration unit shall have a reasonable opportunity to produce its fair share of the gas production from the pool and so that correlative rights shall be protected.

[1-1-50...2-1-96; 19.15.8.603 NMAC - Rn, 19 NMAC 15.H.603, 04-30-03]

19.15.8.604 GAS PRORATION UNITS:

Before issuing a proration schedule for an allocated gas pool, the division after notice and hearing, shall fix the gas proration unit for that pool.

[1-1-50...2-1-96; 19.15.8.604 NMAC - Rn, 19 NMAC 15.H.604, 04-30-03]

19.15.8.605 GAS PRORATION RULES:

A. Well Acreage and Location Requirements

(1) Standard Gas Proration Unit Size and Well Spacing:

(a) Unless otherwise provided for in applicable special pool rules, gas wells in prorated gas pools shall be drilled according to the well spacing and acreage requirements contained in these rules provided that when wells are drilled in pools with 640 acre spacing, a government section shall comprise the proration unit.

(b) Any GPU drilled according to Subparagraph (a), of Paragraph (1) of Subsection A of 19.15.8.605 which contains acreage within the tolerances below shall be considered a standard GPU for calculating allowables:

Standard Proration Unit	Acreage Tolerance
160 acres	158-162 acres
320 acres	316-324 acres
640 acres	632-648 acres

(2) Non-Standard Gas Proration Units:

(a) The district supervisor of the appropriate district office of the division has the authority to approve a nonstandard GPU without notice and hearing when the unorthodox size and shape of the GPU is necessitated by a variation in the legal subdivision of the U.S. public land surveys and the nonstandard GPU is not less that 75% nor more than 125% of a standard GPU by accepting a form C-102 land plat showing the proposed nonstandard GPU with the number of acres contained therein, and shall assign an allowable to the nonstandard GPU based upon the acreage factor for that acreage.

(b) Non-standard proration units and unorthodox locations may be approved by the division according to applicable special pool rules or division rules.

B. Nominations

(1) Gas Purchasers Or Gas Transporters Shall Nominate: Each gas purchaser or each gas transporter as herein provided shall file with the division its nomination for the amount of gas which it in good faith desires to purchase and/or expects to transport during the ensuing allocation period from each gas pool regulated by this order. The purchaser may delegate the nomination responsibility to the transporter, operator, or broker by notifying the division's Santa Fe office. One copy of such nomination for each pool shall be submitted to the division's Santa Fe office on form C-121-A by the first day of the month during which the division will consider at its allocation hearing the nominations for the succeeding allocation period. The division shall consider at its allocation hearing the nominations received, actual production, and such other factors as may be deemed applicable in determining the amount of gas that may be produced without waste during the ensuing allocation period.

The division director may, at his discretion, suspend this rule whenever it appears that the nominations are of little or no value.

(2) Schedule: The division shall issue a gas proration schedule for each allocation period showing the monthly allowable for each GPU that may be produced during each month of the ensuing allocation period, the current classification of each GPU, and such other information as is necessary to show the allowable production status of each GPU on the schedule. The division may issue supplemental proration schedules during an allocation period as necessary to show changes in GPU classification, adjustments to allowables due to changes in market conditions, or to reflect any other changes as the division deems necessary.

(3) Proration of all Gas Wells Within a Pool: The division shall include in the proration schedule the gas wells in the gas pools regulated by this order delivering to a gas transporter, and shall include in the proration schedule any well which it finds is being unreasonably discriminated against through denial of access to a gas transportation facility, which is reasonably capable of handling the type of gas produced by such a well.

C. Allocation and Granting of Allowables

(1) Filing of Form C-102 and Form C-104 Required: No GPU shall be assigned an allowable before receipt of form C-102 (well location and acreage dedication plat) and the approval date of form C-104 (request for allowable and authorization to transport oil and natural gas).

(2) How Allowables are Calculated: The total allowable to be allocated to each gas pool regulated by this order for each allocation period shall be equal to the estimated market demand as determined by the division, plus any adjustments the director deems necessary to equate the total pool allowable to the estimated market demand. The director may make such adjustments as he deems necessary to compensate for overproduction, underproduction, and other circumstances which may necessitate such adjustment to equate pool allowable to the anticipated market demand. The estimated market demand for each pool shall be established from any information the director requires and can consist of nominations from purchasers, transporters or other parties having knowledge of market demand for gas from such pools, actual past production figures, seasonal trends, or any other factors deemed necessary to establish estimated market demand. The director shall not be bound to use all the information requested and can establish market demand by any method so approved. A monthly allowable shall be assigned to each GPU entitled to an allowable for the ensuing allocation period by allocating the pool allowable among all such GPU's in that pool according to the procedure set forth in the following paragraphs of this order. Should market conditions indicate a change is necessary, the director may adjust allowables up or down during the 6-month allocation period using a maximum of 10% as a guideline.

(3) Marginal GPU Allowable: The monthly allowable to be assigned to each marginal GPU shall be equal to its average monthly production from its latest classification period.

(4) Non-Marginal GPU Allowable: Non-marginal GPU allowables shall be determined in conformance with the applicable special pool rules.

(a) In pools where acreage is the only proration factor, the total non-marginal allowable shall be allocated to each GPU in the proportion that each GPU acreage factor bears to the total acreage factor for all non-marginal GPU's.

(b) In pools where acreage and deliverability are proration factors:

(i) A percentage as set forth in special pool rules, of the non-marginal allowable shall be allocated to each GPU in the proportion that each GPU's AD factor bears to the total AD factor for all non-marginal GPU's in the pool; and

(ii) The remaining non-marginal allowable shall be allocated to non-marginal GPU's among each GPU in the proportion that each GPU's acreage factor bears to the total acreage factor for all non-marginal GPU's in the pool.

(5) New Connects Assignment of Allowables: Allowables to newly completed gas wells shall commence, in pools where acreage is the only proration factor, on the date of first delivery of gas to a gas transporter as demonstrated by an affidavit furnished by the transporter to the appropriate division district office or the approval date of form C-102 and form C-104, whichever is later.

(6) Gas Charged Against GPU's Allowable: Except as provided in the Special Pool rules, the volume of produced gas sold or beneficially used other than lease fuel from each GPU shall be charged against the GPU's allowable; however, the gas used in maintaining the producing ability of the well shall not be charged against the allowable.

(7) Change in Acreage: If the acreage assigned to a GPU is changed, the operator shall notify the appropriate division district office in writing of such change by filing a revised plat (form C-102). The revised allowable, as determined by the division, assigned to the GPU shall be effective on the first day of the month following receipt of the notification.

(8) Minimum Allowables: After notice and hearing, the division may assign minimum allowables for prorated gas pools to avoid waste, encourage efficient operations, and to prevent the premature abandonment of wells. (see Special Pool Rules for minimum allowable amount.) In determining the volume of minimum allowable for a well with a standard proration unit, the division shall take into account economic and engineering factors such as drilling and operating costs, anticipated revenues, taxes, and any similar data that will establish that the ultimate recovery of hydrocarbons will be increased from the pool because of the adoption of a minimum allowable for the pool. Once adopted, the minimum allowable for wells with nonstandard proration units shall be proportionally adjusted.

(9) Deliverability Tests: In pools where acreage and deliverability are proration factors, wells on non-marginal GPUs will be tested in accordance with division rules and the test results shall be used in calculating deliverabilities for the succeeding proration period. Wells on GPUs reclassified to non-marginal shall be tested within 90 days of the order and thereafter in accordance with the appropriate testing schedule for the pool. Wells on marginal GPUs are exempt from deliverability testing.

D. Balancing of Production

(1) Underproduction: Any non-marginal GPU which has an underproduced status as of the end of a gas proration period shall be allowed to carry such underproduction forward in the next gas proration period and may produce such underproduction in addition to the allowable assigned during such succeeding period. Any underproduction carried forward into a gas proration period and remaining unproduced at the end of such gas proration period shall be canceled.

(2) Balancing Underproduction: Production during any one month of a gas proration period greater than the allowable assigned to a GPU for such a month shall be applied against the underproduction carried into such a period in determining the amount of allowable, if any, to be canceled.

(3) Overproduction: Any GPU which has an overproduced status as of the end of a gas proration period shall carry such overproduction forward into the next gas proration period. Said overproduction shall be made up by underproduction during the succeeding gas proration period. Any GPU which has not made up the overproduction carried into a gas proration period by the end of said period shall be shut in until such overproduction is made up.

(a) Twelve-Times Overproduced, Northwest: For the prorated gas pools of northwest New Mexico, if it is determined that GPU is overproduced in an amount exceeding twelve times its current year January allowable (or, in the case of a newly connected well, a marginal well, or a well recently reclassified as non-marginal, twelve times the January allowable assigned to a non-marginal GPU of similar acreage and deliverability factors), it shall be shut in until its overproduction is less than twelve times its January allowable, as determined hereinabove.

(b) Six-Times Overproduced, Southeast: For the prorated gas pools of southeast New Mexico, if it is determined that a GPU is overproduced in an amount exceeding six times its current year January allowable (or, in the case of a newly connected well, a marginal well, or a well recently reclassified as non-marginal, six times the January allowable assigned to a non-marginal GPU of a similar acreage factor), it shall be shut in until its overproduction is less than six times its January allowable, as determined hereinabove.

(4) Exception to Shut in for Overproduction: The director shall have authority to permit a GPU which is subject to shut-in, pursuant to Subparagraphs (a) or (b) of Paragraph (3) of Subsection D of 19.15.8.605 NMAC above to produce up to 250 MCF of gas per month upon proper showing to the director that complete shut-in would cause undue hardship, provided however, such permission may be rescinded for any GPU produced greater than the monthly rate authorized by the director.

(5) Balancing Overproduction: Allowable assigned to a GPU during any one month of a gas proration period greater than the production for the same month shall be applied against the overproduction chargeable to such GPU in determining the overproduction which must be made up pursuant to the provisions of Subparagraphs (a) or (b) of Paragraph (3) of Subsection D of 19.15.8.605 NMAC above.

(6) Exception to Balancing Overproduction: The director may allow overproduction to be made up at a lesser rate than permitted under Subparagraphs (a) or (b) of Paragraph (3) of Subsection D of 19.15.8.605 NMAC above upon a showing at public hearing that the same is necessary to avoid material damage to the well.

(7) Hardship Gas Wells: If a GPU containing a hardship gas well is overproduced, the operator must take the necessary steps to reduce production in order to reduce the overproduction. Any overproduction existing at the time of designation of a well as a hardship gas well or accruing to the GPU thereafter shall be carried forward until it is made up by underproduction. No GPU containing a hardship gas well, which GPU is overproduced, shall be permitted to produce at a rate higher than the minimum producing rate authorized by the division.

(8) Moratorium on Shut-ins: The director shall have authority to grant a pool-wide moratorium of up to three months as to the shutting in of gas wells in a pool during periods of high demand emergency upon proper showing that such emergency exists, and that a significant number of the wells in the pool are subject to shut-in pursuant to the provisions of Subparagraphs (a) or (b) of Paragraph (3) of Subsection D of 19.15.8.605 NMAC above. No moratorium beyond the aforementioned three months shall be granted except after notice and hearing.

(9) The director may reinstate allowable to wells which suffered cancellation of allowable under Paragraph (1) of Subsection D of 19.15.8.605 NMAC above or Paragraph (3) of Subsection E of 19.15.8.605 NMAC below or loss of allowable due to reclassification of a well under Paragraph (2) of Subsection E of 19.15.8.605 NMAC below. If such cancellation or loss of allowable was caused by non-access or limited access to the average market demand in the pool rather than inability of the well to produce. Upon petition, with a showing of circumstances which prevented production of the non-marginal allowable, and evidence that the well was capable of producing at allowable rates during the period for which reinstatement is requested, the allowable may be reinstated in such amounts needed to avoid curtailment or shut-in of the well for excessive overproduction. Such petition shall be approved administratively or docketed for hearing within 30 days after receipt in the division's Santa Fe office.

E. Classification of GPU's

(1) Reclassification by the Director: The director may reclassify a marginal or non-marginal GPU anytime the GPU's producing ability justifies such reclassification. The director may suspend the reclassification of GPU's on his own initiative, or upon proper showing by an affected interest owner, should it appear that such suspension is necessary to permit underproduced GPU's, which would otherwise be reclassified, a proper opportunity to make up such underproduction.

(2) Reclassification to Marginal: A non-marginal well may be reclassified as marginal in either of the following ways:

(a) After the production data is available for the last month of each classification period, any GPU which had an underproduced status at the beginning of the allocation period shall be reclassified to marginal if its highest single month's production during the classification period is less than its average monthly allowable during such period; however, the operator of any GPU so classified, or other affected interest owner, shall have 30 days after receipt of notification of marginal classification in which to submit satisfactory evidence to the division that the GPU is not of marginal character and should not be so classified; or

(b) A GPU which is underproduced more than the overproduction limit as described in -Subparagraphs (a) or (b) of Paragraph (3) of Subsection D of 19.15.8.605 NMAC above, whichever is applicable, shall be reclassified as marginal.

(3) Cancellation of Underproduction for Marginal GPU: A GPU which is classified as marginal shall not be permitted to accumulate underproduction, and any underproduction accrued to a GPU before its classification as marginal shall be canceled.

(4) Reclassification to Non-Marginal: If, at the end of any classification period, a marginal GPU has produced more gas during the proration period to that time than its shadow allowable for that same period, the GPU shall be reclassified as a non-marginal GPU.

(5) Reinstatement of Status: A GPU reclassified to non-marginal under the provisions of Paragraph (4) of Subsection E of 19.15.8.605 NMAC above shall have reinstated to it all underproduction which accrued or would have accrued as a non-marginal GPU from the current proration period, underproduction from the prior proration period may be reinstated after notice and hearing. All uncompensated-for overproduction accruing to the GPU while marginal shall be chargeable upon reclassification to non-marginal.

F. Reporting of Production - Filing C-111 and C-115 Reports: Transporters and operators shall file gas transportation and production reports pursuant to 19.15.13.1111 NMAC and 19.15.13.1115 NMAC of the division rules provided that upon approval by the director as to the specific program to be used, any producer or transporter of gas may be permitted to report metered production of gas on a chart-period basis; provided the following provisions shall be applicable to each gas well:

(1) Reports for a month shall include not less that 24 nor more than 32 reported days.

(2) Reported days may include as many as the last seven days of the previous month but no days of the succeeding month.

(3) The total of the monthly reports for a year shall include not less than 360 nor more than 368 reported days.

(4) For purposes of these rules, the term "month" shall mean "calendar month" for those reporting on a calendar month basis, and shall mean "reporting month" for those reporting on a chart-period basis according to the exception provided in this rule.

[5-30-98; 19.15.8.605 NMAC - Rn, 19 NMAC 15.H.605, 04-30-03]

19.15.8.606 TESTS AND TEST PROCEDURES FOR PRORATED POOLS IN NORTHWEST NEW MEXICO:

A. Type of Tests Required for Wells Completed in Prorated Gas Pools

(1) Reclassified GPUs: An operator of a well on a gas proration unit (GPU) that has been reclassified as non-marginal will conduct deliverability tests on that well within 90 days of the order reclassifying it, unless there are current tests on file with the division or that order requires a new test. A current test is a test which was conducted during the last test period for that pool or later.

(2) Non-marginal GPUs: Operators will conduct deliverability tests on wells on non-marginal GPUs every five years. If the division determines that a well's test data and production data warrant more frequent testing of a well, the division may set up special testing schedules for that well.

(3) Scheduling of Tests

(a) Notification of Pools to be Tested: By September 1 of each year the Aztec district office of the division will notify operators of non-marginal GPUs if their wells will be tested during the following test period.

(b) The results of all deliverability tests required must be filed with the Aztec district office within 90 days following the completion of each test. Provided however, that any test completed between December 31 of the test year and March 10 of the following year are due no later than March 31. No extension of time for filing tests beyond March 31 will be granted except after notice and hearing.

(c) Failure to file any test within the above-prescribed times will subject the GPU to the loss of one day's allowable for each day the test is late.

(d) Any well scheduled for testing during its test year may have the conditioning period, test flow period, and part of the seven-day shut-in period conducted in December of the previous year provided that, if the seven-day shut-in period immediately follows the test flow period, the seven-day shut-in pressure is to be measured in January of the test year. The earliest date that a well can be scheduled for a deliverability test would be such that the test flow period would end on December 25 of the previous year.

(e) Downhole commingled wells are to be scheduled for tests on dates for the pool of the lowermost prorated completion of the well.

(f) In the event a well is shut-in by the division for overproduction, the operator may produce the well for a period of time to secure a test after written notification to the division. All gas produced during this testing period will be used in determining the over/under produced status of the well.

(g) An operator may schedule a well for a deliverability retest upon notification to the Aztec district office at least ten days before the test is to be commenced. Such retest will be for substantial reason and will be subject to the approval of the division. A retest will be conducted in conformance with the deliverability test procedures of these rules. The division, at its discretion, may require the retesting of any well by notification to the operator to schedule such retest. These tests, as filed on form C-122A, should be identified as "RETEST" in the remarks column.

(4) Witnessing of Tests: Any deliverability test may be witnessed by any or all of the following: a representative of the division, an offset operator, a representative of the gas transportation facility connected to the well under test, or a representative of the gas transportation facility taking gas from an offset operator.

B. Procedure for Testing

(1) The test shall begin by producing a well in the normal operating manner into the pipeline through either the casing or tubing, but not both, for a period of fourteen consecutive days. This shall be known as the conditioning period. The production valve and choke settings shall not be changed during either the conditioning or flow periods, except during the first ten days of the conditioning period when maximum production would over-range the meter chart or location production equipment. The first ten days of the conditioning period shall not have more than 48 hours of cumulative interruptions of flow. The eleventh to fourteenth days, inclusive of the conditioning period, shall have no interruptions of flow whatsoever. Any interruption of flow that occurs as normal operation of the well as stop-cock flow, intermittent flow, or well blow down will not

be counted as shut-in time in either the conditioning or flow period.

(2) The daily flowing rate shall be determined from an average of seven or eight consecutive producing days, following a minimum conditioning period of 14 consecutive days of production. This shall be known as the flow period.

(3) Instantaneous pressure shall be measured by a deadweight gauge or other method approved by the division during the seven-day or eight-day flow period at the casinghead, tubinghead, and orifice meter, and shall be recorded along with instantaneous meter-chart static pressure reading.

(4) If a well is producing through a compressor that is located between the wellhead and the meter run, the meter run pressure and the wellhead casing pressure and the wellhead tubing pressure are to be reported on form C-122A. (Neither the suction pressure nor the discharge pressure of the compressor is considered **wellhead** pressure.) A note shall be entered in the remarks portion on form C-122A stating: "This well produced through a compressor."

(5) When it is necessary to restrict the flow of gas between the wellhead and the orifice meter, the ratio of the downstream pressure, psia, to the upstream pressure, psia, shall be determined. When this ratio is 0.57 or less, critical flow conditions shall be considered to exist across the restriction.

(6) When more than one restriction between the wellhead and the orifice meter causes the pressures to reflect critical flow between the wellhead and the orifice meter, the pressures across each of these restrictions shall be measured to determine whether critical flow exists at any restriction. When critical flow does not exist at any restriction, the pressures taken to disprove the critical flow shall be reported to the division on form C-122A in item (n) of the form. When critical flow conditions exist, the instantaneous flowing pressures required above shall be measured during the last 48 hours of the seven-day or eight-day flow period.

(7) When critical flow exists between the wellhead and the orifice meter, the measured wellhead flowing pressure of the string through which the well flowed during the test shall be used as P_t when calculating the static wellhead working pressure (P_w) using the method established below.

(8) When critical flow does not exist at any restriction, P_t shall be the corrected average static pressure from the meter chart plus friction loss from the wellhead to the orifice meter.

(9) The static wellhead working pressure (P_w) of any well under test shall be the calculated seven-day or eight-day average static tubing pressure if the well is flowing through the casing; it shall be the calculated seven-day or eight-day average static casing pressure if the well is flowing through the tubing. The static wellhead working pressure (P_w) shall be calculated by applying the tables and procedures set out in the "Gas Well Testing Manual for Northwest New Mexico" ("the Manual") available from the division.

(10) To obtain the shut-in pressure of a well under test, the well shall be shut-in some time during the current testing season for a period of seven to fourteen consecutive days, which have been preceded by a minimum of seven days of uninterrupted production. Such shut-in pressure shall be measured on the seventh to fourteenth day of shut-in of the well with a deadweight gauge or other method approved by the division. The seven-day shut-in pressure shall be measured on both the tubing and the casing when communication exists between the two strings. The higher of such pressures shall be used as P_c in the deliverability calculation. When any such shut-in pressure is determined by the division to be abnormally low or the well can not be shut-in due to "HARDSHIP" classification, the shut-in pressure to be used as P_c shall be determined by one of the following methods:

(a) A division-designated value.

(b) An average shut-in pressure of all offset wells completed in the same zone. Offset wells include the four side and four corner wells, if available.

(c) A calculated surface pressure based on a calculated bottom-hole pressure. Such calculations shall be made in accordance with the examples in the manual.

(11) All wellhead pressures, as well as the flowing meter pressure tests which are to be taken during the seven-day or eight-day deliverability test period as required above, shall be taken with a deadweight gauge or other method approved by the division. The pressure readings and the date and time according to the chart shall be recorded and maintained in the operator's records with the test information.

(12) Orifice meter charts shall be changed and arranged so as to reflect upon a single chart the flow data for the gas from each well for the full seven-day or eight-day deliverability test period; however, no tests shall be voided if satisfactory explanation is made as to the necessity for using test volumes through two chart periods. Corrections shall be made for pressure base, measured flowing temperature, specific gravity, and supercompressibility; provided however, if the specific gravity of the gas from any well under test is not available, an estimated specific gravity may be assumed therefore, based upon that of gas from near-by wells, the specific gravity of which has been actually determined by measurement.

(13) The average flowing meter pressure for the seven-day or eight-day flow period and the corrected integrated volume shall be determined by the purchasing company that integrates the flow charts and furnished to the operator or testing agency.

(14) The seven-day or eight-day flow period volume shall be calculated from the integrated readings as determined from the flow period orifice meter chart. The volume so calculated shall be divided by the number of testing days on the chart to determine the average daily rate of flow during said flow period. The flow period shall have a minimum of seven and a maximum of eight legibly recorded flowing days to be acceptable for test purposes. The volume used in this calculation shall be corrected to the division's standard conditions of 15.025 psia pressure base, 60 degrees F. temperature base and 0.60 specific gravity base.

(15) The daily volume of flow, as determined from the flow period chart readings, shall be calculated by applying the basic orifice meter formula or other acceptable industry standard practices.

$Q = C' (h_w P_f)^{.5}$

Where:

Q = Metered volume of flow Mcf/d @ 15.025 psia, 60 degrees F., and 0.60 specific gravity.

C' = The 24-hour basic orifice meter flow factor corrected for flowing temperature, gravity, and supercompressibility.

h_w = Daily average differential meter pressure from flow period chart.

P_f = Daily average flowing meter pressure from flow period chart.

(16) The basic orifice meter flow factors, flowing temperature factor, and specific gravity factor shall be determined from the tables in the manual.

(17) The daily flow period average corrected flowing meter pressure, psig, shall be used to determine the supercompressibility factor. Supercompressibility tables may be obtained from the division.

(18) When supercompressibility correction is made for a gas containing either nitrogen or carbon dioxide in excess of two percent, the supercompressibility factors of such gas shall be determined by the use of Table V of the C.N.G.A. Bulletin TS-402 for pressures 100-500 psig, or Table II, TS-461 for pressures in excess of 500 psig.

(19) The use of tables for calculating rates of flow from integrator readings which do not specifically conform to the division's "Back Pressure Test Manual", or the Manual, may be approved for determining the daily flow period rates of flow upon a showing that such tables are appropriate and necessary.

(20) The daily average integrated rate of flow for the seven-day or eight-day flow period shall be corrected for meter error by multiplication by a correction factor. Said correction factor shall be determined by dividing the square root of the deadweight flowing meter pressure, psia, by the square root of the chart flowing meter pressure, psia.

(21) "Deliverability pressure" is a defined pressure applied to each well and used in the process of comparing the abilities of wells in a pool to produce at static wellhead working pressures equal to a percentage of the seven-day shut-in pressure of the respective individual wells. Such percentage shall be determined and announced periodically by the division based on the relationship of the average static wellhead working pressures (P_w) divided by the average seven-day shut-in pressure (Pc) of the pool.

(22) The deliverability of gas at the deliverability pressure of any well under test shall be calculated from the test data derived from the tests above required by use of the following deliverability formula:

$$D = Q \left[\frac{(P_c^2 - P_d^2)}{(P_c^2 - P_w^2)} \right]^n$$

Where:

D = Deliverability Mcf/d at the deliverability pressure, (P_d), (at Standard Conditions of 15.025 psia, 60 degrees F. and 0.60 sp. gr.).

Q = Daily flow rate in Mcf/d, at wellhead pressure (P_w).

P_c = Seven-day shut-in wellhead pressure, psia.

P_d = Deliverability pressure, psia, as defined above.

P_w = Average static wellhead working pressure, as determined from seven-day or eight-day flow period, psia, and calculated from tables in the manual entitled "Pressure Loss Due to Friction Tables for Northwest New Mexico".

n = Average pool slope of back pressure curves as follows:

For pictured cliffs and shallower formations, 0.85

For formations deeper than pictured cliffs, 0.75

(Note: Special rules for any specific pool or formation may supersede the above values. Check special rules if in doubt.)

(23) The value of the multiplier in the above formula (ratio factor after the application of the pool slope) by which Q is multiplied shall not exceed a limiting value to be determined and announced periodically by the division. Such determination shall be made after a study of the test data of the pool obtained during the previous testing season.

(24) Downhole commingled wells are to be tested in the test year for the pool of the lowermost prorated completion of the well and shall use pool slope (n), and deliverability pressure of the lowermost pool. The total flow rate from the downhole commingled well will be used to calculate a value of deliverability. For each prorated gas zone of a downhole

commingled well, a form C-122A is required to be filed. Also, in the summary portion of that form all zones will indicate the same data for line h, P_c, Q, P_w, and P_d. The value shown for deliverability (D) will be that percentage of the total deliverability of the well that is applicable to this zone. A note shall be placed in the remarks column that indicates the percentage of deliverability to be allocated to this zone of the well.

(25) Any test prescribed herein will be considered acceptable if the average flow rate for the final seven-day or eight-day deliverability test is not more than ten percent in excess of any consecutive seven-day or eight-day average of the preceding two weeks. A deliverability test not meeting this requirement may be declared invalid, requiring the well to be re-tested.

(26) All charts relative to deliverability tests or copies thereof shall be made available to the division upon its request.

(27) Operators shall use only testing agencies, whether individuals, companies, pipeline companies, or operators, that maintain a log of all tests accomplished by them including all field test data. The operator shall maintain the above data for a period of not less than two years plus the current test year.

(28) All forms heretofore mentioned are hereby adopted for use in the northwest New Mexico area in open form subject to such modification as experience may indicate desirable or necessary.

(29) Deliverability tests for gas wells in all formations shall be conducted and reported in accordance with these rules. Provided, however, these rules shall be subject to any specific modification or change contained in Special Pool Rules adopted for any pool after notice and hearing.

C. Informational Tests

(1) One-Point Back Pressure Test: A one-point back pressure test may be taken on newly completed wells before their connection or reconnection to a gas transportation facility. This test shall not be a required official test, but may be taken for informational purposes at the option of the operator. When taken, this test must be taken and reported as prescribed below.

(2) Test Procedure

(a) This test shall be accomplished after a minimum shut-in of seven days. The shut-in pressure shall be measured with a deadweight gauge or other method approved by the division.

(b) The flow rate shall be that rate in Mcf/d measured at the end of a three hour test flow period. The flow from the well shall be for three hours through a positive choke, which has a 3/4 inch orifice.

(c) A 2-inch nipple which provides a mechanical means of accurately measuring the pressure and temperature of the flowing gas shall be installed immediately upstream from the positive choke.

(d) The absolute open flow shall be calculated using the conventional back pressure formula as shown in the manual or the division’s "Back Pressure Test Manual."

(e) The observed data and flow calculations shall be reported in duplicate on form C-122, "Multi-Point Back Pressure Test for Gas Wells."

(f) Non-critical flow shall be considered to exist when the choke pressure is 13 psig or less. When this condition exists the flow rate shall be measured with a pitot tube and nipple as specified in the manual or in the division's manual of "Tables and Procedure for Pitot Tests." The pitot test nipple shall be installed immediately downstream from the 3/4-inch positive choke.

(g) Any well completed with 2-inch nominal size tubing (1.995-inch ID) or larger shall be tested through the tubing.

(3) Other tests for informational purposes may be conducted prior to obtaining a pipeline connection for a newly completed well upon receiving specific approval therefore from the Aztec district office. Approval of these tests shall be based primarily upon the volume of gas to be vented.

[5-30-98; 19.15.8.606 NMAC - Rn, 19 NMAC 15.H.606, 04-30-03]

History of 19.15.8 NMAC:

Pre-NMAC History:

Rule 601, Allocation of Gas Production, filed 1-8-82;
Rule 601, Allocation of Gas Production, filed 2-5-91;
Rule 602, Proration Period, filed 1-8-82;
Rule 602, Proration Period, filed 2-5-91;
Rule 603, Adjustment of Allowables, filed 1-8-82;
Rule 603, Adjustment of Allowables, filed 2-5-91;
Rule 604, Gas Proration Units, filed 1-8-82;
Rule 604, Gas Proration Units, filed 2-5-91.

History of Repealed Material: [Reserved]

Other History:
Rule 601, Allocation of Gas Production, filed 2-5-91; Rule 602, Proration Period, filed 2-5-91; Rule 603, Adjustment of Allowables, filed 2-5-91; Rule 604, Gas Proration Units, filed 2-5-91 all renumbered, reformatted **to and replaced by** 19 NMAC 15.H, Gas Proration and Allocation, filed 01-18-96.
19 NMAC 15.H, Gas Proration and Allocation, filed 01-18-96 renumbered, reformatted **to and replaced by** 19.15.8 NMAC, effective 4-30-03.

TITLE 19 NATURAL RESOURCES & WILDLIFE
CHAPTER 15 OIL AND GAS
PART 9 SECONDARY OR OTHER ENHANCED RECOVERY, PRESSURE MAINTENANCE, SALT WATER DISPOSAL, AND UNDERGROUND STORAGE

19.15.9.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department.
[2-1-96; 19.15.9.1 NMAC - Rn, 19 NMAC 15.I.1, 11-30-00; A, 11-30-00]

19.15.9.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico. [2-1-96; 19.15.9.2 NMAC - Rn, 19 NMAC 15.I.2, 11-30-00]

19.15.9.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the Oil and Gas Act which grants the Oil Conservation Division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights, and the disposition of wastes resulting from oil and gas operations. [2-1-96; 19.15.9.3 NMAC - Rn, 19 NMAC 15.I.3, 11-30-00]

19.15.9.4 DURATION: Permanent. [2-1-96; 19.15.9.4 NMAC - Rn, 19 NMAC 15.I.4, 11-30-00]

19.15.9.5 EFFECTIVE DATE: February 1, 1996, unless a later date is cited at the end of a section.
[2-1-96; 19.15.9.5 NMAC - Rn, 19 NMAC 15.I.5, 11-30-00; A, 11-30-00]

19.15.9.6 OBJECTIVE: To regulate secondary or other enhanced recovery, pressure maintenance, salt water disposal, and underground storage to prevent waste, protect correlative rights and protect public health and the environment pursuant to the Oil and Gas Act. [2-1-96; 19.15.9.6 NMAC - Rn, 19 NMAC 15.I.6, 11-30-00]

19.15.9.7 DEFINITONS: Reserved. [2-1-96; 19.15.9.7 NMAC - Rn, 19 NMAC 15.I.7, 11-30-00]

19.15.9.8-700 RESERVED [2-1-96; 19.15.9.8-700 NMAC - Rn, 19 NMAC 15.I.7-700, 11-30-00]

19.15.9.701 INJECTION OF FLUIDS INTO RESERVOIRS

A. Permit for Injection Required - The injection of gas, liquefied petroleum gas, air, water, or any other medium into any reservoir for the purpose of maintaining reservoir pressure or for the purpose of secondary or other enhanced recovery or for storage or the injection of water into any formation for the purpose of water disposal shall be permitted only by order of the Division after notice and hearing, unless otherwise provided herein.

B. Method of Making Application

(1) Application for authority for the injection of gas, liquefied petroleum gas, air, water or any other medium into any formation for any reason, including but not necessarily limited to the establishment of or the expansion of water flood projects, enhanced recovery projects, pressure maintenance projects, and salt water disposal, shall be by submittal of Division Form C-108 complete with all attachments.

(2) The Applicant shall furnish, by certified or registered mail, a copy of the application to the owner of the surface of the land on which each injection or disposal well is to be located and to each leasehold operator within one-half mile of the well.

C. Administrative Approval

(1) If the application is for administrative approval rather than for a hearing, it must also be accompanied by a copy of a legal publication published by the applicant in a newspaper of general circulation in the county in which the proposed injection well is located. (The details required in such legal notice are listed on Side 2 of Form C-108).

(2) No application for administrative approval may be approved until 15 days following receipt by the Division of Form C-108 complete with all attachments including evidence of mailing as required under Subsection B, Paragraph (2) above of 19.15.9.701 NMAC and proof of publication as required by Subsection C, Paragraph (1) above of 19.15.9.701 NMAC.

(3 f no objection is received within said 15-day period, and a hearing is not otherwise required, the application may be approved administratively.

D. Hearings - If a written objection to any application for administrative approval of an injection well is filed within 15 days after receipt of a complete application, or if a hearing is required by these rules or deemed advisable by the Division Director, the application shall be set for hearing and notice thereof given by the Division.

E. Salt Water Disposal Wells

(1) The Division Director shall have authority to grant an exception to the requirements of Subsection A of 19.15.9.701 NMAC for water disposal wells only, without hearing, when the waters to be disposed of are mineralized to such a degree as to be unfit for domestic, stock, irrigation, or other general use, and when said waters are to be disposed of into a formation older than Triassic (Lea County only) and provided no objections are received pursuant to Subsection C of 19.15.9.701 NMAC.

(2) Disposal will not be permitted into zones containing waters having total dissolved solids concentrations of 10,000 mg/1 or less except after notice and hearing, provided however, that the Division may establish exempted aquifers for such zones wherein such injection may be approved administratively.

(3) Notwithstanding the provisions of Subsection E, Paragraph (2) above of 19.15.9.701 NMAC, the Division Director may authorize disposal into such zones if the waters to be disposed of are of higher quality than the native water in the disposal zone.

F. Pressure Maintenance Projects

(1) Pressure maintenance projects are defined as those projects in which fluids are injected into the producing horizon in an effort to build up and/or maintain the reservoir pressure in an area which has not reached the advanced or "stripper" state of depletion.

(2) All applications for establishment of pressure maintenance projects shall be set for hearing. The project area and the allowable formula for any pressure maintenance project shall be fixed by the Division on an individual basis after notice and hearing.

(3) Pressure maintenance projects may be expanded and additional wells placed on injection only upon authority from the Division after notice and hearing or by administrative approval.

(4) The Division Director shall have authority to grant an exception to the hearing requirements of

Subsection A of 19.15.9.701 NMAC for the conversion to injection of additional wells within a project area provided that any such well is necessary to develop or maintain efficient pressure maintenance within such project and provided that no objections are received pursuant to Subsection C of 19.15.9.701 NMAC.

G. Water Flood Projects

(1) Water flood projects are defined as those projects in which water is injected into a producing horizon in sufficient quantities and under sufficient pressure to stimulate the production of oil from other wells in the area, and shall be limited to those areas in which the wells have reached an advanced state of depletion and are regarded as what is commonly referred to as "stripper" wells.

(2) All applications for establishment of water flood projects shall be set for hearing.

(3) The project area of a water flood project shall comprise the proration units owned or operated by a given operator upon which injection wells are located plus all proration units owned or operated by the same operator which directly or diagonally offset the injection tracts and have producing wells completed on them in the same formation; provided however, that additional proration units not directly nor diagonally offsetting an injection tract may be included in the project area if, after notice and hearing, it has been established that such additional units have wells completed thereon which have experienced a substantial response to water injection.

(4) The allowable assigned to wells in a water flood project area shall be equal to the ability of the wells to produce and shall not be subject to the depth bracket allowable for the pool nor to the market demand percentage factor.

(5) Nothing herein contained shall be construed as prohibiting the assignment of special allowables to wells in buffer zones after notice and hearing. Special allowables may also be assigned in the limited instances where it is established at a hearing that it is imperative for the protection of correlative rights to do so.

(6) Water flood projects may be expanded and additional wells placed on injection only upon authority from the Division after notice and hearing or by administrative approval.

(7) The Division Director shall have authority to grant an exception to the hearing requirements of Subsection A of 19.15.9.701 NMAC for conversion to injection of additional wells provided that any such well is necessary to develop or maintain thorough and efficient water flood injection for any authorized project and provided that no objections are received pursuant to Subsection C of 19.15.9.701 NMAC.

H. Storage Wells

(1) The Division Director shall have authority to grant an exception to the hearing requirements of Subsection A of 19.15.9.701 NMAC for the underground storage of liquefied petroleum gas or liquid hydrocarbons in secure caverns within massive salt beds, and provided no objections are received pursuant to Subsection C of 19.15.9.701 NMAC.

(2) In addition to the filing requirements of Subsection B of 19.15.9.701 NMAC, the applicant for approval of a storage well under this rule shall file the following:

(a) With the Division Director, a plugging bond in accordance with the provisions of Rule 101;

(b) With the appropriate district office of the Division in TRIPLICATE:

(i) Form C-101, Application for Permit to Drill, Deepen, or Plug Back;
(ii) Form C-102, Well Location and Acreage Dedication Plat; and
(iii) Form C-105, Well Completion or Recompletion Report and Log.

[1-1-50…2-1-96; 19.15.9.701 NMAC - Rn, 19 NMAC 15.I.701, 11-30-00]

19.15.9.702 CASING AND CEMENTING OF INJECTION WELLS:

Wells used for injection of gas, air, water, or any other medium into any formation shall be cased with safe and adequate casing or tubing so as to prevent leakage, and such casing or tubing shall be so set and cemented as to prevent the movement of formation or injected fluid from the injection zone into any other zone or to the surface around the outside of any casing string. [1-1-50…2-1-96; 19.15.9.702 NMAC - Rn, 19 NMAC 15.I.702, 11-30-00]

19.15.9.703 OPERATION AND MAINTENANCE

A. Injection wells shall be equipped, operated, monitored, and maintained to facilitate periodic testing and to assure continued mechanical integrity which will result in no significant leak in the tubular goods and packing materials used and no significant fluid movement through vertical channels adjacent to the well bore.

B. Injection project, including injection wells and producing wells and all related surface facilities shall be operated and maintained at all times in such a manner as will confine the injected fluids to the interval or intervals approved and prevent surface damage or pollution resulting from leaks, breaks, or spills.

C. Failure of any injection well, producing well, or surface facility, which failure may endanger underground sources of drinking water, shall be reported under the "Immediate Notification" procedure of Rule 116.

D. Injection well or producing well failures requiring casing repair or cementing are to be reported to the Division prior to commencement of workover operations.

E. Injection wells or projects which have exhibited failure to confine injected fluids to the authorized injection zone or zones may be subject to restriction of injection volume and pressure, or shut-in, until the failure has been identified and corrected.

[7-1-81…2-1-96; 19.15.9.703 NMAC - Rn, 19 NMAC 15.I.703, 11-30-00]

19.15.9.704 TESTING, MONITORING, STEP-RATE TESTS, NOTICE TO THE DIVISION, REQUESTS FOR PRESSURE INCREASES

A. Testing

(1) Prior to commencement of injection and any time tubing is pulled or the packer is reseated, wells shall be tested to assure the integrity of the casing and the tubing and packer, if used, including pressure testing of the casing-tubing annulus to a minimum of 300 psi for 30 minutes or such other pressure and/or time as may be approved by the appropriate district supervisor. A pressure recorder shall be used and copies of the chart shall be submitted to the appropriate Division district office within 30 days following the test date.

(2) At least once every five years thereafter, injection wells shall be tested to assure their continued mechanical integrity. Tests demonstrating continued mechanical integrity shall include the following:

(a) measurement of annular pressures in wells injecting at positive pressure under a packer or a balanced fluid seal; or,

(b) pressure testing of the casing-tubing annulus for wells injecting under vacuum conditions; or,

(c) such other tests which are demonstrably effective and which may be approved for use by the Division.

(3) Notwithstanding the test procedures outlined above, the Division may require more comprehensive testing of the injection wells when deemed advisable, including the use of tracer surveys, noise logs, temperature logs, or other test procedures or devices.

(4) In addition, the Division may order special tests to be conducted prior to the expiration of five years if conditions are believed to so warrant. Any such special test which demonstrates continued mechanical integrity of a well shall be considered the equivalent of an initial test for test scheduling purposes, and the regular five-year testing schedule shall be applicable thereafter.

(5) The injection well operator shall advise the Division of the date and time any initial, five-year, or special tests are to be commenced in order that such tests may be witnessed.

B. Monitoring - Injection wells shall be so equipped that the injection pressure and annular pressure may be determined at the wellhead and the injected volume may be determined at least monthly.

C. Step-Rate Tests, Notice to the Division, Requests for Injection Pressure Limit Increases

(1) Whenever an operator shall conduct a step-rate test for the purpose of increasing an authorized injection or disposal well pressure limit, notice of the date and time of such test shall be given in advance to the appropriate Division district office.

(2) Copies of all injection or disposal well pressure-limit increase applications and supporting documentation shall be submitted to the Division Director and to the appropriate district office.

[7-1-81…2-1-96; 19.15.9.704 NMAC - Rn, 19 NMAC 15.I.704, 11-30-00]

19.15.9.705 COMMENCEMENT, DISCONTINUANCE, AND ABANDONMENT OF INJECTION OPERATIONS:

A. The following provisions apply to all injection projects, storage projects, salt water disposal wells and special purpose injection wells:

B. Notice of Commencement and Discontinuance

(1) Immediately upon the commencement of injection operations in any well, the operator shall notify the Division of the date such operations began.

(2) Within 30 days after permanent cessation of gas or liquefied petroleum gas storage operations or within 30 days after discontinuance of injection operations into any other well, the operator shall notify the Division of the date of such discontinuance and the reasons therefor.

(3) Before any injection well is temporarily abandoned or plugged, the operator shall obtain approval from the appropriate District Office of the Division in the same manner as when temporarily abandoning or plugging

oil and gas wells or dry holes.

C. Abandonment of Injection Operations

(1) Whenever there is a continuous one year period of non-injection into any injection project, storage project, salt water disposal well, or special purpose injection well, such project or well shall be considered abandoned, and the authority for injection shall automatically terminate *ipso facto*.

(2) For good cause shown, the Division Director may grant an administrative extension or extensions of injection authority as an exception to Subsection C, Paragraph (1) above of 19.15.9.705 NMAC.

[1-1-50…2-1-96; 19.15.9.705 NMAC - Rn, 19 NMAC 15.I.705, 11-30-00; A, 11-30-00; A, 07-15-03]

19.15.9.706 RECORDS AND REPORTS

A. The operator of an injection well or project for secondary or other enhanced recovery, pressure maintenance, natural gas storage, salt water disposal, or injection of any other fluids shall keep accurate records and shall report monthly to the Division gas or fluid volumes injected, stored, and/or produced as required on the appropriate form listed below:

(1) Secondary or Other Enhanced Recovery on Form C-115;

(2) Pressure Maintenance on Form C-115 and as otherwise prescribed by the Division;

(3) Salt Water Disposal on Form C-120-A;

(4) Natural Gas Storage on Form C-131-A; and

(5) Injection of other fluids on a form prescribed by the Division.

B. The operator of a liquefied petroleum gas storage project shall report annually on Form C-131-B, Annual LPG Storage Report.

[1-1-50…2-1-96; 19.15.9.706 NMAC - Rn, 19 NMAC 15.I.706, 11-30-00]

19.15.9.707 RECLASSIFICATION OF WELLS:

The Division Director shall have authority to reclassify an injection well from any category defined in Subsection B of 19.15.9.701 NMAC to any other category without notice and hearing upon request and proper showing by the operator thereof.

[7-1-81…2-1-96; 19.15.9.707 NMAC - Rn, 19 NMAC 15.I.707, 11-30-00]

19.15.9.708 TRANSFER OF AUTHORITY TO INJECT

A. Authority to inject granted under any order of the Division is not transferable except upon approval of the Division. Approval of transfer of authority to inject may be obtained by filing Form C-104 in accordance with Rule 1104 E.

B. The Division may require a demonstration of mechanical integrity prior to approving transfer of authority to inject.

[1-1-50…2-1-96; 19.15.9.708 NMAC - Rn, 19 NMAC 15.I.708, 11-30-00]

19.15.9.709 REMOVAL OF PRODUCED WATER FROM LEASES AND FIELD FACILITIES

A. Transportation of any produced water by motor vehicle from any lease, central tank battery, or other facility, without an approved Form C-133 (Authorization to Move Produced Water) is prohibited.

B. Authorization to transport produced water may be obtained by filing three copies of Form C-133 with the Director of the Division in Santa Fe.

C. No owner or operator shall permit produced water to be removed from its leases or field facilities by motor vehicle except by a person possessing an approved Form C-133.

[1-1-50…2-1-96; 19.15.9.709 NMAC - Rn, 19 NMAC 15.I.709, 11-30-00]

19.15.9.710 DISPOSITION OF TRANSPORTED PRODUCED WATER

A. No person, including any transporter, may dispose of produced water on the surface of the ground, or in any pit, pond, lake, depression, draw, streambed, or arroyo, or in any watercourse, or in any other place or in any manner which will constitute a hazard to any fresh water supplies.

B. Delivery of produced water to approved salt water disposal facilities, secondary recovery or pressure maintenance injection facilities, or to a drill site for use in drilling fluid will not be construed as constituting a hazard to fresh water supplies provided the produced waters are placed in tanks or other impermeable storage at such facilities.

C. The supervisor of the appropriate district office of the Division may grant temporary exceptions to Paragraph A. above for emergency situations, for use of produced water in road construction or maintenance, or for use of produced waters for other construction purposes upon request and a proper showing by a holder of an approved Form C-133 (Authorization to Move Produced Water).

D. Vehicular movement or disposition of produced water in any manner contrary to these rules shall be considered cause, after notice and hearing, for cancellation of Form C-133.

[2-1-82…2-1-96; 19.15.9.710 NMAC - Rn, 19 NMAC 15.I.710, 11-30-00]

19.15.9.711 APPLICABLE TO SURFACE WASTE MANAGEMENT FACILITIES ONLY:

A. A surface waste management facility is defined as any facility that receives for collection, disposal, evaporation, remediation, reclamation, treatment or storage any produced water, drilling fluids, drill cuttings, completion fluids, contaminated soils, bottom sediment and water (BS&W), tank bottoms, waste oil or, upon written approval by the Division, other oilfield related waste. Provided, however, if (a) a facility performing these functions utilizes underground injection wells subject to regulation by the Division pursuant to the federal Safe Drinking Water Act, and does not manage oilfield wastes on the ground in pits, ponds, below grade tanks or land application units, (b) if a facility, such as a tank only facility, does not manage oilfield wastes on the ground in pits, ponds below grade tanks or land application units or (c) if a facility performing these functions is subject to Water Quality Control Commission Regulations, then the facility shall not be subject to this rule.

(1) A commercial facility is defined as any surface waste management facility that does not meet the definition of centralized facility.

(2) A centralized facility is defined as a surface waste management facility that accepts only waste generated in New Mexico and that:

(a) does not receive compensation for waste management;

(b) is used exclusively by one generator subject to New Mexico's "Oil and Gas Conservation Tax Act" Section 7-30-1 NMSA-1978 as amended; or

(c) is used by more than one generator subject to New Mexico's "Oil and Gas Conservation Tax Act" Section 7-30-1 NMSA-1978 as amended under an operating agreement and which receives wastes that are generated from two or more production units or areas or from a set of jointly owned or operated leases.

(3) Centralized facilities exempt from permitting requirements are:

(a) facilities that receive wastes from a single well;

(b) facilities that receive less than 50 barrels of RCRA exempt liquid waste per day and have a capacity to hold 500 barrels of liquids or less or 1400 cubic yards of solids or less and when a showing can be made to the satisfaction of the Division that the facility will not harm fresh water, public health or the environment;

(c) emergency pits that are designed to capture fluids during an emergency upset period only and provided such fluids will be removed from the pit within twenty-four (24) hours from introduction;

(d) facilities that do not meet the requirements of the foregoing exemptions in Subsection A, Paragraph (3) of 19.15.9.711 NMAC, but that are shown by the facility operator to the satisfaction of the Division to not present a risk to public health and the environment.

B. Unless exempt from Section 19.15.9.711 NMAC, all commercial and centralized facilities including facilities in operation on the effective date of Section 19.15.9.711 NMAC, new facilities prior to construction and all existing facilities prior to major modification or major expansion shall be permitted by the Division in accordance with the following requirements:

(1) Application Requirements - An application, Form C-137, for a permit for a new facility or to modify an existing facility shall be filed in DUPLICATE with the Santa Fe Office of the Division and ONE COPY with the appropriate Division district office. The application shall comply with Division guidelines and shall include:

(a) The names and addresses of the applicant and all principal officers of the business if different from the applicant;

(b) A plat and topographic map showing the location of the facility in relation to governmental surveys (1/4 1/4 section, township, and range), highways or roads giving access to the facility site, watercourses, water sources, and dwellings within one (1) mile of the site;

(c) The names and addresses of the surface owners of the real property on which the management facility is sited and surface owners of the real property of record within one (1) mile of the site;

(d) A description of the facility with a diagram indicating location of fences and cattle guards, and detailed construction/installation diagrams of any pits, liners, dikes, piping, sprayers, and tanks on the facility;

(e) A plan for management of approved wastes.

(f) A contingency plan for reporting and cleanup of spills or releases;

(g) A routine inspection and maintenance plan to ensure permit compliance;

(h) A Hydrogen Sulfide Prevention and Contingency Plan to protect public health;

(i) A closure plan including a cost estimate sufficient to close the facility to protect public health and the environment; said estimate to be based upon the use of equipment normally available to a third party contractor;

(j) Geological/hydrological evidence, including depth to and quality of groundwater beneath the site, demonstrating that disposal of oilfield wastes will not adversely impact fresh water;

(k) Proof that the notice requirements of Section 19.15.9.711 NMAC have been met;

(l) Certification by an authorized representative of the applicant that information submitted in the application is true, accurate, and complete to the best of the applicant's knowledge.

(m) Such other information as is necessary to demonstrate that the operation of the facility will not adversely impact public health or the environment and that the facility will be in compliance with OCD rules and orders.

(2) Notice Requirements:

(a) Prior to public notice, the applicant shall give written notice of application to the surface owners of record within one (1) mile of the facility, the county commission where the facility is located or is proposed to be located, and the appropriate city official(s) if the facility is located or proposed to be located within city limits or within one (1) mile of the city limits. The distance requirements for notice may be extended by the Director if the Director determines the proposed facility has the potential to adversely impact public health or the environment at a distance greater than one (1) mile. The Director may require additional notice as needed. A copy and proof of such notice will be furnished to the Division.

(b) The applicant will issue public notice in a form approved by the Division in a newspaper of general circulation in the county in which the facility is to be located. For permit modifications, the Division may require the applicant to issue public notice and give written notice as above.

(c) Any person seeking to comment or request a public hearing on such application must file comments or hearing requests with the Division within 30 days of the date of public notice. Requests for a public hearing must be in writing to the Director and shall set forth the reasons why a hearing should be held. A public hearing shall be held if the Director determines there is significant public interest.

(d) The Division will distribute notice of the filing of an application for a new facility or major modifications with the next OCD and OCC hearing docket following receipt of the application.

(3) Financial Assurance Requirements:

(a) Centralized Facilities: Upon determination by the Director that the permit can be approved, any applicant of a centralized facility shall submit acceptable financial assurance in the amount of $25,000 per facility or a statewide "blanket" financial assurance in the amount of $50,000 to cover all of that applicant's facilities in a form approved by the Director.

(b) New Commercial Facilities or major expansions or major modification of Existing Facilities: Upon determination by the Director that a permit for a commercial facility to commence operation after the effective date of this rule can be approved, or upon determination by the Director that a major modification or major expansion of an existing facility can be approved, any applicant of such a commercial facility shall submit acceptable financial assurance in the amount of the closure cost estimated in Subsection B, Paragraph (1), Subparagraph (i) above of 19.15.9.711 NMAC in a form approved by the Director according to the following schedule:

(i) within one (1) year of commencing operations or when the facility is filled to 25% of the permitted capacity, whichever comes first, the financial assurance must be increased to 25% of the estimated closure cost;

(ii) within two (2) years of commencing operations or when the facility is filled to 50% of the permitted capacity, whichever comes first, the financial assurance must be increased to 50% of the estimated closure cost;

(iii) within three (3) years of commencing operations or when the facility is filled to 75% of the permitted capacity, whichever comes first, the financial assurance must be increased to 75% of the estimated closure cost;

(iv) within four (4) years of commencing operations or when the facility is filled to 100% of the permitted capacity, whichever comes first, the financial assurance must be increased to the estimated closure cost.

(c) Existing Commercial Facilities: All permittees of commercial facilities approved for operation at the time this rule becomes effective shall have submitted financial assurance in the amount of the closure cost estimated pursuant to Subsection B, Paragraph (1), Subparagraph (i) above of 19.15.9.711 NMAC but not less than $25,000 nor more than $250,000 per facility in a form approved by the Director.

(i) within one (1) year of the effective date of Section 19.15.9.711 NMAC the financial assurance amount must be increased to 25% of the estimated closure costs or $62,500.00, whichever is less;

(ii) within two (2) years of the effective date of Section 19.15.9.711 NMAC the financial assurance amounts must be increased to 50% of the estimated closure costs or $125,000.00, whichever is less;

(iii) within three (3) years of the effective date of Section 19.15.9.711 NMAC the financial assurance amounts must be increased to 75% of the estimated closure costs or $187,000.00, whichever is less;

(iv) within four (4) years of the effective date of Section 19.15.9.711 NMAC the financial assurance amounts must be increased to the estimated closure cost or $250,000.00, whichever is less.

(d) The financial assurance required in subparagraphs (a), (b), or (c), above shall be payable to the State of New Mexico and conditioned upon compliance with statutes of the State of New Mexico and rules of the Division, and acceptable closure of the site upon cessation of operation, in accordance with Subsection B, Paragraph (1), Subparagraph (i) of 19.15.9.711 NMAC. If adequate financial assurance is posted by the applicant with a federal or state agency and the financial assurance otherwise fulfills the requirements of this rule, the Division may consider the financial assurance as satisfying the requirement of Section 19.15.9.711 NMAC. The applicant must notify the Division of any material change affecting the financial assurance within 30 days of discovery of such change.

(4) The Director may accept the following forms of financial assurance:

(a) Surety Bonds

(i) A surety bond shall be executed by the permittee and a corporate surety licensed to do business in the State.

(ii) Surety bonds shall be noncancellable during their terms.

(b) Letter of Credit - Letter of credit shall be subject to the following conditions:

(i) The letter may be issued only by a bank organized or authorized to do business in the United States;

(ii) Letters of credit shall be irrevocable for a term of not less than five (5) years. A letter of credit used as security in areas requiring continuous financial assurance coverage shall be forfeited and shall be collected by the State of New Mexico if not replaced by other suitable financial assurance or letter of credit at least 90 days before its expiration date;

(iii) The letter of credit shall be payable to the State of New Mexico upon demand, in part or in full, upon receipt from the Director of a notice of forfeiture.

(c) Cash Accounts - Cash accounts shall be subject to the following conditions:

(i) The Director may authorize the permittee to supplement the financial assurance through the establishment of a cash account in one or more federally insured or equivalently protected accounts made payable upon demand to, or deposited directly with, the State of New Mexico.

(ii) Any interest paid on a cash account shall not be retained in the account and applied to the account unless the Director has required such action as a permit requirement.

(iii) Certificates of deposit may be substituted for a cash account with the approval of the Director.

(d) Replacement of Financial Assurances

(i) The Director may allow a permittee to replace existing financial assurances with other financial assurances that provide equivalent coverage.

(ii) The Director shall not release existing financial assurances until the permittee has submitted, and the Director has approved, acceptable replacements.

(5) A permit may be denied, revoked or additional requirements imposed by a written finding by the Director that a permittee has a history of failure to comply with Division rules and orders and state or federal environmental laws.

(6) The Director may, for protection of public health and the environment, impose additional requirements such as setbacks from an existing occupied structure.

(7) The Director may issue a permit upon a finding that an acceptable application has been filed and that the conditions of paragraphs 2 and 3 above have been met. All permits are revocable upon showing of good cause after notice and, if requested, hearing. Permits shall be reviewed a minimum of once every five (5) years for compliance with state statutes, Division rules and permit requirements and conditions.

C. Operational Requirements

(1) All surface waste management facility permittees shall file forms C-117-A, C-118, and C-120-A as required by OCD rules.

(2) Facilities permitted as treating plants will not accept sediment oil, tank bottoms and other miscellaneous hydrocarbons for processing unless accompanied by an approved Form C-117A or C-138.

(3) Facilities will only accept oilfield related wastes except as provided in Subsection C, Paragraph (4), Subparagraph (c) of 19.15.9.711 NMAC below. Wastes which are determined to be RCRA Subtitle C hazardous wastes by either listing or characteristic testing will not be accepted at a permitted facility.

(4) The permittee shall require the following documentation for accepting wastes, other than wastes returned from the wellbore in the normal course of well operations such as produced water and spent treating fluids, at commercial waste management facilities:

(a) Exempt Oilfield Wastes: As a condition to acceptance of the materials shipped, a generator, or his authorized agent, shall sign a certificate which represents and warrants that the wastes are: generated from oil and gas exploration and production operations; exempt from Resource Conservation and Recovery Act (RCRA) Subtitle C regulations; and not mixed with non-exempt wastes. The permittee shall have the option to accept on a monthly, weekly, or per load basis a load certificate in a form of its choice. While the acceptance of such exempt oilfield waste materials does not require the prior approval of the Division, both the generator and permittee shall maintain and shall make said certificates available for inspection by the Division for compliance and enforcement purposes.

(b) Non-exempt, Non-hazardous Oilfield Wastes: Prior to acceptance, a "Request For Approval To Accept Solid Waste", OCD Form C-138, accompanied by acceptable documentation to determine that the waste is non-hazardous shall be submitted to the appropriate District office. Acceptance will be on a case-by-case basis after approval from the Division's Santa Fe office.

(c) Non-oilfield Wastes: Non-hazardous, non-oilfield wastes may be accepted in an emergency if ordered by the Department of Public Safety. Prior to acceptance, a "Request To Accept Solid Waste", OCD Form C-138 accompanied by the Department of Public Safety order will be submitted to the appropriate District office and the Division's Santa Fe office. With prior approval from the Division, other non-hazardous, non-oilfield waste may be accepted into a permitted surface waste management facility if the waste is similar in physical and chemical composition to the oilfield wastes authorized for disposal at that facility and is either: (1) exempt from the “hazardous waste” provisions of Subtitle C of the federal Resource Conservation and Recovery Act; or (2) has tested non-hazardous and is not listed as hazardous. Prior to acceptance, a "Request For Approval to Accept Solid Waste," OCD Form C-138, accompanied by acceptable documentation to characterize the waste, shall be submitted to and approved by the Division’s Santa Fe office.

(5) The permittee of a commercial facility shall maintain for inspection the records for each calendar month on the generator, location, volume and type of waste, date of disposal, and hauling company that disposes of fluids or material in the facility. Records shall be maintained in appropriate books and records for a period of not less than five years, covering their operations in New Mexico.

(6) Disposal at a facility shall occur only when an attendant is on duty unless loads can be monitored or otherwise isolated for inspection before disposal . The facility shall be secured to prevent unauthorized disposal when no attendant is present.

(7) No produced water shall be received at the facility from motor vehicles unless the transporter has a valid Form

C-133, Authorization to Move Produced Water, on file with the Division.

(8) To protect migratory birds, all tanks exceeding 16 feet in diameter, and exposed pits and ponds shall be screened, netted or covered. Upon written application by the permittee, an exception to screening, netting or covering of a facility may be granted by the district supervisor upon a showing that an alternative method will protect migratory birds or that the facility is not hazardous to migratory birds.

(9) All facilities will be fenced in a manner approved by the Director.

(10) A permit may not be transferred without the prior written approval of the Director. Until such transfer is approved by the Director and the required financial assurance is in place, the transferor's financial assurance will not be released.

D. Facility Closure

(1) The permittee shall notify the Division thirty (30) days prior to its intent to cease accepting wastes and close the facility. The permittee shall then begin closure operations unless an extension of time is granted by the Director. If disposal operations have ceased and there has been no significant activity at the facility for six (6) months and the permittee has not responded to written notice as defined in Subsection D, Paragraph (2), Subparagraph (a) of 19.15.9.711 NMAC, then the facility shall be considered abandoned and shall be closed utilizing the financial assurance pledged to the facility. Closure shall be in accordance with the approved closure plan and any modifications or additional requirements imposed by the Director to protect public health and the environment. At all times the permittee must maintain the facility to protect public health and the environment. Prior to release of the financial assurance covering the facility, the Division will inspect the site to determine that closure is complete.

(2) If a permittee refuses or is unable to conduct operations at the facility in a manner that protects public health or the environment or refuses or is unable to conduct or complete the closure plan, the terms of the permit are not met, or the permittee defaults on the conditions under which the financial assurance was accepted, the Director shall take the following actions to forfeit all or part of the financial assurance:

(a) Send written notice by certified mail, return receipt requested, to the permittee and the surety informing them of the decision to close the facility and to forfeit all or part of the financial assurance, including the reasons for the forfeiture and the amount to be forfeited and notifying the permittee and surety that a hearing request must be made within ten (10) days of receipt of the notice.

(b) Advise the permittee and surety of the conditions under which the forfeiture may be avoided. Such conditions may include but are not limited to:

(i) An agreement by the permittee or another party to perform closure operations in accordance with the conditions of the permit, the closure plan and these Rules, and that such party has the ability to satisfy the conditions.

(ii) The Director may allow a surety to complete closure if the surety can demonstrate an ability to complete the closure in accordance with the approved plan. No surety liability shall be released until successful completion of closure.

(c) In the event forfeiture of the financial assurance is required by this rule, the Director shall proceed to collect the forfeited amount and use the funds collected from the forfeiture to complete the closure. In the event the amount forfeited is insufficient for closure, the permittee shall be liable for the deficiency. The Director may complete or authorize completion of closure and may recover from the permittee all reasonably incurred costs of closure and forfeiture in excess of the amount forfeited. In the event the amount forfeited was more than the amount necessary to complete closure and all costs of forfeiture, the excess shall be returned to the party from whom it was collected.

(d) Upon showing of good cause, the Director may order immediate cessation of operations of the facility when it appears that such cessation is necessary to protect public health or the environment, or to assure compliance with Division rules and orders.

(e) In the event the permittee cannot fulfill the conditions and obligations of the permit, the State of New Mexico, its agencies, officers, employees, agents, contractors and other entities designated by the State shall have all rights of entry into, over and upon the facility property, including all necessary and convenient rights of ingress and egress with all materials and equipment to conduct operation, termination and closure of the facility, including but not limited to the temporary storage of equipment and materials, the right to borrow or dispose of materials, and all other rights necessary for operation, termination and closure of the facility in accordance with the permit.

E. Waste management facilities in operation at the time Section 19.15.9.711 NMAC becomes effective shall:

(1) within one (1) year after the effective date permitted facilities submit the information required in Subsection B, Paragraph (1), Subparagraphs (a, h, i and l) of 19.15.9.711 NMAC not already on file with the Division;

(2) within one (1) year after the effective date unpermitted facilities submit the information required in Subsection B, Paragraph (1), Subparagraphs (a) through (j) and Subsection B, Paragraph (1), Subparagraph (l) of 19.15.9.711 NMAC;

(3) comply with Subsections C and D of 19.15.9.711 NMAC unless the Director grants an exemption from a requirement in these sections based upon a demonstration by the operator that such requirement is not necessary to protect public

health and the environment.
[6-6-88…2-1-96; 19.15.9.711 NMAC - Rn, 19 NMAC 15.I.711, 11-30-00; A, 4-15-03]

19.15.9.712. DISPOSAL OF CERTAIN NON-DOMESTIC WASTE AT SOLID WASTE FACILITIES.

A. General - Certain non-domestic waste arising from the exploration, development, production or storage of crude oil or natural gas, certain nondomestic waste arising from the oil field service industry, and certain non-domestic waste arising from the transportation, treatment or refinement of crude oil or natural gas, may be disposed of at a solid waste facility.

B. Definitions - The following words and phrases have particular meanings for purposes of this section:

(1) "BTEX." The acronym "BTEX" in this section refers to benzene, toluene, ethelbenzene and xylene.

(2) "Discharge Plan." A "discharge plan" is a plan submitted and approved by the Division pursuant to NMSA 1978, Section 70-2-12(B)(22) (2000 Cum.Supp.) and rules and regulations of the Water Quality Control Commission.

(3) "EPA." The acronym "EPA" refers to the United States Environmental Protection Agency.

(4) "EPA Clean." The phrase "EPA Clean" refers to cleanliness standards established by the EPA in 40 C.F.R. Part 261, Section 261.7(b).

(5) "NESHAP." The acronym "NESHAP" refers to the National Emission Standards for Hazardous Air Pollutants of the EPA, 40 C.F.R. Part 61.

(6) "NORM." The acronym "NORM" refers to naturally occurring radioactive materials regulated by 20 NMAC 3.1, Subpart 14.

(7) "Section." "Section" or "this section" refers to Section 19.15.9.712.

(8) "Solid Waste Facility." A "solid waste facility" is a facility permitted or authorized as a solid waste facility by the New Mexico Environment Department pursuant to the Solid Waste Act, NMSA 1978, Sections 74-9-1 et seq. and rules and regulations of the Environmental Improvement Board, to accept industrial solid waste or other special waste.

(9) "TCLP" The acronym "TCLP" in this section refers to the testing protocol established by the EPA in 40 C.F.R. Part 261, entitled "Toxicity Characteristic Leaching Procedure" or an alternative hazardous constituent analysis approved by the Division.

(10) "TPH." The acronym "TPH" in this section refers to the phrase "total petroleum hydrocarbons."

(11) "Waste." The word "waste" refers to nondomestic waste resulting from the exploration, development, production or storage of crude oil or natural gas pursuant to NMSA 1978, Section 70-2-12(B)(21) and nondomestic waste arising from the oil field service industry, and certain non-domestic waste arising from the transportation, treatment or refinement of crude oil or natural gas pursuant to NMSA 1978, Section 70-2-12(B)(22).

C. Procedure

(1) Waste Listed in Subsection D, Paragraph (1) of Section 19.15.9.712. Waste listed in Subsection D,

Paragraph (1) of Section 19.15.9.712 may be disposed of at a solid waste facility without prior written authorization of the Division.

(2) Waste Listed in Subsection D, Paragraph (2) of Section 19.15.9.712. Waste listed in Subsection D, Paragraph (2) of Section 19.15.9.712 may be disposed of at a solid waste facility after testing and prior written authorization of the Division. Before authorization is granted, copies of test results must be provided to the Division and to the solid waste facility where the waste is to be disposed. Disposal may commence only after written authorization of the Division. In appropriate cases and so long as a representative sample is tested, the Division may authorize disposal of a waste stream listed in Subsection D, Paragraph (2) of Section 19.15.9.712 without individual testing of each delivery.

(3) Waste Listed in Subsection D, Paragraph (3) of Section 19.15.9.712. Waste listed in Subsection D, Paragraph (3) of Section 19.15.9.712 may be disposed of at a solid waste facility on a case-by-case basis after testing required at the discretion of the Division and after prior written authorization of the Division. Before authorization is granted, copies of test results must be provided to the Division and to the solid waste facility where the waste is to be disposed. Disposal may commence only after written authorization of the Division.

(4) Simplified Procedure for Holders of Discharge Plans. Holders of an approved discharge plan may amend the discharge plan to provide for disposal of waste listed in Waste Listed in Subsection D, Paragraph (2) of Section 19.15.9.712 and, as applicable, Subsection D, Paragraph (3) of Section 19.15.9.712. If the amendment to the Discharge Plan is approved, wastes listed in Subsection D, Paragraph (2) of Section 19.15.9.712 and Subsection D, Paragraph (3) of Section 19.15.9.712 may be disposed of at a solid waste facility without the necessity of prior written authorization of the Division.

D. Waste Governed By This Section

(1) Waste That Does Not Require Testing Before Disposal:

(a) Barrels, drums, 5-gallon buckets, 1-gallon containers so long as empty and EPA-clean.

(b) Uncontaminated brush and vegetation arising from clearing operations.

(c) Uncontaminated concrete.

(d) Uncontaminated construction debris.

(e) Non-friable asbestos and asbestos contaminated waste material, so long as the disposal complies with all applicable federal and state regulations for nonfriable asbestos materials and so long as asbestos is removed from steel pipes and boilers and, if applicable, the steel recycled.

(f) Detergent buckets, so long as completely empty.

(g) Fiberglass tanks so long as the tank is empty, cut up or shredded, and EPA clean.

(h) Grease buckets, so long as empty and EPA clean.

(i) Uncontaminated ferrous sulfate or elemental sulfur so long as recovery and sale as a raw material is not possible.

(j) Metal plate and metal cable.

(k) Office trash.

(l) Paper and paper bags, so long as empty (paper bags).

(m) Plastic pit liners, so long as cleaned well.

(n) Soiled rags or gloves. If wet, must pass Paint Filter Test prior to disposal.

(o) Uncontaminated wood pallets.

(2) Waste That Must Be Tested:

(a) Activated alumina must be tested for TPH and BTEX.

(b) Activated carbon must be tested for TPH and BTEX.

(c) Amine filters must be tested for BTEX (and air-dried for at least 48 hours before testing).

(d) Friable asbestos and asbestos-contaminated waste material must be tested pursuant to NESHAP (and so long as the disposal otherwise complies with all applicable federal and state regulations for friable asbestos materials, and so long as asbestos is removed from steel pipes and boilers and, if applicable, the steel should be recycled before disposal).

(e) Cooling tower filters must be tested for TCLP/chromium (and drained and then air-dried for at least 48 hours before testing).

(f) Dehydration filter media must be tested for TPH and BTEX (and drained and then air-dried for at least 48 hours before testing).

(g) Gas condensate filters must be tested for BTEX (and drained and then air-dried for at least 48 hours before testing).

(h) Glycol filters must be tested for BTEX (and drained and then air-dried for at least 48 hours before testing).

(i) Iron sponge must be oxidized completely and then undergo Ignitability Testing.

(j) Junked pipes, valves, and metal pipe must be tested for NORM.

(k) Molecular sieve must be tested for TPH and BTEX (and must be cooled in a non-hydrocarbon inert atmosphere and hydrated in ambient air for at least 24 hours before testing).

(l) Pipe scale and other deposits removed from pipeline and equipment must be tested for TPH, TCLP/metals and NORM.

(m) Produced water filters must be tested for Corrosivity (and drained and then air-dried for at least 48 hours before testing).

(n) Sandblasting sand must be tested for TCLP/metals or, at the discretion of the Division, TCLP/total metals.

(o) Waste oil filters must be tested for TCLP/metals (and must be drained thoroughly of oil for at least 24 hours before testing and oil and metal parts must be recycled).

(3) Waste That May Be Disposed Of On A Case-By-Case Basis:

(a) Sulfur contaminated soil.

(b) Catalysts.

(c) Contaminated soil other than petroleum contaminated soil.

(d) Petroleum contaminated soil in the event of an emergency declared by the director.

(e) Contaminated concrete.

(f) Demolition debris not otherwise specified herein.

(g) Unused dry chemicals (in addition to any testing required by the Division, a copy of the Material Safety Data Sheet shall be forwarded to the Division and the solid waste facility on each chemical proposed for disposal).

(h) Contaminated ferrous sulfate or elemental sulfur.

(i) Unused pipe dope.

(j) Support balls.

(k) Tower packing materials.

(l) Contaminated wood pallets.

(m) Partial sacks of unused drilling mud (in addition to any testing required by the Division, a copy of the Material Safety Data Sheet shall be forwarded to Division and the solid waste facility at which the partial sacks will be disposed).

(n) Other wastes as applicable.

E. Testing

(1) General - Testing required herein shall be conducted according to the Test Methods for Evaluating Solid Waste, EPA No. SW-846. Any questions concerning the standards or a particular testing facility should be directed to the Division.

(2) Methodology - Testing must be conducted according to the test method listed:

(a) TPH: EPA method 418.1 or 8015 (D-R-O and G-R-O only) or an alternative hydrocarbon analysis approved by the Division.

(b) TCLP: EPA Method 1311 or an alternative hazardous constituent analysis approved by the Division.

(c) Paint Filter Testing: EPA Method 9095A.

(d) Ignitability Test: EPA Method 1030.

(e) Corrosivity: EPA Method 1110.

(f) Reactivity: Test procedures and standards established on a case-by-case basis by the Division.

(g) NORM. 20 NMAC 3.1, Subpart 14.

(3) Limits - To be eligible for disposal pursuant to this section, substances found during testing shall not exceed the following limits:

(a) Benzene: Less than 10 mg/Kg.

(b) BTEX: Less than 500 mg/Kg (sum of all).

(c) TPH: Shall not exceed 1000 mg/Kg.

(d) Hazardous Air Pollutants: Shall not exceed the standards set forth in NESHAP.

(e) TCLP: Shall not exceed the following:

(i) Arsenic: 5.0 mg/l
(ii) Barium: 100.0 mg/l
(iii) Cadmium: 1.0 mg/l
(iv) Chromium: 5.0 mg/l
(v) Lead: 5.0 mg/l
(vi) Mercury: 0.2 mg/l
(vii) Selenium: 1.0 mg/l
(viii) Silver: 5.0 mg/l

19.15.9.713 This entire section moved and renumbered to 19 NMAC 15.A.32.
[12-30-95, 2-1-96; A, 6-15-99; 19.15.9.713 NMAC - Rn, 19 NMAC 15.I.713; 11-30-00]

19.15.9.714 DISPOSAL OF REGULATED NATURALLY OCCURRING RADIOACTIVE MATERIAL (REGULATED NORM)

A. Purpose - This rule establishes procedures for the disposal of regulated naturally occurring radioactive material (Regulated NORM) associated with the oil and gas industry. Any person disposing of Regulated NORM, as defined at 19 NMAC 15.A.7, is subject to this rule and to the New Mexico Environmental Improvement Board regulations at 20 NMAC 3.1, Subpart 14.

B. Nonretrieved Flowlines and Pipelines

(1) The Division will consider a proposal for leaving flowlines and pipelines (hereinafter "pipeline") that contain Regulated NORM in the ground provided such abandonment procedures are performed in a manner to protect the environment, public health, and fresh waters. Division approval is contingent on the applicant meeting the following requirements as a minimum:

(2) An application submitted to the Division must contain the following as a minimum:

(a) The pipeline layout over its entire length on an OCD Form C-102 (Well Location and Acreage Dedication Plat) including the legal description of the location of both ends and all surface ownership along the pipeline.

(b) Results of a radiation survey conducted at all accessible points and a surface radiation survey along the complete pipeline route in a form approved by the Division. All surveys are to be conducted consistent with procedures approved by the Division.

(c) The type of material for which the pipeline had been used.

(d) The procedure to be used for flushing hydrocarbons and/or produced water from the pipeline.

(e) An explanation as to why it is more beneficial to leave the pipeline in the ground than to retrieve it.

(f) Proof of notice of the proposed abandonment to all surface owners where the pipeline is located. Additional notification may be required as described in Subsection F of 19.15.9.714 NMAC.

(3) Procedure

(a) Upon approval of the application by the Division, the operator must notify the OCD District office at least 24 hours prior to beginning any work on the pipeline abandonment.

(b) As a condition of completion of the pipeline abandonment, all accessible points must be permanently capped.

(4) General

(a) No additional Regulated NORM may be placed in any pipeline to be abandoned under this section other than that which accumulated in the pipeline under normal operation of the pipeline.

(b) Any pipeline that does not exhibit Regulated NORM pursuant to required surveys may be abandoned without application under this section in accordance with the operator's applicable lease agreements.

(c) If an appurtenance of a pipeline contains Regulated NORM, but upon removal of the appurtenance, no accessible point or surface above the pipeline exhibits the presence of

Regulated NORM, then the applicant must submit to the Division the information regarding the Regulated NORM in the appurtenance and a statement concerning management of that Regulated NORM. With respect to the pipeline left in the ground, the applicant will be subject to the requirements under Subsection B of 19.15.9.714 NMAC with the exception of Subsection B, Paragraph (2), Subparagraph (f) of 19.15.9.714 NMAC.

C. Commercial or Centralized Surface Waste Management Facilities

(1) The Division will consider proposals for the disposal of Regulated NORM in commercial or centralized surface waste management facilities, provided such disposal is performed in a manner to protect the environment, public health, and fresh waters. Division approval is contingent on the applicant obtaining a permit in accordance with Section 19.15.9.711 NMAC for the facility and complying with additional requirements specifically related to Regulated NORM disposal as described below.

(2) Application - All requests for authority to receive and dispose of Regulated NORM in commercial or centralized surface waste management facilities must be set for hearing by the Division in order for the operator of the facility to obtain or modify a permit in accordance with Section 19.15.9.711 NMAC. A request to dispose of Regulated NORM at a facility previously permitted under Section 19.15.9.711 NMAC will be considered a major modification to that facility. The hearing request must be submitted to the Division and must contain the following at a minimum:

(a) Complete plans for the facility, including the sources of Regulated NORM, radiation survey readings, quantities of Regulated NORM to be disposed, and monitoring proposals;

(b) A copy of this permit for the facility, if one has been issued by the Division;

(c) Proof of public notice of the application as required by Section 19.15.9.711 NMAC; and

(d) Evidence of issuance of a specific license pursuant to 20 NMAC 3.1, Subpart 14, a license pursuant to 20 NMAC 3.1, Subpart 13, and any other authorizations required by law.

(3) Procedures

(a) Operating procedures that are protective of the environment, public health, and fresh waters will be established in the Division's order.

(b) Any person desiring to dispose of Regulated NORM in an approved commercial or centralized surface waste management facility must furnish Regulated NORM information to the facility operator sufficient for the operator to submit Form C-138 (Request for Approval to Accept Solid Waste) for approval to the Division. The facility operator must receive Division approval prior to receiving the Regulated NORM at the disposal facility.

D. Downhole Disposal in Wells to be Plugged and Abandoned

(1) The Division will consider proposals for downhole disposal of Regulated NORM in wells that are to be plugged and abandoned, provided such plugging and abandonment procedures are performed in a manner to protect the environment, public health and fresh waters and in accordance with Division Rules pertaining to well plugging and abandonment.

(2) Application

(a) A plugging and abandonment (P&A) Form C-103 must be completed by the applicant and submitted to the Division for approval.

(b) In addition to all other information required for P&A submittal, the form must specifically state that Regulated NORM will be placed in the wellbore. The abandonment procedure contained in the application must identify depths at which the Regulated NORM will be placed, radiation survey results conducted on the Regulated NORM to be disposed, the procedure to be used to place the Regulated NORM in the wellbore, and the specific form of Regulated NORM being placed in the wellbore (e.g. scale, pipe, dirt, etc).

(c) Notice of the submittal of an application to dispose of Regulated NORM in a P&A well must be sent to the surface owner and the mineral lessor. Additional notification may be required as described in Subsection F of 19.15.9.714 NMAC.

(3) Procedures

(a) All P&A procedures routinely required by the Division must be followed unless specifically superseded at the instruction of the Division to facilitate the Regulated NORM disposal.

(b) No work will be commenced until the application for Regulated NORM disposal in a P&A well has been approved by the Division.

(c) The cement plug located directly above the Regulated NORM and the surface plug must be color-dyed with red iron oxide.

(4) General

(a) Regulated NORM must be disposed at a depth of at least 100 feet below the lower most known Underground Source of Drinking Water (USDW) zone. There must be evidence that there is cement across the known USDW zones.

(b) Abnormally pressured zone(s) in the wellbore that might result in migration of the Regulated NORM after it has been placed in the P&A well must be addressed in the application.

E. Injection

(1) The Division will consider proposals for injecting Regulated NORM into injection wells provided such injection is performed in a manner to protect the environment, public health, and fresh waters and such injection is in compliance with Division Rules pertaining to injection. Division approval is contingent on the applicant meeting the following requirements at a minimum:

(2) Disposal wells

(a) An application submitted to the Division must contain the following information at a minimum:

(i) For both existing and newly permitted disposal wells, a completed Form C-108 (Application for Authorization to Inject) with proof of required notification and a statement that Regulated NORM will be injected;

(ii) Description of Regulated NORM to be disposed including its source, radiation levels, and quantity; and

(iii) Description of any process used on the material to improve injectivity;

(b) Procedures

(i) Regulated NORM to be injected may only be from the applicant's operations.

(ii) Each time Regulated NORM is injected, a Form C-103 (Subsequent Report Form) must be submitted to the Division and District offices. This form must be submitted within five (5) working days following the injection and must contain the following information: source of Regulated NORM; NORM radiation level; quantity of material injected; description of any process used on the material to improve injectivity; the injection pressure while injecting; and date(s) of injection.

(iii) Failures and repairs - All mechanical failures must be reported to the appropriate District office within 24 hours of the occurrence. A description of the failure and immediate measures taken in response to the failure must be submitted no later than 15 days following the occurrence. The operator must notify the District office of proposed repair plans. Approval of repair plans must be received prior to any work commencing, and notice of commencement must be given to the District office such that the repairs may be witnessed and/or inspected. All well repairs must be monitored by the operator to ensure Regulated NORM does not escape the wellbore or is completely contained in the repair operations.

(iv) At the time of abandonment of the disposal well, the injection interval that was used for Regulated NORM injection must be squeezed with cement or a cement plug must be located directly above the injection interval. Cement in either case must contain red iron oxide.

(v) The injection zone must be at a depth of at least 100 feet below the lower most known USDW zone.

(3) Injection in Enhanced Oil Recovery (EOR) Injection Wells - The Division will consider issuing a permit for the disposal of Regulated NORM into injection wells within an approved Enhanced Oil Recovery (EOR) Project only after notice and hearing and upon a minimum demonstration that:

(a) such injection will not reduce the efficiency of the project or otherwise cause a reduction in the ultimate recovery of hydrocarbons from the project;

(b) such injection will not cause an increase in the radiation level of Regulated NORM produced from the EOR interval in any producing well located either within or offsetting the project area; and

(c) the operations will be in conformance with provisions of Subsection E, Paragraph (2) of 19.15.9.714 NMAC above.

(4) Injection Above Fracture Pressure

(a) The Division will consider issuing a permit for the disposal of Regulated NORM in a disposal well above fracture pressure only after notice and hearing and upon receiving the following minimum information from the applicant:

(i) A completed Form C-108 clearly stating that disposal of Regulated NORM at or above fracture pressure is proposed.

(ii) Information required under Subsection E, Paragraph (2) of 19.15.9.714 NMAC above.

(iii) Model results predicting the fracture propagation including the expected height, extension, direction, and any other evidence sufficient to demonstrate that the fracture will not extend beyond the injection interval or into the confining zones. The application must include the procedure, the anticipated pressures and the type and pressure rating of equipment that will be used. The current or potential utilization of zones immediately above and below the zone of interest may be considered by the Division in the acceptance or rejection of model predictions.

(iv) A contingency plan of the procedures, including containment plans, that will be employed if a mechanical failure occurs.

(b) Procedures

(i) 24 hour notice that injection will commence must be given to the District office.

(ii) Upon completion of the injection, the disposal interval must be squeezed with cement or a cement plug must be located directly above the injection interval (cement in either case must contain red iron oxide), and a Form C-103 (Subsequent Report Form) must be submitted to the Division and the District office within five working days of the injection. If the operator desires to return the well to injection below fracture pressure, such plans must be contained in the application.

(5) Injection in Commercial Disposal Facilities - The Division will consider issuing a permit for the commercial disposal of Regulated NORM by injection only after notice and hearing, and provided a specific license has been obtained pursuant to 20 NMAC 3.1, Subpart 14 and a license has been obtained pursuant to 20 NMAC 3.1, Subpart 13. In addition to obtaining these licenses the operator must also comply with Subsection E, Paragraph (2), Subparagraph (b), Sub-subparagraph (i) above of 19.15.9.714 NMAC.

F. Additional Notification

(1) The Director may, at his discretion, require additional notice for any application under this rule.

(2) Any notified party seeking to comment or request a public hearing on such an application must file comments or a hearing request with the Division within 20 days of notice. A request for a hearing must be in writing and must set forth the reasons why a hearing should be held.

(3) A public hearing will be held as required in 19.15.9.714 NMAC or if the Director determines there is sufficient cause.

[7-15-96; 19.15.9.714 NMAC - Rn, 19 NMAC 15.I.714, 11-30-00]

HISTORY of 19.15.9 NMAC:

Pre-NMAC History:

Material in the part was derived from that previously filed with the commission of public records - state records center and archives:

Rule 701, Injection of Fluids into Reservoirs, 1-08-82

Rule 701, Injection of Fluids into Reservoirs, 1-28-87

Rule 701, Injection of Fluids into Reservoirs, 2-05-91

Rule 702, Casing and Cementing of Injection Wells, 1-08-82
Rule 702, Casing and Cementing of Injection Wells, 2-05-91
Rule 703, Operation and Maintenance, 1-08-82
Rule 703, Operation and Maintenance, 2-05-91
Rule 704, Testing and Monitoring, 1-08-82
Rule 704, Testing, Monitoring, Step-Rate Tests, Notice to the Division, Requests for Pressure Increases, 11-07-86
Rule 704, Testing, Monitoring, Step-Rate Tests, Notice to the Division, Requests for Pressure Increases, 2-05-91
Rule 705, Commencement, Discontinuance, And Abandonment of Injection Operations, 1-08-82
Rule 705, Commencement, Discontinuance, And Abandonment of Injection Operations, 2-05-91
Rule 706, Records and Reports, 1-08-82
Rule 706, Records and Reports, 2-05-91
Rule 707, Reclassification of Wells, 1-08-82
Rule 707, Reclassification of Wells, 2-05-91
Rule 708, Transfer of Authority To Inject, 1-08-82
Rule 708, Transfer of Authority To Inject, 2-05-91
Rule 709, Removal of Produced Water from Leases and Field Facilities, 1-27-82
Rule 709, Removal of Produced Water from Leases and Field Facilities, 9-16-85
Rule 709, Removal of Produced Water from Leases and Field Facilities, 2-05-91
Rule 710, Disposition of Transported Produced Water, 1-27-82
Rule 710, Disposition of Produced Water, 9-16-85
Rule 710, Disposition of Transported Produced Water, 2-05-91
Rule 711, Commercial Surface Waste Disposal Facilities, 6-6-88
Rule 711, Commercial Surface Waste Disposal Facilities, 10-11-89
Rule 711, Commercial Surface Waste Disposal Facilities, 2-5-91
Rule 711, Applicable to Surface Waste Management Facilities Only, 7-27-95
Rule 711, Applicable to Surface Waste Management Facilities Only, 12-18-95
Rule 712, Qualification of Production Restoration Projects and Certification for the Production Restoration Incentive Tax Exemption, 12-07-95
Rule 713, Qualification of Well Workover Projects and Certification for the Well Workover Incentive Tax Rate, 12-07-95

Other History:
Rule 701, Injection of Fluids into Reservoirs, 2-05-91; Rule 702, Casing and Cementing of Injection Wells, 2-05-91; Rule 703, Operation and Maintenance, 2-05-91; Rule 704, Testing, Monitoring, Step-Rate Tests, Notice to the Division, Requests for Pressure Increases, 2-05-91; Rule 705, Commencement, Discontinuance, And Abandonment of Injection Operations, 2-05-91; Rule 706, Records and Reports, 2-05-91; Rule 707, Reclassification of Wells, 2-05-91; Rule 708, Transfer of Authority To Inject, 2-05-91; Rule 709, Removal of Produced Water from Leases and Field Facilities, 2-05-91; Rule 710, Disposition of Transported Produced Water, 2-05-91; Rule 711, Applicable to Surface Waste Management Facilities Only, 12-18-95; Rule 712, Qualification of Production Restoration Projects and Certification for the Production Restoration Incentive Tax Exemption, 12-07-95; and Rule 713, Qualification of Well Workover Projects and Certification for the Well Workover Incentive Tax Rate, 12-07-95 **all renumbered and reformatted to 19 NMAC 15.I,** filed 01-18-96.
Renumbered and amended **from** 19 NMAC 15.I, filed 01-18-96 **to** 19.15.9 NMAC, effective 11-30-2000.

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 10 OIL PURCHASING AND TRANSPORTING

19.15.10.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Dept., Oil Conservation Division, 2040 S. Pacheco, Santa Fe, New Mexico 87505, (505) 827-7131.
[2/1/96; 19.15.10.1 NMAC - Rn, 19 NMAC 15.J.1, 04-15-03]

19.15.10.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico.
[2/1/96; 19.15.10.2 NMAC - Rn, 19 NMAC 15.J.2, 04-15-03]

19.15.10.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the Oil and Gas Act which grants the Oil Conservation Division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights and the disposition of wastes resulting from oil and gas operations.
[2/1/96; 19.15.10.3 NMAC - Rn, 19 NMAC 15.J.3, 04-15-03]

19.15.10.4 DURATION: Permanent.
[2/1/96; 19.15.10.4 NMAC - Rn, 19 NMAC 15.J.4, 04-15-03]

19.15.10.5 EFFECTIVE DATE: February 1, 1996 [unless a later date is cited at the end of a section]
[2/1/96; 19.15.10.5 NMAC - Rn, 19 NMAC 15.J.5, 04-15-03]

19.15.10.6 OBJECTIVE: To regulate oil purchasing and transporting under the Oil and Gas Act.
[2/1/96; 19.15.10.6 NMAC - Rn, 19 NMAC 15.J.6, 04-15-03]

19.15.10.7 DEFINITIONS: [RESERVED]

19.15.10.8 - 800 [RESERVED]

19.15.10.801 ILLEGAL SALE PROHIBITED:
The sale or purchase or acquisition, or the transporting, refining, processing or handling in any other way, of crude petroleum oil or of any crude petroleum produced in excess of the amount allowed by any statute of this state, or by any rule, regulation or order of the division made thereunder, is prohibited.
[1/1/50...2/1/96; 19.15.10.801 NMAC - Rn, 19 NMAC 15.J.801, 04-15-03]

19.15.10.802 RATABLE TAKE; COMMON PURCHASER:
A. Every person now engaged or hereafter engaging in the business of purchasing oil to be transported through pipelines shall be a common purchaser thereof, and shall without discrimination in favor of one producer as against another in the same field, purchase any oil tendered to it which has been lawfully produced in the vicinity of, or which may be reasonably reached by pipelines through which it is transporting oil, or the gathering branches thereof, or which may be delivered to the pipeline or gathering branches thereof by truck or otherwise and shall fully perform all the duties of a common purchaser. If any common purchaser shall not have need for all such oil lawfully produced within a field, or if for any reason it shall be unable to purchase all such oil, then it shall purchase from each producer in a field ratably, taking and purchasing the same quantity of oil from each well to the extent that each well is capable of producing its ratable portions; provided, however, nothing herein contained shall be construed to require more than one pipeline connection for each producing well. In the event any such common purchaser of oil is likewise a producer or is affiliated with a producer, directly or indirectly, it is hereby expressly prohibited from discriminating in favor of its own production or in favor of the production of an affiliated producer as against that of others and the oil produced by such common purchaser, or by the affiliate of such common purchaser shall be treated as that of any other producer for the purposes of ratable taking.

B. It shall be unlawful for any common purchaser, to unjustly or unreasonably discriminate as to the relative quantities of oil purchased by it in various fields of the state; the question of the justice or reasonableness to be determined by the division, taking into consideration the production and age of wells in the respective fields and all other factors. It is the intent of this rule that all fields shall be allowed to produce and market a just and equitable share of the oil produced and marketed in the state, insofar as the same can be effected economically and without waste.

C. In order to preclude premature abandonment, the common purchaser within its purchasing area is authorized and directed to make 100 percent purchases from units of settled production producing ten (10) barrels or less daily of crude petroleum in lieu of ratable purchases or takings. Provided, however, where such purchaser's takings are curtailed below ten (10) barrels per unit of crude petroleum daily, then such purchaser is authorized and directed to purchase equally from all such units within its purchasing area, regardless of their producing ability insofar as they are capable of producing.
[7/1/52…2/1/96; 19.15.10.802 NMAC - Rn, 19 NMAC 15.J.802, 04-15-03]

19.15.10.803 PRODUCTION OF LIQUID HYDROCARBONS FROM GAS WELLS:
A. All liquid hydrocarbons produced incidental to the authorized production of gas from a well classified by the division as a gas well shall, for all purposes, be legal production.
B. For purposes of this rule, all gas produced from a gas well shall be considered to be authorized production with the following exceptions:
(1) When the well is being produced without an approved form C-104, designating the gas transporter and the oil or condensate transporter for said well.
(2) When the well has been directed to be shut in by the division.
C. In the event a gas well is directed to be shut in by the division, both the gas transporter and oil transporter named on the well's form C-104 shall be immediately notified of such fact.
[12/1/57...2/1/96; 19.15.10.803 NMAC - Rn, 19 NMAC 15.J.803, 04-15-03]

19.15.10.804 DOCUMENTATION REQUIRED:
A. All off-lease transportation of crude oil or lease condensate by motor vehicle shall be pursuant to an approved form C-104 and shall be accompanied by a run ticket or equivalent document. The documentation shall identify the name and address of the transporter, the name of the operator and of the lease or facility from which the oil was taken, the date of removal, the API gravity of the oil, the observed percentage of BS and W, the volume of oil or opening and closing tank gauges or meter readings and the signature of the driver. The document shall provide space for recording of the lease number and for signature of the operator or his representative.
B. After August 1, 1982, all such transportation must be accompanied by documentation sufficient to verify the location of the tanks or facility from which the liquid was removed. The location may be shown on the run ticket or equivalent document or may be carried separately.
C. All off-lease transportation of liquids which may contain crude oil, lease condensate, sediment oil or miscellaneous hydrocarbons shall be accompanied by a run ticket, work order or equivalent document, i.e., form C-117-A. The documentation shall identify the name and address of the transporter, the name of the operator and of the lease or facility from which the liquid was removed, the nature of the liquid removed including the observed percentage of liquid hydrocarbons, the volume or estimated volume of liquids and the destination.
D. After August 1, 1982, all such transportation must be accompanied by documentation sufficient to verify the location of the tanks or facility from which the liquid was removed. The location may be shown on the run ticket or equivalent document or may be carried separately.
E. The documentation required under Subsections A and B of 19.15.10.804 NMAC above shall be carried in the vehicle during transportation and shall be produced for examination and inspection by any employee of the division, any state police officer or any other law enforcement officer upon identification and request.
F. Except where the owner and the transporter are the same, one copy of such documentation shall be left at the facility from which the oil or other liquids were removed.
[2/1/82...2/1/96; 19.15.10.804 NMAC - Rn, 19 NMAC 15.J.804, 04-15-03]

HISTORY OF 19.15.10 NMAC:
Pre-NMAC History: The material in this Part was derived from that previously filed with the State Records Center and Archives:
Rule 801, Illegal Sale Prohibited, 1/8/82.
Rule 801, Illegal Sale Prohibited, 2/5/91.
Rule 802, Ratable Take; Common Purchaser, 1/8/82.
Rule 802, Ratable Take; Common Purchaser, 2/5/91.
Rule 803, Production of Liquid Hydrocarbons From Gas Wells, 1/8/82.
Rule 803, Production of Liquid Hydrocarbons From Gas Wells, 2/5/91.
Rule 804, Documentation Required, 1/27/82.
Rule 804, Documentation Required, 2/5/91.

History of Repealed Material: [RESERVED]

Other History:
Rule 801, Illegal Sale Prohibited, 2/5/91; Rule 802, Ratable Take; Common Purchaser, 2/5/91; Rule 803, Production of Liquid Hydrocarbons From Gas Wells, 2/5/91; Rule 804, Documentation Required, 2/5/91, **all renumbered and reformatted to 19 NMAC 15.J,** filed 01/18/96.
Renumbered and reformatted **from** 19 NMAC 15.J, filed 01-18-96 **to** 19.15.10 NMAC, effective 04/15/2003.

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 11 GAS PURCHASING AND TRANSPORTING

19.15.11.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Dept., Oil Conservation Division, 2040 S. Pacheco, Santa Fe, New Mexico 87505, (505) 827-7131.
[2/1/96; 19.15.11.1 NMAC - Rn, 19 NMAC 15.K.1, 09-30-03]

19.15.11.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico.
[2/1/96; 19.15.11.2 NMAC - Rn, 19 NMAC 15.K.2, 09-30-03]

19.15.11.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the Oil and Gas Act which grants the oil conservation division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights and the disposition of wastes resulting from oil and gas operations.
[2/1/96; 19.15.11.3 NMAC - Rn, 19 NMAC 15.K.3, 09-30-03]

19.15.11.4 DURATION: Permanent.
[2/1/96; 19.15.11.4 NMAC - Rn, 19 NMAC 15.K.4, 09-30-03]

19.15.11.5 EFFECTIVE DATE: February 1, 1996 [unless a later date is cited at the end of a section].
[2/1/96; 19.15.11.5 NMAC - Rn, 19 NMAC 15.K.5, 09-30-03]

19.15.11.6 OBJECTIVE: To regulate gas purchasing and transporting and enable the oil conservation division to fulfill its statutory mandate pursuant to the Oil and Gas Act.
[2/1/96; 19.15.11.6 NMAC - Rn, 19 NMAC 15.K.6, 09-30-03]

19.15.11.7 DEFINITIONS: [RESERVED]

19.15.11.8 - 900 [RESERVED]

19.15.11.901 ILLEGAL SALE PROHIBITED:
The sale, purchase or acquisition or the transporting, refining, processing or handling in any other way, of natural gas in whole or in part (or of any product of natural gas so produced) produced in excess of the amount allowed by any statute of this state, or by any rule, regulation or order of the division made thereunder, is prohibited.
[1/1/50...2/1/96; 19.15.11.901 NMAC - Rn, 19 NMAC 15.K.901, 09-30-03]

19.15.11.902 RATABLE TAKE:
A. Any person now or hereafter engaged in purchasing from one or more producers, gas produced from gas wells or casinghead gas produced from oil wells shall be a common purchaser thereof within each common source of supply from which it purchases, and as such it shall purchase gas lawfully produced from gas wells or casinghead gas produced from oil wells with which its gas transportation facilities are connected in the pool and other gas lawfully produced within the pool and tendered to a point on its gas transportation facilities. Such purchases shall be made without unreasonable discrimination in favor of one producer against another in the price paid, the quantities purchased, the bases of measurement or the gas transportation facilities afforded for gas of like quantity, quality and pressure available from such wells. In the event any such person is likewise a producer, he is prohibited to the same extent from discriminating in favor of himself on production from gas wells or casinghead gas produced from oil wells in which he has an interest, direct or indirect, as against other production from gas wells or casinghead gas produced from oil wells in the same pool. For the purposes of Section 902 of 19.15.11 NMAC, reasonable differences in prices paid or facilities afforded, or both, shall not constitute unreasonable discrimination if such differences bear a fair relationship to differences in quality, quantity or pressure of the gas available or to the relative lengths of time during which such gas will be available to the purchaser. The provisions of this Subsection shall not apply to:
(1) any wells or pools used for storage and withdrawal from storage of natural gas originally produced not in violation of the rules, regulations or orders of the division; or
(2) persons purchasing gas principally for use in the recovery or production of oil or gas, or
(3) any well which has been designated a "hardship well" by the division.

B. Any common purchaser taking gas produced from gas wells or casinghead gas produced from oil wells from a common source of supply shall take ratably under such rules, regulations and orders, concerning quantity, as may be promulgated by the division consistent with Section 902 of 19.15.11 NMAC. The division, in promulgating such rules, regulations and orders may consider the quality and the deliverability of the gas, the pressure of the gas at the point of delivery, acreage attributable to the well, market requirements in the case of unprorated pools and other pertinent factors.

C. Nothing in Section 902 of 19.15.11 NMAC shall be construed or applied to require, directly or indirectly, any person to purchase gas of a quality or under a pressure or under any other condition by reason of which such gas cannot be economically and satisfactorily used by such purchaser by means of his gas transportation facilities then in service.
[1/1/50...2/1/96; 19.15.11.902 NMAC - Rn, 19 NMAC 15.K.902, 09-30-03]

HISTORY OF 19.15.11 NMAC:
Pre-NMAC History: The material in this Part was derived from that previously filed with the State Records Center and Archives:
Rule 901, Illegal Sale Prohibited, filed 1/8/82;
Rule 901, Illegal Sale Prohibited, filed 2/5/91;
Rule 902, Ratable Take, filed 1/8/82;
Rule 902, Ratable Take, filed 2/5/91.

History of Repealed Material: [RESERVED]

Other History:
Rule 901, Illegal Sale Prohibited and Rule 902, Ratable Take, (both filed 2/5/91) were both renumbered and reformatted and replaced by 19 NMAC 15.K, Gas Purchasing and Transporting, effective 2/1/96.
19 NMAC 15.K, Gas Purchasing and Transporting (filed 01-18-96)**,** renumbered **from** 19 NMAC 15.K **to** 19.15.11 NMAC, effective 09-30-03.

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 12 REFINING

19.15.12.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Dept., Oil Conservation Division, 2040 S. Pacheco, Santa Fe, New Mexico 87505, (505) 827-7131.
[2/1/96; 19.15.12.1 NMAC - Rn, 19 NMAC 15.L.1, 10/15/03]

19.15.12.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico.
[2/1/96; 19.15.12.2 NMAC - Rn, 19 NMAC 15.L.2, 10/15/03]

19.15.12.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the Oil and Gas Act which grants the oil conservation division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights and the disposition of wastes resulting from oil and gas operations.
[2/1/96; 19.15.12.3 NMAC - Rn, 19 NMAC 15.L.3, 10/15/03]

19.15.12.4 DURATION: Permanent.
[2/1/96; 19.15.12.4 NMAC - Rn, 19 NMAC 15.L.4, 10/15/03]

19.15.12.5 EFFECTIVE DATE: February 1, 1996 [unless a later date is cited at the end of a section]
[2/1/96; 19.15.12.5 NMAC - Rn, 19 NMAC 15.L.5, 10/15/03]

19.15.12.6 OBJECTIVE: To regulate refining to enable the oil conservation division to fulfill its statutory mandates under the Oil and Gas Act.
[2/1/96; 19.15.12.6 NMAC - Rn, 19 NMAC 15.L.6, 10/15/03]

19.15.12.7 DEFINITIONS: [RESERVED]

19.15.12.8 - 1000 [RESERVED]

19.15.12.1001 REFINERY REPORTS:
Each refiner of oil within the state of New Mexico shall furnish for each calendar month a "Refiner's Monthly Report," form C-113, containing the information and data indicated by such form, respecting oil and products involved in such refiner's operations during each month. Such report for each month shall be prepared and filed according to instructions on the form, on or before the 15th day of the next succeeding month.
[1/1/50...2/1/96; 19.15.12.1001 NMAC - Rn, 19 NMAC 15.L.1001, 10/15/03]

19.15.12.1002 GASOLINE PLANT REPORTS:

A. Each operator of a gasoline plant, cycling plant or any other plant at which gasoline, butane, propane, condensate, kerosene, oil or other liquid products are extracted from natural gas within the state of New Mexico shall furnish for each calendar month a Gas Purchaser's Monthly Report, form C-111, containing the information indicated by such form respecting natural gas and products involved in the operation of each plant during each month. (19.15.12.1002 NMAC shall also be applicable to plants in the state of New Mexico processing carbon dioxide gas into liquid or solid form.)

B. Form C-111 shall be filed in accordance with the provisions of Rule 1111 [now 19.15.13.1111 NMAC].
[1/1/50...2/1/96; 19.15.12.1002 NMAC - Rn, 19 NMAC 15.L.1002, 10/15/03]

HISTORY OF 19.15.12 NMAC:
Pre-NMAC History: The material in this Part was derived from that previously filed with the State Records Center and Archives:
Rule 1001, Refinery Reports, filed 1/8/82.
Rule 1001, Refinery Reports, filed 2/5/91.
Rule 1002, Gasoline Plant Reports, filed 1/8/82.
Rule 1002, Gasoline Plant Reports, filed 2/5/91.

History of Repealed Material: [RESERVED]

Other History:
Rule 1001, Refinery Reports, filed 2/5/91 and Rule 1002, Gasoline Plant Reports, filed 2/5/91 were both renumbered, reformatted and replaced by 19 NMAC 15.L, Refining, effective 2/2/96.
19 NMAC 15.L, Refining (filed 1/18/96) was renumbered, reformatted and replaced by 19.15.12 NMAC, effective 10/15/03.

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 13 REPORTS

19.15.13.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department, Oil Conservation Division, 2040 S. Pacheco, Santa Fe, New Mexico 87505, (505) 827-7131.
[2-1-96; 19.15.13.1 NMAC - Rn, 19 NMAC 15.M.1, 06/30/04]

19.15.13.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico.
[2-1-96; 19.15.13.2 NMAC - Rn, 19 NMAC 15.M.2, 06/30/04]

19.15.13.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the Oil and Gas Act which grants the oil conservation division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights and the disposition of wastes resulting from oil and gas operations.
[2-1-96; 19.15.13.3 NMAC - Rn, 19 NMAC 15.M.3, 06/30/04]

19.15.13.4 DURATION: Permanent.
[2-1-96; 19.15.13.4 NMAC - Rn, 19 NMAC 15.M.4, 06/30/04]

19.15.13.5 EFFECTIVE DATE: February 1, 1996 [unless a later date is cited at the end of a section]
[2-1-96; 19.15.13.5 NMAC - Rn, 19 NMAC 15.M.5, 06/30/04]

19.15.13.6 OBJECTIVE: To provide for the filing of reports to enable the oil conservation division to carry out its statutory mandates under the Oil and Gas Act.
[2-1-96; 19.15.13.6 NMAC - Rn, 19 NMAC 15.M.6, 06/30/04]

19.15.13.7 DEFINITIONS: [RESERVED].

19.15.13.8 - 1099 [RESERVED].

19.15.13.1100 GENERAL:

A. Where to file reports: Unless otherwise specifically provided for in any rule or order of the division, all forms and reports required by these rules shall be filed with the appropriate district office of the division as provided in 19.15.15.1301 NMAC and 19.15.15.1302 NMAC.

B. Additional data: These rules shall not be construed to limit or restrict the authority of the oil conservation division to require the furnishing of such additional reports, data or other information relative to the production, transportation, storing, refining, processing or handling of crude petroleum oil, natural gas or products in the state of New Mexico as may appear to it to be necessary or desirable, either generally or specifically, for the prevention of waste and the conservation of natural resources of the state of New Mexico.

C. Books and records: All producers, injectors, transporters, storers, refiners, gasoline or extraction plant operators, treating plant operators, and initial purchasers of natural gas within the state of New Mexico shall make and keep appropriate books and records for a period of not less than five years, covering their operations in New Mexico, from which they may be able to make and substantiate the reports required by these rules.

D. Written notices, requests, permits and reports: The forms listed below shall be used for the purpose shown in accordance with the instructions printed thereon and the rule covering the use of the form, or any special rule or order pertaining to its use:

(1) Form C-101 Application for Permit to Drill, Deepen or Plug Back
(2) Form C-102 Well Location and Acreage Dedication Plat

(3) Form C-103 Sundry Notices and Reports on Wells
(4) Form C-104 Request for Allowable and Authorization to Transport Oil and Natural Gas
(5) Form C-105 Well Completion or Recompletion Report and Log
(6) Form C-106 Notice of Intention to Utilize Automatic Custody Transfer Equipment
(7) Form C-107 Application for Multiple Completion
(8) Form C-108 Application to Dispose of Salt Water by Injection into a Porous Formation
(9) Form C-109 Application for Discovery Allowable and Creation of a New Pool
(10) Form C-111 Gas Transporter's Monthly Report (Sheet 1 and Sheet 2)
(11) Form C-112 Transporter's and Storer's Monthly Report
(12) Form C-113 Refiner's Monthly Report (Sheet 1 and Sheet 2)
(13) Form C-115 Operators Monthly Report
(14) Form C-115-EDP Operator's Monthly Report (electronic data processing)
(15) Form C-116 Gas-Oil Ratio Tests
(16) Form C-117-A Tank Cleaning, Sediment Oil Removal, Transportation of Miscellaneous Hydrocarbons and Disposal Permit
(17) Form C-117-B Monthly Sediment Oil Disposal Statement
(18) Form C-118 Treating Plant Operator's Monthly Report (Sheet 1 and Sheet 2)
(19) Form C-119 Carbon Black Plant Monthly Report
(20) Form C-120-A Monthly Water Disposal Report
(21) Form C-121 Crude Oil Purchaser's Nomination
(22) Form C-121-A Purchaser's Gas Nomination
(23) Form C-122 Multi-Point and One Point Back Pressure Test for Gas wells
(24) Form C-122-A Gas Well Test Data Sheet-San Juan Basin (Initial Deliverability Test, blue paper; Annual Deliverability Test, white)
(25) Form C-122-B Initial Potential Test Data Sheet
(26) Form C-122-C Deliverability Test Report
(27) Form C-122-D Worksheet for Calculation of Static Column Wellhead Pressure (P_w).
(28) Form C-122-E Worksheet for Stepwise Calculation of (Surface) (Subsurface) Pressure (Pc & Pw)
(29) Form C-122-F Worksheet for Calculation of Wellhead Pressures (Pc or Pw) from Known Bottomhole Pressure (Pf or Ps)
(30) Form C-122-G Worksheet for Calculation of Static Column Pressure at Gas Liquid Interface
(31) Form C-123 Request for the Creation of a New Pool
(32) Form C-124 Reservoir Pressure Report
(33) Form C-125 Gas Well Shut-in Pressure Report
(34) Form C-126 Permit to Transport Recovered Load Oil
(35) Form C-127 Request for Allowable Change
(36) Form C-129 Application for Exception to No-Flare Rule 306
(37) Form C-130 Notice of Disconnection
(38) Form C-131-A Monthly Gas Storage Report
(39) Form C-131-B Annual LPG Storage Report
(40) Form C-133 Authorization to Move Produced Water Exhibit "A"
(41) Form C-134 Application for Exception to Division Order R-8952, (Protection of Migratory Birds Rule Subsection B of 19.15.3.105 NMAC, Subsection H of 19.15.5.312 NMAC, 19.15.5.313 NMAC, or Paragraph (8) of Subsection C of 19.15.9.711 NMAC
(42) Form C-135 Gas Well Connection, Reconnection or Disconnection Notice
(43) Form C-136 Application for Approval To Use An Alternate Gas Measurement Method
(44) Form C-137 Application for Waste Management Facility
(45) Form C-138 Request for Approval to Accept Solid Waste
(46) Form C-139 Application For Qualification of Production Restoration Project and Certification

of Approval

(47) Form C-140 Application For Qualification of Well Workover Project and Certification of Approval

[1-1-50...2-1-96; 19.15.13.1100 NMAC - Rn, 19 NMAC 15.M.1100, 06/30/04]

19.15.13.1101 APPLICATION FOR PERMIT TO DRILL, DEEPEN OR PLUG BACK (Form C-101):

A. Before commencing drilling or deepening operations, or before plugging a well back to another zone, the operator of the well must obtain a permit to do so. To obtain such permit, the operator shall submit to the division five copies of form C-101, application for permit to drill, deepen or plug back, completely filled out. If the operator has an approved bond in accordance with 19.15.3.101 NMAC, one copy of the drilling permit will be returned to him on which will be noted the division's approval, with any modification deemed advisable. If the proposal cannot be approved for any reason, the forms C-101 will be returned with the cause for rejection stated thereon.

B. Form C-101 must be accompanied by three copies of form C-102, well location and acreage dedication plat. (See 19.15.13.1102 NMAC.)

C. If the well is to be drilled on state land, submit six copies of form C-101 and four copies of form C-102, the extra copy of each form being for the state land office.

[1-1-64...2-1-96; 19.15.13.1101 NMAC - Rn, 19 NMAC 15.M.1101, 06/30/04]

19.15.13.1102 WELL LOCATION AND ACREAGE DEDICATION PLAT (Form C-102):

A. Form C-102 is a dual purpose form used to show the exact location of the well and the acreage dedicated thereto. The form is also used to show the ownership and status of each lease contained within the dedicated acreage. When there is more than one working interest or royalty owner on a given lease, designation of the majority owner et al. will be sufficient.

B. All information required on form C-102 shall be filled out and certified by the operator of the well except the well location on the plat. This is to be plotted from the outer boundaries of the section and certified by a professional surveyor, registered in the state of New Mexico, or surveyor approved by the division.

C. Form C-102 shall be submitted in triplicate or quadruplicate as provided in 19.15.13.1101 NMAC.

D. Amended form C-102 (in triplicate or quadruplicate) shall be filed in the event there is a change in any of the information previously submitted. The well location need not be certified when filing amended form C-102.

[1-1-65...2-1-96; 19.15.13.1102 NMAC - Rn, 19 NMAC 15.M.1102, 06/30/04]

19.15.13.1103 SUNDRY NOTICES AND REPORTS ON WELLS (Form C-103):

Form C-103 is a dual purpose form to be filed with the appropriate district office of the division to obtain division approval prior to commencing certain operations and also to report various completed operations.

A. Form C-103 as a notice of intention

(1) Form C-103 shall be filed in triplicate by the operator and approval obtain from the division prior to:

(a) Effecting a change of plans from those previously approved on form C-101 or form C-103.

(b) Altering a drilling well's casing program or pulling casing or otherwise altering an existing well's casing installation.

(c) Temporarily abandoning a well.

(d) Plugging and abandoning a well.

(e) Performing remedial work on a well which, when completed, will affect the original status of the well. (This shall include making new perforations in existing wells or squeezing old perforations in existing wells, but is not applicable to new wells in the process of being completed nor to old wells being deepened or plugged back to another zone when such recompletion has been authorized by an approved form C-101, application for permit to drill, deepen or plug back, nor to acidizing, fracturing or cleaning out previously completed wells, nor to installing artificial lift equipment.)

(2) In the case of well plugging operations, the notice of intention shall include a detailed statement of the proposed work, including plans for shooting and pulling casing, plans for mudding, including weight of mud, plans for cementing, including number of sacks of cement and depths of plugs, and the time and date of the proposed plugging operations. If not previously filed, a complete log of the well on form C-105 (See 19.15.13.1105 NMAC.) shall accompany the notice of intention to plug the well; the bond will not be released until this is complied with.

B. Form C-103 as a subsequent report

(1) Form C-103 as a subsequent report of operations shall be filed in accordance with the section of this rule applicable to the particular operation being reported.

(2) Form C-103 is to be used in reporting such completed operations as:

(a) commencement of drilling operations;

(b) casing and cement test;

(c) altering a well's casing installation;

(d) temporary abandonment;

(e) plug and abandon;

(f) plugging back or deepening;

(g) remedial work;

(h) installation of artificial lifting equipment;

(i) change of operator of a drilling well;

(j) such other operations which affect the original status of the well but which are not specifically covered herein.

C. Information to be entered on form C-103, subsequent report, for a particular operation is as follows: Report of commencement of drilling operations. Within ten days following the commencement of drilling operations, the operator of the well shall file a report thereof on form C-103 in triplicate. Such report shall indicate the hour and the date the well was spudded.

D. Report of results of test of casing and cement job; report of casing alteration: A report of casing and cement test shall be filed by the operator of the well within ten days following the setting of each string of casing or liner. Said report shall be filed in triplicate on form C-103 and shall present a detailed description of the test method employed and the results obtained by such test and any other pertinent information required by 19.15.1.107 NMAC. The report shall also indicate the top of the cement and the means by which such top was determined. It shall also indicate any changes from the casing program previously authorized for the well.

E. Report of temporary abandonment: A report of temporary abandonment of a well shall be filed by the operator of the well within thirty days following completion of the work. The report shall be filed in triplicate and shall present a detailed account of the work done on the well, including location and type of plugs used, if any, and status of surface and downhole equipment and any other pertinent information relative to the overall status of the well.

F. Report on plugging of well

(1) A report of plugging operations shall be filed by the operator of the well within 30 days following completion of plugging operations on any well. Said report shall be filed in triplicate on form C-103 and shall include the date the plugging operations were begun and the date the work was completed, a detailed account of the manner in which the work was performed including the depths and lengths of the various plugs set, the nature and quantities of materials employed in the plugging operations including the weight of the mud used, the size and depth of all casing left in the hole and any other pertinent information. (See 19.15.4.201 NMAC - 19.15.4.204 NMAC regarding plugging operations.)

(2) No plugging report will be approved by the division until the pits have been filled and the location levelled and cleared of junk. It shall be the responsibility of the operator to contact the appropriate district office of the division when the location has been so restored in order to arrange for an inspection of the plugged well and the location by a division representative.

G. Report of remedial work - A report of remedial work performed on a well shall be filed by the operator of the well within 30 days following completion of such work. Said report shall be filed in quadruplicate on form C-103 and shall present a detailed account of the work done and the manner in which such work was performed; the daily production of oil, gas and water both prior to and after the remedial operation; the size and depth of shots; the quantity of and, crude, chemical or other materials employed in the operation, and any other pertinent information. Among the remedial work to be reported on form C-103 are the following:

(1) report on shooting, fluid fracturing or chemical treatment of a previously completed well;

(2) report of squeeze job;

(3) report on setting of liner or packer;

(4) report of installation of pumping equipment or gas lift facilities;

(5) report of any other remedial operations which are not specifically covered herein.

H. Report on deepening or plugging back within the same pool - A report of deepening or plugging back shall be filed by the operator of the well within 30 days following completion of such operations on any well. Said report shall be filed in quadruplicate on form C-103 and shall present a detailed account of work done and the manner in which such work was performed. If the well is recompleted in the same pool, it shall also report the daily production of oil, gas, and water both prior to and after recompletion. If the well is recompleted in another pool, forms C-101, C-102, C-104 and C-105 must be filed in accordance with Sections 1101, 1102, 1104 and 1105 of 19.15.13 NMAC.

I. Report of change of operator of a drilling well - A report of change of ownership shall be filed by the new operator of any drilling well within ten days following actual transfer of ownership or responsibility. Said report shall be filed in triplicate on form C-103 and shall include the name and address of both the new operator and the previous operator, the effective date of the change of ownership or responsibility and any other pertinent information. No change in the operator of a drilling well will be approved by the division unless the new operator has an approved bond in accordance with 19.15.3.101 NMAC. (Form C-104 shall be used to report transfer of operator of a completed well; see 19.15.13.1104 NMAC.

J. Other reports on wells - Reports on any other operations which affect the original status of the well but which are not specifically covered herein shall be submitted to the division on form C-103, in triplicate, by the operator of the well ten days following the completion of such operation.

[1-1-65...2-1-96; 19.15.13.1103 NMAC - Rn, 19 NMAC 15.M.1103, 06/30/04]

19.15.13.1104 REQUEST FOR ALLOWABLE AND AUTHORIZATION TO TRANSPORT OIL AND NATURAL GAS (Form C-104):

A. Form C-104 completely filled out by the operator of the well must be filed in quintuplicate before an allowable will be assigned to any newly completed or recompleted well. (A recompleted well shall be considered one which has been deepened or plugged back to produce from a different pool than previously.) Form C-104 must be accompanied by a tabulation of all deviation tests taken on the well as provided by 19.15.3.111 NMAC.

B. The allowable assigned to an oil well shall be effective at 7:00 o'clock a.m. on the date of completion, provided the form C-104 is received by the division during the month of completion. Date of completion shall be that date when new oil is delivered into the stock tanks. Unless otherwise specified by special pool rules, the allowable assigned to a gas well shall be effective at 7:00 o'clock a.m. on the date of connection to a gas transportation facility, as evidenced by an affidavit of connection from the transporter to the division, or the date of receipt of form C-104 by the division, whichever date is later.

C. No allowable will be assigned to any well until a standard unit for the pool in which the well is completed has been dedicated by the operator, or a non-standard unit has been approved by the division, or a standard unit has been communitized or pooled and dedicated to the well.

D. No allowable will be assigned to any well until all forms and reports due have been received by the division and the well is otherwise in full compliance with these rules.

E. Form C-104 with sections I, II, III and VI, completely filled out shall be filed in quintuplicate by the operator of the well in the event there is a change of operator of any producing well, injection well or disposal well, a change in pool designation, lease name or well number, or any other pertinent change in condition of any such well. When filing form C-104 for change of operator, the new operator shall file the form in the above manner, and shall give the name and address of the previous as well as the present operator. The form C-104 will not be approved by the division unless the new operator has an approved bond in compliance with 19.15.3.101 NMAC.

[1-1-65...2-1-96; A, 7-31-97; 19.15.13.1104 NMAC - Rn, 19 NMAC 15.M.1104, 06/30/04]

19.15.13.1105 WELL COMPLETION OR RECOMPLETION REPORT AND LOG (Form C-105):

A. Within 20 days following the completion or recompletion of any well, the operator shall file form C-105 with the division. It must be filed in quintuplicate and each copy accompanied by a summary of all special tests conducted on the well, including drill stem tests. In addition, one copy of all electrical and radio-activity logs run on the well must be filed with form C-105. If the form C-105 with attached log(s) and summaries is not received by the division within the specified 20-day period, the allowable for the well will be withheld until this rule has been complied with.

B. In the case of a dry hole, a complete record of the well on form C-105 with the above attachments shall accompany the notice of intention to plug the well, unless previously filed. The plugging report will not be approved nor the bond released until this rule has been complied with.

C. Form C-105 and accompanying attachments will not be kept confidential by the division unless so requested in writing by the owner of the well. Upon such request, the division will keep these data confidential for 90 days from the date of completion of the well, provided, however, that the report, log(s) and other attached data may, when pertinent, be introduced in any public hearing before the division or its examiners or in any court of law, regardless of the request that they be kept confidential.
[1-1-65...2-1-96; 19.15.13.1105 NMAC - Rn, 19 NMAC 15.M.1105, 06/30/04]

19.15.13.1106 NOTICE OF INTENTION TO UTILIZE AUTOMATIC CUSTODY TRANSFER EQUIPMENT (Form C-106):

Form C-106, when applicable, shall be filed in accordance with Subsection A of 19.15.5.309 NMAC.
[1-1-65...2-1-96; 19.15.13.1106 NMAC - Rn, 19 NMAC 15.M.1106, 06/30/04]

19.15.13.1107 APPLICATION FOR MULTIPLE COMPLETION (Form C-107):

Form C-107, when applicable, shall be filed in accordance with Subsection A of 19.15.3.112 NMAC.
[1-1-65...2-1-96; 19.15.13.1107 NMAC - Rn, 19 NMAC 15.M.1107, 06/30/04]

19.15.13.1108 APPLICATION FOR AUTHORIZATION TO INJECT (Form C-108):

Form C-108 shall be filed in accordance with Subsection B of 19.15.9.701 NMAC.
[1-1-65...2-1-96; 19.15.13.1108 NMAC - Rn, 19 NMAC 15.M.1108, 06/30/04]

19.15.13.1109 APPLICATION FOR DISCOVERY ALLOWABLE AND CREATION OF A NEW POOL (Form C-109):

Form C-109, when applicable, shall be filed in accordance with 19.15.7.509 NMAC.
[9-1-66...2-1-96; 19.15.13.1109 NMAC - Rn, 19 NMAC 15.M.1109, 06/30/04]

19.15.13.1110 No Rule; there is no form C-110 at present.
[1-1-65...2-1-96; 19.15.13.1110 NMAC - Rn, 19 NMAC 15.M.1110, 06/30/04]

19.15.13.1111 GAS TRANSPORTER'S MONTHLY REPORT (Form C-111):

A. Form C-111, gas transporter's monthly report, shall be filed monthly in accordance with the rules below. It shall be postmarked on or before the 15th day of the second month following the month gas was taken. One copy shall be filed with the appropriate district office of the division and one copy with the Santa Fe office of the division. One additional copy shall also be sent to the Hobbs office of the division. Information on sheet no. 2 of form C-111 shall be itemized by pools, by operators and by leases, in alphabetical order.

B. Form C-111 shall be filed each month by the operator of any gas gathering system, gas transportation system, recycling system, fuel system, gas lift system, gas drilling operation, etc. The form shall cover all natural gas, casinghead gas and carbon dioxide gas taken into any such system during the preceding month and shall show the source of the gas and the disposition thereof.

C. Form C-111 shall also be filed each month by the operator of any gasoline plant, cycling plant or other plant at which gasoline, butane, propane, kerosene, oil or other products are extracted from gas within the state of New Mexico. The form shall cover all natural gas, casinghead gas and carbon dioxide gas taken by any such plant during the preceding month and shall show the source of the gas and the disposition thereof. If a plant operator owns more than one plant in a given division district, sheet no. 1 of form C-111 shall be filed for each such plant. In preparing sheet no. 2, the plant operator shall consolidate all requisitions for all plants in the district, itemized in the order described in the Subsection A of 19.15.13.1111 NMAC.

D. Where gas is taken by the producer and utilized by the producer for any of the above uses, the producer shall file Form C-111 itemizing such gas. The producer shall also include this gas on the operator's monthly report, form C-115. Gas used on the lease from which it was produced for consumption in lease houses, treaters, compressors, combustion engines and other similar equipment, or gas which is flared, shall also be included on the Form C-115 but is not to be included on the form C-111.

[1-1-65...2-1-96; 19.15.13.1111 NMAC - Rn, 19 NMAC 15.M.1111, 06/30/04]

19.15.13.1112 TRANSPORTER'S AND STORER'S MONTHLY REPORT (Form C-112):
Each transporter and each storer of crude petroleum oil and liquid hydrocarbons within the state of New Mexico shall file for each calendar month a transporter's and storer's monthly report, form C-112, containing complete information and data indicated by such form respecting stocks of crude petroleum oil and liquid hydrocarbons on hand and receipts and deliveries of crude petroleum oil and liquid hydrocarbons by pipeline and trucks within the state of New Mexico, and receipts and deliveries from leases to storers or refiners; between transporters within the state; between storers and refiners within the state. Form C-112 shall be filed in duplicate and postmarked on or before the 15th day of the second succeeding month.

[1-1-65...2-1-96; 12-31-96; 19.15.13.1112 NMAC - Rn, 19 NMAC 15.M.1112, 06/30/04]

19.15.13.1113 REFINER'S MONTHLY REPORT (Form C-113):
Every refiner of crude petroleum oil within the state of New Mexico shall furnish for each calendar month refiner's monthly report, form C-113, containing the information and data indicated by such form respecting crude petroleum oil and products involved in such refiner's operation during each month. Such report for each month shall be filed in duplicate and be postmarked on or before the 15th day of the next succeeding month.

[1-1-65...2-1-96; 12-31-96; 19.15.13.1113 NMAC - Rn, 19 NMAC 15.M.1113, 06/30/04]

19.15.13.1114 No Rule; there is no form C-114 at present.

[1-1-65...2-1-96; 12-31-96; 19.15.13.1114 NMAC - Rn, 19 NMAC 15.M.1114, 06/30/04]

19.15.13.1115 OPERATOR'S MONTHLY REPORT (Form C-115):

A. Operator's monthly report, form C-115 or form C-115-EDP, shall be filed on each producing lease and each secondary or other enhanced recovery project or pressure maintenance project injection well within the state of New Mexico for each calendar month, setting forth complete information and data indicated on said forms in the order, format and style prescribed by the division director. Oil production from wells which are producing into common storage shall be estimated as accurately as possible on the basis of periodic tests.

B. The reports required to be filed by 19.15.13.1115 NMAC shall be filed by the operator as follows:

(1) Any operator which operates fewer than one hundred (100) wells in the state of New Mexico shall file a C-115 either electronically or by delivery of a printed copy of the report to the oil conservation division at its Santa Fe office on or before the fifteenth (15th) day of the second month following the month of production, or if such day falls on a weekend or holiday, the first workday following the fifteenth.

(2) Any operator which operates one hundred (100) or more wells in the state of New Mexico shall file a C-115 electronically, either by physical delivery of electronically readable media or by electronic transfer of data, to the oil conservation division at its Santa Fe office on or before the fifteenth day of the second month following the month of production, or if such day falls on a weekend or holiday, the first workday following the fifteenth. Any operator otherwise required to file electronically may apply to the division for exemption from this requirement based upon a demonstration that such electronic filing requirement would operate as an economic or other hardship.

(3) If an operator fails to file a C-115 or if the division finds errors in any C-115, the division shall, within thirty (30) days of the appropriate filing date, prepare and send to the operator an error/omission message which identifies the specific well as to which the report has not been filed or is in error and a statement of the error. The operator to whom the error/omission message is addressed shall respond to the division within thirty (30) days acknowledging receipt of the error/omission message and informing the division of the operator's schedule to file the report or correct the error. If the division does not receive the operator's response within thirty (30) days, the division shall send notice to the operator that operator has failed to comply with the provisions of 19.15.13.1115 NMAC and may be subjected to loss of authority to produce from the affected well if the operator does not respond to the division. Willful failure of the operator to respond to the notice and to correct the error or omission may result in the division informing the operator by certified return receipt letter that thirty (30) days from the date of such letter the division will cancel the C-104 authority of operator to produce or inject into the well. Any operator which receives such notice may contact the division and request that the matter of the cancellation of authority to produce or inject be set for hearing before a hearing officer duly appointed by the division. If the division sends certified return receipt correspondence informing the operator of cancellation of authority to produce and the operator does not request a hearing, the division may cancel the authority of the operator to produce the well on the date set forth in the letter.

(4) The electronic filing requirements set forth in Paragraph (2), Subsection B, of 19.15.13.115 NMAC shall be phased in with all operators of three hundred (300) or more wells being required to file electronically for January 1997 production, all operators of two hundred (200) or more wells being required to file electronically for July 1997 production and all operators of one hundred (100) or more wells being required to file electronically for January 1998 production.
[1-1-65…2-1-96; 19.15.13.1115 NMAC - Rn, 19 NMAC 15.M.1115, 06/30/04]

19.15.13.1116 GAS-OIL RATIO TESTS (Form C-116):
Gas-oil ratio tests shall be made and reported on form C-116 as prescribed in 19.15.5.301 NMAC, Gas-Oil Ratio Tests, and any applicable special pool rules. This form shall be submitted in duplicate.
[1-1-65…2-1-96; 19.15.13.1116 NMAC - Rn, 19 NMAC 15.M.1116, 06/30/04]

19.15.13.1117 TANK CLEANING, SEDIMENT OIL REMOVAL, TRANSPORTATION OF MISCELLANEOUS HYDROCARBONS AND DISPOSAL PERMIT (Form C-117-A) AND MONTHLY SEDIMENT OIL DISPOSAL STATEMENT (Form C-117-B):

A. Form C-117-A, tank cleaning, sediment oil removal, transportation of miscellaneous hydrocarbons and disposal permit, shall be submitted to the appropriate district office of the division in quintuplicate and in accordance with Subsections B, C and H of 19.15.5.311 NMAC.

B. Form C-117-B, monthly sediment oil disposal statement, shall be submitted both to the Santa Fe office and the appropriate district office(s) of the division in accordance with Subsection D of 19.15.5.311 NMAC.
[1-1-65...2-1-96; 19.15.13.1117 NMAC - Rn, 19 NMAC 15.M.1117, 06/30/04]

19.15.13.1118 TREATING PLANT OPERATOR'S MONTHLY REPORT (Form C-118):
Form C-118 shall be submitted in duplicate to the appropriate district office of the division in accordance with 19.15.9.711 NMAC, and shall contain all the information required thereon. Column 1 of sheet 1-A of form C-118 entitled "permit number," has reference to the tank cleaning, sediment oil removal, transportation of miscellaneous hydrocarbons and disposal permit, form C-117-A, for each lot of oil picked up for processing.
[1-1-65...2-1-96; 19.15.13.1118 NMAC - Rn, 19 NMAC 15.M.1118, 06/30/04]

19.15.13.1119 CARBON BLACK PLANT MONTHLY REPORT (Form C-119):
Each operator of a carbon black plant within the state of New Mexico shall file for each calendar month the monthly volume of gas received by him from a gasoline extraction plant or plants, and a monthly volume or volumes

of gas received by him from each lease operator delivering natural gas directly to such plant, together with the opening and closing stocks and the production and deliveries by grades of carbon black or other products produced. Such reports shall be filed in duplicate on form C-119, carbon black plant monthly report, and be postmarked on or before the 15th day of the next succeeding month. In addition, form C-111 shall be filed each month in accordance with 19.15.13.1111 NMAC if the carbon black plant operator makes any purchase directly from a lease or operates any gas gathering or transmission system.
[1-1-65...2-1-96; 19.15.13.1119 NMAC - Rn, 19 NMAC 15.M.1119, 06/30/04]

19.15.13.1120 MONTHLY WATER DISPOSAL REPORT (Form C-120-A):
Each operator of a salt water disposal system shall report such operations on form C-120-A. Form C-120-A shall be filed in duplicate (one copy with the Santa Fe office and one copy with the appropriate district office) and shall be postmarked no later than the 15th day of the second succeeding month.
[1-1-65...2-1-96; 19.15.13.1120 NMAC - Rn, 19 NMAC 15.M.1120, 06/30/04]

19.15.13.1121 PURCHASER'S NOMINATION FORMS (Form C-121 and Form C-121-A):

A. Unless requested otherwise by the division director, one copy of form C-121, crude oil purchaser's nomination, shall be submitted to the Santa Fe office of the division not later than the 20th day of each odd-numbered month. Nominations shall be filed by each person expecting to purchase oil from producing wells in New Mexico during the second and third succeeding two months. As an example, nominations submitted by the 20th day of July shall indicate the amount of oil the purchaser desires to purchase daily during September and October

B. One copy of form C-121-A, purchaser's gas nomination, shall be submitted to the Santa Fe office of the division by the first day of the month during which the division will consider at the gas allowable hearing the nominations for the purchase of gas from producing wells in New Mexico during the succeeding month. As an example, purchaser's nominations to take gas from a pool during the month of August would be considered by the division at a hearing during July, and should be submitted to the Santa Fe office of the division by July 1.

C. In addition to the monthly gas nominations, twelve-months nominations shall be filed in accordance with the appropriate pool rules.
[1-1-65...2-1-96; 19.15.13.1121 NMAC - Rn, 19 NMAC 15.M.1121, 06/30/04]

19.15.13.1122 MULTIPOINT AND ONE POINT BACK PRESSURE TEST FOR GAS WELL (Form C-122):

A. Gas well test data sheet - san juan basin (form C-122-A)

B. Initial potential test data sheet (form C-122-B)

C. Deliverability test report (form C-122-C)

D. Worksheet for calculation of static column wellhead pressure (P_w) (form C- 122-D)

E. Worksheet for stepwise calculation of (surface) (subsurface) pressure (P_c & P_w) (P_f & P_s) (form C-122-E)

F. Worksheet for calculation of wellhead pressures (P_c or P_w) from known bottomhole pressure (P_f or P_s) (form C-122-F)

G. Worksheet for calculation of status column pressure at gas liquid interface (form C-122-G). The above forms shall be submitted to the appropriate district office of the division in accordance with the provisions of the "manual for back-pressure testing of natural gas wells," or "gas well testing manual for northwest New Mexico", 19.15.6.401 NMAC of the division rules and regulations, and applicable special pool rules and proration orders. These forms shall be submitted in duplicate except form C-122-A which shall be submitted in triplicate.
[1-1-66...2-1-96; 19.15.13.1122 NMAC - Rn, 19 NMAC 15.M.1122, 06/30/04]

19.15.13.1123 REQUEST FOR THE CREATION OF A NEW POOL (Form C-123):
The operator of a well which requires the creation of a pool shall be given written instructions by the appropriate district office regarding the filing of form C-123 in duplicate.
[1-1-65...2-1-96; 19.15.13.1123 NMAC - Rn, 19 NMAC 15.M.1123, 06/30/04]

19.15.13.1124 RESERVOIR PRESSURE REPORT (Form C-124):
Form C-124 shall be submitted in triplicate and shall be used to report bottom hole pressures as required under the provisions of 19.15.5.302 NMAC and any applicable special pool rules.
[1-1-65...2-1-96; 19.15.13.1124 NMAC - Rn, 19 NMAC 15.M.1124, 06/30/04]

19.15.13.1125 GAS WELL SHUT-IN PRESSURE TESTS (Form C-125):
Form C-125 shall be submitted in triplicate and shall be used to report shut-in pressure tests on gas wells as required under the provisions of 19.15.6.402 NMAC and any applicable special pool rules.
[1-1-65...2-1-96; 19.15.13.1125 NMAC - Rn, 19 NMAC 15.M.1125, 06/30/04]

19.15.13.1126 PERMIT TO TRANSPORT RECOVERED LOAD OIL (Form C-126):
Form C-126 shall be submitted in quadruplicate to the appropriate district office of the division and shall be used in conformance with 19.15.7.508 NMAC.
[1-1-65...2-1-96; 19.15.13.1126 NMAC - Rn, 19 NMAC 15.M.1126, 06/30/04]

19.15.13.1127 REQUEST FOR ALLOWABLE CHANGE (Form C-127):
One copy of form C-127 shall be filed by the oil producer with the appropriate district office of the division not later than the 10th day of the month preceding the month for which oil well allowable changes are requested.
[1-1-65...2-1-96; 19.15.13.1127 NMAC - Rn, 19 NMAC 15.M.1127, 06/30/04]

19.15.13.1128 FORMS REQUIRED ON FEDERAL LAND:
A. Federal forms shall be used in lieu of state forms when filing application for permit to drill, deepen or plug back and sundry notices and reports on wells and well completion or recompletion report and log for wells on federal lands in New Mexico. However, it shall be the duty of the operator to submit two extra copies of each of such forms to the BLM, which, upon approval, will transmit same to the division. The following BLM forms will be used in lieu of division forms by operators of wells on federal land:

BLM Form No	Title of Form (Same for both agencies)	Form No.
3160-3 (Nov. 1993)	Application for Permit to Drill, Deepen or Plug Back	C-101
3160-5 (Nov. 1983)	Sundry Notices and Reports on Wells	C-103
3160-4 (Nov. 1983)	Well Completion or Recompletion Report and Log	C-105

B. The above forms as may be revised are the only forms that may be submitted in place of division forms.
C. After a well is completed and ready for pipeline connection, division form C-104 shall be filed along with a copy of form C-105 or BLM form No. 3160-4, whichever is applicable, with the division on any and all wells drilled in the state, regardless of land status. Further, all reports and forms as required under the preceding rules of this section of the rules and regulations that pertain to production must be filed on the proper oil conservation division form as set out in said rule - no other forms will be accepted.
D. Failure to comply with the provisions of this rule will result in the cancellation of form C-104 for the affected well or wells.
[1-1-65...2-1-96; 19.15.13.1128 NMAC - Rn, 19 NMAC 15.M.1128, 06/30/04]

19.15.13.1129 APPLICATION FOR EXCEPTION TO NO-FLARE RULE 306 (Form C-129):
Form C-129, when applicable, shall be filed in accordance with 19.15.5.306 NMAC.
[9-1-72...2-1-96; 19.15.13.1129 NMAC - Rn, 19 NMAC 15.M.1129, 06/30/04]

19.15.13.1130 NOTICE OF DISCONNECTION (Form C-130):

A. Form C-130, notice of disconnection, shall be filed in triplicate with the division by the operator of the well as provided in 19.15.6.407 NMAC.

B. The operator shall state, to the best of his knowledge, the reasons for disconnecting any gas well from gas transportation facilities.

C. The division shall furnish the New Mexico public service commission with any form C-130 indicating that a disconnected gas well may or will be reconnected to a gas transportation facility for ultimate distribution to consumers outside of the state of New Mexico.

[8-23-77...2-1-96; 19.15.13.1130 NMAC - Rn, 19 NMAC 15.M.1130, 06/30/04]

19.15.13.1131 MONTHLY GAS STORAGE REPORT (Form C-131-A) ANNUAL LPG STORAGE REPORT (Form C-131-B):

A. Each operator of an underground natural gas storage project shall report its operation monthly on form C-131-A. Form C-131-A shall be filed in duplicate (one copy to the appropriate district office) and shall be postmarked not later than the 24th day of the next succeeding month.

B. Each operator of an underground liquefied petroleum gas storage project approved by the division shall report its operation annually on form C-131-B.

[7-1-81...2-1-96; 19.15.13.1131 NMAC - Rn, 19 NMAC 15.M.1131, 06/30/04]

19.15.13.1132 [RESERVED].

19.15.13.1133 AUTHORIZATION TO MOVE PRODUCED WATER:

A. Each person who is a transporter of produced water shall obtain approval of form C-133, authorization to move produced water, in accordance with Subsection C of 19.15.9.709 NMAC. prior to any such transportation.

B. Approval of a single form C-133 is valid for all leases served by such transporter.

[2-1-82...2-1-96; 19.15.13.1133 NMAC - Rn, 19 NMAC 15.M.1133, 06/30/04]

19.15.13.1134 [RESERVED].

19.15.13.1135 GAS WELL CONNECTION, RECONNECTION OR DISCONNECTION NOTICE:

Every gas transporter accepting gas for delivery from a wellhead or central point of delivery shall notify the division within thirty (30) days of a new connection or reconnection to or disconnection from the gathering or transportation system by filing form C-135 in duplicate with the appropriate district office of the division.

[2-1-91...2-1-96; 19.15.13.1135 NMAC - Rn, 19 NMAC 15.M.1135, 06/30/04]

19.15.13.1136 APPLICATION FOR APPROVAL TO USE AN ALTERNATE GAS MEASUREMENT METHOD (Form C-136):

A. Form C-136 shall be used to request and approve use of an alternate procedure for measuring gas production from a well which is not capable of producing more than 15 MCFD (Paragraph (1) of Subsection B of 19.15.6.403 NMAC or for any well which has a producing capacity of 100 MCFD or less and is on a multi-well lease (Paragraph (2) of Subsection B of 19.15.6.403 NMAC.)

B. All applicable information required on form C-136 shall be filled out with the required supplemental information attached, and shall be submitted in quadruplicate to the appropriate district office of the division.

[12-23-91; 2-1-96; 19.15.13.1136 NMAC - Rn, 19 NMAC 15.M.1136, 06/30/04]

HISTORY OF 19.15.13 NMAC:

Pre-NMAC History: The material in this Part was derived from that previously filed with the State Records Center and Archives:

Rule 1100, General, 1/8/82.

Rule 1100, Amendment No. 1, General M-Reports, 1/27/82.
Rule 1100, Amendment No. 2, General M-Reports, 5/6/82.
Rule 1100, General M-Reports, 3/17/86.
Rule 1100, General, 10/11/89.
Rule 1100, General, 2/5/91.
Rule 1101, Application for Permit to Drill, Deepen, or Plug Back (Form C-101), 1/8/82.
Rule 1101, Application for Permit to Drill, Deepen, or Plug Back (Form C-101), 2/5/91.
Rule 1102, Well Location and Acreage Dedication Plat (Form C-102), 1/8/82.
Rule 1102, Well Location and Acreage Dedication Plat (Form C-102), 3/15/89.
Rule 1102, Well Location and Acreage Dedication Plat (Form C-102), 2/5/91.
Rule 1103, Sundry Notices and Reports on Wells (Form C-103), 1/8/82.
Rule 1103, Sundry Notices and Reports on Wells (Form C-103), 2/5/91.
Rule 1104, Request for Allowable and Authorization to Transport Oil and Natural Gas (Form C-104), 1/8/82.
Rule 1104, Request for Allowable and Authorization to Transport Oil and Natural Gas (Form C-104), 2/5/91.
Rule 1105, Well Completion or Recompletion Report and Log (Form C-105), 1/8/82.
Rule 1105, Well Completion or Recompletion Report and Log (Form C-105), 2/5/91.
Rule 1106, Notice of Intention to Utilize Automatic Custody Transfer Equipment (Form C-106), 1/8/822.
Rule 1106, Notice of Intention to Utilize Automatic Custody Transfer Equipment (Form C-106), 2/5/91.
Rule 1107, Application for Multiple Completion (Form C-107), 1/8/82.
Rule 1107, Amendment No. 1, Application for Multiple Completion (Form C-107), 1/27/82.
Rule 1107, Application for Multiple Completion (Form C-107), 2/5/91.
Rule 1108, Application for Authorization to Inject (Form C-108), 1/8/82.
Rule 1108, Application for Authorization to Inject (Form C-108), 2/5/91.
Rule 1109, Application for Discovery Allowable and Creation of a New Pool (Form C-109), 1/8/82.
Rule 1109, Application for Discovery Allowable and Creation of a New Pool (Form C-109), 2/5/91.
Rule 1111, Gas Transporter’s Monthly Report (Form C-111), 1/8/82.
Rule 1111, Gas Transporter’s Monthly Report (Form C-111), 3/17/86.
Rule 1111, Gas Transporter’s Monthly Report (Form C-111), 2/5/91.
Rule 1112, Transporter’s and Storer’s Monthly Report (Form C-112), 1/8/82.
Rule 1112, Transporter’s and Storer’s Monthly Report (Form C-112), 2/5/91.
Rule 1113, Refiner’s Monthly Report (Form C-113), 1/8/82.
Rule 1113, Refiner’s Monthly Report (Form C-113), 10/11/89.
Rule 1113, Refiner’s Monthly Report (Form C-113), 2/5/91.
Rule 1115, Operator’s Monthly Report (Form C-115), 1/8/82.
Rule 1115, Operator’s Monthly Report (Form C-115), 2/5/91.
Rule 1116, Gas-Oil Ratio Tests (Form C-116), 1/8/82.
Rule 1116, Gas-Oil Ratio Tests (Form C-116), 2/5/91.
Rule 1117, Sediment Oil Disposition Permits (Form C-117-A and C-117-B), 1/8/82.
Rule 1117, Amendment No. 1, Tank Cleaning, Sediment Oil Removal, Transportation of Miscellaneous Hydrocarbons and Disposal Permit (Form C-117-A) and Monthly Sediment Oil Disposal Statement (Form C-117-B), 1/27/82.
Rule 1117, Tank Cleaning, Sediment Oil Removal, Transportation of Miscellaneous Hydrocarbons and Disposal Permit (Form C-117-A) and Monthly Sediment Oil Disposal Statement (Form C-117-B), 2/5/91.
Rule 1118, Treating Plant Operator’s Monthly Report (Form C-118), 1/8/82.
Rule 1118, Amendment No. 1, Treating Plant Operator’s Monthly Report (Form C-118), 1/27/82.
Rule 1118, Treating Plant Operator’s Monthly Report (Form C-118), 2/5/91.
Rule 1119, Carbon Black Plant Monthly Report (Form C-119), 1/11/82.
Rule 1119, Carbon Black Plant Monthly Report (Form C-119), 2/5/91.
Rule 1120, Monthly Water Disposal Report (Form C-120), 1/11/82.
Rule 1120, Monthly Water Disposal Report (Form C-120), 2/5/91.

Rule 1121, Purchaser's Nomination Forms (Form C-121 and Form C-121-A), 1/11/82.
Rule 1121, Purchaser's Nomination Forms (Form C-121 and Form C-121-A), 2/5/91.
Rule 1122, Multipoint and One Point Back Pressure Test for Gas Well (Form C-122), 1/11/82.
Rule 1122, Multipoint and One Point Back Pressure Test for Gas Well (Form C-122), 10/11/89.
Rule 1122, Multipoint and One Point Back Pressure Test for Gas Well (Form C-122), 2/5/91.
Rule 1123, Request for the Creation of a New Pool (Form C-123), 1/11/82.
Rule 1123, Request for the Creation of a New Pool (Form C-123), 2/5/91.
Rule 1124, Reservoir Pressure Report (Form C-124), 1/11/82.
Rule 1124, Reservoir Pressure Report (Form C-124), 2/5/91.
Rule 1125, Gas Well Shut-In Pressure Tests (Form C-125), 1/11/82.
Rule 1125, Amendment No. 1, Gas Well Shut-In Pressure Tests (Form C-125), 2/23/84.
Rule 1125, Gas Well Shut-In Pressure Tests (Form C-125), 2/5/91.
Rule 1126, Permit to Transport Recovered Load Oil (Form C-126), 1/11/82.
Rule 1126, Permit to Transport Recovered Load Oil (Form C-126), 2/5/91.
Rule 1127, Request for Allowable Change (Form C-127), 1/11/82.
Rule 1127, Request for Allowable Change (Form C-127), 2/5/91.
Rule 1128, Forms Required on Federal Land, 1/11/82.
Rule 1128, Forms Required on Federal Land, 2/5/91.
Rule 1129, Application for Exception to No-Flare Rule306 (Form C-129), 1/11/82.
Rule 1129, Application for Exception to No-Flare Rule306 (Form C-129), 2/5/91.
Rule 1130, Notice of Disconnection (Form C-130), 1/11/82.
Rule 1130, Notice of Disconnection (Form C-130), 2/5/91.
Rule 1131, Monthly Gas Storage Report (Form C-131-A) Annual LPG Storage Report (Form C-131-B), 1/11/82.
Rule 1131, Monthly Gas Storage Report (Form C-131-A) Annual LPG Storage Report (Form C-131-B), 2/5/91.
Rule 1133, Authorization to Move Produced Water, 1/27/82.
Rule 1133, Authorization to Move Produced Water, 2/5/91.
Rule 1135, Gas Well Connection, Reconnection or Disconnection Notice, 1/14/91.
Rule 1135, Gas Well Connection, Reconnection or Disconnection Notice, 2/5/91.

History of Repealed Material: [RESERVED].

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 14 PROCEDURE

19.15.14.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department, Oil Conservation Division, 2040 S. Pacheco St., Santa Fe, New Mexico 87505 (505) 827-7131.
[2-1-96; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1, 8-29-03]

19.15.14.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico.
[2-1-96; 19.15.14 NMAC - Rn, 19 NMAC 15.N.2, 8-29-03]

19.15.14.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the Oil and Gas Act which grants the oil conservation division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights and the disposition of wastes resulting from oil and gas operations.
[2-1-96; 19.15.14 NMAC - Rn, 19 NMAC 15.N.3, 8-29-03]

19.15.14.4 DURATION: Permanent.
[2-1-96; 19.15.14 NMAC - Rn, 19 NMAC 15.N.4, 8-29-03]

19.15.14.5 EFFECTIVE DATE: February 1, 1996 [unless a later date is cited at the end of a section.]
[2-1-96; 19.15.14 NMAC - Rn, 19 NMAC 15.N.5, 8-29-03]

19.15.14.6 OBJECTIVE: The objective of this Part is to set forth general provisions and definitions pertaining to the authority of the oil conservation division and the oil conservation commission pursuant to the Oil and Gas Act, NMSA 1978, Sections 70-2-1 through 70-2-38.
[2-1-96; 19.15.14 NMAC - Rn, 19 NMAC 15.N.6, 8-29-03]

19.15.14.7 DEFINITIONS: [RESERVED]

19.15.14.8 - 1200 [RESERVED]

19.15.14.1201 RULEMAKING PROCEEDINGS:
A. Before any rule, including revocation or amendment of an existing rule, shall be made by the division or commission, a public hearing before the commission or a duly appointed division examiner shall be held at such time and place as may be prescribed by the commission in accordance with Section 10-15-1 NMSA 1978.
B. When the commission, the division, an operator or any interested person applies to adopt, amend or rescind any rule, such application shall constitute a request for rulemaking, and the division shall publish notice of the proposed rulemaking:
(1) one time in a newspaper of general circulation in the counties in New Mexico affected by the proposed rule (or if the proposed rule will be of statewide application, in a newspaper of general circulation in this state), with the publication date not less than 20 days prior to the date set for the public hearing;
(2) on the applicable docket for the commission or division hearing at which the matter will be heard, which shall be sent by regular mail or electronic mail to all who have requested such notice, not less than 20 days prior to the public hearing;
(3) one time in the New Mexico register, with the publication date not less than 10 days prior to the public hearing; and
(4) by posting to the division's website not less than 20 days prior to the public hearing.
C. If the rule proposed to be adopted, amended or rescinded is of statewide application, the hearing

shall be conducted before the commission in the first instance unless the division director otherwise directs.

D. 19.15.14.1201 NMAC shall not apply to special pool rules, which may be adopted, amended or rescinded in adjudicatory proceedings subject to the notice provisions of Sections 1204 and 1207 of 19.15.14 NMAC.

[1-1-50...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1201, 8-29-03; A, 06/15/04]

19.15.14.1202 EMERGENCY ORDERS AND RULES:

A. Notwithstanding any other provision of 19.15 NMAC, in the event an emergency is found to exist by the division or commission, which requires adoption of a rule or the issuance of an order without a hearing, such emergency rule or order shall have the same validity as if a hearing had been held before the division or commission after due notice. Such emergency rule or order shall remain in force no longer than 15 days from its effective date.

B. Notwithstanding any other provision of 19.15.14 NMAC, in the event an emergency is found to exist by the division or commission, a hearing may be conducted upon any application within less than twenty-three (23) days after the filing thereof, and notice of such hearing may be given within such lesser time than twenty (20) days as the director of the division shall order.

[1-1-50...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1201, 8-29-03; A, 06/15/04]

19.15.14.1203 INITIATING A HEARING:

A. The division, the attorney general, any operator or producer or any other person may apply for a hearing. The application shall be signed by the person seeking the hearing or by an attorney representing that person. Two copies of the application must be filed and shall state:

(1) the name of the applicant;

(2) the name or general description of the common source or sources of supply or the area affected by the order sought;

(3) briefly, the general nature of the order or rule sought;

(4) a list of the names and addresses of persons to whom notice has been sent;

(5) a proposed notice advertisement for publication; and

(6) any other matter required by these rules or order of the division.

B. Applications for hearing before the division or commission must be in writing and received by the division at least 23 days in advance of the hearing on that application.

[1-1-50...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1203, 8-29-03]

19.15.14.1204 PUBLICATION OF NOTICE OF HEARING:

A. The division shall give notice of each hearing before the commission or a division examiner by (1) posting notice on the division's website, and (2) delivering notice by ordinary first class United States mail or electronic mail to each person who has requested in writing to be notified of such hearings.

B. In addition, the division shall give notice of each hearing before the commission by publication once in accordance with the requirements of Chapter 14, Article 11 NMSA 1978, in a newspaper of general circulation in the counties that are affected by the application or, if the effect of the application will be statewide, in a newspaper of general circulation in this state.

[1-1-50...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1204, 8-29-03; A, 06/15/04]

19.15.14.1205 CONTENTS OF NOTICE OF HEARING:

A. Published notices shall be issued in the name of "The State of New Mexico" and signed by the director of the division, and the seal of the commission shall be impressed thereon.

B. The notice shall specify: whether the case is set for hearing before the commission or a division examiner; the number and style of the case; the time and place of hearing; and the general nature of the application. The notice shall also state the name of the applicant. If the application seeks to adopt, revoke or amend special pool rules, establish or alter a non-standard unit, permit an unorthodox location, or establish or affect the allowable of any well or proration unit, the notice shall specify each pool or common source of supply that may be affected if the

application is granted. If the application seeks compulsory pooling or statutory unitization, the notice shall contain a legal description of the spacing unit or geographical area sought to be pooled or unitized. In all other cases, the notice shall reasonably identify the subject matter so as to alert persons who may be affected if the application is granted.
[1-1-50...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1205, 8-29-03; A, 06/15/04]

19.15.14.1206 [RESERVED] [Formerly "PREPARATION OF NOTICES"]

19.15.14.1207 NOTICE REQUIREMENTS FOR SPECIFIC ADJUDICATIONS:

A. Applicants for the following adjudicatory hearings before the division or commission shall give notice, in addition to that required by 19.15.14.1204 NMAC, as set forth below:

(1) Compulsory pooling and statutory unitization.

(a) Notice shall be given to any owner of an interest in the mineral estate of any portion of the lands proposed to be pooled or unitized whose interest is evidenced by a written document of conveyance either of record or known to the applicant at the time of filing the application and whose interest has not been voluntarily committed to the area proposed to be pooled or unitized (other than a royalty interest subject to a pooling or unitization clause).

(b) When notice is given as required in Subparagraph (a) of Paragraph (1) of Subsection A of 19.15.14.1207 NMAC, of an application for compulsory pooling and the application is unopposed by those owners located, the applicant may file under the following alternate procedure. The application shall include the following:

(i) a statement that no opposition is expected and why;

(ii) a map outlining the spacing unit(s) to be pooled, showing the nature and percentage of the ownership interests and location of the proposed well;

(iii) the names and last known addresses of the interest owners to be pooled and the nature and percent of their interests and an attestation that a diligent search has been conducted of all public records in the county where the well is located and of phone directories, including computer searches;

(iv) the names of the formations and pools to be pooled (note: this procedure does not apply to an application to pool a spacing unit larger in size than provided in 19.15.3.104 NMAC or applicable special pool orders);

(v) a statement as to whether the pooled unit is for gas and/or oil production (see note under item (iv) of Subparagraph (b) of Paragraph (1) of Subsection A of 19.15.14.1207 NMAC;

(vi) written evidence of attempts made to gain voluntary agreement including but not limited to copies of relevant correspondence;

(vii) proposed overhead charges (combined fixed rates) to be applied during drilling and production operations along with the basis for such charges;

(viii) the location and proposed depth of the well to be drilled on the pooled units; and

(ix) a copy of the authorization for expenditure (AFE) to be submitted to the interest owners in the well.

(c) All submittals required shall be accompanied by sworn and notarized statements by those persons who prepared the submittals, attesting that the information is correct and complete to the best of their knowledge and belief.

(d) All unopposed pooling applications will be set for hearing. If the division finds the application complete, the information submitted with the application will constitute the record in the case, and an order will be issued based on the record.

(e) At the request of any interested person or upon the division's own initiative, any pooling application submitted shall be set for full hearing with oral testimony by the applicant.

(2) Unorthodox well locations.

(a) Definition "affected persons" are the following persons owning interests in the adjoining spacing units:

(i) the division-designated operator;

(ii) in the absence of an operator, any lessee whose interest is evidenced by a written document of conveyance either of record or known to the applicant as of the date the application is filed; and

(iii) in the absence of an operator or lessee, any mineral interest owner whose interest is evidenced by a written document of conveyance either of record or known to the applicant as of the date the application was filed. In the event the operator of the proposed unorthodox well is also the operator of an existing adjoining spacing unit and ownership is not common between the adjoining spacing unit and the spacing unit containing the proposed unorthodox well, then "affected persons" include all working interest owners in that spacing unit.

(b) If the proposed location is unorthodox by being located closer to the outer boundary of the spacing unit than permitted by 19.15.3.104 NMAC or applicable special pool orders, notice shall be given to the affected persons in the adjoining spacing units towards which the unorthodox location encroaches.

(c) If the proposed location is unorthodox by being located in a different quarter-quarter section or quarter section than provided in special pool orders, notice shall be given to all affected persons.

(3) Non-standard proration unit. Notice shall be given to all owners of interests in the mineral estate to be excluded from the proration unit in the quarter-quarter section (for 40-acre pools or formations), the one-half quarter section (for 80-acre pools or formations), the quarter section (for 160-acre pools or formations), the half section (for 320-acre pools or formations), or section (for 640-acre pools or formations) in which the non-standard unit is located and to such other persons as required by the division.

(4) Special pool orders regulating or affecting a specific pool.

(a) Except for non-standard proration unit applications, if the application involves changing the amount of acreage to be dedicated to a well, notice shall be given to:

(i) all division-designated operators in the pool; and

(ii) all owners of interests in the mineral estate in existing spacing units with producing wells.

(b) If the application involves other matters, notice shall be given to:

(i) all division-designated operators in the pool; and

(ii) all division-designated operators of wells within the same formation as the pool and within one (1) mile of the outer boundary of the pool which have not been assigned to another pool.

(5) Special orders regarding any division-designated potash area. Notice shall be given to all potash lessees, oil and gas operators, oil and gas lessees and unleased mineral interest owners within the designated potash area. (a) through (d). The material on unorthodox locations was moved to Paragraph (2) of Subsection A of 19.15.14.1207 NMAC.

(6) Downhole commingling. Notice shall be given to all owners of interests in the mineral estate in the spacing unit if ownership is not common for all commingled zones within the spacing unit.

(7) Surface disposal of produced water or other fluids. Notice shall be given to any surface owner within one-half mile of the site.

(8) Surface commingling. Notice shall be given as prescribed in 19.15.5.303 NMAC.

(9) Adjudications not listed above. Notice shall be given as required by the division.

B. Type and content of notice. Any notice required by 19.15.14.1207 NMAC shall be sent by certified mail, return receipt requested, to the last known address of the person to whom notice is to be given at least 20 days prior to the date of hearing of the application and shall include a copy of the application, the date, time and place of the hearing, and the means by which protests may be made. When an applicant has been unable to locate all persons entitled to notice after exercising reasonable diligence, notice shall be provided by publication, and proof of publication shall be submitted at the hearing. Such proof shall consist of a copy of the legal advertisement that was published in a newspaper of general circulation in the county or counties in which the property is located or if the effect of the application is statewide, in a newspaper of general circulation in this state.

C. At the hearing, the applicant shall make a record, either by testimony or affidavit signed by the applicant or its authorized representative, that: (a) the notice provisions of 19.15.14.1207 NMAC have been complied with; (b) the applicant has conducted a good-faith diligent effort to find the correct address of all persons entitled to notice; and (c) pursuant to 19.15.14.1207 NMAC notice has been given at that correct address as required by 19.15.14.1207 NMAC. In addition, the record shall contain the name and address of each person to whom notice was sent and, where proof of receipt is available, a copy of the proof.

D. Evidence of failure to provide notice as required in 19.15.14.1207 NMAC may, upon proper showing, be considered cause for reopening the case.

E. In the case of an administrative application where the required notice was sent and a timely filed protest was made, the division shall notify the applicant and the protesting party in writing that the case has been set for hearing and the date, time and place of the hearing. No further notice is required.

[1-1-86…2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1207, 8-29-03; A, 06/15/04]

19.15.14.1208 PLEADINGS, COPIES AND PRE-HEARING STATEMENTS:

A. For pleadings and correspondence filed in cases pending before a division examiner, two copies must be filed with the division. For pleadings and correspondence filed in cases pending before the commission, five copies must be filed with the division. The division will disseminate copies to the members of the commission. The party filing the pleading or correspondence shall at the same time either hand deliver or transmit by facsimile or electronic mail to any party who has entered an appearance therein or the attorneys of record, a copy of the pleading or correspondence. An appearance of any interested party shall be made either by letter addressed to the division or in person at any proceeding before the commission or before a division examiner, with notice of such appearance to the parties of record.

B. Parties to an adjudicatory proceeding who intend to present evidence at the hearing shall file a pre-hearing statement, and serve a copy thereof on opposing counsel of record in the manner provided in Subsection A of 19.15.14.1208 NMAC, at least four days in advance of a scheduled hearing before the division or the commission, but in no event later than the Friday preceding the scheduled hearing. The statement must include: the names of the parties and their attorneys; a concise statement of the case; the names of all witnesses the party will call to testify at the hearing; the approximate time the party will need to present its case; and identification of any procedural matters that are to be resolved prior to the hearing.

[9-15-55...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1208, 8-29-03; A, 06/15/04]

19.15.14.1209 CONTINUANCE OF HEARING WITHOUT NEW SERVICE:

Any hearing before the commission or a division examiner held after due notice may be continued by the person presiding at such hearing to a specified time and place without the necessity of notice of the same being again served or published.

[1-1-50...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1209, 8-29-03; A, 06/15/04]

19.15.14.1210 CONDUCT OF HEARINGS:

A. Hearings before the commission or a division examiner shall be conducted without rigid formality. A transcript of testimony shall be taken and preserved as a part of the permanent records of the division. Any person testifying shall do so under oath. However, relevant unsworn comments and observations by any interested party will be designated as such and included in the record.

B. The division director may order the parties to file prepared written testimony in advance of the hearing for cases pending before the commission. The witness must be present at the hearing and shall adopt, under oath, the prepared written testimony, subject to cross-examination and motions to strike unless the presence of the witness at hearing is waived upon notice to and without objection of the parties. Pages of the prepared written testimony shall be numbered and contain line numbers on the left-hand side.

[1-1-50...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1210, 8-29-03]

19.15.14.1211 POWER TO REQUIRE ATTENDANCE OF WITNESSES AND PRODUCTION OF EVIDENCE:

A. The commission or any member thereof and the division director or the division director’s authorized representative have statutory power to subpoena witnesses and to require the production of books, papers, and records in any proceeding before the commission or division. A subpoena will be issued for attendance at a hearing upon the written request of any party. In case of the failure of a person to comply with the subpoena issued, an attachment of the person may be issued by the district court of any district in the state. Any person found guilty of testifying falsely at any hearing may be punished for contempt.

B. A pre-hearing conference may be held prior to the hearing on the merits in cases pending before the division or the commission either upon request of a party or upon notice by the division director or a division examiner. The pre-hearing conference will be to narrow issues, eliminate or resolve other preliminary matters and to encourage settlement. The division director or the division examiner may issue a pre-hearing order following the pre-hearing conference.

[1-1-50…2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1211, 8-29-03]

19.15.14.1212 RULES OF EVIDENCE AND EXHIBITS:

A. Full opportunity shall be afforded all interested parties at a hearing before the commission or division examiner to present evidence and to cross-examine witnesses. In general, the rules of evidence applicable in a trial before a court without a jury shall be applicable, provided that such rules may be relaxed, where, by so doing, the ends of justice will be better served. No order shall be made that is not supported by competent legal evidence.

B. Parties introducing exhibits at hearings before the commission or a division examiner must provide a complete set of exhibits for the court reporter, each commissioner or division examiner and other parties of record.

[1-1-50…2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1212, 8-29-03]

19.15.14.1213 DIVISION EXAMINERS' QUALIFICATIONS AND APPOINTMENT:

The division director shall appoint division examiners. Each division examiner so appointed shall be a member of the staff of the division. Each individual appointed as a division examiner must have at least six years of experience as a geologist, petroleum engineer or licensed lawyer, or at least two years of such experience and a college degree in geology, engineering or law; provided however, that nothing herein shall prevent any member of the commission from serving as a division examiner.

[9-15-55...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1213, 8-29-03]

19.15.14.1214 REFERRAL OF CASES TO DIVISION EXAMINERS:

The division director may refer any matter or proceeding to a division examiner for hearing in accordance with these rules. The division examiner appointed to hear any specific case shall be designated by name.

[9-15-55...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1214, 8-29-03]

19.15.14.1215 DIVISION EXAMINER'S POWER AND AUTHORITY:

The division director may limit the powers and duties of the division examiner in any particular case to such issues or to the performance of such acts as the director deems expedient; however, subject only to such limitations as may be ordered by the director, the division examiner to whom any matter is referred under these rules shall have full authority to hold hearings on such matter in accordance with these rules. The division examiner shall have the power to perform all acts and take all measures necessary or proper for the efficient and orderly conduct of such hearing, including administering oaths to witnesses and receiving testimony and exhibits offered in evidence subject to such objections as may be imposed. The division examiner shall cause a complete record of the proceedings to be made and transcribed and shall certify same to the director as hereinafter provided.

[9-15-55...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1215, 8-29-03]

19.15.14.1216 HEARINGS THAT MUST BE HELD BEFORE COMMISSION:

Notwithstanding any other provisions of these rules, the hearing on any matter shall be held before the commission if:

A. it is a hearing pursuant to Section 70-2-13 NMSA 1978; or

B. the division director desires the commission to hear the matter.

[9-15-55...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1216, 8-29-03]

19.15.14.1217 [RESERVED]
[9-15-55...2-1-96; Repealed 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1217, 8-29-03]

19.15.14.1218 REPORT AND RECOMMENDATIONS FROM DIVISION EXAMINER'S HEARING:
Upon the conclusion of any hearing before a division examiner, the division examiner shall promptly consider the proceedings in such hearing, and based upon the record of such hearing the division examiner shall prepare a written report with recommendations for the disposition of the matter or proceeding by the division. Such report shall either be accompanied by a proposed order or shall be in the form of a proposed order and shall be submitted to the division director with the certified record of the hearing.
[9-15-55...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1218, 8-29-03]

19.15.14.1219 DISPOSITION OF CASES HEARD BY DIVISION EXAMINERS:
After receipt of the report of the division examiner, the division director shall enter the division's order disposing of the matter.
[9-15-55…2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1219, 8-29-03]

19.15.14.1220 HEARING BEFORE COMMISSION AND STAYS OF DIVISION ORDERS:
A. When an order has been entered by the division pursuant to a hearing held by a division examiner, a party of record adversely affected by the order has the right to have the matter heard de novo before the commission, provided that within 30 days from the date the order is issued the party files with the division a written application for such hearing. If an application is filed, the matter or proceeding shall be set for hearing before the commission.
B. Any party requesting a stay of a division order must file the request with the division and provide copies of the request to the parties of record or their attorneys in the case at the time the request is filed. The request must have attached a proposed stay order. The director may grant stays under other circumstances if such a stay is necessary to prevent waste, protect correlative rights, protect public health and the environment or prevent gross negative consequences to any affected party.
C. Any party of record adversely affected by the order issued by the commission after hearing may apply for rehearing pursuant to 19.15.14.1222 NMAC.
[9-15-55...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1220, 8-29-03]

19.15.14.1221 COPIES OF COMMISSION AND DIVISION ORDERS:
Within 10 days after an order, including any order granting or refusing rehearing or order following rehearing, has been issued, a copy of such order shall be mailed by the division to each party or its attorney of record. For purposes of 19.15.14.1221 NMAC only, the parties to a case are the applicant and each person who has entered an appearance in the case, in person or by attorney, either by filing a protest, pleading or notice of appearance with the division or by entering an appearance on the record at a hearing.
[9-15-55...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1221, 8-29-03; A, 06/15/04]

19.15.14.1222 REHEARINGS:
Within 20 days after entry of any order of the commission any party of record adversely affected thereby may file with the division an application for rehearing on any matter determined by such order, setting forth the respect in which the order is believed to be erroneous. The commission shall grant or refuse any such application in whole or in part within 10 days after it is filed and failure to act within such period shall be deemed a refusal and a final disposition of such application. In the event the rehearing is granted, the commission may enter a new order after rehearing as may be required under the circumstances.
[1-1-50...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1222, 8-29-03]

19.15.14.1223 EX PARTE COMMUNICATIONS:
A. In an adjudicatory proceeding, except for filed pleadings, at no time after the filing of an application for hearing shall any party, interested participant or their representatives communicate regarding the issues involved

in the application with any commissioner or the division examiner appointed to hear the case when all other parties of record to the proceedings have not had the opportunity to be present.

B. The prohibition in Subsection A of 19.15.14.1223, above, does not apply to those applications that are believed by the applicant to be unopposed. However, in the event that an objection is filed in a case previously believed to be unopposed, the prohibition in A, above, is immediately applicable.
[7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1223, 8-29-03]

HISTORY OF 19.15.14 NMAC:
Pre-NMAC History: The material in this Part was derived from that previously filed with the State Records Center and Archives:
Rule 1201, Necessity for Hearing, 1-11-82;
Rule 1201, Necessity for Hearing, 2-5-91;
Rule 1202, Emergency Orders, 1-11-82;
Rule 1202, Emergency Orders, 2-5-91;
Rule 1203, Method of Initiating a Hearing, 1-11-82;
Rule 1203, Method of Initiating a Hearing, 2-5-91;
Rule 1204, Method of Giving Legal Notice for Hearing, 1-11-82;
Rule 1204, Method of Giving Legal Notice for Hearing, 11-5-85;
Rule 1204, Method of Giving Legal Notice for Hearing, 2-5-91;
Rule 1204, Publication of Notice for Hearing, 4-12-91;
Rule 1205, Contents of Notice of Hearing, 1-11-82;
Rule 1205, Contents of Notice of Hearing, 11-5-85;
Rule 1205, Contents of Notice of Hearing, 2-5-91;
Rule 1206, Personal Service of Notice, 1-11-82;
Rule 1206, Preparation of Notices, 11-5-85;
Rule 1206, Personal Service of Notice, 2-5-91;
Rule 1207, Preparation of Notices, 1-11-82;
Rule 1207, Additional Notice Requirements, 11-5-85;
Rule 1207, Additional Notice Requirements, 3-27-87;
Rule 1207, Additional Notice Requirements, 1-6-88;
Rule 1207, Additional Notice Requirements, 2-5-91;
Rule 1208, Filing Pleadings, 1-11-82;
Rule 1208, Filing Pleadings, 2-5-91;
Rule 1209, Continuance of Hearing Without New Service, 1-11-82;
Rule 1209, Continuance of Hearing Without New Service, 2-5-91;
Rule 1210, Conduct of Hearings, 1-11-82;
Rule 1210, Conduct of Hearings, 2-5-91;
Rule 1211, Power to Require Attendance of Witnesses and Production of Evidence, 1-11-82;
Rule 1211, Power to Require Attendance of Witnesses and Production of Evidence, 2-5-91;
Rule 1212, Rules of Evidence, 1-11-82;
Rule 1212, Rules of Evidence, 2-5-91;
Rule 1213, Examiners' Qualifications and Appointment, 1-11-82;
Rule 1213, Examiners' Qualifications and Appointment, 2-5-91;
Rule 1214, Referral of Cases to Examiners, 1-11-82;
Rule 1214, Referral of Cases to Examiners, 2-5-91;
Rule 1215, Examiner's Power of Authority, 1-11-82;
Rule 1215, Examiner's Power of Authority, 2-5-91;
Rule 1216, Hearings Which Must be Held Before the Commission, 1-11-82;
Rule 1216, Hearings Which Must be Held Before the Commission, 2-5-91;
Rule 1217, Examiner's Manner of Conducting Hearing, 1-11-82;

Rule 1217, Examiner's Manner of Conducting Hearing, 2-5-91;
Rule 1218, Report and Recommendations, Examiner's Hearings, 1-11-82;
Rule 1218, Report and Recommendations, Examiner's Hearings, 2-5-91;
Rule 1219, Disposition of Cases Heard by Examiners, 1-11-82;
Rule 1219, Disposition of Cases Heard by Examiners, 2-5-91;
Rule 1220, De Novo Hearing Before Commission, 1-11-82;
Rule 1220, De Novo Hearing Before Commission, 12-30-86;
Rule 1220, De Novo Hearing Before Commission, 2-5-91;
Rule 1221, Notice of Commission and Division Orders, 1-11-82;
Rule 1221, Notice of Commission and Division Orders, 2-5-91;
Rule 1222, Rehearings, 1-11-82;
Rule 1222, Rehearings, 2-5-91.

History of Repealed Material:
Rule 1206, Personal Service of Notice, Repealed 4-12-91.

Other History: Rule 1201, Necessity for Hearing, filed 2-5-91; Rule 1202, Emergency Orders, filed 2-5-91; Rule 1203, Method of Initiating a Hearing, filed 2-5-91; Rule 1204, Publication of Notice for Hearing, filed 4-12-91; Rule 1205, Contents of Notice of Hearing, filed 2-5-91; Rule 1207, Additional Notice Requirements, filed 2-5-91; Rule 1208, Filing Pleadings, filed 2-5-91; Rule 1209, Continuance of Hearing Without New Service, filed 2-5-91; Rule 1210, Conduct of Hearings, filed 2-5-91; Rule 1211, Power to Require Attendance of Witnesses and Production of Evidence, filed 2-5-91; Rule 1212, Rules of Evidence, filed 2-5-91; Rule 1213, Examiners' Qualifications and Appointment, filed 2-5-91; Rule 1214, Referral of Cases to Examiners, filed 2-5-91; Rule 1215, Examiner's Power of Authority, filed 2-5-91; Rule 1216, Hearings Which Must be Held Before the Commission, filed 2-5-91; Rule 1217, Examiner's Manner of Conducting Hearing, filed 2-5-91; Rule 1218, Report and Recommendations, Examiner's Hearings, filed 2-5-91; Rule 1219, Disposition of Cases Heard by Examiners, filed 2-5-91; Rule 1220, De Novo Hearing Before Commission, filed 2-5-91; Rule 1221, Notice of Commission and Division Orders, filed 2-5-91; Rule 1222, Rehearings, filed 2-5-91 were all renumbered, reformatted and replaced by 19 NMAC 15.N, Procedure, effective 2-1-96.
19 NMAC 15.N, Procedure, filed 1-18-96 was renumbered, reformatted and replaced by 19.15.14 NMAC, Procedure, effective 8-29-03.

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 15 ADMINISTRATION

19.15.15.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department, Oil Conservation Division, 2040 S. Pacheco, Santa Fe, New Mexico 87505, (505) 827-7131.
[2-1-96; 19.15.15.1 NMAC - Rn, 19 NMAC 15.O.1, 07-30-04]

19.15.15.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico.
[2-1-96; 19.15.15.2 NMAC - Rn, 19 NMAC 15.O.2, 07-30-04]

19.15.15.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the and Gas Act which grants the oil conservation division jurisdiction and authority over all matters relating to the observation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights, and the disposition of wastes resulting from oil and gas operations.
[2-1-96; 19.15.15.3 NMAC - Rn, 19 NMAC 15.O.3, 07-30-04]

19.15.15.4 DURATION: Permanent.
[2-1-96; 19.15.15.4 NMAC - Rn, 19 NMAC 15.O.4, 07-30-04]

19.15.15.5 EFFECTIVE DATE: February 1, 1996. [Unless a later date is cited at the end of a section.]
[2-1-96; 19.15.15.5 NMAC - Rn, 19 NMAC 15.O.5, 07-30-04]

19.15.15.6 OBJECTIVE: The objective of this part is to provide for administration of the authority granted to the Oil Conservation Division under the Oil and Gas Act.
[2-1-96; 19.15.15.6 NMAC - Rn, 19 NMAC 15.O.6, 07-30-04]

19.15.15.7 DEFINITIONS: [RESERVED].

19.15.15.8-1300 [RESERVED].

19.15.15.1301 DISTRICT OFFICES:

A. To expedite administration of the work of the oil conservation division of the New Mexico energy, minerals and natural resources department and the enforcement of its rules and regulations, the state shall be divided into four districts as follows:

(1) district 1: Lea, Roosevelt, and Curry counties, and that portion of Chaves county lying east of the north-south line dividing ranges 29 and 30 east, NMPM; the district office shall be in Hobbs, New Mexico.

(2) district 2: Eddy, Otero, Dona Ana, Luna, Hidalgo, Grant, Sierra, Lincoln, and De Baca counties, and that portion of Chaves county lying west of the north-south line dividing ranges 29 and 30 east, NMPM; the district office shall be in Artesia, New Mexico.

(3) district 3: San Juan, Rio Arriba, McKinley, and Sandoval counties; the district office shall be in Aztec, New Mexico;

(4) district 4: remainder of state; the district office shall be in Santa Fe, New Mexico; each district office shall be under the charge of a district supervisor, an oil and gas inspector, or a deputy oil and gas inspector; unless otherwise specifically required, all matters pertaining to the division shall be taken care of through the district office of the district in which the affected land is located.
[1-1-50...2-1-96; 19.15.15.1301 NMAC - Rn, 19 NMAC 15.O.1301, 07-30-04]

19.15.15.1302 WHERE TO FILE REPORTS AND FORMS:
All reports and forms required by the rules to be filed with the division shall be filed in the number and at the time specified on the form or report or by the applicable rules in 19.15.13 NMAC. Unless otherwise specified, all such reports and forms shall be filed at the district office of the district in which the land that is the subject matter of the report is located. All plugging bonds shall be filed directly with the Santa Fe office of the division. A list of all plugging bonds approved and in force shall be kept in each district office.
[1-1-50...2-1-96; 19.15.15.1302 NMAC - Rn, 19 NMAC 15.O.1302, 07-30-04]

19.15.15.1303 DUTIES AND AUTHORITY OF FIELD PERSONNEL:
Oil and gas inspectors, deputy oil and gas inspectors, scouts, engineers and geologists duly appointed by the division have the authority and duty to enforce the rules and regulations of the division. Only oil and gas inspectors and their deputies shall have discretion to allow minor deviations from requirements of the rules as to field practices where, by so doing, waste will be prevented or burdensome delay or expenses on the part of the operator will be avoided.
[1-1-50...2-1-96; 19.15.15.1303 NMAC - Rn, 19 NMAC 15.O.1303, 07-30-04]

19.15.15.1304 NUMBERING OF DIVISION ORDERS:
A. All orders of the division made after January 1, 1950, pertaining to the allocation of production of oil and gas are prefixed with the letter "A" or "AG" in the case of gas pools and are numbered consecutively, commencing with the number 1, i.e., the first allocation order issued after January 1, 1950, is No. A-1, the next A-1, etc or AG-1 and AG-2.
B. All other orders of the division made after January 1, 1950, are prefixed with the letter "R" and are numbered consecutively, commencing with the number 1, i.e., the first such order issued after January 1, 1950, is No. R-1, the next R-2, etc.
[1-1-50...2-1-96; 19.15.15 NMAC.1304 - Rn, 19 NMAC 15.O.1304, 07-30-04]

History of 19.15.15 NMAC:
Pre-NMAC History: The material in this Part was derived from that previously filed with the State Records Center and Archives:
Rule 1301, District Offices, filed 1-11-82;
Rule 1301, District Offices, filed 2-5-91;
Rule 1302, Where to File Reports and Forms, filed 1-11-82;
Rule 1302, Where to File Reports and Forms, filed 2-5-91;
Rule 1303, Duties and Authority of Field Personnel, filed 1-11-82;
Rule 1303, Duties and Authority of Field Personnel, filed 2-5-91;
Rule 1304, Numbering of Division Orders, filed 1-11-82;
Rule 1304, Numbering of Division Orders, filed 10-11-89;
Rule 1304, Numbering of Division Orders, filed 2-5-91.

History of Repealed Material: [Reserved]

Other History: Rule 1301, District Offices (filed 2-5-91); Rule 1302, Where to File Reports and Forms (filed 2-5-91); Rule 1303, Duties and Authority of Field Personnel (filed 2-5-91); and Rule 1304, Numbering of Division Orders (filed 2-5-91) were all renumbered, reformatted and replaced by 19 NMAC 15.O, Administration, effective 2-1-96.
19 NMAC 15.O, Administration (filed 1-18-96) was renumbered, reformatted and replaced by 19.15.15 NMAC, Administration, effective 07-30-04.

PART P
(RESERVED)

PART Q
(RESERVED)

Appendix D - Oklahoma Regulatory Summary (General)

TITLE 165: CORPORATION COMMISSION
CHAPTER 10: OIL AND GAS CONSERVATION

Effective July 1, 2004

Last Amended
The Oklahoma Register
Volume 21, Number 17
June 15, 2004 publication
Pages 1921 - 2642

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CHAPTER 10. OIL AND GAS CONSERVATION

[**Authority**: 52 O. S. §§ 86.2 through 320, 528 through 614]

[**Source**: Codified 12-31-91]

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SUBCHAPTER 1. ADMINISTRATION

PART 1. GENERAL PROVISIONS

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PART 1. GENERAL PROVISIONS

165:10-1-1. Purpose

The rules of this Chapter were promulgated in furtherance of the public policy and statutory laws of the State of Oklahoma to prevent the waste of oil and gas, to assure the greatest ultimate recovery from the State's reservoirs, to protect the correlative rights of all interest owners, and to prevent pollution.

165:10-1-2. Definitions.

The following words and terms, when used in this Chapter, shall have the following meaning unless the context clearly indicates otherwise:

"Agent" means any person authorized by another person to act for him.

"Aquifer" means a geological formation, group of formations, or part of a formation that is capable of yielding a significant amount of water to a well or spring.

"Area of exposure" means an area within a circle constructed with the point of escape of poisonous gas (hydrogen sulfide) as its center and the radius of exposure as its radius.

"Associated gas" means any gas produced from a Commission ordered combination oil and gas reservoir in which allowed rates of production are based upon volumetric withdrawals.

"BS&W" means basic sediment and water which is that portion of fluids and/or solids that settle in the bottom of storage tanks and/or treating vessels and is unsaleable to the first purchaser in its present form. BS&W usually consists of water, paraffin, sand, scale, rust, and other sediments.

"Barrel" means 42 (U.S.) gallons at 60 F at atmospheric pressure.

"Basic sediment pit" means a pit used in conjunction with a tank battery for storage of basic sediment removed from a production vessel or from the bottom of an oil storage tank.

"Blowout" means the uncontrolled escape of oil or gas, or both, from any formation.

"Blowout preventer" means a heavy casinghead control fitted with special gates and/or rams which can be closed around the drill pipe or which completely closes the top of the casing.

"Blowout preventer stack" means the assembly of well control equipment including preventers, spools, valves, and nipples connected to the top of the casinghead.

"Carrier", or **"transporter"**, or **"taker"** means any person moving or transporting oil or gas away from a lease or from any common source of supply.

"Casing pressure" means the pressure within the casing or between the casing and tubing at the wellhead.

"Choke manifold" means an assembly of valves, chokes, gauges, and lines used to control the rate of flow from the well when the blowout preventers are closed.

"Closed drilling fluid/mud system" means a system where drilling fluids/muds are circulated in the well bore and contained in non-earthen tanks.

"Closure" means the practice of dewatering, trenching, filling, leveling, terracing, and/or vegetating a pit site after its useful life is reached in order to restore or reclaim the site to near its original condition.

"Commercial disposal well" means a disposal well which:

(A) Is operated primarily for profit from the disposal of salt water and/or other deleterious substances for a fee; and

(B) Disposes of salt water and/or other deleterious substances transported by truck to the facilities used in conjunction with said disposal well or is a disposal well for which none of its owners is an owner in any of the oil and gas wells which produce the salt water and/or other deleterious substances which will be disposed into said disposal well.

"Commercial pit" is a disposal facility which is authorized by Commission order and used for the disposal, storage, and handling substances or soils contaminated by deleterious substances produced, obtained, or used in connection with drilling and/or production operations. This does not include a disposal well pit.

"Commercial soil farming" means the practice of soil farming or land applying drilling fluids and/or other deleterious substances produced, obtained, or used in connection with the drilling of a well or wells at an off-site location. Multiple applications to the same land are likely.

"Commission" means the Corporation Commission of the State of Oklahoma.

"Common source of supply" or **"pool"** means "that area which is underlaid or which, from geological or other scientific data, or from drilling operations, or other evidence, appears to be underlaid by a common accumulation of oil and/or gas; provided that, if any such area is underlaid, or appears from geological or other scientific data or from drilling operations, or other evidence, to be underlaid by more than one common accumulation of oil or gas or both, separated from each other by strata of earth and not connected with each other, then such area shall, as to each said common accumulation of oil or gas or both, shall be deemed a separate common source of supply." [52. O.S.A. §86.1(c)].

"Completion/fracture/workover pit" means a pit used for temporary storage of spent completion fluids, frac fluids, workover fluids, drilling fluids, silt, debris, water, brine, oil scum, paraffin, or other deleterious substances which have been cleaned out of the wellbore of a well being completed, fractured, recompleted, or worked over.

"Condensate" means a liquid hydrocarbon which:

(A) Was produced as a liquid at the surface,

(B) Existed as gas in the reservoir, and

(C) Has an API gravity greater than or equal to fifty degrees, unless otherwise proven.

"Conductor casing" means a casing string which is often set and cemented at a shallow depth to support and protect the top of the borehole from erosion while circulating and drilling the surface casing hole.

"Conservation Division" means the Division of the Commission charged with the administration and enforcement of the rules of this Chapter.

"Contingency plan" is a written document which provides for an organized plan of action for alerting and protecting the public within an area of exposure following the accidental release of a potentially hazardous volume of poisonous gas such as hydrogen sulfide.

"Contractor" means any person who contracts with another person for the performance of prescribed work.

"Cubic foot of gas" means the volume of gas contained in one cubic foot of space at an absolute pressure of 14.65 pounds per square inch and at a temperature of 60°F. Conversion of volumes to conform to standard conditions shall be made in accordance with Ideal Gas Laws corrected for deviation from Boyle's Law when the pressure at point of measurement is in excess of 200 pounds per square inch gauge.

"Date of completion" means:

(A) For an oil well, the date that the well first produces oil into the lease tanks through permanent wellhead equipment.

(B) For a gas well, the date of completion of a gas well is the date that gas is capable of being delivered to a pipeline purchaser.

(C) For a well, which does not produce either oil or gas, is the date on which attempts to obtain production from the well cease.

"Day" means a period of 24 consecutive hours. For reporting purposes, it shall be from 7:00 a.m. to 7:00 a.m. the following day.

"Deleterious substances" means any chemical, salt water, oil field brine, waste oil, waste emulsified oil, basic sediment, mud, or injurious substance produced or used in the drilling, development, production, transportation, refining, and processing of oil, gas and/or brine mining.

"Design mud weight" means the planned drilling mud weight to be used. This mud weight is used in the design of the casing strings.

"Design wellhead pressure" means the maximum anticipated wellhead pressure which is expected to be experienced on the inside of the casing string and on wellhead equipment. This pressure is used to design the casing string and to select wellhead equipment with sufficient working pressure rating.

"Development" means any work which actively looks toward bringing in production, such as erecting rigs, building tankage, drilling wells, etc.

"Directional drilling" means intentional changing of the direction of the well from the vertical.

"Director of Conservation" means the person in official charge of the Conservation Division.

"Discharge" means the release or setting free by any spilling, leaking, pumping, pouring, emitting, emptying, or dumping of substances.

"Distressed well" means a well authorized by Commission order to produce at an unrestricted rate in the interest of public safety due to technical difficulties which temporarily cannot be controlled.

"Diverter" means a device attached to the wellhead to close the vertical access and direct any flow into a line away from the rig. Diverters differ from blowout preventers in that flow is not stopped but rather the flow path is redirected away from the rig.

"Duly authorized representative" means, for the purpose of underground injection well applications, that person or position having a responsibility for the underground injection well.

"Emergency pit" means a pit used for the storage of excessive or unanticipated amounts of fluids during an immediate emergency situation in the drilling or operation of a well, such as a well blowout or a pipeline rupture. This does not include a spill prevention structure required by local, state, or federal regulations.

"Enhanced recovery operation" means the introduction of fluid or energy into a common source of supply for the purpose of increasing the recovery of oil therefrom according to a plan which has been approved by the Commission after notice and hearing.

"Enhanced recovery well" means a well producing in an enhanced recovery operation in accordance with Commission order.

"Exchangeable Sodium Percentage (ESP)" is the relative amount of the sodium ion present on the soil surface, expressed as a percentage of the total Cation Exchange Capacity (CEC). Since the determination of CEC is time consuming and expensive, a practical and satisfactory correlation between the Sodium Adsorption Ratio (SAR) and ESP was established. The SAR is defined elsewhere in this Section. ESP can be estimated by the following empirical formula:

$$ESP = 100 \quad (-0.0126 + 0.01475 \times SAR) \div 1 + (-0.0126 + 0.01475 \times SAR)$$

"Exempted aquifer" means an aquifer or its portion that meets the criteria in the definition of "underground source of drinking water" or in the definition of "treatable water", but which has been exempted according to the procedures in 165:5-7-28 and 165:10-5-14.

"Facility" means, for the purposes of 165:10-21-15, any building(s), parts of a building, equipment, property, or vehicles that are actively engaged in the reuse, recycling, or ultimate destruction of deleterious substances pursuant to 68 O.S. Supp. 1986, §2357.14-§2357.20.

"Field" means the general area underlaid by one or more common sources of supply.

"Flare pit" means a pit which contains flare equipment and which is used for temporary storage of liquid hydrocarbons which are sent to the flare but are not burned due to equipment malfunction. Flare pits may be used in conjunction with tank batteries or wells.

"Flowing well" means any well from which oil or gas is produced naturally and without artificial lifting equipment.

"Fresh water strata" means a strata from which fresh water may be produced in economical quantities.

"Gas" means any petroleum hydrocarbon existing in the gaseous phase.

(A) Casinghead gas means any gas or vapor, or both, indigenous to an oil stratum and produced from such stratum with oil.

(B) Dry gas or dry natural gas means any gas produced in which there are no appreciable hydrocarbon liquids recoverable by separation at the wellhead.

(C) Condensate gas means any gas which is produced with condensate as defined as "condensate".

"Gas allowable" or **"allowable gas"** means the amount of natural gas authorized to be produced from any well by order of the Commission or as provided by statute.

"Gas lift" means any method of lifting liquid to the surface by injecting gas into the well bore from which production is obtained.

"Gas repressuring" means the injection of gas into a common source of supply to restore or increase the gas energy of a reservoir.

"GOR (Gas/Oil Ratio)" means the ratio of the gas produced in standard cubic feet to one barrel of oil produced during any stated period. Condensate and load oil excepted under 165:10-13-6 shall not be considered as oil for purposes of determining GOR.

"Hardship well" means a well authorized by Commission order to produce at a specified rate because reasonable cause exists to expect that production below said rate would damage the well and cause waste.

"Hydrogen sulfide gas (H_2S)" means a toxic poisonous gas with a chemical composition of H_2S which is sometimes found mixed with and produced with fluids from oil and gas wells.

"Hydrostatic head" or **"hydrostatic pressure"** means the pressure which exists at any point in the wellbore due to the weight of the column of fluid or gas above that point.

"Illegal gas" means gas which has been produced within the State from any well or wells in violation of any rule, regulation, or order of the Commission, as distinguished from gas produced within the State not in violation of any such rule, regulation, or order which is "legal gas".

"Illegal oil" means oil which has been produced within the State from any well or wells in violation of any rule, regulation or order of the Commission, as distinguished from oil produced within the State not in violation of any such rule, regulation, or order which is "legal oil".

"Intermediate casing" means the casing string or strings run after setting the surface casing and prior to setting the production string or liner.

"Kick" means the intrusion of formation liquids or gas that results in an increase in circulation pit volume. Without corrective measures, this condition can result in a blowout.

"Land application" is the application of deleterious substances and/or soils contaminated by deleterious substances to the land for the purpose of disposal or land treatment; also known as soil farming.

"Lease allowable" means the total of the allowables of the individual wells on the lease.

"Liner" means a length of casing used downhole as an extension to a previously installed casing string to case the hole for further drilling operations and/or for producing operations.

"Load Ticket" means a document or bill of lading describing the source, contents and destination of any load of petroleum tank bottoms, BS&W or deleterious substance, the name and address of the company owning or leasing the transporting vehicle, either the Oklahoma Tax Commission Gross production Vehicle Permit number of the vehicle or the Oklahoma Corporation Commission Motor Carrier License number, the date of transport, the name of the company or person owning the lease or storage facility from which the product is being removed, or if different, the name of the company or person owning the product before its removal, the OTC assigned production unit number of the lease or a precise description of the location of non-lease storage from which the product is removed, a description of the product being transported, the name and address of the person or firm who will receive or store the load and the driver's signature.

"Meter" means an instrument for measuring and indicating or recording the volumes of gases or liquids.

"Mud" means any mixture of water and clay or other material as the term is commonly used in the industry.

"Multiple zone completion" means the completion of any well so as to permit the production from more than one common source of supply, with such common sources of supply completely segregated.

"Noncommercial pit" means an earthen pit which is located either on-site or off-site and is used for the handling, storage, or disposal of deleterious substances or soils contaminated by deleterious substances produced, obtained, or used in connection with the drilling and/or operation of a well or wells, and is operated by the generator of the waste. This does not include a disposal well pit.

"Normal pressure" means a formation pore pressure, proportional to depth, which is roughly equal to the hydrostatic pressure gradient of a column of salt water (.465 psi/ft).

"Off-site reserve pit" means a reserve pit used for the handling, storage and/or disposal of drilling fluids/muds and cuttings where all parts of the pit are located further than 300 feet from the well bore.

"Oil" or **"crude oil"**, means, for purposes of these regulations, any petroleum hydrocarbon, except condensate, produced from a well in liquid form by ordinary production methods.

"Oil allowable" or **"allowable oil"** means the amount of oil authorized to be produced from any well by order of the Commission.

"Operator" means the person who is duly authorized and in charge of the development of a lease or the operation of a producing property.

"Overage" means the oil or gas delivered to a carrier, transporter, or taker in excess of the allowable set by the Commission for any given period.

"Owner" means the person or persons who have the right to drill into and to produce from any common source of supply, and to appropriate the production either for himself, or for himself and others.

"Person" means any natural person, corporation, association, partnership, receiver, trustee, guardian, executor, administrator, fiduciary, or representative of any kind, and shall include the plural.

"Plug" means the closing off, in a manner prescribed by the Commission, of all oil, gas, and waterbearing formations in any producing or nonproducing wellbore before such well is abandoned.

"Pollution" means the contamination of fresh water or soil, either surface or subsurface, by salt water, mineral brines, waste oil, oil, gas, and/or other deleterious substances produced from or obtained or used in connection with the drilling, development, producing, refining, transporting, or processing of oil or gas within the State of Oklahoma.

"Pool" See "common source of supply".

"Potential" means the properly determined capacity of a well to produce oil or gas, or both, under conditions prescribed by the Commission.

"Producer" See "Operator" or "Owner".

"Production casing" means the casing string set above or through the producing zone of a well which serves the purpose of confining and/or producing the well production fluids.

"Productivity index" means the daily production of oil in barrels per unit pressure differential between the static reservoir pressure and the stabilized flowing pressure during flow at a stated rate.

"Proration period" means:

(A) The proration period for any well, other than an unallocated gas well, shall be one calendar month which shall begin at 7 a.m. on the first day of such month and end at 7 a.m. on the first day of the next succeeding month unless otherwise specified by order of the Commission.

(B) The proration period for any unallocated gas well shall be one calendar year which shall begin at 7:00 a.m. the first day of such year and end at 7:00 a.m. on the first day of the next succeeding year unless otherwise specified by order of the Commission.

"Public area" means a dwelling place, a business, school, hospital, school bus stop, government building, a public road, all or any portion of a park, city, town, village, or other similar area that can be expected to be populated.

"Public street" or **"road"** means any federal, state, county, or municipal street or road owned or maintained for public access or use.

"Purchaser" or **"transporter"** means any person who acting alone or jointly with any person or persons, via his own, affiliated or designated carrier, transporter, or taker, shall directly or indirectly purchase, take, or transport by any means whatsoever or otherwise remove from any lease, oil or gas, and/or other hydrocarbons produced from any common source of supply in this State, excepting royalty portions from leases owned by that person.

"Radius of exposure" means that radius constructed with the point of escape of poisonous (hydrogen sulfide) gas as its starting point and its length calculated by use of the Pasquill-Gifford equations.

"Reclaimer" or **"reclamation plant"** includes any person licensed by the Oklahoma Tax Commission pursuant to 68 O.S.§1015.1 who reclaims or salvages or in any way removes or extracts oil from waste products associated with the production, storage, or transportation of oil including, but not limited to BS&W, tank bottoms, pit and waste oil, and/or waste oil residue.

"Recomplete" or **"recompletion"** means any operation to:

(A) Convert an existing well from an injection well or disposal well, to a producing well, or

(B) Add or change common sources of supply in an existing well.

"Recycling" is the reuse, processing, reclaiming, treating, neutralizing, or refining of materials and by-products into a product of beneficial use which, if discarded, would be deleterious substances.

"Recycling/reuse pit" means a pit which is used for the recycling or reuse of deleterious substances, is located off-site, and is operated by the generator of the waste.

"Re-enter" or **"re-entry"** is the act of entering a plugged well for the purpose of utilizing said well for the production of oil or gas, for the disposal of fluids therein, for a service well, or for the salvaging of tubing or casing therefrom.

"Remediation pit" means a pit which is used for the handling, storage, or disposal of deleterious substances and/or soils contaminated by deleterious substances which are relocated to the pit for the purpose of remediating a site which is known to be or suspected to be causing pollution.

"Reserve pit" or **"circulation pit"** means a pit located either on-site or off-site which is used in conjunction with a drilling rig for the handling, storage, or disposal of drilling fluids and/or cuttings.

"Reservoir" See "common source of supply".

"Reservoir pressure" means the static or stabilized pressure in pounds per square inch existing at the face of the formation of an oil or gas well.

"Reuse" is the introduction (or reintroduction) into an industrial, manufacturing, or disposal process of a material which would otherwise be classified as a deleterious substance. A material will be considered "used or reused" if it is either:

(A) Employed as an ingredient (including use as an intermediate) in an industrial, manufacturing, or disposal process to make or recover a product.

(B) Employed in a particular function or application as an effective substitute for a commercial product or non-deleterious substance.

"Rotating head" means a rotating, pressure sealing device used in drilling operations utilizing air, gas, foam, or any other drilling fluid whose hydrostatic pressure is less than the formation pressure.

"Secretary" means the duly appointed and qualified Secretary of the Commission or any person appointed by the Commission to act as such Secretary during the absence of the Secretary, his inability, or disqualification to act.

"Separator" means any apparatus for separating oil, gas, and water as they are produced from a well at the surface.

"Seismic shot hole" shall mean any hole drilled to allow explosive charges to provide an energy source for seismic exploration.

“Slick spot” means a small area of soil having a puddled, crusted, or smooth surface and an excess of exchangeable sodium. The soil is generally silty or clayey, is slippery when wet, and is low in productivity.

"Sodium Adsorption Ratio (SAR)" means the index which indicates the relative abundance of sodium ions in solution as compared to the combined concentration of calcium and magnesium ions. It is calculated as follows:

$$\text{SAR} = \frac{(\text{Na ppm}/23.0)}{\text{sq. root of } [\ \{(\text{Ca ppm}/20.02) + (\text{Mg ppm}/12.16)\}\ /\ 2]}$$

where Na=Sodium
Ca=Calcium

Mg=Magnesium

"Soil farming" means the application of oilfield drilling or produced wastes to the soil for the purpose of disposing of the waste without being a detriment to water or land; also known as land application.

"Spill containment pit" means a permanent pit which is used for the emergency storage of oil and/or saltwater spilled as a result of any equipment malfunction.

"Stratigraphic test hole" shall mean any hole drilled to obtain geological information which may lead to the discovery of hydrocarbons. Such wells are drilled without the intention of being completed for hydrocarbon production.

"Subnormal pressure" means the formation pore pressure, proportional to depth, which is less than a hydrostatic pressure gradient of .465 psi/ft.

"Sulfide stress cracking" means the cracking phenomenon which is the result of corrosive action of hydrogen sulfide on susceptible metals under stress.

"Surface casing" means the first casing string designed and run to protect the treatable water formations and/or control fluid or gas flow from the well.

"Tank bottoms" means the liquids and/or solids in a storage facility that are unsaleable to the crude oil first purchaser in its present form. Tank bottoms may consist of a combination of several elements including, but not limited to, crude oil, BS&W, and spent treating fluids.

"Treatable water" means, for purposes of setting surface casing and other casing strings, subsurface water in its natural state, useful or potentially useful for drinking water for human consumption, domestic livestock, irrigation, industrial, municipal, and recreational purposes, and which will support aquatic life, and contains less than 10,000 mg/liter total dissolved solids or less than 5,000 ppm chlorides. Treatable water includes, but is not limited to, fresh water.

"Trenching" means the practice of constructing trenches in or adjacent to a pit for the purpose of relocating all or a portion of the solids so as to facilitate closure.

"Ultimate destruction" means the treatment of a deleterious substance such that both its weight and volume remaining for disposal have been substantially reduced, and there is no demonstrated process or technology commercially available to further reduce its weight and volume and remove or reduce its harmful properties, if any. For the purposes of demonstrating a substantial reduction in weight and volume, any aqueous portion separated from the balance of a waste that meets drinking water standards or is evaporated into the ambient air shall count toward the weight and volume reduction.

"Underage" means the volume of allowable oil or gas not actually delivered to a carrier, transporter, or taker during any given proration period.

"Underground Source of Drinking Water (USDW)" means an aquifer or its portion which:

(A) Supplies any public water system; or

(B) Contains a sufficient quantity of ground water to supply a public water system; and

(i) Currently supplies drinking water for human consumption; or

(ii) Contains fewer than 10,000 mg/l total dissolved solids; and

(C) Is not an exempted aquifer.

"Unit operations" means a unit consisting of a portion of a lease, a lease, or more than one lease or portions thereof which covers contiguous lands containing one or more common sources of supply which has been approved by Commission order as a unit for the purpose of unitized management, after notice and hearing.

"Vacuum" means pressure below the prevailing pressure of the atmosphere.

"Waste" means:

(A) As applied to the production of oil, in addition to its ordinary meaning, "shall include economic waste, underground waste, including water encroachment in the oil or gas bearing strata; the use of reservoir energy for oil producing purposes by means or methods that unreasonably interfere with obtaining from the common source of supply the largest ultimate recovery of oil; surface waste and waste incident to the production of oil in excess of transportation or marketing facilities or reasonable market demands." [52 O.S.A., 86.2]

(B) As applied to gas, in addition to its ordinary meaning, shall include economic waste; "the inefficient or wasteful utilization of gas in the operation of oil wells drilled to and producing from a common source of supply; the inefficient or wasteful utilization of gas in the operation of gas wells drilled to and producing from a common source of supply; the production of gas in such quantities or in such manner as unreasonably to reduce reservoir pressure or unreasonably to diminish the quantity of oil or gas that might be recovered from a common source of supply; the escape, directly or indirectly, of gas from oil wells producing from a common source of supply into the open air in excess of the amount necessary in the efficient drilling, completion or operation thereof; waste incident to the production of natural gas in excess of transportation and marketing facilities or reasonable market demand; the escape, blowing, or releasing, directly or indirectly, into the open air, of gas from well productive of gas only, drilled into any common source of supply, save only such as is necessary in the efficient drilling and completion thereof; and the unnecessary depletion or inefficient utilization of gas energy contained in a common source of supply." [52 O.S.A. §86.3]

(C) The use of gas for the manufacture of carbon black or similar products predominately carbon, except as specifically authorized by the Commission, shall constitute waste.

(D) The flaring of tail gas at gasoline, pressure maintenance, or recycling plants where a market is available.

"Waste oil" shall include, but not be limited to, crude oil or other hydrocarbons used or produced in the process of drilling for, developing, producing, or processing oil or gas from wells, oil retained on cuttings as a result of the use of oil-based drilling muds, or any residue from any oil storage facility on a producing lease or on a commercial disposal operation or pit. The term "waste oil" shall not include any refined hydrocarbons to which lead has been added.

"Waste oil residue" means that portion of waste oil remaining after treatment and after the saleable liquids and water have been extracted. Waste oil residue is a type of waste oil.

"Well log" or **"well record"** means a systematic, detailed and correct record of formations encountered in the drilling of a well.

[**Source:** Amended at 12 Ok Reg 2017, eff 7-1-95; Amended in Rule Making 97000002, eff 7-1-97; Amended in Rule Making 980000034, eff 7-1-99; Amended in Rule Making 200000002, eff 7-1-2000]

165:10-1-3. Scope of rules

All rules of general application in this Chapter promulgated to prevent waste, assure the greatest ultimate recovery from the reservoirs of this state, protect the correlative rights of all interests, and to prevent pollution shall be effective throughout the State of Oklahoma and be in force in all pools except as amended, modified, altered, or enlarged in specific individual pools by orders now in effect or hereafter issued by the Commission.

165:10-1-4. Citation effective date

(a) These rules shall be cited as OAC Title 165 Chapter 10 (OAC 165:10).
(b) The effective date of the rules of this Chapter is as set out below:
(1) Order No. 937 - Effective 06/16/15
(2) Order No. 1299 - Effective 08/20/17
(3) Order No. 1986 - Effective 01/05/22
(4) Order No. 6251 - Effective 04/12/33
(5) Order No. 6252 - Effective 04/15/33
(6) Order No. 6393 - Effective 07/19/33
(7) Order No. 6394 - Effective 07/20/33
(8) Order No. 7263 - Effective 04/10/34
(9) Order No. 8229 - Effective 10/31/33
(10) Order No. 17528 - Effective 01/24/45

(11) Order No. 19334 - Effective 10/24/46
(12) Order No. 29232 - Effective 10/06/54
(13) Order No. 30712 - Effective 09/09/55
(14) Order No. 44297 - Effective 04/01/61
(15) Order No. 47397 - Effective 12/01/61
(16) Order No. 53568 - Effective 12/08/63
(17) Order No. 53749 - Effective 01/03/64
(18) Order No. 62481 - Effective 05/11/66
(19) Order No. 62631 - Effective 06/01/66
(20) Order No. 63817 - Effective 10/04/66
(21) Order No. 64203 - Effective 11/10/66
(22) Order No. 64207 - Effective 12/01/66
(23) Order No. 65747 - Effective 05/05/67
(24) Order No. 66006 - Effective 06/08/67
(25) Order No. 66778 - Effective 09/05/67
(26) Order No. 67113 - Effective 10/09/67
(27) Order No. 67379 - Effective 11/06/67
(28) Order No. 69103 - Effective 06/01/68
(29) Order No. 69104 - Effective 06/01/68
(30) Order No. 69340 - Effective 07/01/68
(31) Order No. 70704 - Effective 01/03/69
(32) Order No. 75248 - Effective 07/01/69
(33) Order No. 77627 - Effective 01/01/70
(34) Order No. 78830 - Effective 01/01/70
(35) Order No. 78831 - Effective 01/01/70
(36) Order No. 79460 - Effective 04/01/70
(37) Order No. 79461 - Effective 04/01/70
(38) Order No. 80401 - Effective 06/01/70
(39) Order No. 80402 - Effective 06/01/70
(40) Order No. 81221 - Effective 08/01/70
(41) Order No. 81222 - Effective 08/01/70
(42) Order No. 83168 - Effective 01-01-71
(43) Order No. 84223 - Effective 04-01-71
(44) Order No. 84224 - Effective 04-01-71
(45) Order No. 84318 - Effective 03-29-71
(46) Order No. 85138 - Effective 06-01-71
(47) Order No. 85139 - Effective 06-01-71
(48) Order No. 87730 - Effective 01-01-72
(49) Order No. 87829 - Effective 01-01-72
(50) Order No. 93381 - Effective 10-05-72
(51) Order No. 93382 - Effective 10-05-72
(52) Order No. 94418 - Effective 01-01-73
(53) Order No. 96671 - Effective 04-01-73
(54) Order No. 87829 - Effective 01-01-72
(55) Order No. 94418 - Effective 01-01-73
(56) Order No. 102096 - Effective 01-01-74
(57) Order No. 109595 - Effective 01-01-75
(58) Order No. 117899 - Effective 03-01-76
(59) Order No. 128534 - Effective 03-01-77
(60) Order No. 128781 - Effective 03-01-77
(61) Order No. 138348 - Effective 03-01-78
(62) Order No. 151077 - Effective 03-23-79
(63) Order No. 161968 - Effective 01-03-80
(64) Order No. 164345 - Effective 03-17-80
(65) Order No. 164346 - Effective 02-14-80
(66) Order No. 164347 - Effective 02-14-80
(67) Order No. 165935 - Effective 04-01-80
(68) Order No. 185407 - Effective 03-09-81
(69) Order No. 185890 - Effective 03-16-81
(70) Order No. 187373 - Effective 04-02-81
(71) Order No. 211505 - Effective 03-30-82
(72) Order No. 228675 - Effective 01-01-83
(73) Order No. 230515 - Effective 01-01-83
(74) Order No. 230781 - Effective 01-01-83

(75) Order No. 246797 - Effective 01-01-84
(76) Order No. 250273 - Effective 01-01-84
(77) Order No. 250466 - Effective 01-01-84
(78) Order No. 260734 - Effective 07-01-84
(79) Order No. 290210 - Effective 01-09-86
(80) Order No. 292212 - Effective 02-10-86
(81) Order No. 299185 - Effective 06-12-86
(82) Order No. 302126 - Effective 10-08-86
(83) Order No. 303650 - Effective 10-02-86
(84) Order No. 304257 - Effective 10-16-86
(85) Order No. 305211 - Effective 11-07-86
(86) Order No. 311872 - Effective 05-06-87
(87) Order No. 312391 - Effective 05-14-87
(88) Order No. 310755 - Effective 06-01-87
(89) Order No. 313445 - Effective 06-12-87
(90) Order No. 313446 - Effective 07-09-87
(91) Order No. 313660 - Effective 06-17-87
(92) Order No. 313932 - Effective 06-25-87
(93) Order No. 314001 - Effective 06-27-87
(94) Order No. 313446 - Effective 07-09-87
(95) Order No. 315275 - Effective 08-19-87
(96) Order No. 320171 - Effective 12-21-87
(97) Order No. 320741 - Effective 01-08-88
(98) Order No. 320742 - Effective 01-08-88
(99) Order No. 321123 - Effective 01-21-88
(100) Order No. 323847 - Effective 05-01-88
(101) Order No. 325144 - Effective 05-02-88
(102) Order No. 326275 - Effective 06-27-88
(103) Order No. 326343 - Effective 06-01-88
(104) Order No. 326344 - Effective 06-01-88
(105) Order No. 327514 - Effective 07-01-88
(106) Order No. 327515 - Effective 07-01-88
(107) Order No. 329661 - Effective 08-26-88
(108) Order No. 329662 - Effective 08-26-88
(109) Order No. 329663 - Effective 08-26-88
(110) Order No. 334130 - Effective 01-04-89
(111) Order No. 337475 - Effective 03-31-89
(112) Order No. 337476 - Effective 03-31-89
(113) Order No. 339860 - Effective 05-07-89
(114) Order No. 341102 - Effective 08-25-89
(115) Order No. 341103 - Effective 08-14-89
(116) Order No. 346071 - Effective 03-29-90
(117) Order No. 346107 - Effective 03-30-90
(118) Order No. 355458 - Effective 03-20-91
(119) Order No. 355461 - Effective 03-20-91
(120) Order No. 355463 - Effective 03-20-91
(121) Order No. 355471 - Effective 03-21-91
(122) Order No. 364365 - Effective 06-25-92
(123) Order No. 364382 - Effective 06-25-92
(124) Order No. 368011 - Effective 05-23-93
(125) Order No. 372796 - Effective 06-25-93
(126) Order No. 381632 - Effective 07-11-94
(127) Order No. 381755 - Effective 07-11-94
(128) Order No. 387223 - Effective 10-20-94
(129) RM No. 950000023 - Effective 07-01-96
(130) RM No. 950000024 - Effective 07-01-96
(131) RM No. 950000025 - Effective 07-11-96
(132) RM No. 960000008 - Effective 07-01-96
(133) RM No. 960000009 - Effective 07-01-96
(134) RM No. 960000018 - Effective 10-15-96
(135) RM No. 970000002 - Effective 07-01-97
(136) RM No. 970000011 - Effective 07-01-98
(137) RM No. 970000025 - Effective 07-11-98
(138) RM No. 980000013 - Effective 07-15-98

(139) RM No. 980000016 Emergency, - Effective 03-30-98
(140) RM No. 980000017 Emergency, - Effective 03-30-98
(141) RM No. 980000020 Emergency, - Effective 01-05-99
(142) RM No. 980000033 - Effective 07-01-99
(143) RM No. 980000034 - Effective 07-01-99
(144) RM No. 980000035 - Effective 07-01-99
(145) RM No. 990000010 - Emergency, - Effective 12-28-99
(146) RM No. 200000002 - Effective 07-01-00
(147) RM No. 200000009 - Emergency, - Effective 11-02-00
(148) RM No. 200000009 - Permanent, - Effective 05-11-01
(149) RM No. 200100005 - Effective 07-01-01
(150) RM No. 200100006 - Effective 07-01-01
(151) RM No. 200100009 - Emergency, - Effective 01-14-02
(152) RM No. 200200017 - Effective 07-01-02

[**SOURCE:** Amended in Rule Making 980000033, eff 7-1-99; Amended in Rule Making 200200017, eff 7-1-02; Amended in Rule Making 200300001, eff 7-1-03]

165:10-1-5. Conservation Division [RESERVED]

165:10-1-6. Duties and authority of the Conservation Division

(a) It shall be the duty of the Conservation Division to administer and enforce the statutes of this State and the rules, regulations, and orders of the Commission relating to the conservation of oil and gas and the prevention of pollution in connection with the exploration, drilling, producing, transporting, purchasing, processing, and storage of oil and gas, and to administer and enforce the applicable provisions of the Natural Gas Policy Act of 1978.

(b) The Conservation Division shall have the right at all times to go upon and inspect any oil and gas properties, pipelines, tank farms, refineries, and other processing plants and pump stations for the purpose of making any investigations or tests to ascertain whether the rules, regulations, and orders of the Commission are being complied with, and shall report to the Commission any violation thereof.

(c) The Conservation Division may require the testing or retesting of any oil, gas, injection, or disposal well upon 48-hour notice. Until the test is completed or excused, no allowable will be assigned the well and the purchaser or taker of oil or gas from such well shall not run oil or gas until authorized by the Conservation Division.

(d) The Director of the Conservation Division may administratively reclassify a well according to the gas-oil ratio as specified in 165:10-13-2 if the retesting of a well pursuant to this Section as reported on Form 1029A indicates a change in the original gas-oil ratio. This administrative reclassification shall only be used for allowable or priority purposes pursuant to 165:10-17-12. The operator shall be notified in writing by the Conservation Division within 15 days of the effective date of any change in classification.

(e) If the operator of the well which has been reclassified objects to said reclassification, he may file a written objection with the Conservation Division within 15 days of receiving notice of the reclassification. At the same time that the objection is filed, the operator shall file an application and notice setting cause for hearing with the Court Clerk Commission. The notice shall be published one time at least 15 days prior to the hearing in a newspaper of general circulation published in Oklahoma County and in a newspaper of general circulation published in each county in which lands embraced in the application are located.

(f) The Conservation Division shall have access to all well records, wherever located. All companies, operators, drilling contractors, drillers, service companies, or other persons shall permit any authorized employee of the Commission to come upon any lease or property operated or controlled by them, and to inspect the records of wells; provided, that information so obtained

shall be confidential. Any person who attempts, by means of any threat or violence, to deter or prevent any authorized employee of the Commission from performing any duty hereunder shall be prosecuted to the fullest extent of the law.
(g) Upon request of the Conservation Division, service companies or other persons shall furnish and file reports and records showing gun perforating, hydraulic fracturing, cementing, shooting, chemical treatment, and all other service operations on any well.

[**SOURCE:** Amended at 9 Ok Reg 2337, eff 6-25-92]

165:10-1-7. Prescribed forms
(a) Required Conservation Division forms may be submitted to the Commission on forms supplied by the Commission or on xerographic copies of Commission forms or by operator computer generated forms. Operator computer generated forms will be printed from Commission designed files made available to operators via the electronic Bulletin Board Service (BBS), Internet (World Wide Web) or magnetic disk. Operator computer generated forms must contain the exact language and wording of Commission forms. Any alteration of Commission forms language and wording may subject the signature party and/or operator to perjury charges.
(b) The following Conservation Division forms are prescribed for filing purposes:

(1) **Form 1000 - Notice of Intention to Drill application:** Operator shall file Form 1000 before any oil, gas, injection, disposal, or service well is drilled, recompleted, or re-entered. Such notice shall include the name(s) and address(es) of the surface owner(s) of the land upon which the well is to be located. The Commission shall process the application and, if approved, return a computer-generated permit to the operator. The Commission shall mail a copy of the permit to drill or re-enter to the land owner(s). Upon approval, the operator will have six months to commence the permitted operations. A six month extension may be granted without fee providing the Conservation Division staff determines that no material change of condition has occurred, if written request for such extension is received from the operator prior to the expiration of the original permit. Only one extension may be granted. A copy of the approved permit shall be posted at the well site. [Reference 165:10-3-1 and 165:10-1-25]

(2) **Form 1000A - Request for Reserve Pit Requirements:** The operator shall file Form 1000A in duplicate for information before any noncommercial pit is constructed. The Commission shall indicate the necessary liner requirements, if any, and return to the operator. [Reference 165:10-7-16]

(3) **Form 1000B - Application to Drill Deep Anode Groundbeds:** Form 1000B is required to be filed for wells drilled for deep anode groundbeds as required by OAC 165:10-7-14. The purpose of Commission Form 1000B is to ensure groundwater is being protected in construction of the deep anode groundbed. [Reference 165:10-7-14]

(4) **Form 1000S - Application to Drill Seismograph and Stratigraphic Test Holes:** The applicant must post a $50,000 bond with the Surety Department in the Oil and Gas Conservation Division. The application must also be accompanied with a plat of the project area. [Reference 165:10-7-31]

(5) **Form 1001 - Notification of Intention to Plug:** Operator shall file notice on Form 1001, in duplicate, five days prior to plugging operations and shall notify the appropriate Commission District Office before work is started. If the well is an exhausted producer, list OTC assigned county and lease number. If the Intent to Plug is cancelled, the operator shall notify the Commission by letter. The operator of each offset producing lease shall be notified prior to the plugging of any well other than a dry hole. [Reference 165:10-11-4, 165:10-11-5, and 165:10-11-6]

(6) **Form 1001A - Notification of Spudding of New Well:** Form 1001A is mailed to the operator with the intent to drill permit. Operator shall file with the Conservation Division within 14 days of spudding a new well or reentering a previously plugged well. [Reference 165:10-3-1]

(7) **Form 1002A - Well completion report:** Operator shall furnish a complete well record on Form 1002A within 30 days after completion of operations to

drill, recomplete, re-enter, or convert to injection or disposal well. Effective for both dry hole and/or producer. If well is an oil or gas producer, list OTC assigned county and lease number. Gas-oil ratio must be shown when Form 1002A is filed. List on a 24-hour basis both oil and gas. [Reference 165:10-3-25]

(A) **Oil well:** GOR less than 15,000:1

(B) **Gas well:** GOR 15,000:1 or more

(8) **Form 1002B - Confidential Filing of Electric Logs:** Operator shall file Form 1002B within 60 days of the running of the last formation evaluation type wire line log to hold logs confidential for one year period. Optional extension for six months may be requested by operator in writing to the Technical Department of the Conservation Division. [Reference 165:10-3-26]

(9) **Form 1002C - Cementing Report to accompany Well Completion Report:** Operator shall file Form 1002C with the Well Completion Report (Form 1002A) describing all cementing operations on surface, intermediate, and production casing strings, including multistage cementing jobs. The form shall be completed and signed by employees of both the operator and the cementing company. [Reference 165:10-3-4(h)]

(10) **Form 1003 - Plugging Record:** Operator will file Form 1003, in duplicate, within 30 days after plugging operations are completed. Both copies are to be mailed to the applicable Commission District Office. If a depleted producer, list OTC assigned county and lease number. [Reference 165:10-11-6 and 165:10-11-7]

(11) **Form 1003A - Notice of Temporary Exemption from Well Plugging**: Form 1003A shall be filed with the appropriate District Office. [Reference 165:10-11-3]

(12) **Form 1003C - Cementing Report to accompany Plugging Record:** operator shall file Form 1003/1003C when well has been plugged. Form 1003/1003C shall be completed and signed by employees of both the operator and the cementing company. [Reference 165:10-11-6 and 165:10-11-7]

(13) **Form 1004 - Monthly Report of Unallocated Natural Gas Wells Production:** Each operator of the required meter under 165:10-17-5 shall make a monthly well on Form 1004 report with the Commission of all natural gas volumes transferred through the meter for the preceding month, by the last day of the month following such transfer. List formation name plus OTC assigned county and lease number. If more than one meter, the operator of each shall file this form. [Reference 165:10-1-47]

(14) **Form 1004B - Notice of Gas Purchase Curtailments:** In any month wherein a first purchaser or first taker has a market demand/supply imbalance and must curtail purchases or takes in compliance with 165:10-17-12, Form 1004B shall be filed by said first purchaser or first taker with the Conservation Division. [Reference 165:10-17-12]

(15) **Form 1005 - Monthly Report of Purchasers** (Gas: subject to field rules): [Reference 165:10-1-47 and 165:10-15-1]

(A) **GAS:** Each operator of the required meter or meters under 165:10-17-5 shall complete computer-generated Form 1005, and return a copy to the Conservation Division indicating the gas amounts transferred through the meter for the preceding month on allocated and special allocated gas wells.

(B) **OIL:** Each first purchaser, or first taker of oil from wells and projects which are capable of producing in excess of their maximum assigned allowables, must complete computer-generated Form 1005 and return a copy to the Conservation Division indicating the amount of oil taken from each well or unit for the preceding month.

(16) **Form 1006 - Surety bond for oil, gas, injection, or disposal wells**: Prior to drilling and/or operating a well, the operator shall furnish the Conservation Division a surety bond ($25,000.00) or other present alternate surety, Form 1006A or 1006C. Operator must file the original copy only with a copy of the power of attorney from the bonding company. The name and address of the Oklahoma resident service agent shall be endorsed on the bond form. [Reference 165:10-1-12]

(17) **Form 1006A - Financial Statement for oil, gas, injection or disposal wells**: Prior to drilling and/or operating a well, the operator shall furnish the Conservation Division a verifiable financial statement (minimum net worth $50,000.00 within the State of Oklahoma) or other present

alternate surety, Form 1006 or 1006C. Operator must file an original copy on Form 1006A, which must be updated annually from the last filing date. [Reference 165:10-1-11]

(18) **Form 1006B - Operator Agreement to plug oil, gas, and service wells within the State of Oklahoma:** Operator shall agree to plug well(s) in compliance with the Commission rules. This agreement must accompany the operator's elective choice of surety (Form 1006, 1006A, or 1006C). The operator is required to file a Form 1006B with the Conservation Division once every twelve (12) months. [Reference 165:10-1-10, 165:10-1-11, 165:10-1-12, 165:10-1-13, and 165:10-1-14]

(19) **Form 1006BR – Recycling, Reclaiming Operator's Agreement to Close the Reclaiming Facility:** Prior to operating a recycling or reclaiming facility the operator shall file an agreement to close the facility in compliance with OCC rules. This agreement must accompany the application for certification (Form 1020A). [Reference 165:10-8-1 and/or 165:10-8-2]

(20) **Form 1006C - Irrevocable commercial letter of credit:** Prior to drilling and/or operating a well, the operator shall furnish the Conservation Division an irrevocable commercial letter of credit ($25,000.00) or other present alternate surety, Form 1006A or 1006. Operator must file the original copy with the bank seal affixed. A letter of credit must be valid for at least a one year period. [Reference 165:10-1-13]

(21) **Form 1006SB - Surety bond for seismic shot hole plugging within the State of Oklahoma:** Before commencing any seismic operation that requires the drilling of shot holes, those companies actually doing the work in the field must secure a bond in the amount of $50,000.00. Seismic companies must file the original Form 1006B only with a copy of the power of attorney from the bonding company. The name and address of the Oklahoma resident service agent shall be endorsed on the bond form. Form 1006S shall be filed with the bond. [Reference 165:10-11-6]

(22) **Form 1007A - IBM operator annual unallocated natural gas wells survey:** Annual Survey Form 1007A will be furnished to all operators at the end of each calendar year in duplicate. The form shall be updated by the operator as of December 31 notifying the Commission of any new wells, wells sold (to whom and address), or abandoned since the last 1007A was filed. Original only shall be forwarded to Conservation Division by February 15th for the previous year's activity. List OTC assigned county and lease number (if not imprinted). See 165:10-17-11 for production penalties on overproduced wells. [Reference 165:10-17-1 and 165:10-17-16]

(23) **Form 1008S - Operators agreement to plug seismic shot holes with the State of Oklahoma:** Before commencing any seismic operation that requires the drilling of shot holes, those companies actually doing the work in the field shall be duly registered with the Conservation Division on Form 1006SB. [Reference 165:10-11-6]

(24) **Form 1010 - Application for Cancelled Underage:** Operator shall file, within 30 days for oil, and six months for special allocated and allocated gas from the date of cancellation, to reinstate cancelled underage; stating reason for this request and notifying all offset operators. List OTC assigned county and lease number. [Reference 165:10-15-5]

(25) **Form 1012 - Annual Fluid Injection Report:** Operators shall file Form 1012 by April 1 of each year covering the previous calendar year (January 1 through December 31) on all enhanced recovery projects, pressure maintenance projects, and salt water disposal wells (commercial disposal wells will report twice per year on January 31 and July 31 for the previous six months) for each UIC well. The completed form will list well identification including API number, the Commission order number, injection volume and pressure, etc., as required on the form. No UIC well is to be operated for injection or disposal unless the Form 1012 is filed by the above dates. [Reference 165:10-5-7].

(26) **Form 1013 - Application for adjusting an allowable for an Excessive Water Exemption or Reservoir Dewatering Oil Spacing unit:** An operator in an unallocated oil pool may be permitted to produce at a full capacity allowable rate, provided that the water- oil ratio at the well is greater than or equal to 3:1 as in excessive water exemption. To qualify for the

reservoir dewatering oil spacing unit allowable shown on Appendix J, the operator must provide data to show that the water - oil ratio is greater than 1:1 [Reference 165:10-15-1, 165:10-15-16, 165:10-15-17 and 165:10-15-18].

(27) **Form 1014 - Application for Permit to Use Earthen Pit:** The operator of a proposed off-site reserve pit, recycling/reuse pit, spill containment pit, or remediation pit must submit Form 1014 in duplicate to the appropriate District Office for approval before constructing or using the pit. [Reference 165:10-7-16]

(28) **Form 1014CS - Application for Commercial Soil Farming:** For a commercial soil farming site which has an order to operate, the operator shall submit a Form 1014CS to the Pollution Abatement Department for prior approval each time that soil farming is proposed to be done. The application must be processed within ten (10) days of submission. [Reference 165:10-9-2]

(29) **Form 1014D - Application for Surface Discharge:** Each application for surface discharge of produced water must be submitted to a Field Operations office on Form 1014D in quadruplicate. Applications will be processed within five working days. [Reference 165:10-7-17 or 165:10-7-32]

(30) **Form 1014HD - Application for Disposal of Hydrostatic Test Water:** Company wishing to discharge water as required by OAC 165:10-7-17, used to test a pipeline or tank, must submit a Form 1014HD to the Pollution Abatement Department for prior approval. [Reference 165:10-7-17]

(31) **Form 1014L - Surface Owner Permission for Land Application:** Each application for land application must include an original Form 1014L, whereby the applicable surface owner gives permission for the applicant to land apply certain deleterious substances to a specific property. [Reference 165:10-7-19 and 165:10-7-26]

(32) **Form 1014N - Application for Commercial Pit Construction:** After a Commission order is obtained, Form 1014N must be submitted for approval by the Manager of Pollution Abatement prior to the construction of each commercial pit authorized by the order. [Reference 165:10-9-1]

(33) **Form 1014S - Application for Land Application:** Each application for land application of materials must be submitted to a Field Operations office on Form 1014S. An original and three copies are required. The applicant must be the operator of the well or other operator responsible for generating the waste to be land applied, except that a commercial pit operator may also apply in case of emergency or for the purpose of facilitating repair or closure, and the Oklahoma Energy Resources Board or its contractor may apply in cases where there is no responsible party. The Form 1014S shall be processed within five working days of submission of all required or requested information. [Reference 165:10-7-19 and 165:10-7-26]

(34) **Form 1014W - Application for waste oil or drill cuttings use by County Commissioners:** Application to apply waste oil, waste oil residue, or freshwater drill cuttings must be made by any Board of County Commissioners on Form 1014W. An original and one copy are required to be submitted to the appropriate District Manager. [Reference 165:10-7-22 and 165:10-7-28]

(35) **Form 1014X - Application for waste oil or drill cuttings use by operators:** Application to apply waste oil, waste oil residue, or freshwater drill cuttings must be made by any operator on Form 1014X. An original and one copy are required to be submitted to the appropriate District Manager. [Reference 165:10-7-27 and 165:10-7-29]

(36) **Form 1015 - Application for Administrative Approval to Dispose of or Inject Water into Well(s):** Applicant shall file an original and six copies of application and one complete set of attachments to the Commission on Form 1015. Applicant will also furnish one copy of the application on Form 1015 to the landowner and a copy of the application to each operator of a producing leasehold within one-half (1/2) mile of the well location. Applicant will submit an affidavit of delivery or mailing not later than five days after the application is filed and shall file proof of publication in an Oklahoma City newspaper and a county newspaper in which the well is located. [Reference 165:10-5-5]

(37) **Form 1015SI - Application for Permit for Simultaneous Injection Well:** Operator shall file original and three copies with the Underground Injection

Control Department on Form 1015SI. A copy of the form will also be supplied to the operator of any producing lease within (1/2) mile of the proposed injection well. [Reference 165:10-5-15]

(38) **Form 1015T - Application for Injection of Reserve Pit Fluids:** Each application for the on-site injection of reserve pit fluids (i.e., drilling mud fluids or fracture fluids) used in drilling or well completion shall be filed with the Underground Injection Control Department by the well operator on Form 1015T. The original and three copies of the application and one complete set of attachments shall be furnished to the Underground Injection Control Department. A copy of the application will also be supplied to the land owner and the operator of any producing lease within 1/2 mile of the proposed well. [Reference 165:10-5-13]

(39) **Form 1015U - Unit-wide application for Injection:** Optionally, the operator can file a unit-wide application for injection (Form 1015U) that fulfills all the requirements of 165:5-7-27 (b) through (e). Upon review and approval, the operator receives a unit-wide order that allows the operator to file an individual well application (Form 1015) and if it fits the unit-wide criteria, the UIC order can be issued immediately without an additional area of review, notice, or protest period. [Reference 165:5-7-27]

(40) **Form 1016 - Back Pressure Test for Natural Gas Wells:** Operators and/or purchasers, on the Form 1016, will report all single-point and four-point potential tests as required by pool rule orders or general rules. List OTC assigned county and lease numbers and special allocated pool numbers, first date of sales, and complete flow data. [Reference 165:10-17-6 and 165:10-17-7]

(41) **Form 1017 - Guymon-Hugoton Field Gas Well Deliverability Tests:** Operators and/or purchasers of gas in this field shall take deliverability tests between January 1 and August 31 of each year, and on the test sheet Form 1017 file the results with the Commission. List OTC assigned lease number for each well. [Reference Orders No. 17867 and 87291]

(42) **Form 1019 - Guymon-Hugoton Field Acreage Statement for Gas Wells:** A fact statement as to acreage attributable to each well shall be filed with the Commission on Form 1019 within 30 days of the well completion with a plat or map showing location of the well. List OTC assigned county and lease number. [Reference Order No. 17867]

(43) **Form 1020A - Application for Certification for the Recycling, Reuse of Deleterious Substances:** Applicant shall file an original Form 1020A with necessary attachments with the Pollution Abatement Department. Form 1020A is filed prior to construction of facility or change of operator. [Reference 165:10-8-1 and/or 165:10-8-2]

(44) **Form 1021 - Application for Priority Hardship Classification:** The applicant shall file Form 1021 and the necessary attachments with the Technical Department for review prior to any hearing for priority one hardship classification. In addition, a formal application for hearing must be filed with the Court Clerk's Office of the Commission. [Reference 165:10-17-12]

(45) **Form 1021A - Application for limited deviation from the priority gas rules:** The applicant shall file Form 1021A and the necessary attachments with the Technical Department for review prior to any hearing for deviation from the priority gas rules. In addition, a formal application for hearing must be filed with the Court Clerk's Office of the Commission. [Reference 165:10-17-12]

(46) **Form 1022 - Application to flare or vent gas:** Operator shall file one copy of Form 1022 to the Technical Department of the Conservation Division listing OTC assigned county lease number. [Reference 165:10-3-15]

(47) **Form 1022A - Application to operate vacuum pump:** Operator shall file one copy of Form 1022A with the required attachments to the Technical Department of the Conservation Division. No filing fee will be required for application to operate a vacuum pump. Notice requirements as set out in OAC 165:5-7-25 shall apply. [Reference 165:10-3-31]

(48) **Form 1023 - Application for multiple completion, multichoke assembly or commingle completion:** Operator will file the original and four copies

of Form 1023 with the required attachments. List OTC assigned county and lease number. [Reference 165:10-3-35; 165:10-3-39; 165:10-3-37]

(49) **Form 1024 - Packer setting affidavit:** Operator will submit Form 1024 as required. [Reference 165:10-3-35 and pertinent field rules]

(50) **Form 1025 - Packer leakage test:** Operator will submit Form 1025 as required. [Reference 165:10-3-35 and pertinent field rules]

(51) **Form 1027 - Bottom hole pressure test:** Operator, on the pink sheet of Form 1027, shall take BHP tests in the manner and during periods prescribed by special field rules. List OTC assigned county and lease numbers. [Reference Special Field Rules and 165:10-13-3]

(52) **Form 1028 - Application for discovery oil allowable:** Operator shall file Form 1028 with the required exhibits and tests within 30 days of completion of each new well in a discovery oil pool. [Reference 165:10-15-7]

(53) **Form 1029A - Production or potential test - oil only:** Operator of each newly completed oil well shall file a potential test Form 1029A not later than 30 days after completion of the well. All tests, if requested, shall be witnessed by another operator.

(54) **Form 1030 - Application for allowable adjustment:** Each operator or other interested parties desiring to adjust the allowable for a well or wells shall file Form 1030 for administrative review and approval. The allowable may be increased, decreased, or transferred as the evidence may indicate for the most efficient rate of production from the well or wells. [Reference 165:10-13-5, 165:10-13-8, 165:10-15-18 and 165:5-7-12]

(55) **Form 1034 - Nominations and purchasers report:** [Reference 165:10-1-49]

(A) **Oil:** Purchasers will furnish nomination data, actual runs from leases, stocks, and other information on Form 1034 to the Conservation Division not later than noon Friday of the week preceding each scheduled market demand hearing. On months in which no market demand hearing is held, Form 1034 shall be filed by the 20th of the month listing crude oil runs for the previous month on line 5 only. Any change in nominations from the previous hearing shall be so indicated on this monthly report.

(B) **Gas:** Purchasers shall file their nominations by letter for wells in special allocated pools no later than one week prior to the market demand hearing.

(56) **Form 1040 - Monthly allocation schedule (gas):** Monthly gas schedule Form 1040 will be forwarded to operators by the Conservation Division indicating the status of special allocated gas wells and their current allowables. Operators will inform the Conservation Division of errors, if any, found in Form 1040 as promptly as possible. Additionally, purchasers will receive the monthly schedule and shall return the production from each well as requested. [Reference 165:10-1-47]

(57) **Form 1062 - Field Operations Inspection Report:** IN-HOUSE USE ONLY.

(58) **Form 1070 - Inventory of authorized existing enhanced recovery wells:** Operators shall file reporting Form 1070 before injecting into any enhanced recovery well. [Reference 165:10-5-3]

(59) **Form 1071 - Inventory of authorized existing disposal wells:** Operators shall file the reporting Form 1071 before disposing into any disposal well. [Reference 165:10-5-3]

(60) **Form 1072 - Notice of (commencement) (termination) of injection:** Within 30 days of either the commencement or termination of injection Form 1072 must be filed. Failure to file Form 1072 within 18 months from the date of authorization results in termination of the Commission order. [Reference 165:10-5-7]

(61) **Form 1073 - Notice of transfer of well operatorship:** The new operator shall file Form 1073 to notify the Conservation Division of any change of operation or purchaser of any oil, gas injection, disposal, or enhanced recovery injection well within 30 days after transfer of the well. [Reference 165:10-5-10 and 165:10-1-15]

(62) **Form 1073I - Notice of transfer of well operatorship:** The new operator shall file Form 1073I to notify the Underground Injection Control Section of any change of operation of any injection, disposal, or enhanced

recovery injection well within 30 days after transfer of the well. [Reference 165:10-5-10 and 165:10-1-15]

(63) **Form 1075 - Mechanical integrity pressure test:** A pressure or monitoring test must be performed on new and existing enhanced recovery injection wells and disposal wells. Information must be submitted on Form 1075 and witnessed by a Field Inspector. Forms shall be submitted to the Conservation Division's Underground Injection Control Department. [Reference 165:10-5-6]

(64) **Form 1081 - Mineral owners escrow account:** Operator shall file, in quadruplicate, Form 1081 annually on anniversary date of first pooling order issued after effective date of Senate Bill 299 (7-1-84) and shall include all applicable orders issued during the twelve-month reporting period. [Reference 165:10-25-1 through 165:10-25-10]

(65) **Form 1085 - Complaint report:** Form 1085 is used by Commission personnel to report violations of General Rules of the Commission to report progress on ongoing remedial actions. Copies are sent to all parties concerned with investigation. Form 1085 combines and replaces old Forms 1034 and 1062. [Reference 165:10-7-7]

(66) **Form 1139 - Application for gross production tax exemption:** Operators shall file one copy of Form 1139 with the required attachments to the Technical Department of the Conservation Division. [Reference 165:10-21-75 through 165:10-21-80]

(67) **Form 1534 - Application for tax rebate:** Operators shall file one original of Form 1534 with the required attachments to the Technical Department of the Conservation Division. To obtain the tax exemption of the gross production tax, the operator shall forward a copy of the Commission order to the Oklahoma Tax Commission, together with any other data required by that agency. [OTC Rule 10.030.03] [Reference 165:10-21-23, 165:10-21-37, 165:10-21-47, 165:10-21-57, 165:10-21-67 and 165:10-21-82.2]

(68) **Form 1535 - Application for classification of reservoir dewatering project for exemption of sales tax on electricity used for such operations:** Operators shall file one original of Form 1535 with the required attachments to the Technical Department of the Conservation Division. To obtain the exemption of sales tax on the sale of electricity and associated delivery and transmission used for reservoir dewatering operations, the operator shall contact the Director's Office, Taxpayer Assistance Division, Oklahoma Tax Commission, 2501 N. Lincoln Blvd., Oklahoma City, Ok. 73194. [Reference 165:10-21-83, 165:10-21-83.1 and 165:10-21-83.2]

[**SOURCE:** Amended at 12 Ok Reg 2017, eff 7-1-95; Amended at 13 Ok Reg 2373 and 2381, eff 7-1-96; Amended in Rule Making 97000002, eff 7-1-97; Amended in Rule making 980000013, eff 7-15-98; Amended in Rule Making 980000033, eff 7-1-99; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200200017, eff 7-1-02; Amended in Rule Making 200300001, eff 7-1-03]

PART 3. SURETY

165:10-1-10. Operator's agreement; Category A and Category B surety

(a) "Any person who drills or operates any well for the exploration, development or production of oil or gas, or as an injection or disposal well, within this State, shall furnish in writing, on forms approved by the Corporation Commission, his agreement to drill, operate and plug wells in compliance with the rules and regulations of the Commission and the laws of this state, together with evidence of financial ability to comply with the requirements for plugging, closure of surface impoundments, removal of trash and equipment as established by the rules of the Commission and by law." [52 O.S. § 318.1] Any operator violating this Section shall be fined $500.00. To establish evidence of financial ability, the Commission shall require:

(1) Category A surety which shall include a financial statement listing assets and liabilities and including a general release that the information may be verified with banks and other financial institutions. The statement shall prove a net worth of not less than $50,000.00 in U.S. dollars; or

(2) Category B surety shall include an irrevocable commercial letter of credit, cash, a cashier's check, a certificate of deposit, bank joint custody receipt, other approved negotiable instrument, or a blanket surety bond. Except as provided in (3) of this subsection, the amount of such Category B surety shall be in the amount of $25,000.00 in U.S. dollars but may be set higher at the discretion of the Director of the Conservation Division. The Commission is authorized to establish Category B surety in an amount greater than $25,000.00 in U.S. dollars based upon the past performance of the operator and its insiders and affiliates regarding compliance with the laws of this state, and compliance with any rules promulgated thereto including but not limited to the drilling, operation and plugging of wells, closure of surface impoundments, or removal of trash and equipment. Any such Category B surety shall constitute an unconditional promise to pay and be in a form negotiable by the Commission.
(3) The Commission may grant Category B surety in an amount less than $25,000.00 in U.S. dollars to an operator whose statewide well plugging liability is less than $25,000.00 in U.S. dollars. Said Category B surety shall be in an amount that is sufficient to cover the total estimated cost of properly plugging and abandoning each and every well, the operations for which, an operator is responsible. Statewide well plugging liability shall be documented by an affidavit filed on Form 1006D and shall be properly executed by a duly licensed pipe pulling and well plugging company and shall be approved by the Conservation Division. Said affidavit shall state, among other things, an estimated cost of plugging, closure, and removal operations for each well in accordance with 165:10-11-3 through 165:10-11-8 inclusively and shall be accompanied by a Form 1000 (Intent to Drill) if the estimate involves a proposed well or by a Form 1002A (Completion Report) if the estimate involves a well that is a producing, injection, or disposal well. The estimated cost shall not include any salvage value as to recoverable casing, tubing, or well head equipment. The total statewide well plugging liability of an operator utilizing this Category B surety shall be kept current and shall be increased as additional wells are added to the responsibility of the operator and may be decreased as included wells are plugged and abandoned, but in no event shall exceed $25,000.00 in U.S. dollars unless otherwise ordered by the Commission.
(b) Operators of record as of June 7, 1989, who do not have any outstanding contempt citations or fines and whose insiders or affiliates have no outstanding contempt citations or fines may post Category A surety.
(1) New operators, operators who have outstanding fines or contempt citations and operators whose insiders or affiliates have outstanding contempt citations or fines as of June 7, 1989, shall be required to post Category B surety. Operators who have posted Category B surety and have operated under this type surety and have no outstanding fines at the end of three years may post Category A surety.
(2) Operators using Category A surety who are assessed a fine of $2,000.00 or more and who do not pay the fine within the specified time shall be required to post a Category B surety within 30 days of notification by the Commission.
(c) If a bond is required, the bond shall be executed by a corporate surety authorized to do business in this State and shall be renewed and continued in effect until the conditions have been met or release of the bond is authorized by the Commission.
(d) Irrespective of (a), (b), and (c) of this Section, for good cause shown concerning pollution or improper plugging of wells by an operator posting either Category A or Category B surety or by an insider or affiliate of such operator, the Commission, upon application of the Director of the Conservation Division after notice and hearing, may require the filing of additional Category B surety in an amount greater than $25,000.00 in U.S. dollars but not to exceed $100,000.00 in U.S. dollars.
(e) The agreement (Form 1006B-Operator’s Agreement to Plug Oil, Gas and Service Wells Within the State of Oklahoma) provided for in (a) of this Section shall provide that if the Commission determines, after notice and hearing, that the person furnishing the agreement has neglected, failed, or refused to plug and abandon, or cause to be plugged and abandoned, or replug any well or has neglected, failed or refused to close any surface impoundment or remove or cause to be removed trash and equipment in compliance with the rules of this Chapter,

then the person shall forfeit from his bond, letter of credit, or negotiable instrument or shall pay to this State, through the Commission for deposit in the State Treasury, a sum equal to the cost of plugging the well, closure of any surface impoundment, or removal of trash and equipment. The Commission may cause the remedial work to be done, issuing a warrant in payment of the cost thereof drawn against the monies accruing in the State Treasury from the forfeiture or payment. Any monies accruing in the State Treasury by reason of a determination that there has been a noncompliance with the provisions of the agreement (Form 1006B) or the rules and regulations of the Commission, in excess of the cost of remedial action ordered by the Commission, shall be credited to the Conservation Fund. The Commission shall also recover any costs arising from litigation to enforce this provision if the Commission prevails. Provided, before a person is required to forfeit or pay any monies to the State pursuant to this Section, the Commission shall notify the person at his last-known address of the determination of neglect, failure, or refusal to plug or replug any well, or close any surface impoundment, or remove trash and equipment, and said person shall have ten days from the date of notification within which to commence remedial operations. Failure to commence remedial operations shall result in forfeiture or payment as provided in this subsection. If the operator is a corporation, association, partnership, limited liability company or any entity other than an individual, the operator shall file as part of its Form 1006B a complete list, in tabular form, of the names, addresses, telephone numbers, social security numbers or driver license numbers, and percentages of ownership of all officers, directors, partners or principals of the operator and the insiders and affiliates of the operator. The operator shall also file as part of its Form 1006B the current names and addresses of all service agents of the operator and the operator's insiders and affiliates. The operator is required to file a Form 1006B with the Conservation Division every twelve (12) months.

(f) No person shall drill or operate any well, or receive an allowable, without complying with the provisions of this Section.

(g) The Commission shall shut in, without notice, hearing or order of the Commission, the wells of any such person violating the provisions of this Section and such wells shall remain shut in for noncompliance until the required evidence of Category B surety is obtained and verified by the Commission. No taker, transporter, or purchaser of oil or gas shall take, transport, or purchase oil or gas from the wells of any such drillers or operators after receiving a copy of the shut-in order or notice by certified mail of the issuance of such an order.

(h) If title to property or a well is transferred, the transferee shall furnish the evidence of financial ability to plug the well and close surface impoundments required by the provisions of this section, prior to the transfer.

(i) The following words, when used in this Section, shall have the following meaning:

(1) "Affiliate" means an entity which owns twenty percent (20%) or more of the operator, or an entity of which twenty percent (20%) or more is owned by the operator.

(2) "Insider" means officer, director, or person in control of the operator; general partners of or in the operator; general or limited partnership in which the operator is a general partner; spouse of an officer, director, or person in control of the operator; spouse of a general partner of or in the operator; corporation of which the operator is a director, officer, or person in control; affiliate, or insider of an affiliate as if such affiliate were the operator; or managing agent of the operator.

[SOURCE: Amended at 9 Ok Reg 2295, eff 6-25-92; Amended at 13 Ok Reg 2373, eff 7-1-96]

165:10-1-11. Financial statement as surety

(a) A plugging agreement shall be accompanied by surety. The surety requirement may be met by furnishing the operator's current financial statement (Form 1006A) to the Conservation Division, which shall be a full statement of

the operator's assets and liabilities and shall reflect the operator's total net worth of not less than $50,000.00 in U.S. dollars located in this State.
(b) The value of producing oil and gas leaseholds for which the financial statement stands as surety will be deducted from total net worth unless the financial statement is accompanied by the written appraisal of a recognized independent appraiser of oil and gas properties showing the fair market value of the leasehold interest owned by the operator.
(c) The Director of Conservation may require proof in the form of an appraisal or other proof of the fair market value of any asset listed in the financial statement, and the Director of Conservation may also require proof that the financial statement truly shows the net fair market value of all assets over and above all debts and encumbrances.
(d) A current financial statement shall be filed every twelve (12) months on Form 1006A.
(e) Only one operator's name shall appear on each Form 1006A.
(f) Along with the Form 1006A, an operator is required to file a Form 1006B (Operator's Agreement to Plug Oil, Gas and Service Wells Within the State of Oklahoma) with the Conservation Division.
(g) The Commission shall reject the operator's Form 1006A if the operator fails to file the documentation required by this Section with the Conservation Division.

[SOURCE: Amended at 13 Ok Reg 2373, eff 7-1-96]

165:10-1-12. Corporate surety bond
(a) An operator may file a blanket surety bond in the principal amount of $25,000.00 in U.S. dollars on Form 1006 as surety. In the alternative, the operator may file a surety bond of a lesser amount but that is sufficient to cover the total estimated cost of properly plugging and abandoning each and every well, the operations for which, the operator is responsible. Said estimated cost shall be documented on Form 1006D (Affidavit of Well Plugging Cost) for each and every well. Said alternative surety bond shall be increased upward, but not to exceed $25,000.00 in U.S. dollars, as additional wells are added to the operator's responsibilities, unless otherwise ordered by the Commission.
(b) For purposes of (a) of this Section, an operator may file a surety bond issued by a corporation authorized to issue such bonds in the State of Oklahoma.
(c) The Conservation Division shall not accept a bond unless the surety agrees to give the Conservation Division six months written notice before cancellation of a bond prior to expiration of the bond and evidence furnished of acceptable alternate surety if required.
(d) Only one operator's name shall appear on each Form 1006.
(e) Along with the Form 1006, an operator is required to file a Form 1006B (Operator's Agreement to Plug Oil, Gas and Service Wells Within the State of Oklahoma) with the Conservation Division.
(f) The Commission shall reject the operator's Form 1006 if the operator fails to file the documentation required by this Section with the Conservation Division.

[SOURCE: Amended at 13 Ok Reg 2373, eff 7-1-96]

165:10-1-13. Irrevocable commercial letter of credit
(a) At his option, an operator may file an irrevocable commercial letter of credit of a bank in the sum of $25,000.00 in U.S. dollars on Form 1006C as surety. In the alternative, the operator may file an irrevocable commercial letter of credit of a lesser amount but that is sufficient to cover the total estimated cost of properly plugging and abandoning each and every well, the operations for which, the operator is responsible. Said estimated cost shall be documented on Form 1006D (Affidavit of Well Plugging Cost) for each and every well. Said alternative irrevocable commercial letter of credit shall be

increased upward, but not to exceed $25,000.00 in U.S. dollars, as additional wells are added to the operator's responsibilities, unless otherwise ordered by the Commission.
(b) The letter of credit shall be for a term of not less than one year.
(c) The bank issuing the letter of credit shall endorse thereon that the letter of credit shall remain in effect until canceled or revoked by the bank or principal/operator upon six months notice in writing to the Conservation Division and evidence furnished of acceptable alternate surety if required.
(d) Only one operator's name shall appear on each Form 1006C.
(e) Along with the Form 1006C, an operator is required to file a Form 1006B (Operator's Agreement to Plug Oil, Gas and Service Wells Within the State of Oklahoma) with the Conservation Division.
(f) The Commission shall reject the operator's Form 1006C if the operator fails to file the documentation required by this Section with the Conservation Division.

[SOURCE: Amended at 13 Ok Reg 2373, eff 7-1-96]

165:10-1-14. Cashier's check, certificate of deposit, or other negotiable instrument
(a) An operator may deposit cash, a cashier's check, a certificate of deposit, bank joint custody receipt, or other negotiable instrument in the amount of $25,000.00 in U.S. dollars as surety. In the alternative, the operator may deposit cash, a cashier's check, a certificate of deposit, bank joint custody receipt, or other negotiable instrument of a lesser amount but that is sufficient to cover the total estimated cost of properly plugging and abandoning each and every well, the operations for which, the operator is responsible. Said estimated cost shall be documented on Form 1006D (Affidavit of Well Plugging Cost) for each and every well. Said alternate amount shall be increased upward, but not to exceed $25,000.00 in U.S. dollars, as additional wells are added to the operator's responsibilities, unless otherwise ordered by the Commission. However, any instrument must constitute an unconditional promise to pay and be in the form negotiable by the Commission.
(b) A certificate of deposit shall be for a term of no less than three hundred sixty-five (365) days.
(c) Financial institutions issuing certificates of deposit pursuant to this Section shall do so in the following manner: **"Oklahoma Corporation Commission or Oklahoma Corporation Commission and (Name of the Operator)."** Financial institutions issuing the certificates of deposit shall retain the original documents and copies of the certificates of deposit shall be furnished to the Commission.
(d) Along with the negotiable instruments described in (a) of this Section, an operator is required to file a Form 1006B (Operator's Agreement to Plug Oil, Gas and Service Wells Within the State of Oklahoma) with the Conservation Division.
(e) The Commission shall reject the negotiable instruments described in (a) of this Section if the operator fails to file the documentation required by this Section with the Conservation Division.

[SOURCE: Amended at 13 Ok Reg 2373, eff 7-1-96]

165:10-1-15. Transfer of operatorship of wells
(a) Before the operations of a well can be transferred to a new operator, the following must be submitted:
(1) The new operator, or transferee, must comply with 165:10-1-10 before a change in operator is approved.
(2) Change of operator Form 1073 must be signed by both the transferor and transferee, with both stipulating that the facts presented are true and correct as to the area covered and the wells being transferred. Unless otherwise stated, the new operator assumes all responsibility for the wells specified within the boundaries of the outlined area. For transfers

involving more than ten (10) wells, a transferor and transferee may file a single Form 1073 with the Conservation Division indicating the transfer of multiple wells, provided that such multiple well transfer shall be accompanied by a well list containing the following information regarding each well being transferred:

(A) API number of the well;

(B) Well name and number;

(C) Legal location of the well, described by section, township and range.

(3) The well list may be provided in spreadsheet form, if possible, and may be filed in digital format specified by the Conservation Division. In lieu of the spreadsheet, the transferor and transferee, at their option, may file one Form 1073 indicating the transfer of multiple wells with an OCC Form 1002A Completion Report attached for each well transferred. Upon review by the Conservation Division, it may require additional information from the transferor and/or the transferee to assist in identifying the specific well(s) being transferred. The additional information may include, but not be limited to, the quarter, quarter, quarter section calls, footages from the south and west quarter section lines, and the drilling and completion dates.

(4) The Conservation Division shall notify both the transferor and transferee of approval of the transfer of operatorship within thirty (30) days of the Conservation Division's approval of said transfer.

(5) Compliance with 165:5-7-11 when and if operatorship was designated by orders of the Commission in pooling, increased density, and location exception applications.

(b) Before the operatorship of a well can be transferred to a new operator when the current or former operator is unavailable for signature, one of the following may be submitted as proof of operatorship:

(1) A certified copy of a recorded lease or assignment transferring all rights, title, and interest to the wells described on Form 1073 to the new operator.

(2) A certified copy of a journal entry of judgment rendered by a district court of Oklahoma having jurisdiction over the wells described on Form 1073 vesting legal title to the new operator.

(3) A certified copy of bankruptcy proceeding by the federal district court having jurisdiction over the wells described on Form 1073.

(c) If an operator is not in compliance with an enforceable order of the Commission, the Conservation Division shall not approve any Form 1073 transferring well(s) to said operator until the operator complies with the order. The transferor of the well(s) listed on the Form 1073 remains responsible for the well(s) until any transfer is approved by the Commission.

[SOURCE: Amended at 13 Ok Reg 2373, eff 7-1-96; Amended in Rule Making 2000000002, eff 7-1-00]

165:10-1-16. Change of address

Each operator of a well or other facility subject to a permit shall give written notice of his change of address. Such notice shall be sent to the Director of the Conservation Division. It shall be due within 30 days after changing address.

[SOURCE: Amended at 9 Ok Reg 2295, eff 6-25-92; Amended at 13 Ok Reg 2373, eff 7-1-96]

PART 5. SPACING

165:10-1-20. Spacing [RESERVED]

165:10-1-21. General well spacing requirements

Any well drilled for oil or gas to an unspaced common source of supply 2,500 feet or more in depth shall be located not less than 330 feet from any property line or lease line, and shall be located not less than 600 feet from any other producible or drilling oil or gas well when drilling to the same common source of supply; provided and except that in drilling to an unspaced common source of supply that is less than 2,500 feet in depth, the well shall be located not less than 165 feet from any property line or lease line and not less than 300 feet from any other producible or drilling oil or gas well in the same common source of supply; provided, however, that the completed depth of the discovery well shall be recognized as the depth of the common source of supply for the purpose of this Section; provided further, when an exception to this Section is granted, the Commission may adjust the allowable or take such other action as it deems necessary for the prevention of waste and protection of correlative rights.

165:10-1-22. Drilling and spacing units

(a) The Commission may establish drilling and spacing units in any common source of supply as provided by law, and the special orders creating drilling and spacing units shall supersede the provisions of 165:10-1-21. It shall be the responsibility of any operator who proposes to drill a well to ascertain the existence and provisions of special spacing orders.
(b) The drilling of a well or wells into a common source of supply in an area covered by an application pending before the Commission seeking the establishment of drilling and spacing units is prohibited except by special order of the Commission. However, if an Intent to Drill (Form 1000) has been approved by the Commission and operations commenced prior to the filing of a spacing application, the operator shall be permitted to drill and complete the well without a special order of the Commission.
(c) Standard drilling and spacing units shall be either approximately square or rectangular; if rectangular, the drilling and spacing unit shall consist of two approximately square tracts.
(d) Standard square drilling and spacing units shall be those containing approximately 10, 40, 160, or 640 acres; standard rectangular units shall contain approximately 20, 80, or 320 acres.
(e) The drilling and spacing units within any common source of supply of oil or gas shall be of approximately uniform size and shape. In a combination reservoir, the drilling and spacing units within the oil portion of the reservoir shall be of approximately uniform size and shape, and the drilling and spacing units within the gas portion of the reservoir shall be of approximately uniform size and shape; provided, however, the drilling and spacing units within the gas portion of a combination reservoir along the gas-oil contact line or transition zone may be of nonuniform size and shape.

[**SOURCE:** Amended at 9 Ok Reg 2337, eff 6-25-92]

165:10-1-23. Extension of pool rules

(a) Any application to establish pool rules for a common source of supply shall include the entire common source of supply.
(b) To extend pool rules to a drilling and spacing unit, an application shall be filed and notice provided in the same manner as required to establish pool rules. In the event that more than one set of pool rules are in effect within a field, the Commission shall extend the appropriate pool rules consistent with available geological and engineering reservoir information.

165:10-1-24. Permitted well locations within standard drilling and spacing units

(a) The permitted well location within any standard square drilling and spacing unit shall be the center of the unit. The permitted well locations within standard rectangular drilling and spacing units shall be the centers of alternate square tracts constituting the units (alternate halves of the units);

provided, however, a well will be deemed drilled at the permitted location if drilled within the following tolerance areas:

(1) Not less than 165 feet from the boundary of any standard 10-acre drilling and spacing unit or the proper square 10-acre tract within any standard 20-acre drilling and spacing unit.

(2) Not less than 330 feet from the boundary of any standard 40-acre drilling and spacing unit or the proper square 40-acre tract within any standard 80-acre drilling and spacing unit.

(3) Not less than 660-feet from the boundary of any standard 160-acre drilling and spacing unit or the proper square 160-acre tract within any standard 320-acre drilling and spacing unit.

(4) Not less than 1320 feet from the boundary of any standard 640-acre drilling and spacing unit.

(b) The proper square tract of a rectangular drilling and spacing unit established prior to January 1, 1971, for which a slot drilling pattern was prescribed, shall be the northeast quarter and the southwest quarter of the governmental section, quarter section, or quarter quarter section containing two abutting rectangular drilling and spacing units; provided, slot patterns may be established or re-established upon application, notice, and hearing where consistent with available geological and engineering information when necessary to prevent waste or protect correlative rights.

(c) The permitted well location tolerance areas set out in (a) of this Section shall apply to each standard drilling and spacing unit heretofore or hereafter established, notwithstanding the provisions of any special order of the Commission prescribing a different permitted well location tolerance area; provided, however, this Section shall not affect any adjusted allowable or penalty applied to any well by special order of the Commission prior to the effective date of this Section, nor shall any well heretofore drilled within a then permitted tolerance area be deemed outside the permitted tolerance area by reason of this Section.

(d) Wells drilled offpattern without first obtaining an exception after notice and hearing by the Commission are hereby prohibited from producing either oil or gas.

(e) Whenever permission is granted to drill a well at a location other than specified in this Chapter, the allowable or production therefrom, or both, may be adjusted for the protection of the correlative rights of all persons entitled to share in the common source of supply.

(f) Unless the order granting a well location exception provides otherwise, the permission to drill the well at the excepted location shall expire twelve (12) months after the date of the order, unless a well was commenced at the excepted location on or before the expiration date. The order granting the well location exception will thereafter expire when the well is plugged, abandoned, or converted.

(g) An application for an emergency order granting a well location exception may be granted if the applicant has obtained the written consent of the operator of each adjoining or cornering tract of land or drilling and spacing unit, currently producing from the same formation, toward which the well location is proposed to be moved. Provided, however, if the applicant is the operator of the well in an adjoining or cornering tract of land or drilling and spacing unit, currently producing from the same formation, toward which the well location is proposed to be moved, the applicant shall obtain the written consent of each working interest owner in such well.

(1) Letters evidencing the written consent of off-set operators and working interest parties as described in this subsection shall be introduced and received into evidence at the time of the emergency hearing and reviewed. Copies of said letters shall be filed with the Court Clerk of the Commission.

(2) If the written consent described in this subsection cannot be obtained, the applicant may send written notice to said non-consenting party giving that party at least five days notice of the emergency hearing. If said non-consenting party fails to appear, then the emergency application shall be considered and may be granted without the non-consenting party's written consent. The applicant shall file an affidavit of mailing with the Court Clerk to prove the mailing of the five day notice.

(h) If a spacing application is currently pending and the applicant or any party who owns the right to drill needs to commence a well prior to issuance of the spacing order, the applicant or party shall obtain an emergency order to commence such well and an emergency location exception order if:

(1) The proposed well is offpattern according to the existing spacing for any formation involved, or

(2) The well is offpattern according to 165:10-1-21 governing well patterns for unspaced areas.

(i) Whenever an order permits an offpattern well, the order permitting said well may provide, at the request of a party of record in the cause, for said party to have the right, at his sole cost and risk, to attend and monitor the initial potential testing and all subsequent annual testing of the proposed offpattern well. If the order permits witnessing of tests as prescribed above, then the order shall further provide that at least five days prior to the initial potential testing and each subsequent annual testing of the proposed well, the operator of the well shall notify, in writing, all parties of record in the cause who requested to attend and monitor these tests of the date and time upon which said testing shall commence.

165:10-1-25. Replacement well

(a) Approval by the Conservation Division of a Notice of Intent to Drill (Form 1000) for a second well to be drilled in a common source of supply in a single drilling and spacing unit as a replacement well may be permitted when:

(1) The replacement well is to be drilled at a location permitted for the common source of supply by either an order or rule of the Commission; and

(2) The operator of the replacement well is either the operator or a working interest owner in the original unit well; and

(3) The Notice of Intent to Drill for the replacement well is accompanied by an affidavit from the operator, stating that on completion of the second well as a commercial producer, the common source of supply in the first well shall be plugged off immediately. The affidavit shall be attached to Notice of Intent to Drill.

(b) A replacement well shall not receive an allowable to produce oil or gas from the same common source of supply as the first well until:

(1) Said common source of supply in the original well in the drilling and spacing unit is plugged off; or

(2) The Commission issues an order authorizing the replacement well as an increased density well for said common source of supply; or

(3) The Commission issues an order reforming the drilling and spacing units in said common source of supply thereby placing the original well and the replacement well in different drilling and spacing units for the common source of supply.

165:10-1-26. Permitted producing well location within an enhanced recovery project

Any well drilled for or used for the production of oil or gas within any enhanced recovery project shall be located not less than 165 feet from the lease or project line, whichever is the outside boundary.

165:10-1-27. Increased density well

Upon application after notice and hearing, the Commission may issue an order permitting one or more additional wells within a drilling and spacing unit, if each additional well will prevent or assist in preventing the various types of waste prohibited by statute or if each additional well will protect or assist in protecting the correlative rights of interest owners in said common source of supply.

165:10-1-28. Geological correlation chart

The chart initially prepared by Phillips Petroleum and maintained by the Oklahoma City Geologic Society entitled "Geologic Section of Oklahoma and Northern Arkansas", along with ensuing revisions, shall be used as a guideline for stratigraphic nomenclature in all oil and gas conservation applications which are submitted to the Commission.

PART 7. MARKET DEMAND

165:10-1-35. Market demand [RESERVED]

165:10-1-36. Regulation, classification, and naming of pools

(a) When the Commission finds, upon notice and hearing, that oil or gas production from any source of supply exceeds the current market demand therefor or finds that the operation of the reservoir should be regulated in order to prevent waste, increase ultimate recovery, or protect correlative rights, the Commission shall thereupon promulgate appropriate pool rules to accomplish such objectives. Where any of the above findings are made by the Commission, the total production from the pool may be restricted and equitable allocation made to the various wells located therein, or the operation of the reservoir may be otherwise regulated and controlled to insure proper and adequate conservation.
(b) Any pool may be classified or reclassified by the Commission, upon hearing, as an oil pool, gas pool, combination pool, or condensate pool. All pool rules so promulgated shall be based on operating and technical data and shall be consistent with the characteristics attributable to each classification.
(c) All oil and gas pools in the State shall be named by the Commission.

165:10-1-37. Determination of market demand

(a) The Commission shall instruct the Director of Conservation to determine the reasonable market demand for oil, gas, and other hydrocarbon products produced in Oklahoma for consumption in and outside the State for the ensuing proration period(s) that can be produced from each common source of supply on a statewide basis without avoidable waste and with equitable participation in production and markets by all operators and other interested parties.
(b) Waste, in addition to its statutory and ordinary meaning, shall include but not be restricted to economic waste, underground waste, surface waste, and waste incident to the production of oil and gas in excess of the transportation or marketing facilities or reasonable market demand.
(c) Reasonable market demand shall include, but not be restricted to, the demand for oil, gas, and other hydrocarbons for reasonable current requirements for current consumption and use within and outside the State, with such adjustment as may be necessary upward or downward to maintain adequate aboveground stocks of crude oil and its products and underground stocks of natural gas, so as to provide a continuous supply of petroleum products to the consumer and essential strategic supplies for national defense.
(d) In determining the reasonable market demand, the Commission may consider:
  (1) Any statement communicated to the Commission by any purchaser or taker of oil and gas, stating the amount of oil or gas produced from common sources of supply that such purchaser or taker contemplates or intends to purchase during the period of time involved; or in lieu thereof, the capacity of the purchaser's transportation or marketing facilities which will be, during the time involved, available for transporting and/or marketing the oil or gas that may be produced from common sources of supply.
  (2) Official records, reports, and statistical information compiled and kept by the Conservation Division that can be utilized in determining reasonable market demand.
  (3) Reports, facts, and materials by the Bureau of Mines or any other recognized authority that impartially reflects reasonable market demand.

(4) Sworn or unsworn statements of interested parties and any other evidence which the Commission may deem relevant to the determination of reasonable market demand.

(e) For purposes of periodic market demand hearings, the Manager of Production and Proration for the Conservation Division shall prepare exhibits summarizing the nominations from the various interested parties specified in (d) in this Section. Said exhibits shall be available for public inspection not less than five days before the hearing. At the time of hearing, if no one announces any objection to the introduction of said exhibits, then the exhibits shall be admitted into evidence without need for sponsoring testimony.

(f) After the Commission has determined the amount of oil or gas to be produced from all oil and/or gas pools during the following proration period, the amount so determined will be allocated ratably and without discrimination among the various pools within the State.

PART 9. PURCHASERS AND TRANSPORTERS

165:10-1-45. Purchasers and transporters [RESERVED]

165:10-1-46. Reports of purchasers and/or transporters

Purchasers and/or transporters of oil, waste oil, or waste oil residue, including truckers, shall file reports with the Commission as follows:

(1) On or before the last day of the succeeding month, transporters shall file a report showing monthly takings by barrels from leases in all pools in the State, other than wells or leases as specified in (2), (3), (4), and (5) of this Section; a copy of the Gross Production Tax Report made to the Oklahoma Tax Commission will satisfy this requirement.

(2) A report on computer generated Form 1005 showing monthly takings by barrels from leases or wells with capacities greater than the maximum allowable determined by the appropriate rule governing the classification of the oil pool or order of the Commission. The report shall be filed on or before the last day of the succeeding month.

(3) Upon request, storage and nomination information shall be filed on Form 1034.

(4) All truck transporters hauling crude oil shall file a report showing the amount of all crude oil taken by them during the preceding proration period, and showing the source and the disposition of the crude oil, waste oil, or waste oil residue. The report shall be filed on or before the last day of the succeeding month.

(5) All truck transporters hauling crude shall provide their drivers with copies of standard run tickets which must be in the possession of the drivers at all times and which run tickets shall show the source and the disposition of crude oil, including but not limited to waste oil or waste oil residue.

165:10-1-47. Gas volume reports to Conservation Division

(a) On or before the last day of the succeeding month, the person responsible for operating the required meter under 165:10-17-5 for each well classified as an unallocated gas well for allowable purposes shall report to the Conservation Division on Form 1004 the amount of gas in MCF which passed through the meter on a monthly basis.

(b) If a well classified as a gas well for allowable purposes is subject to special pool rules other than the Guymon-Hugoton or South Guymon Fields, the Conservation Division shall mail Form 1005 (Monthly Allocated Schedule) to the operator of record for each such well(s) on or before the 15th day of each month. The operator of record shall, in turn, complete said form by listing the gas volume sold on a monthly basis in MCF by well and return a copy to the

Conservation Division on or before the last day of the month succeeding the sales.
(c) If a well classified as a gas well for allowable purposes is subject to the special pool rules for the Guymon-Hugoton or South Guymon Fields, the Conservation Division shall mail Form 1005 (Monthly Allocated Schedule) to the operator of record for each such well(s) on or before the tenth day of each month. The operator of record shall, in turn, complete said form by listing the gas volume sold, including gas bought by the landowner, on a monthly basis in MCF by well and return a copy to the Conservation Division on or before the 15th day of the month succeeding the sales.
(d) If there is a split connection at the well site, then the operator of record measuring gas volumes shall be responsible for reporting the total volume sold for each well.
(e) If a well classified as a gas well for allowable purposes is subject to special pool rules (including the Guymon-Hugoton Field), the Conservation Division shall mail Form 1040 to each operator on or before the tenth day of the second succeeding month following the custody transfer indicating the reported volume of gas taken from each well.
(f) If a well classified as a gas well for allowable purposes is subject to multiple gas purchase contracts or interest owners taking their gas in kind, the producing owner shall report and account to the well operator all volumes sold and the identity of all purchasers on or before the last day of the following month after sale of such gas. The operator(s) of the required meter(s) under 165:10-17-5 shall report and account to the well operator all volumes of gas measured by such meter(s) on or before the last day of the following month after measurement. Failure to comply with this subsection will result in such gas production being ordered shut-in.
(g) Failure of an operator to timely file sales volumes on Form 1005 shall result in a zero allowable being assigned to the operator's wells for the month in which the sales volumes would have been used in calculating the field allowable. Allocation factors for a pool shall not be recalculated as a result of the filing of a late Form 1005.

[**Source:** Amended at 12 Ok Reg 2017, eff 7-1-95]

165:10-1-48. Common purchaser and carrier rules
(a) 52 O.S., l961, Sections 54, 55, 56, and 240 are hereby adopted as common purchaser and common carrier rules as fully as if set out verbatim herein.
(b) No person shall purchase, take, or transport any oil or gas in excess of the allowable fixed by the Commission, or, when notified by the Conservation Division, such oil or gas being produced in violation of any rule, regulation, or order of the Commission; provided, this Section shall not require splitting a tank.

165:10-1-49. Filing of nominations
(a) All purchasers, buyers, and takers of crude oil in Oklahoma shall file their nominations for purchases of crude oil from wells in allocated pools, unallocated pools, and enhanced oil recovery pools with the Conservation Division on Form 1034-0 not later than noon Friday of the week preceding the regularly scheduled market demand hearing.
(b) All operators of natural gas wells in special allocated gas pools shall file their pool nominations on Form 1034-G not later than one week prior to the date of the market demand hearing.
(1) Nominations shall be restricted to the volume not to exceed the wellhead absolute open flow (WHAOF) times calendar days for each well in a pool. For wells in pools where the WHAOF is not utilized, the equivalent well deliverability or calculated rate of flow applicable to that particular pool may be used in lieu of the WHAOF. For wells exempt from testing, nominations shall be restricted to a volume not to exceed the well's minimum, double minimum, or special allowable time calendar days.

(2) Operators shall attach to Form 1034-G a listing of each of their special allocated wells by pool, OTC Lease Number, API Number, well name and number, and location as recorded on Form 1040, plus the applicable WHAOF, deliverability, or rate of flow value as determined by the appropriate well test for that time period. Wells exempt from testing shall be indicated as test-exempt on the list.

(3) Failure of an operator to properly file nominations on Form 1034-G shall result in a zero allowable being assigned to the operator's wells for the month in which the nominations would have been used in calculating the field allowable. Allocation factors for a pool shall not be recalculated as a result of the filing of a late Form 1034-G.

[**Source:** Amended at 12 Ok Reg 2017, eff 7-1-95]

SUBCHAPTER 3. DRILLING, DEVELOPING, AND PRODUCING

PART 1. DRILLING

Section

PART 3. COMPLETIONS

PART 5. OPERATIONS

PART 7. PRODUCTION

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PART 1. DRILLING

165:10-3-1. Required approval of notice of intent to drill, deepen, re-enter, or recomplete; Permit to Drill

(a) **Permit to Drill.**

(1) Except as provided in (1) of this Section, on temporary authorization to commence, the operator shall obtain for the well a Permit to Drill approved by the Conservation Division before:

(A) Spudding a well for the exploration for and production of oil or gas.

(B) Spudding a well for use as an injection, disposal, or service well.

(C) Re-entry into a plugged well.

(D) Recompletion of a well.

(2) A Permit to Drill shall be valid only for each common source of supply listed on the permit.

(3) Any operator who drills, deepens or reenters a well without a permit to drill shall be subject to a fine of $1,000.00.

(b) **Amended or additional Form 1000 requirements.**

(1) **When required.** If the Conservation Division has issued a Permit to Drill for a well, the operator of the well shall submit an amended Form 1000 for the well and obtain an amended Permit to Drill before:

(A) Completing the well in a common source of supply which is not listed on the current unexpired Permit to Drill for the well.

(B) Recompleting the well in a common source of supply which is not listed on the current unexpired Permit to Drill for the well.

(C) Installing less surface casing than the amount approved on the unexpired Permit to Drill for the well.

(D) Deviating from an alternative casing and cementing procedure which the Conservation Division approved on the unexpired Permit to Drill for the well.

(E) Completing a well in a common source of supply at a subsurface location which does not correspond with the surface location on the most recently issued Permit to Drill for the well.

(2) **Effect of amended or additional Permit to Drill on prior Permit to Drill.** Each approved, amended, or additional Permit to Drill for a well cancels any previously issued Permit to Drill for the well.

(c) **Expired or revoked Permit to Drill.** If a Permit to Drill for a well expires or is revoked, the operator shall be subject to the requirements of (a) of this Section.

(d) **Casing and cementing requirements.** Each Permit to Drill shall list the minimum amount of surface casing to be used or an approved alternative casing and cementing program under 165:10-3-4.

(e) **Spud report and well spacing requirements.** In addition to complying with the requirement of obtaining a Permit to Drill, the operator shall comply with the following:

(1) The spud report requirement of 165:10-3-2.

(2) Any well spacing requirements applicable by order or rule of the Commission. Well spacing requirements do not apply to injection or disposal wells.

(f) **Disposal of drilling fluids.**

(1) The operator shall indicate on Form 1000 the proposed method(s) for disposal of drilling fluids. These methods shall include, but not be limited to:

(A) Evaporation/dewatering and leveling of the reserve pit.

(B) Soil farming.

(C) Recycling.

(D) Commercial off-site earthen pit disposal.

(E) Annular injection.

(F) Hauling to a facility or location other than a commercial earthen pit.

(2) If the method in (1)(F) in this subsection is used, the operator shall provide the location to which the drilling fluids are to be hauled.

(3) Issuance of the Permit to Drill shall not be construed as constituting approval of the disposal method(s) indicated. An operator who desires to

dispose of drilling fluids through either evaporation/dewatering and leveling of the reserve pit, soil farming, commercial earthen pit disposal, or annular injection must comply with 165:10-7-16, 165:10-7-19 or 165:10-9-2, 165:10-9-1, or 165:10-5-13 respectively.

(4) If the proposed method for drilling fluid disposal is changed, the operator shall notify the appropriate District Office of the Conservation Division, either by telephone or in writing, within a reasonable time after the change. An amended Form 1000 for the well shall not be required for a change in disposal method.

(g) **Notice to surface owners.**

(1) The operator shall include on each Form 1000 submitted to the Conservation Division, the name and address of each surface owner of record for the wellsite.

(2) For each Permit to Drill other than a Permit to Drill for a recompletion, the Conservation Division shall mail by regular U.S. mail a copy of the Permit to Drill to each surface owner listed on the Form 1000.

(h) **Disapproval for noncompliance with Commission order.** If an operator is not in compliance with an enforceable order of the Commission, the Conservation Division shall not issue any Permit to Drill for the operator, until the operator complies with the order.

(i) **Erroneous approval.** Erroneous issuance of a Permit to Drill shall not excuse noncompliance with any order or rule of the Commission.

(j) **Expiration.**

(1) **Six-month period.** Except as provided in (2) of this subsection for expiration after submission of a completion report, a permit to drill shall expire six months from the date of issuance, unless drilling operations are commenced and thereafter continued with due diligence to completion.

(2) **Six-month extension.** A six month extension may be granted without fee providing the Conservation Division staff determines that no material change of condition has occurred, if written request for such extension is received from the operator prior to the expiration of the original permit. Only one extension may be granted.

(3) **If Form 1002A is filed.** If the operator of the well submits to the Conservation Division a Completion Report (Form 1002A) for the well, the Permit to Drill for the well shall expire on the date the Completion Report is approved by the Conservation Division.

(k) **Posting of Permit to Drill at the wellsite.** During any activity subject to this Section, the operator shall maintain at the wellsite an original or legible copy of the Permit to Drill for inspection by Commission personnel.

(l) **Temporary authorization without approval of a Permit to Drill.** In an emergency, the Manager of the Technical Services Department of the Conservation Division may temporarily authorize commencement of activities without a Permit to Drill for a period up to five working days.

(m) **Limits of authority.** A Permit to Drill does not grant the operator authority to produce, inject or dispose without the required permits or allowable assignment.

[**SOURCE:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended in Rule Making 980000033, eff 7-1-99]

165:10-3-2. Notification of spudding of new well

(a) Except as provided in (c) of this Section, the operator of a new well shall file with the Conservation Division a Notice of Spudding of New Well on Form 1001A within 14 days after spudding of the well.

(b) For the purposes of (a) of this Section, spudding of a new well refers to:

(1) The first boring of the hole in the drilling of a well for the production of oil and gas or for the use as an injection or disposal well.

(2) Reentry into a previously plugged well for purposes of producing oil and gas or for use as an injection or disposal well.

(c) Filing of a Notice of Spudding of a New Well on Form 1001A shall not apply to:

(1) Any workover operation to deepen, plug-back, or recomplete.

(2) An unplugged hole spudded before January 9, 1986.
(3) Recompletion attempts in an unplugged hole for which a Notice of Spudding of New Well has been filed.

165:10-3-3. Surface and production casing
(a) Owners, operators, and drilling contractors shall comply with 165:10-3-4 and 165:10-5-2.
(b) In the event a rupture, break, or opening occurs in the surface or production casing, the owner, operator, or drilling contractor shall take immediate action to repair it and shall report the occurrence to the appropriate District Office or the Manager of Pollution Abatement.
(c) Any operator who fails to timely report a rupture, break, or opening in the surface casing shall be fined $1,000.00, and the well shall be shut down until it is repaired or plugged.

[**SOURCE:** Amended at 9 Ok Reg 2295, eff 6-25-92]

165:10-3-4. Casing, cementing, wellhead equipment, and cementing reports
(a) **Scope.**
(1) This Section governs the following:
(A) Surface casing and cementing requirements.
(B) Alternate casing and cementing procedure used instead of adequate surface casing and cement.
(C) Minimum cementing and testing requirements for intermediate and production casing.
(D) Minimum valve and blowout preventer requirements.
(E) Cementing reports.
(2) This Section shall apply to the following:
(A) Wells drilled or reentered for the production of oil, gas or brine.
(B) Wells drilled or reentered for disposal of oilfield wastes.
(C) Wells drilled for enhanced recovery injection.
(D) Wells drilled in subsurface gas storage units created by order of the Commission.
(E) Other oilfield related service wells.
(b) **Effect on area rules.**
(1) If any area rules promulgated by order of the Commission require less casing and cement than required by this Section, then this Section shall supersede the area rules.
(2) If an applicable area rule promulgated by order of the Commission has more stringent casing and cementing requirements than what are required by this Section, the Conservation Division shall enforce the area rules.
(c) **Surface casing and cementing requirements for wells listed in (a)(2) of this Section:**
(1) **Minimum surface casing requirements.** Unless an alternate casing program is authorized by the Conservation Division or by an order of the Commission, suitable and sufficient surface casing shall be run and cemented from bottom to top with a minimum setting depth which is the greater of:
(A) Ninety feet below the surface, or
(B) Fifty feet below the base of treatable water.
(2) **Penalty for noncompliance.** An operator setting less than the required amount of surface casing or failing to remediate uncirculated cement before resuming operations shall be fined $5,000.00.
(3) **Exceptions to (c)(1).** Operators having wells producing hydrocarbons which were in compliance with the surface casing requirements at the time of completion shall not be required to comply with (1) of this subsection.
(4) **Well to be used for annular injection under 165:10-5-13.** If the operator intends to dispose of drilling or stimulation fluids by annular injection, then the operator shall comply with 165:10-5-13 which requires a surface casing string to be set not less than 200 feet below the base of treatable water, unless a Commission order provides otherwise.

(5) **Depth limitation on setting surface casing.** The well operator shall run and cement the surface casing string required by this subsection before drilling the well more than 250 feet below the base of treatable water, unless otherwise approved on the Permit to Drill.
(6) **Penalties.** Operators failing to obtain permission to drill a well more than 250 feet below the treatable water, or to obtain permission for an alternate casing and cementing procedure may be fined $2,500.00.
(7) **Cementing procedures.**
(A) **Approved methods.** Except as provided in (B) of this paragraph for bradenhead cementing, cement shall be run by either the tubing and pump method, the pump and plug method, or the displacement method.
(B) **Bradenhead cementing prohibited.** Bradenhead cementing is prohibited without written permission from the District Office of the Conservation Division.
(C) **Restrictions on stage cementing.**
(i) **Above 200 feet.** Running cement through small tubulars is permitted above 200 feet in depth without special permission.
(ii) **Below 200 feet.** Below 200 feet in depth, the operator shall obtain permission from the District Office of the Conservation Division before using small tubulars to run cement.
(D) **Steel casing required.** For purposes of the surface casing requirements of this Section, surface casing shall be oil field grade steel casing.
(E) **Witnessing of setting of surface casing.** The operator shall give at least 24 hours notice by telephone to the appropriate District Office or Field Inspector as to the time when surface casing will be run.
(F) **Minimum cement setup time.** The cement behind the surface casing shall set at least eight hours before further drilling.
(G) **Down-hole testing of surface casing and cement.** Before drilling the shoe of the surface casing, the operator shall test the surface casing using the procedure prescribed by (f) of this Section.
(H) **Failure to circulate cement or fall back of cement behind surface casing.**
(i) **Verifying the top of cement.** If no conductor string is set and the cement did not circulate to the surface or falls back more than five feet, the operator shall determine the top of the cement using a method approved by the District Manager or Field Inspector.
(ii) **Top of cement less than 200 feet from the surface.** If the top of the cement is found less than 200 feet from the surface, the operator may circulate cement to surface using small tubulars.
(iii) **Top of cement greater than 200 feet from the surface.** If a conductor string has been set and the cement has been found to be ten feet or more above the base of the conductor string, no corrective action is required. If no conductor string has been set and the top of the cement is greater than 200 feet from the surface, the operator shall perform a corrective cementing operation by circulating cement to the surface from a point 50 feet below the base of the treatable water or from the determined top of the cement, whichever is shallower. The District Manager or Field Inspector may grant permission to circulate cement through small tubulars.
(I) **Insufficient surface casing or mechanical failure.** Within 24 hours after discovery of a problem with the surface casing or cement, the operator shall notify the appropriate District Office of the Conservation Division by telephone of:
(i) Any mechanical failure of the surface casing or cement.
(ii) Discovery of a treatable water formation below the shoe of the surface casing.
(J) **Penalty.** An operator, failing to report a rupture, break, or opening in the surface casing, shall be fined $1,000.00 and the well shut down.
(K) **Notice.** The District Manager or Field Inspector shall be given at least 24 hours notice prior to any cementing operation in order that they may have the opportunity to witness.
(d) **Alternate casing and cementing procedures.**

(1) **Requirement of approval on the Permit to Drill.** Use of an alternative casing and cementing procedure instead of surface casing and cement required by (c) of this Section is prohibited without authorization on the Permit to Drill for the well.

(2) **Disapproval.** The Manager of Technical Department may not issue a permit for an alternate casing string and cementing procedure if one or more of the following conditions exist:

(A) The well will penetrate a known lost circulation zone.

(B) The treatable water bearing formation(s) will be endangered.

(C) The projected depth of the well is less than 100 feet from the top of any authorized secondary project or gas storage facility.

(3) **Applicability of other casing and cementing standards.** Alternate casing and cementing procedures under this subsection are subject to the provisions of (c)(7) of this Section.

(4) **Alternate casing and cementing procedure.**

(A) An operator having permission to run an alternate casing string may, for protection of the treatable water, drill the well to casing point and circulate cement to the surface, or circulate cement from a depth of 100 feet below the base of treatable water to the surface after following the procedures set out in (f) of this Section.

(B) Oil based drilling mud shall be prohibited.

(C) If a well is completed using an alternate casing and cementing procedure, a bond log covering the interval from 100 feet below the base of the treatable water to the surface shall be required. The District Manager may waive this requirement. A completion attempt, in cases where the protection of treatable water is questionable, is strictly prohibited.

(D) Unless extended by the District Manager, the operator shall have 72 hours after drilling and testing is completed to run production casing or plug the well. A minimum of 24 hours prior notice must be given to the appropriate District Office prior to cementing operations so that a Field Inspector may have the opportunity to witness the cementing or plugging procedures. If the well is plugged and abandoned, procedures set out in (e) of this Section shall be followed.

(E) In the event that casing is run and cement does not circulate to the surface, or falls back, the operator shall determine the top of the cement using a method approved by the District Manager.

(5) **Remedial actions.**

(A) If the top of the cement is less than 200 feet from the surface, the operator may circulate cement from that point to the surface using small tubulars or by perforating the casing at that point and circulating cement to the surface.

(B) If the top of the cement is greater in depth than 200 feet, the operator shall perforate the casing at the top of the cement and circulate cement to the surface, or with the written permission of the Field Inspector, use small tubulars.

(C) In the event that a conductor string had been set and the top of the cement is at least ten feet above the base of the conductor casing no remedial action is needed.

(D) Unless waived by the District Office, all corrective cementing operations shall be approved and witnessed by the Field Inspector.

(E) In wells where corrective actions were needed for casing or cementing problems, a completion attempt shall not be made without approval by the District Manager.

(e) **Permanent well marker.** In the event that the well is a dry hole and no casing has been run, then during the plugging of the well the operator shall run and cement from bottom to top at least one joint of casing at the surface not less than 25 feet in length for use as a permanent well marker. The casing used as a well marker shall be oil field grade steel casing with an outside diameter of at least seven inches. The top of the marker shall be three feet below the surface and be capped with a steel plate inscribed or embedded with the well number and date of plugging on the steel plate. An operator failing to run and cement the well marker as required shall be fined $1,000.00 and shall, under the supervision of the Commission, replug the well.

(f) **Minimum cement for additional casing strings.** If additional casing other than surface casing is run, except for temporary purposes, it shall be run, set, and cemented with a calculated volume of cement sufficient to fill the annular space behind the casing string from the base of the casing string to a minimum height which is the greater of five percent of the depth to which the casing string is set or a height of 200 feet. Wells approved for horizontal completion are exempt upon approval of the Conservation Division.
(g) **Pressure testing of casing strings.**
(1) Before drilling the cement plug in a casing string, the operator shall pressure test the installed casing for 30 minutes at a minimum pressure which is the lesser of the surface gauge pressure equal in pounds per square inch to 0.2 of the length of the casing in feet or 1500 psig.
(2) During the 30 minute test, if the surface pressure drops ten percent or more, the operator shall:
(A) Repair and retest the casing until the requirements of this subsection are met; or
(B) Plug the well according to the rules of this Chapter.
(h) **Minimum wellhead equipment for drilling wells.** Except in proven areas where less equipment is known to be adequate, every drilling well shall be equipped with a mastergate, or its equivalent, or an adequate blowout preventer. A flow line valve of proper size and working pressure shall be attached.
(i) **Cementing reports.**
(1) The operator of the well shall submit, attached to Form 1002A Completion Report, a Form 1002C Cementing Report describing all cementing operations on surface, intermediate, and production casing strings, including multistage cementing jobs.
(2) If additional cementing operations occur after submission of the Cementing Report, the operator shall submit an amended Form 1002C for the well.
(j) **Surface casing requirements for re-entry wells.** For a re-entry as defined by 165:10-1-2, casing and cementing requirements at the time of re-entry shall apply.
(k) **Surface casing requirement for recompletions.** For a recompletion as defined by 165:10-1-2, casing and cementing requirements applicable to wells commenced on the latter of the spud date or re-entry date for the well shall apply.
(l) **Casing and cementing requirements for wells converted for injection or disposal.** If a well is converted for use as an injection or disposal well, it shall be subject to the casing and cementing requirements of this Section effective at the time of conversion of the well.
(m) **Casing and cementing requirements for wells penetrating unitized common sources of supply.** Each newly drilled or re-entered well which penetrates a common source of supply in which enhanced recovery operations are being conducted shall be properly cased and cemented from not less than 100 feet below to not less than 100 feet above each unitized common source of supply to prevent migration of formation fluids and contain formation pressure. In the event the well is to be plugged without being cased, the well shall be properly cemented over the aforementioned interval(s) during plugging procedures.
(n) **Insufficient surface casing and cement.** When it has been determined that a treatable water-bearing formation has not been properly cased and cemented, the operator shall take such measures designated by the Director of Conservation or ordered by the Commission to protect any treatable water-bearing formation.

[**SOURCE:** Amended at 9 Ok Reg 2337, eff 6-25-92]

165:10-3-5. Underground storage

(a) **Scope.** This Section shall apply to all operations pertaining to the drilling, completion, recompletion, or remedial work on wells located within the boundaries of an underground storage facility as defined in (b)(4) of this Section.
(b) **Definitions.**

(1) "Underground storage" shall mean storage of natural gas in a subsurface stratum or formation of the earth.

(2) "Natural gas" shall mean gas either while in its natural state or after the same has been processed by removal therefrom of component parts not essential to its use for lights and fuel.

(3) "Storage operator" shall mean any person, firm, or corporation which operates an underground storage facility.

(4) "Underground storage facility" shall mean any subsurface stratum or formation of the earth used for underground storage. Provided that, in the case of a natural gas bearing subsurface stratum or formation, the commercially producible native gas shall have been substantially depleted and the gas therein shall not be used primarily for the secondary recovery of oil in paying quantities from the subsurface stratum or formation.

(5) "Well" means a well drilled or bored or to be drilled or bored within the boundaries of an underground storage facility.

(6) "Well operator" shall be the person, firm, or corporation that is the operator of a well.

(7) "Major remedial work" shall mean any workover operations requiring wire line or pump truck services.

(8) "Good quality cement" means that cement that would obtain a compressive strength to prevent oil, gas, or water migration within an eight (8) hour period.

(c) **Operational procedures.**

(1) Before spudding a well within the boundaries of a gas underground storage facility, the well operator shall mail a copy of the Permit to Drill to the storage operator at the address listed at the Commission. The storage operator will inform the well operator of the estimated depth, thickness, and pressure of the underground storage facility at that location. Failure of the storage operator to provide the data to the well operator shall not be a cause to delay drilling, but the well operator is required to notify the storage operator, by phone a minimum of 24 hours prior to commencing drilling operations at a 24 hour telephone number furnished to the Commission by the storage operator.

(2) A well operator shall comply with the provisions of 165:10-3-4(c). Alternate casing programs shall not be permitted.

(3) Drilling rigs shall be equipped with a blowout preventer. The preventer shall be installed and tested at least 500 psig above the anticipated underground storage facility pressure before drilling below the base of the surface casing.

(4) The storage operator shall receive drilling reports daily and shall be notified at a 24 hour telephone number furnished to the Commission by the storage operator in ample time to witness any tests or logging operations from the surface to 500 feet below the base of the underground storage facility. Any abnormal conditions occurring during the drilling operation, such as abnormal pressures and/or lost circulation, shall be reported immediately to the storage operator.

(5) The well operator shall drill the well in such a manner as to prevent invasion of drilling fluids into, or the escape of natural gas from, the underground storage facility. The well operator shall be required to mud up at least 100 feet above the anticipated depth of the underground storage facility.

(6) If run, a copy of either an open hole porosity or resistivity well log run from the base of surface casing to total depth shall be promptly forwarded to the storage operator. At the option of the well operator, the logs submitted to the storage operator may be terminated 500 feet below the base of the underground storage facility. The storage operator shall be given prior notice of logging operations of the underground storage facility interval and has the option of witnessing the open hole logging operation.

(7) In the event that the well is noncommercial and is to be plugged and abandoned, the well operator shall place a cement plug using a good quality cement, covering from not less than 100 feet below the base to not less than 100 feet above the top of the underground storage facility. The storage operator shall be given prior notice so as to have the option of witnessing

the plugging operation. The field inspector may invoke the provisions of 165:10-11-6 (l), (m), and (n).

(8) In the event that casing is run, the well operator will cause the underground storage facility interval to be covered with steel casing and be cemented from not less than 100 feet below the base to not less than 100 feet above the top of the underground storage facility using a good quality cement. The Commission field inspector for the area and storage operator shall be given prior notice so as to have the option of witnessing the operation.

(9) The well operator shall be required to run a cement bond log through the underground storage facility formation before any completion attempts are made. The storage operator shall be given prior notice so that he will have the option of witnessing the logging operation and be furnished with a copy of the bond log from the top of cement to total depth or, at the option of the well operator, to 500 feet below the base of the underground storage facility. If the integrity of the bond log is questioned by the storage operator, the storage operator may, at its sole risk and expense, run additional logs. No completion work shall be permitted until the fact has been established, between the parties concerned, and the district manager of the Commission, that the integrity of the cement is sound and that the underground storage facility is isolated from the remainder of the bore hole. The remedial work, if needed to protect the storage reservoir, shall be at the risk and expense of the well operator.

(10) The storage operator shall be notified in ample time to witness completion, recompletion, or major remedial work operations. The well site shall be made accessible at all times to the storage operator and all information pertaining to the completion shall be forwarded daily to the storage operator. If the completion, recompletion, or major remedial operations attempt is to be made in any formation within 500 feet in depth to the underground storage facility, the proposed plan of completion shall be forwarded to the storage operator ten days prior to commencement of operations. The storage operator shall have five days after receipt of the proposed plan to forward any objection to the well operator. Completion operations, recompletion, or major remedial operations shall not be permitted until the matter is resolved.

(11) At any time that the storage operator shall reasonably believe that damage may be occurring to the underground storage facility or that gas may be escaping into any other formations or otherwise believe that a well may be compromising the integrity of the underground storage facility, the storage operator may request that the operator of the well conduct specific tests solely at the storage operator's risk and expense. If an agreement cannot be obtained between the parties concerned, the storage operator may bring the matter before the Corporation Commission for determination by application, notice, and hearing following the procedure set out in OAC 165:5-7.

(12) If tests establish that damage is occurring and/or that natural gas is escaping by the continued operation of the well, the well shall be shut down immediately and the remedial operation to rectify the condition shall be commenced within ten days, at the sole risk and expense of the well operator.

(13) All information furnished to the storage operator shall be kept confidential until released in writing by the well operator.

PART 3. COMPLETIONS

165:10-3-10. Fracture and acidizing

In the completion of an oil, gas, injection, disposal, or service well, where acidizing or fracture processes are used, no oil, gas, or deleterious substances shall be permitted to pollute any surface and subsurface fresh water.

165:10-3-11. Swabbing and bailing

In swabbing, bailing, or purging a well, all deleterious substances removed from the borehole shall be placed in adequate pits or tanks, and no such substances shall be permitted to pollute any surface and subsurface fresh water.

165:10-3-12. Leakage prevention in producing oil and gas wells

All wellhead connections, surface equipment, and tank batteries shall be maintained at all times so as to prevent leakage of oil, gas, saltwater, or other deleterious substances.

165:10-3-13. Water pollution prevention in tanks; protection of migratory birds

(a) Tanks for drilling mud or deleterious substances used in the drilling, completion, or recompletion of wells shall be constructed and maintained so as to prevent pollution of surface and subsurface fresh water.
(b) The protection of migratory birds shall be the responsibility of the operator. Therefore, the Conservation Division recommends that to prevent the loss of birds due to oil, all open top tanks containing oil on the surface be protected from access to birds. [See Advisory Notice 165:10-7-3(c)].

165:10-3-14. Waste of oil or gas

Except as provided in 165:10-3-15, waste of oil, condensate, or gas as defined in 165:10-1-2, is hereby prohibited.

PART 3. COMPLETIONS

165:10-3-15. Venting and flaring

(a) **Conditioning a well without a permit.** An operator may blow a producing well without permit if:
(1) Blowing the well is necessary for efficient operation of the well.
(2) Blowing the well will not damage any producing formation in the well.
(3) The operator complies with the H_2S requirements of 165:10-3-16.
(b) **Gas volumes less than or equal to 50 mcf/d.** An operator may vent or flare up to 50 mcf/d without a permit if:
(1) It is not economically feasible to market the gas.
(2) A suitable stand, line, or stack is used to prevent a hazard to people.
(3) H_2S content of gas exceeds 100 ppm, then the gas must be flared.
(c) **Permit to vent or flare gas volumes in excess of 50 mcf/d.**
(1) The Conservation Division may administratively grant a permit to vent or flare on a daily basis gas volumes in excess 50 mcf/d, if:
(A) The operator applies for the permit on Form 1022.
(B) The application lists the location of the well and the maximum daily volume of gas to be vent or flared.
(C) It is not economically feasible to market the gas.
(D) A suitable stack, stand, or line will be used to prevent a hazard to people or property.
(2) The operator shall file an amended application in the event that the amount of gas to be vented exceeds the permitted volume.
(d) **Application for an order permitting venting or flaring.**
(1) If the Conservation Division denies a Form 1022 application for a well, the operator of a well may apply for an order permitting venting or flaring of gas.
(2) The application and notice shall be accordance with OAC 165:5-7.
(3) Upon application, notice, and hearing, the Commission may grant or deny an application made pursuant to OAC 165:5-7.

[**SOURCE:** Amended in Rule Making 980000033]

165:10-3-16. Operation in hydrogen sulfide areas

(a) **Applicability.** Each operator who conducts operations as described in this subsection shall be subject to this Section and shall provide safeguards to protect the general public from the harmful effects of hydrogen sulfide:

(1) Operations including drilling, working over, producing, injecting, gathering, processing, transporting, and storage of hydrocarbon fluids that are part of, or directly related to, field production, transportation, and handling of hydrocarbon fluids that contain gas in the system which has hydrogen sulfide as a constituent of the gas to the extent as specified in (b) of this Section.

(2) This Section shall not apply to:

(A) Operations involving processing oil, gas, or hydrocarbon fluids which are either an industrial modification or products from industrial modifications, such as refining, petrochemical plants, or chemical plants.

(B) Operations involving gathering, storing, and transporting stabilized liquid hydrocarbons.

(C) Operations where the concentration of hydrogen sulfide in the system is less than 100 PPM.

(b) **General provisions.**

(1) Each operator shall determine the hydrogen sulfide concentration in the gaseous mixture in the operation or system. Tests shall be made in accordance with standards as set by ASTM Standard D-2385-81 or other methods approved by the Commission.

(2) For all operations subject to this Section, the radius of exposure shall be determined, except in the cases of storage tanks, by the following Pasquill-Gifford equations or by other methods approved by the Commission such as air dispersion models accepted or approved by the U.S. Environmental Protection Agency:

(A) For determining the location of the 100 ppm radius of exposure: x = [(1.589)(mole fraction H_2S)(Q)] to the power of (.6258).

(B) For determining the location of the 300 ppm radius of exposure: x = [(0.6743) (mole fraction H_2S) (Q)] to the power of (.6258).

(C) For determining the location of the 500 ppm radius of exposure: x = [(0.4546)(mole fraction H_2S)(Q)] to the power of (.6258); **Where: x =** radius of exposure in feet; **Q =** maximum volume determined to be available for escape in cubic feet per day; **H_2S** = mole fraction of hydrogen sulfide in the gaseous mixture available for escape.

(3) The volume used as the escape rate in determining the radius of exposure shall be that specified below as is applicable:

(A) The maximum daily volume rate of gas containing hydrogen sulfide handled by that system for which the radius of exposure is calculated.

(B) For existing gas wells, the current adjusted open flow rate or the operator's estimate of the well's capacity to flow against zero back-pressure at the well head shall be used.

(C) For new wells drilled in developed areas, the escape rate shall be determined by using the current adjusted open-flow rate of offset wells or the field average current adjusted open-flow rate, whichever is larger.

(D) The escape rate used in determining the radius of exposure shall be corrected to standard conditions of 14.65 psia and 60° Fahrenheit.

(4) For drilling of a well in an area where insufficient data exists to calculate a radius of exposure but where hydrogen sulfide may be expected, then a 100 ppm radius of exposure equal to 3,000 feet shall be assumed. A lesser-assumed radius may be considered upon written request setting out the justification for same.

(c) **Storage tank provision.** Storage tanks which are utilized as a part of a production operation, and which are operated at or near atmospheric pressure and where the vapor accumulation has a hydrogen sulfide concentration in excess of 500 ppm, shall be subject to the following:

(1) It shall not be necessary to determine a radius of exposure for storage tanks as described in this Section.

(2) A warning sign shall be posted at the facility. A wind indicator is to be located at the tank battery site so that it may be seen from the entrance to the site and from the storage tanks.
(3) Fencing as a security measure is required when storage tanks are located inside the populated limits of a townsite or city, where conditions cause the storage tanks to be exposed to the public. In other areas where storage tanks may be considered to be a danger the Commission may require a hearing to establish security measures. (See definitions.)
(4) **Vapor safety.**
(A) A vent, flare or vapor recovery system shall be installed on all tanks over 500 ppm H_2S.
(B) The vent pipe shall be required to extend a minimum of 25 ft. horizontally from the center of the last tank.
(5) **Sign requirements.** In satisfying the sign requirement of this subsection, the following will be acceptable:
(A) A sign shall be located within 50 feet of the facility and of sufficient size to be readable from the road or at the entrance to the facility.
(B) The warning sign shall state at a minimum that; hydrogen sulfide has been found and could be present.
(C) New signs constructed to satisfy this subsection shall use the language **"Caution, Poisonous Gas May Be Present"**, using black and yellow colors or **"Danger Poison Gas (Hydrogen Sulfide)"**, using red and white colors or equivalent language. Colors shall satisfy Table 1 of American National Standards Institute Standard 253.1-1967. Signs installed to satisfy this subsection are to be compatible with the regulations of the Federal Occupational Safety and Health Administration.
(d) **Drilling, completion, workover and production operations.** All operators whose operations are subject to this Section, and where the 100 ppm radius of exposure is in excess of 50 feet, shall be subject to the following:
(1) **Warning and marker provision.**
(A) For aboveground and fixed surface facilities, the operator shall post, where permitted by law, clearly visible warning signs on access roads or public streets, or roads which provide direct access to facilities located within the area of exposure.
(B) In populated areas such as townsites and cities where the use of signs is not considered to be appropriate, an alternative warning plan may be approved upon written request to the Commission.
(C) For buried lines subject to this Section, the operator shall comply with the following:
(i) A marker sign shall be installed at public road crossings on both sides of the road as close to the pipeline as possible.
(ii) Marker signs shall be installed along the line, when it is located within a public area or along a public road, at intervals frequent enough in the judgment of the operator so as to provide warning to avoid the accidental rupturing of line by excavation.
(iii) The marker sign shall contain the name of the operator and a 24-hour phone number (including area code), and shall indicate by the use of the words "Warning", "Caution", or "Danger" and "Poison Gas" that a potential danger exists. Markers installed in compliance with the regulations of the Federal Department of Transportation shall satisfy the requirements of this provision. Marker signs installed prior to the June 12, 1987 shall be acceptable provided they are in good condition and indicate the existence of a potential hazard.
(D) In satisfying the sign requirement of this subsection, the following will be acceptable:
(i) Sign of sufficient size to be readable from the road or at the entrance to the facility.
(ii) New signs constructed to satisfy this subsection shall refer to (c) (5) (iii) of this Section.
(2) **Security provision.**
(A) Unattended fixed surface facilities shall be protected from public access when located within one-forth (1/4) mile of a dwelling, place of business, hospital, school, church, government building, school bus stop,

public park, town, city, village, or similarly populated area. This protection shall be provided by fencing and locking, or removal of pressure gauges and plugging of valve openings, or other similar means. For the purpose of this paragraph, surface pipeline shall not be considered as a fixed surface facility.

(B) For well sites, fencing as a security measure is required when a well is located inside populated limits of a townsite or city, where conditions cause the well to be exposed to the public. In other areas considered to be a danger, the Commission may require a hearing to establish security requirements.

(C) The fencing provision will be considered satisfied where the fencing structure is a deterrent to public access.

(e) **Control and equipment safety; contingency plan.**

(1) **Applicability; radius of exposure.** All operations subject to (a) of this Section shall be subject to (2) and (3) of this subsection, if any of the following conditions apply:

(A) The 100 ppm radius of exposure is in excess of 50 feet and includes any part of a "public area" except a public road.

(B) The 500 ppm radius of exposure is in excess of 50 feet and includes any part of a "public road".

(C) The 100 ppm radius of exposure is greater than 3,000 feet.

(2) **Control and equipment safety provision.** Operators subject to this subsection shall either install safety devices and maintain them in an operable condition, or shall establish written safety procedures designed to prevent the undetected continuing escape of hydrogen sulfide. Safety devises should be tested annually and a record kept of such tests.

(3) **Contingency plan provision.** A contingency plan provision shall be developed for each drilling, producing, well servicing, and plant operation that could reasonably result in accidental exposure of the public to a concentration of hydrogen sulfide in excess of 300 ppm. The operator should make appropriate contacts with any public agency listed in the contingency plan. The contingency plan shall provide an organized plan of action for alerting and protecting the public. The details of a contingency plan are determined largely by the time required for a potentially hazardous concentration of hydrogen sulfide to reach a public area and by the population density in the public area. A copy of the contingency plan should be maintained at the location which lends itself best to activation of the plan. A copy shall be submitted to the Conservation Division's District Office.

(A) The plan shall include instructions and procedures for alerting the general public and public safety personnel of the existence of an emergency.

(B) The plan shall include procedures for requesting assistance and for follow-up action to remove the public from an area of exposure.

(C) The plan shall include a call list which shall include the following as they may be applicable:

(i) Local supervisory personnel.
(ii) County Sheriff.
(iii) Department of Public Safety.
(iv) City Police.
(v) Ambulance Service.
(vi) Hospital.
(vii) Fire Department
(viii) Contractors for supplemental equipment.
(ix) District Commission Office.
(x) Local Department of Environmental Quality Office.
(xi) Other public agencies.

(D) The plan shall include a plat detailing the area of exposure. The plat shall include the locations of private dwellings or residential areas, public facilities, such as schools, business locations, public roads, or other similar areas where the public might reasonably be expected within the area of exposure.

(E) The plan shall include provisions for advance briefing of occupied dwellings within the 300 ppm radius of exposure. The following provisions apply;

(i) The hazards and characteristics of hydrogen sulfide.

(ii) The necessity for an emergency action plan.

(iii) the possible sources of hydrogen sulfide within the area of exposure.

(iv) Instructions for reporting a gas leak.

(v) The manner in which the public will be notified of an emergency.

(vi) Steps to be taken in case of an emergency.

(F) In a high density population area, or the case where the population density may be unpredictable, a reaction type of plan, in lieu of advance briefing for public notification, will be acceptable. The reaction plan option must be approved by the Commission.

(G) The plan shall include names and telephone numbers of residents within the area of exposure, except in cases where the reaction plan option has been approved by the Commission.

(H) The plan shall include a list of the names and telephone numbers of the responsible parties for each of the possibly occupied public areas, such as schools, churches, businesses, or other public areas or facilities within the area of exposure.

(f) **Training and requirement provision.** Each operator shall provide appropriate H_2S training for its employees who will be on-site. This training should include:

(1) Hazards and characteristics of hydrogen sulfide.

(2) Effect on metal components of the system.

(3) Operations of safety equipment and life support systems.

(4) First aid in event of an employee exposure.

(5) Use and operation of H_2S monitoring equipment.

(6) Emergency response procedures to include corrective actions, shut-down procedures, evacuation routes, and rescue methods.

(g) **Injection of fluids.** Injection of fluids containing hydrogen sulfide shall not be allowed under the conditions specified in this Section unless first approved by the Commission.

(h) **Venting and flaring.** Venting and flaring of gas shall be conducted in accordance with OAC 165:10-3-15.

(i) **Other requirements.** In addition to any other requirements of this Section, drilling and workover operations and processing plant sites where the 100 ppm radius of exposure is 50 feet or greater shall be subject to the following:

(1) Protective breathing equipment shall be maintained in good operating condition at two or more locations at the site.

(2) Wind direction indicators shall be installed at strategic locations at or near the site and be readily visible from the site.

(3) Automatic hydrogen sulfide detection and alarm equipment that will warn of the presence of hydrogen sulfide gas in harmful concentrations shall be utilized at the site.

(4) The Commission District Office shall be notified of the intention to conduct a drill stem test of a formation containing hydrogen sulfide in sufficient concentration to meet the requirements of this Section.

(j) **Accident notification.** Operators shall immediately notify the appropriate Commission District Office or field inspector of any accidental release of hydrogen sulfide gas of sufficient volume to present a public hazard and hydrogen sulfide related accident resulting in death or hospitalization of personnel.

(k) **Exception provision.** Any application for exception to the provisions of this Section should specify the provisions to which exception is requested, and set out in detail the basis on which the exception is to be requested.

(l) **Referenced organizations and publications.** The following organizations and publications are referenced in this Section:

(1) ANSI - American National Standards Institute 1430 Broadway, New York, New York 10018; Table I, Standard 253.1-1967.

(2) API - American Petroleum Institute 300 Corrigan Tower Building, Dallas, Texas 75201; Publication API RP-55.

(3) ASTM - American Society for Testing and Materials 1916 Race Street, Philadelphia, Pennsylvania 19103; Standard D-2385-81.
(4) EPA - U.S. Environmental Protection Agency, Office or Air Quality Planning and Standards, Technical Support Division, Research Triangle Park, North Carolina 27711; Screen 2 Model User's Guide.

[**SOURCE:** Amended at 13 Ok Reg 2395, eff 7-1-96; Amended in Rule Making 980000013; eff 7-15-98]

165:10-3-17. Well site and surface facilities

(a) **Scope.** This Section shall be applicable to all operators and owners of oil and gas wells, leases, secondary recovery units, converted or newly drilled saltwater disposal or injection wells, and re-entries or reworkings of the above; however, this Section does not cover pits used in connection with oil and gas operations (see 165:10-7-16).

(b) **Removal of fire hazards.** Any material that might constitute a fire hazard shall be removed a safe distance from the well location, tanks, and separator. All waste oil shall be burned or disposed of in a manner to avoid creating a fire hazard.

(c) **Removal of surface trash.**

(1) All surface trash, debris, and junk associated with the operations of the property shall be removed from the premises. Equipment and material that may be useable and related to the operations of the property are not considered trash, debris and junk. With written permission from the surface owner, the operator may, without applying for an exception to 165:10-3-17(b), bury all nonhazardous material at a minimum depth of three feet; cement bases are included.

(2) The District Office or field inspector may issue a Form 1036 for any alleged violation of this subsection. If the operator fails to remove trash, debris, and junk after written notice, the Commission may fine the operator up to $1,000.

(d) **Required lease signs.** Within 30 days after the completion of any producing oil or gas well, a sign shall be posted and maintained at the location showing operator of the well and the operator's business phone number, name of farm, number of the well, and legal description of the well; provided, however, where more than one well is producing on a lease, the operator may post and maintain a sign at the principal lease entrance showing the lease name, operator, legal description, and number of wells, and on each well designate the number of the well. Within 30 days after completion or recompletion of an enhanced recovery injection well or a disposal well, a sign shall be posted and maintained at the well location showing the operator of well, name of farm, well number, legal description of the well, and the Commission order number by which it was authorized. The legal description of each well completed on or after March 1, 1976, shall be posted at the well and shall describe the location of the well to the nearest quarter quarter quarter section and shall show the section, township, and range. On a 160-acre or larger drilling and spacing unit, a sign shall also be posted at the entrance to the well site. The District Office or field inspector may issue Form 1036A for failure to post a required sign. If an operator fails to post a sign as directed, the Commission may fine the operator $50.00 per violation; provided that total fines per incident shall not exceed $500.00 per lease.

(e) **Notice of fire or blowout.** In case of a fire or blowout, the well operator shall notify by telephone or telegraph, as soon as possible, either the Conservation Division or the appropriate District Office of the Conservation Division.

(f) **OTC numbers on stock tanks for oil and condensate.**

(1) On all oil and gas producing leases, the first purchaser of crude oil or condensate shall print its name or affix the company logo and print or affix the OTC Gross Production Division Purchaser Reporting Number on at least one of the storage tanks from which marketable liquids are being delivered.

(2) On all oil and gas producing leases, the well operator shall print or affix the OTC Gross Production Division assigned Production Unit Number and

the OTC Gross Production Division Operator Reporting Number on at least one of the tanks from which marketable liquids are being stored. In the case of an enhanced recovery or unitization operation where several OTC Gross Production Division assigned Production Unit Numbers exist for the wells in the unit, the word "unitized" shall be printed or affixed to one of the storage tanks from which marketable liquids are being delivered to the purchaser.

(3) The identification numbers required in this subsection shall always be clearly legible. All letters and numbers shall be a minimum of two inches in height. Any operator failing to post required information shall be fined $50.00 per violation; provided that total fines per incident shall not exceed $500.00 per well.

(g) **OTC numbers on gas meter or meter house.**

(1) On all gas producing leases, the operator of the well site gas meter required under 165:10-17-5 shall print or affix its name and OTC reporting number on the outside of the meter house or on the outside of the meter itself if no meter house exists.

(2) The operator of the lease shall print its OTC lease number and operator reporting number on the meter house or on outside of the meter if no meter house exists.

(3) The identification required in this subsection shall always be clearly legible. All letters and numbers shall be a minimum of two inches in height.

(h) **Valve and seals on stock tanks.** The operator shall install tank valves such that metal identification seals can be properly utilized. These seals shall be used on all delivery tank valves to lessen unauthorized movement of marketable products.

(i) **Man-ways on frac tanks.** Each frac tank used at the wellsite shall have protective man-ways to prevent persons from accidentally falling into the frac tank.

(j) **Guy line anchors.** All guy line anchors left buried for use in future operations of the well shall be properly marked by a marker of bright color not less than four feet in height and not greater than one foot east of the guy line anchor.

(k) **Well site cleared.** Within 90 days after a well is plugged and abandoned, the well site shall be cleared of all equipment, trash, and debris. Any foreign surface material is to be removed and the location site restored to as near to its natural state as reasonably possible, except by written agreement with the surface owner to leave the surface in some other condition. If the location site is restored but the vegetative cover is destroyed or significantly damaged, a bona fide effort shall be made to restore or re-establish the vegetative cover within 180 days after abandonment of the well.

(l) **Restored surface.** Within 90 days after a lease has been abandoned, surface equipment such as stock tanks, heater, separators, and other related items shall be removed from the premises. The surface shall be restored to as near to its natural state as reasonably possible, except by written agreement with the surface owner to leave the surface in some other condition. If the surface is restored but the vegetative cover is destroyed or significantly damaged, a bona fide effort shall be made to restore or re-establish the vegetative cover within 180 days after abandonment of the lease.

(m) **Leasehold roads.** All leasehold roads shall be kept in a passable condition and shall be made accessible at all times for representatives and field inspectors of the Commission. At the time of abandonment of the property, the area of the road shall be restored to as near to its natural state as reasonably possible, except by written agreement with the surface owner to leave the surface in some other condition. If the road area is restored but the vegetative cover is destroyed or significantly damaged, a bona fide effort shall be made to restore or re-establish the vegetative cover within 180 days after abandonment of the property.

(n) **Extension of time.**

(1) An operator may request an extension of time required in (k), (l), and (m) of this Section for not more than six months by applying to the District Office and showing that there is no imminent danger to the environment and that one of the following conditions exists:

(A) That an agreement with the surface owners is not possible.

(B) That adverse weather conditions exist or existed.
(C) That the equipment needed to conform to (k), (l), and (m) of this Section was not or is not available.
(2) If approved by the District Manager, the extension shall be granted and the surface owner shall be notified by the operator. Any extension beyond six months shall require application, notice and hearing pursuant to OAC 165:5-7-41.

[**SOURCE:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended in Rule Making 980000034]

PART 5. OPERATIONS

165:10-3-25. Completion Reports

(a) **Initial Completion Report.** A Completion Report shall be filed with the Commission on Form 1002A within 30 days after completion of operations regardless of whether or not the well was completed as a dry hole, producer, injection, disposal, or service well. An operator who fails to file a complete and correct Form 1002A Completion Report within the allotted time limit shall be subject to a fine of $250.00.
(b) **Amended Completion Report.** An amended Completion Report shall be filed with the Commission on Form 1002A within 30 days after completion of operations to reenter, recomplete and/or convert to injection or disposal well regardless of whether or not the well was completed as a dry hole, producer, injection, disposal, or service well.
(c) **No allowable without Completion Report.** The Conservation Division shall not assign an allowable to a well without an up-to-date Completion Report on file with the Conservation Division.

[**SOURCE:** Amended at 9 OK Reg 2295, eff 6-25-92]

165:10-3-26. Well logs

(a) **60 days to submit well log(s).** All well logs required by this Section shall be submitted to the Conservation Division within 60 days from the earlier of the date of completion of the well or the date that the last formation evaluation type wireline log was run. An operator who fails to properly submit wireline surveys, if run, shall be subject to a warning with time limit followed by a fine of $250.00.
(b) **Wireline logs.** This Section does not require an operator to run a wireline survey. However, if an operator does run wireline surveys, the operator shall only be required under this Section to submit a resistivity type wireline log and a porosity type wireline log, if available. Resistivity and porosity type wireline logs include but are not limited to spontaneous potential, induction, laterolog, density, and gamma ray neutron logs.
(c) **Other logs to be available upon request.** Dipmeter, velocity, and radioactive tracer logs, if available, shall be submitted to the Technical Services Department upon Commission order or special request of the Conservation Division.
(d) **Requirements for submitting a copy of a log.** A copy of a log submitted under this Section, instead of the original log, shall be a legible finished copy, complete, in one piece and with the well's legal description noted on it. If there are separate runs for multiple casing strings, the operator shall submit the separate runs.
(e) **Obtaining confidential treatment of well log(s).**
(1) Unless the operator requests confidential treatment of a well log(s), any well log(s) submitted to the Conservation Division shall be available for public inspection.
(2) To obtain confidential treatment of a well log, the operator of the well shall:

(A) Place the well log(s) in a sealed envelope with a completed Form 1002B attached to the envelope.
(B) Submit to the Technical Services Department of the Conservation Division the envelope with the log(s) and Form 1002B within 60 days from the earlier of:
(i) The completion date of the well, or
(ii) The date that the last formation evaluation log was run.
(3) A confidential well log under (2)(B) of this Section, shall remain confidential for one year from the date the last log was run on the well. Upon written request, the Conservation Division may administratively extend the period of confidentiality for six months. Under no circumstances shall confidentiality be granted for a period in excess of 18 months from the date the last log was run on the well.
(f) **No allowable before submission of well logs.** The Conservation Division shall not assign an allowable to a well before the operator of the well submits to the Conservation Division any well log required to be submitted under (b) of this Section.

[**SOURCE:** Amended at 9 OK Reg 2295, eff 6-25-92]

3-10-3-27. Deviation from the vertical
(a) **Well location for purposes of well spacing.** For purposes of the well spacing requirements of 165:10-1-21 and 165:10-1-24, the location of a well in a common source of supply is the point at which the wellbore penetrates the top of the common source of supply.
(b) **Presumed bottom hole location.** For purposes of review of Form 1000 applications, the Conservation Division may presume that the location in a common source of supply of a well without a horizontal drainhole is the same as the surface location for the well unless:
(1) The operator submits a bottom hole survey, if the well has been drilled; or
(2) The operator complies with (c)(1) of this Section.
(c) **Permitted and prohibited locations.**
(1) **Offpattern surface location; permitted subsurface location.**
(A) The Conservation Division may approve a Form 1000 for a well to be commenced without a location exception at an offpattern surface location for a common source of supply when:
(i) The Form 1000 lists a subsurface location which is a permitted location for the common source of supply.
(ii) Issuance of a Permit to Drill is conditioned on the operator running a bottom hole survey within 30 days after reaching total depth and on the operator submitting the survey to the Conservation Division within 45 days after the well reaches total depth.
(B) The well shall not receive an allowable for the common source of supply until a bottom hole survey shows that the well is at a permitted location or until the operator obtains a location exception order for the subsurface location.
(2) **Offpattern subsurface location.**
(A) The Conservation Division shall not approve a Form 1000 without a location exception order for an offpattern subsurface location.
(B) Issuance of a Permit to Drill under (1) of this subsection does not permit an operator to have, without a location exception order, an offpattern subsurface location for a common source of supply.
(d) **Required directional and bottom hole surveys.** For good cause, the Commission may order an operator to run directional and/or bottom-hole surveys for a common source of supply in a well:
(1) Upon application, notice, and hearing; or
(2) In any case involving the location of a well, upon motion of an affected party or upon the Commission's own motion.

165:10-3-28. Horizontal drilling

(a) **Scope.** This Section affects a horizontal well with one or more laterals.

(b) **Definitions.**

(1) **"Horizontal well"** shall mean a well drilled, completed, or recompleted in a manner in which the horizontal component of the completion interval in the geological formation exceeds the vertical component thereof and which horizontal component extends a minimum of 150 feet in the formation.

(2) **"Geological formation"** shall mean the common source of supply.

(3) **"Point of entry"** shall mean the point at which the borehole first intersects the top of the common source of supply.

(4) **"True vertical depth"** shall mean that depth at the point of entry in a horizontal borehole perpendicular to the surface as measured from the elevation of the kelly bushing on the drilling rig.

(5) **"Terminus"** shall mean the end point of the borehole in the common source of supply.

(6) **"Lateral"** shall mean the measured distance drilled from the point of entry to the terminus.

(7) **"Horizontal well unit"** shall mean a drilling and spacing unit established by the Commission, after application, notice, and hearing, for a common source of supply into which a horizontal well has been or will be drilled.

(8) **"Directional survey"** shall mean that survey or report showing the location of any point of the wellbore as it relates to the surveyed surface location from the surface to the terminus of each lateral.

(9) **"Date of first production"** shall mean the date hydrocarbons are first produced from the horizontal well, whether or not production occurs during drilling, completion, or through permanent surface equipment.

(10) **"Vertical component"** shall mean the calculated vertical distance from the point of entry to the terminus of the lateral.

(11) **"Horizontal component"** shall mean the calculated horizontal distance from the point of entry to the terminus.

(c) **Drilling and producing on a lease basis or in a conventional drilling and spacing unit.**

(1) This subsection shall apply to a horizontal well, not a part of a horizontal well unit. For purposes of 165:10-1-21, 165:10-1-24, and 165:10-1-25, compliance with well location requirements shall be determined considering:

(A) The location at which the wellbore penetrates the top of the common source of supply.

(B) The location of each lateral and its terminus in the common source of supply.

(2) No operator shall be assigned an allowable to produce oil, gas, or gas condensate from the well until he submits a downhole survey showing that each lateral is at location permitted by general rule or location exception order. For allowable purposes, the well shall be considered as a single wellbore. For a gas well, the Conservation Division shall compute the gross allowable in the manner prescribed for a vertically drilled gas well at that location in the common source of supply. For an oil well, the Conservation Division shall compute the gross allowable using the provisions applicable to a horizontal well unit.

(d) **Horizontal well units.** Subsections (e) through (l) of this Section establish criteria for spacing, pooling, drilling, and producing a horizontal well with one or more laterals.

(e) **Drilling and spacing units.**

(1) A horizontal well may be drilled on any drilling and spacing unit.

(2) A horizontal well unit may be created in accordance with 165:10-1-22 and 165:5-7-6, 165:5-15-8, and 165:5-15-9. Such units shall be created as new units after notice and hearing as provided for by the Rules of Practice, OAC 165:5.

(3) A horizontal well unit may be established for a common source of supply for which there are already established non-horizontal drilling and spacing units, and said horizontal well unit may include within the boundaries thereof more than one existing non-horizontal drilling and spacing unit for the common source of supply.

(A) Horizontal well units may exist concurrently with producing non-horizontal drilling and spacing units.
(B) Horizontal well units shall supersede existing non-developed non-horizontal drilling and spacing units for the duration of the horizontal well unit.

(f) **Single wellbore.**
(1) All laterals in the same common source of supply in a horizontal well with at least one lateral which exceeds 150 feet of total horizontal component shall be considered as a single wellbore for allowable purposes.
(2) Laterals in the same common source of supply directly connected through the wellbore to the same surface location in a horizontal well and which form an angle of 90 degrees or more shall be considered a single lateral in determining projected horizontal displacement for horizontal well unit purposes. The horizontal lateral displacement used to determine the appropriate horizontal well unit where multiple laterals exist shall be the horizontal displacement of the longest lateral, plus the projection of any other lateral on a line that extends in a one hundred eighty degree (180°) direction from the longest lateral.

(g) **Location.** For purposes of 165:10-1-22 and Appendix C (Table HD) to this Chapter, compliance with well location requirements shall be determined considering:
(1) The location of the point of entry.
(2) The location of each lateral in terms of direction and depth.
(3) The terminus of each lateral.

(h) **Determination of unit size and allowable.**
(1) The size of the proposed horizontal well unit shall be determined by the projected length of the horizontal component as shown in Appendix C (Table HD) to this Chapter.
(2) The allowable for the horizontal oil well shall be determined by the actual length of the lateral as shown in Appendix C (Table HD) to this Chapter.

(i) **Horizontal well spacing requirements.**
(1) A horizontal wellbore from its point of entry and along any part of the lateral shall be located not closer than the minimum distance as set out below from any other wellbore completed in or drilling to the same common source of supply except by a special order of the Commission:
(A) Three hundred feet from any other producible or drilling oil or gas well when drilling to the same common source of supply that is less than 2,500 feet in depth.
(B) Six hundred feet from any other producible or drilling oil or gas well when drilling to the same common source of supply that is 2,500 feet or more in depth.
(C) This paragraph does not apply to horizontal wells drilled in a unit created for secondary or enhanced recovery operations pursuant to 52 O.S. 287.1 et seq.
(2) A horizontal wellbore from its point of entry and along any part of the lateral shall be located not less than the minimum tolerance distance from the boundary of the horizontal well unit as follows:
(A) Not less than 165 feet from the boundary of any 10, 20, or 40 acre horizontal well unit.
(B) Not less than 330 feet from the boundary of any 80 or 160 acre horizontal well unit.
(C) Not less than 660 feet from the boundary of any 320 acre or 640 acre horizontal drilling and spacing unit.
(3) Any horizontal wellbore drilled into an unspaced common source of supply may not be located closer to the lease line or voluntary unit or to another wellbore completed in the same common source of supply than the tolerance distance prescribed for a well drilled in a standard horizontal well unit as determined by the length of the horizontal component of the unspaced horizontal wellbore.

(j) **Allowable.**
(1) Horizontal oil well allowables may be established administratively based on Appendix C (Table HD) to this Chapter.

(2) Allowables will be effective as of the date of first production. Underproduction will not be accumulated during drilling.
(3) Bonus allowables will be established for multilaterals by the summation of each individual lateral in an otherwise qualifying horizontal oil well, as provided in (f) of this Section.

(k) **Establishing allowables.** To establish an allowable for a horizontal well, the following must be submitted to the Commission:
(1) Directional survey.
(2) A plat constructed from data gathered from the directional survey showing point of entry, true vertical depth at point of entry, actual length, and direction of the lateral and horizontal component.
(3) An approved copy of Form 1002A.
(4) Total amount of oil or gas that has been produced from the well prior to the date of completion.

(l) **Pooling.** Horizontal well units may be pooled as provided for under 52 O.S. 87.1 and Commission Rules of Practice, OAC 165:5.

165:10-3-29. Oil storage

Oil storage tanks shall be constructed so as to prevent leakage. Dikes or walls, where necessary, shall be constructed so as to prevent oil or deleterious substances from polluting surface and subsurface water.

165:10-3-30. Use of gas for artificial lifting

(a) **Use of gas for artificial lifting of oil.** Gas may be used for the artificial lifting of oil; provided, all gas returned to the surface with the oil is not vented or otherwise wasted

(b) **The use of production.** The use of production from one common source of supply to assist in lifting the production from another common source of supply by commingling the production from both common sources of supply in the tubing string shall be permitted when the operator has authority to commingle the production in the tubing.

(c) **Use of artificial lift.** Artificial lift, initial or subsequent, in conjunction with the separate orifice or choke assembly shall be governed by OAC 165:10-3-37.

[**SOURCE:** Amended in Rule Making 980000033, eff 7-1-99]

165:10-3-31. Use of vacuum

(a) **Prohibited without an order.** Imposing vacuum on an oil or gas bearing formation is prohibited without an order of the Commission.

(b) **Requirement.** A vacuum shall not be permitted unless it can be shown that to use a vacuum as permitted will prevent waste and protect correlative rights.

(c) **Application for an order.** Each application for an order authorizing use of vacuum on a common source of supply shall be made according to 165:5-7-25.

(d) **Records required to be kept by the operator.**
(1) If an operator obtains an order authorizing use of vacuum, the operator shall make a record on a monthly basis of:
(A) The vacuum imposed in pounds per square inch or inches of mercury.
(B) The amount of gas, oil and water production per day.
(2) Any record required to be kept under this Section shall be made available to the Conservation Division upon request.

PART 7. PRODUCTION

165:10-3-35. Multiple zone production

(a) Production from more than one common source of supply from a single well is hereby prohibited except as authorized by the Conservation Division.
(b) For the purpose of this Section, completion of a well so as to separately produce or account for the production from two or more common sources of supply shall be a multiple completion, and the production from more than one common source of supply without segregation of the production shall be commingling.
(c) Any operator violating this Section shall be subject to a fine of $500.00. The Conservation Division may shut down a multiply completed well pending compliance with this Section.

[**SOURCE:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended in Rule Making 980000033, eff 7-1-99]

165:10-3-36. Multiple zone completions
(a) Each application for the approval of the multiple completion of a well shall be filed on Form 1023 and shall be verified.
(b) A copy of the application shall be mailed or delivered to each operator of a producing leasehold within one-half (1/2) mile of the well location. The applicant shall file an affidavit of delivery or mailing not later than five (5) days after the application is filed.
(c) If a written objection to the application is filed within fifteen (15) days after the application is filed, or if hearing is required by the Commission, the application shall be set for hearing and notice thereof shall be given as the Commission shall direct. If no objection is filed and the Commission does not require a hearing, the matter shall be presented administratively to the Director of Conservation or his designee who shall file his report and make his recommendations. If the Conservation Division denies an application, the applicant may request a hearing on said application in accordance with OAC 165:5-7-22.

[**SOURCE:** Amended in Rule Making 980000033, eff 7-1-99]

165:10-3-37. Control of multiply completed wells
(a) Every multiply completed well shall be equipped, operated, produced, and maintained so that there will be no commingling of the production from separate common sources of supply in the well, except as hereinafter provided. The production from each common source of supply shall be separately accounted for or separately stored and measured on the lease. The production shall be measured by either:
 (1) A positive displacement dump-type device;
 (2) A continuous-flow measuring device; or
 (3) A measuring device of any other type authorized by the Commission.
(b) Each application for the approval of production through a multiple choke assembly in a well shall be filed on Form 1023 and shall be verified. The multiple choke assembly must be so designed and located in the wellbore as to prevent commingling within the common sources of supply, but to permit commingling in the tubing string through individual choke orifices. The commingled production shall be measured at the surface and allocated to each common source of supply.
(c) A copy of the application shall be mailed or delivered to each operator of a producing leasehold within one-half (1/2) mile of the well location. The applicant shall file an affidavit of delivery or mailing not later than five days after the application is filed.
(d) If a written objection to the application is filed within 15 days after the application is filed, or if hearing is required by the Commission, the application shall be set for hearing and notice thereof shall be given as the Commission shall direct. If no objection is filed and the Commission does not require a hearing, the matter shall be presented administratively to the Director of Conservation who shall file his report and make his recommendations.

[**SOURCE:** Amended in Rule Making 980000033, eff 7-1-99]

165:10-3-38. Testing of multiply completed wells

The Conservation Division may at any time require a multiply completed well to be tested to determine the effectiveness of the separation of common sources of supply. The tests may be witnessed by representatives of the Conservation Division and may be witnessed by any offset operator. Testing procedures must be acceptable to a representative of the Conservation Division.

[**SOURCE:** Amended in Rule Making 980000033, eff 7-1-99]

165:10-3-39. Commingling of production

(a) **Commingling order required.** Commingling of production from a well from separate common sources of supply is prohibited without a commingling order. A commingling order shall be required when production is from more than one source of supply, without segregation of the production in the wellbore, or is produced separately in the wellbore and then combined together downstream of the wellhead prior to measurement. Commingling downstream of the wellhead shall require Form 1024 (Packer Setting Affidavit) and Form 1025 (Packer Leakage Test) to be filed and approved. The Commission shall assess a fine of $500.00 for non-permitted commingling either down hole or downstream prior to measurement.

(b) **Restrictions.**

(1) Commingling shall only be authorized when it would prevent waste and protect correlative rights.

(2) Commingling shall be prohibited where one producing zone is predominately gas and a second zone is predominately oil, unless the operator can verify in writing, submitted with the application, that no cross flow will occur resulting in reservoir damage.

(c) **Application requirements.** Each application for a commingling order shall comply with OAC 165:5-7-24.

(d) **Commingled allowables.**

(1) **Single allowable for commingled production.** Common sources of supply commingled under this Section receive a single allowable as if they constituted a single common source of supply in the wellbore.

(2) **Gross daily allowable for commingled production.** The gross daily allowable shall be based on the classification of the well as an oil or gas well for allowable purposes under OAC 165:10-13-2.

(A) **Unallocated oil well (GOR < 15,000:1).** The gross daily allowable shall be based on what would be the allowable if commingled production comes from the deepest commingled common source of supply.

(B) **Unallocated gas well (GOR > 15,000:1).** The gross daily allowable shall be a single unallocated gas allowable, as determined by OAC 165:10-17-11(c). Upon request in a commingling application or in any other appropriate application and upon proper notice thereof, the Commission may designate in the commingling order or other appropriate order the specific gas formation, completed and producing in the applicable well, to which the allowable for such well is to be attributed when the Commission determines that such designation is necessary to prevent waste and to protect correlative rights.

(C) **Special allocated gas pool.** The gross daily allowable shall be based on what would be the allowable if the commingled production came from the special allocated gas pool in the well.

(3) **Operator option if multiple pool rules exist.** If more than one common source of supply under a commingling order for a gas well is subject to gas pool rules, the order shall designate which set of pool rules is applicable for allowable purposes.

(4) **Net daily allowable.** The net daily allowable is the gross daily allowable under (3) of this subsection:

(A) Reduced accordingly by any penalty against any of the commingled common sources of supply under the order.

(B) Reduced accordingly by any overage carried forward against a commingled common source of supply.
(C) Increased by any underage carried forward for the well under applicable allocated or special allocated pool rules.

[**SOURCE:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended in Rule Making 980000033, eff 7-1-99]

165:10-3-40. Production of brine

(a) All wells in excess of 300 feet in depth and producing brine for the extracting of minerals shall be under the full jurisdiction of the Conservation Division.
(b) The establishment of a unitized area for the purpose of efficient operations, prevention of waste, and the protection of correlative rights may be formed by following the procedures set out in 165:5-7-21
(c) Category B surety shall be a requirement for all brine producing wells or units. [See 165:5-7-21(f)]

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SUBCHAPTER 5. UNDERGROUND INJECTION CONTROL

Section

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165:10-5-1. Classification of underground injection wells

Underground injection wells shall be classified as follows:

(1) **Enhanced recovery injection well.** An enhanced recovery injection well is a well which injects fluids to increase the recovery of hydrocarbons.

(2) **Disposal well.** A disposal well is a well which injects, for purposes other than enhanced recovery, those fluids brought to the surface in connection with oil or natural gas production.

(3) **Storage well.** A storage well is a well used to inject, for storage purposes, hydrocarbons which are liquid at standard temperature and pressure.

(4) **Simultaneous injection well.** A well that injects or disposes of salt water at the same time it is producing oil and/or gas to the surface.

[SOURCE: Amended at 13 Ok Reg 2387, eff 7-1-96]

165:10-5-2. Approval of enhanced recovery injection wells or disposal wells

(a) The subsurface injection or disposal of any substance for any purpose is prohibited except upon approval of the Commission pursuant to 165:10-5-5 or 165:10-5-12 and 165:10-5-13. This authorization may be conditioned upon the applicant taking corrective action to protect treatable water as specified by the Commission in its order. The Commission shall fine an operator $5,000.00 for any violation of this subsection.

(b) Except as provided in (c) and (d) in this Section, every well used for injection or disposal shall be cased and tested in accordance with 165:10-3-4 and 165:10-5-6.

(c) The testing requirements of 165:10-5-6 shall not apply to wells permitted by Commission order for subsurface injection of onsite reserve pit fluids.

(d) The Conservation Division may approve a Form 1015 application to convert for injection or disposal an existing well which does not comply with 165:10-3-4 if:

(1) The operator attaches to the Form 1015 application a description of an alternate method of protecting treatable water.

(2) The Conservation Division approves the proposed alternate method.

(3) The application is filed in accordance with OAC 165:5-7 if a hearing is required.

(4) The application is not protested.

(e) Any newly drilled or newly converted injection or disposal well which is within one-half (1/2) mile of any active or reserve municipal water supply well shall not be approved without notice and hearing, and the Commission shall not issue an order authorizing injection or disposal into said well until the applicant proves by substantial evidence that said well shall not pollute said water supply well. A commercial disposal well shall not be approved within a designated wellhead protection area.

[**SOURCE:** Amended at 9 Ok Reg 2295; Amended at 9 Ok Reg 2337, eff 6-25-92]

165:10-5-3. Authorization for existing enhanced recovery injection wells and existing disposal wells

(a) Each enhanced recovery injection well authorized under order of the Commission on the effective date of this Section is an existing enhanced recovery injection well. Injection is prohibited in any existing enhanced recovery injection well unless the operator has included that well on a completed Form 1070 submitted to the Commission within one year following the effective date of this Section. Form 1070 (Inventory of Authorized Existing Enhanced Recovery Injection Wells) shall include each well name, location, authorizing Commission order number (including all orders authorizing exceptions), date of order, maximum authorized injection rate, and maximum authorized injection pressure.

(b) Each disposal well being operated under order of the Commission on the effective date of this Section is an existing disposal well. Injection is prohibited in any existing disposal well unless the operator has included that well on a completed Form 1071 submitted to the Commission within one year following the effective date of this Section. Form 1071 (Inventory of Authorized Existing Disposal Wells) shall include each well name, location, authorizing Commission order number (including all orders authorizing exceptions), date of order, maximum authorized injection rate, and maximum authorized injection pressure.

165:10-5-4. Application for approval of enhanced recovery projects

(a) An enhanced recovery project shall be permitted only by order of the Commission after notice and hearing.

(b) The application for an order authorizing an enhanced recovery project shall contain the following:

(1) The names and addresses of the operator or operators of the project.

(2) A plat showing the lease, group of leases, or unit included within the proposed project; the location of the proposed injection well or wells, and the location of all oil and gas wells including abandoned and drilling wells and dry holes; and the names of all operators offsetting the area encompassed within the project.

(3) The common source of supply in which all wells are currently completed.

(4) The name, description, and depth of each common source of supply to be affected.

(5) A log of a representative well completed in the common source of supply.

(6) A description of the existing or proposed casing program for injection wells and the proposed method of testing casing.

(7) A description of the injection medium to be used, its source, and the estimated amounts to be injected daily.

(8) For a project with an allocated pool, a tabulation showing recent gas-oil ratio and oil and water production tests for each of the producing oil and gas wells.

(9) The proposed plan of development of the area included within the project.

(c) A copy of the application and notice of hearing shall be mailed to the owner or owners of the surface of the land upon which the project is located and to each operator offsetting the project as shown on the application within five days after the application is filed. An affidavit of compliance with this Section shall be filed on or before the hearing.

165:10-5-5. Application for approval of enhanced recovery injection and disposal operations

(a) Each application for approval of a well for use as an injection well or disposal well shall be filed in accordance with 165:5-7-27.

(b) In addition to the requirements of 165:5-7-27, the Resource Conservation Department may request the applicant to submit the following information as a prerequisite to approval of the application:

(1) For those wells included in 165:5-7-27(b)(1) which penetrate the top of the injection interval, a tabulation of the wells indicating the following information, if available, from public records:

(A) Dates the wells were drilled.

(B) The present status of the wells.

(C) The identity of any abandoned well which was improperly plugged or remains unplugged.

(2) A list of the following information, if available, to the applicant:

(A) The shut-in bottom hole formation pressure in psi; or the stabilized shut-in surface pressure and fluid level in the proposed injection well.

(B) The permeability of the proposed injection zone expressed in millidarcies.

(C) The porosity of the proposed injection zone expressed as a percentage of pore volume.
(D) Documentation of the methods used to arrive at the data requested above.

(c) An order authorizing an enhanced oil recovery injection well or a disposal well or a commercial disposal well will expire and become null and void if no well completion report (Form 1002A) is filed within six months from the date of completion or recompletion of the well.

(d) In addition to the well construction requirements as set out in 165:10-3-1, commercial saltwater disposal wells shall comply with the following requirements:

(1) At a minimum, the well shall be constructed with a wellhead, surface casing, production casing, tubing, and packer.
(2) The surface casing shall be set and cemented at least fifty (50) feet below the base of the treatable water bearing zone.
(3) The production casing must be set and cemented through the injection zone with the cement circulated behind the casing to a height at least two hundred fifty (250) feet above the disposal zone. A cement bond log showing quality and placement of the cement must be furnished to and approved by the Commission before the application will be approved. The production casing will not be allowed to also serve as the surface casing.
(4) The annulus between the tubing and the casing must be open from the surface to the packer to allow for pressure testing and monitoring of the injection tubing and packer and the annulus filled with a packer fluid that protects against corrosion.
(5) The packer must be set at least within seventy-five (75) feet of the top of the perforations.
(6) Adequate gauges shall be installed on each annulus to allow proper monitoring of the disposal operation.
(7) Tubing must be internally coated or lined to prevent corrosion from injected fluids. PVC, Plastic Coated, Stainless Steel or Fiberglass will qualify.
(8) The packer must either internally coated or stainless steel.
(9) Commercial disposal wells authorized with a positive injection pressure must be equipped with a down hole shut-off device with a seal divider installed between the packer and the tubing. A Stainless Steel Profile Nipple and an "ON-OFF" Tool will qualify under this Section.

(e) No Commercial disposal well will be permitted whose injection pressure approaches or exceeds the demonstrated frac gradient of the injection zones(s).

(f) All permitted injection zones must be completed for injection. Authorization for any zones not initially completed as an injection zone will expire within 60 days following initial completion or recompletion date.

[**Source:** Amended at 11 Ok Reg 3691, eff 7-11-94]

165:10-5-6. Testing and monitoring requirements for enhanced recovery injection wells and disposal wells

(a) **Mechanical integrity during injection.** The operator of an injection, disposal or commercial disposal well must maintain mechanical integrity in order to continue operation of the well.

(b) **Initial pressure test requirements for wells permitted on or after December 2, 1981.**

(1) **Mandatory initial mechanical test.** Before commencement of operation, each well authorized for enhanced recovery injection or disposal by a Commission order issued on or after December 2, 1981, must pass an initial pressure test of the casing tubing annulus according to the minimum testing standards of (2) of this subsection, unless a Commission order permits other test procedures of the mechanical integrity of the well. Any operator failing to comply with initial mechanical integrity testing and reporting requirements shall be subject to a fine of $500.00.
(2) **Minimum testing standards for initial tests.** For each initial test required by (1) of this subsection, the minimum testing standards are:

(A) **Witnessing of the test.** The test shall be witnessed by an authorized representative of the Conservation Division. It shall be the responsibility of the well operator to secure the presence of the Commission representative.
(B) **Down-hole equipment.** Injection and disposal shall be through adequate tubing and packer.
(C) **Aboveground extensions and fittings.** Adequate aboveground extensions shall be installed in each annulus in the well. In addition, the operator shall install a one-fourth (1/4) inch female fitting, with cutoff valve to the tubing, so that the amount of injection pressure may be measured by the Commission representative using a gauge having a one-fourth (1/4) inch male fitting.
(D) **Packer setting depth under the order.** The mechanical packer shall be set within 20 feet of the packer setting depth prescribed by the order permitting the well for injection.
(E) **Verification of packer setting depth.** The Commission District Manager may require the operator of the well to verify the packer setting depth by running a wireline or other method approved by the Manager of the Underground Injection Control Department.
(F) **Minimum testing pressure.** Noncommercial disposal and injection wells shall be tested as follows:
(i) If the maximum authorized injection pressure for the well is less than 300 psig under the order permitting the well for injection, the minimum testing pressure shall be 300 psig.
(ii) If the maximum authorized injection pressure is greater than 300 psig under the order permitting the well for injection, the minimum testing pressure shall be the lesser of 1000 psig or the maximum authorized injection pressure under the order permitting the well.
(G) **Thirty minute minimum testing period.** The minimum testing period shall be 30 minutes at the testing pressure.
(H) **Ten percent maximum permitted bleed-off.** The maximum permitted bleed-off during the testing period shall be ten percent of the maximum testing pressure used.
(I) **Test report on Form 1075.** The operators shall submit the results of the mechanical integrity test on Form 1075 within 30 days from the date the test is performed.
(J) **Cement circulated above injection zone.** The minimum cement height circulated above the injection or disposal zone in the annulus between the casing and the borehole shall be 250 feet.
(K) **Packer setting depth.** The packer must be set at a depth which is at least 50 feet below the depth of the top of cement behind the production casing.
(3) **Alternative testing procedures.** Operators can test at a maximum of 500 psi if there is in place an automatic and continuous pressure monitor on the tubing-casing annulus that will shut-in the well if there is a significant pressure increase on the annulus. Application for this alternative test procedure shall be made in writing to the Manager of the UIC Department.
(4) **Use of fluid seal without a mechanical packer.** Use of a fluid seal without a mechanical packer is prohibited.

(c) **Initial pressure test requirements for wells permitted prior to December 2, 1981.**
(1) **Mandatory initial pressure test or monitoring test.**
(A) Each well authorized for enhanced recovery injection or disposal by Commission order issued prior to December 2, 1981, must pass an initial mechanical integrity test according to the minimum testing standards of (2) of this subsection.
(B) In lieu of casing test required in (A) of this paragraph, the operator shall monitor and record during actual injection the pressure in the casing-tubing annulus monthly and report the pressure annually on Form 1075. A measurable positive pressure must be maintained at the casing valve and be continuously measured to qualify.
(2) **Minimum testing standards for initial mechanical integrity tests.**

(A) **Wells with casing-tubing annulus.** The minimum testing standards of (a)(2) of this Section for an initial test of a well with a casing tubing annulus shall apply with the following modifications:

(i) The District Manager shall have the option to waive witnessing of the test.

(ii) If the test is not witnessed, the well operator shall submit documentation of the test to the Conservation Division within 30 days after the test on Form 1075.

(iii) The minimum testing pressure shall be 200 psig.

(B) **Wells without a casing-tubing annulus or wells with perforations above the packer.** The minimum testing standards for an initial test of a well without a casing-tubing annulus or wells with perforations above the packer are:

(i) **Witnessing of the test.** The test shall be witnessed by an authorized representative of the Conservation Division unless the District Manager for the Conservation Division waives the requirement of witnessing the initial test. It shall be the responsibility of the well operator to secure the presence of the commission representative for witnessing the test.

(ii) **Documentation for unwitnessed tests.** If the test is not witnessed, then the operator shall submit on Form 1075 documentation of the test to the Conservation Division within 30 days after the test.

(iii) **Aboveground extensions and fittings.** The operator shall install a one-fourth (1/4) inch female fitting, with cutoff valve to the tubing, so that the amount of injection pressure may be measured by the Commission representative using a gauge having a one-fourth (1/4) inch male fitting.

(iv) **Setting depth for plug.** For purposes of the test, a mechanical packer, retrievable bridge plug, or seating nipple plug shall be placed in the injection string not more than 75 feet above the top of the injection interval.

(v) **Pressure testing of tubing string.** The well operator shall pressure test the tubing string for at least 30 minutes. The minimum testing pressure shall be the greater of 300 psig, or the maximum authorized injection pressure provided that the actual working injection pressure for the well may be used instead of the maximum authorized injection pressure when necessary to prevent damage to the casing or packer.

(vi) **Ten percent maximum permitted bleedoff.** The maximum permitted bleedoff during the testing period shall be ten percent of the maximum testing pressure used.

(vii) **Radioactive tracer survey.** A radioactive tracer survey shall be run demonstrating that the injected fluid is going into the authorized zone when there is no cement bond log or cementing reports to demonstrate sufficient cement behind pipe to isolate the injection zone or to insure the packer is properly set.

(viii) **Pressure test using a gas media.** In lieu of a pressure test using a liquid testing media, the UIC Department may approve a mechanical integrity test using a gas media if it conforms to a method previously approved by the EPA.

(ix) **Test report on Form 1075.** The operator shall submit the results of the mechanical integrity test on Form 1075 to the Conservation Division within 30 days after the test.

(d) **Subsequent mechanical integrity test requirements.**

(1) **Pressure test every five years.** Unless a well has been approved by an order of the Commission for other testing procedures or monitoring, each well permitted for injection shall demonstrate mechanical integrity at least once every five years according to the minimum testing standards of (3) of this subsection. Any operator failing to comply with periodic mechanical integrity testing and reporting requirements shall be subject to a fine of $500.00.

(2) **Required retest if down-hole equipment is moved or replaced.** After a well passes a pressure test required by this Section, if the operator moves the packer or replaces either the packer or the tubing, then the operator

shall retest the well according to the minimum testing standards of (3) of this subsection.

(3) **Minimum testing standards.**

(A) **Wells with casing-tubing annulus.** For a five year test or retest required by this subsection, the minimum testing standards of (a)(2) of this Section shall apply to wells with casing-tubing annulus with the following modifications:

(i) The District Manager shall have the option to waive witnessing of the test.

(ii) If the test is not witnessed, the well operator shall submit documentation of the test to the Conservation Division within 30 days after the test.

(iii) The minimum testing pressure shall be:

(I) 200 psig for a noncommercial well.

(II) 300 psig or the authorized injection pressure, whichever is greater, for commercial disposal wells.

(B) **Wells without a casing-tubing annulus or wells with perforations above the packer.** For a five year test or retest required by this subsection, the minimum testing reporting standards of (b)(3)(B) of this Section, shall apply to wells without a casing-tubing annulus or wells with perforations above the packer.

(C) **Wells with automatic monitoring of positive tubing-casing pressure.** Subsequent pressure tests will not be required if there is in place a pressure monitor on the annulus to demonstrate the maintenance of a certain, positive pressure. This monitor will be connected to an automatic alarm or a continuous chart recorder. Application for this alternative shall be made in writing to the Manager of the UIC Department. Monitoring records will be sent annually attached to Form 1012 to the UIC Department.

(e) **Monitoring requirements.**

(1) **Report on Form 1075.** In lieu of a mechanical integrity test every five years, the operator of a well permitted for injection or disposal may demonstrate the mechanical integrity by:

(A) Monitoring and recording the injection rate, volume, and casing-tubing annulus pressure monthly.

(B) Submitting to the Conservation Division the results of monthly monitoring for the calendar year on Form 1075 by the first day of April of the next calendar year.

(2) **Required positive casing-tubing annulus pressure.** A measurable positive pressure must be maintained at the casing valve and be continuously measured to qualify for mechanical integrity.

(f) **Testing requirements for commercial disposal wells.**

(1) **Before commencement of operation.** Before commencement of operation, each commercial disposal well must pass a pressure test of the casing tubing annulus.

(2) **Minimum testing standards.**

(A) The test shall be witnessed by an authorized representative of the Conservation Division.

(B) The well shall be tested at the maximum authorized injection pressure, but not less than 300 psig.

(C) The minimum testing period shall be thirty (30) minutes.

(D) The maximum allowable change in pressure during the testing period shall be ten percent (10%) of the testing pressure.

(E) The results of the test shall be submitted on Form 1075 within 30 days from the date of the test.

(3) **Subsequent mechanical integrity tests.**

(A) The well shall be tested a minimum of every twelve (12) months.

(B) After a well passes a pressure test required by this Section, if the operator moves the packer or replaces the packer or tubing, then the operator shall notify the Commission and retest the well according to the minimum testing standards of (2) of this subsection.

(4) **Alternative testing procedures.** Operators can test at a maximum of 500 psi if there is in place an automatic and continuous pressure monitor on the tubing-casing annulus that will shut-in the well if there is a significant

pressure increase on the annulus. Application for this alternative test procedure shall be made in writing to the Manager of the UIC Department.

[SOURCE: Amended at 9 Ok Reg 2295; Amended at 9 Ok Reg 2337, eff 6-25-92; Amended at 11 Ok Reg 3691, eff 7-11-94; Amended at 13 Ok Reg 2387, eff 7-1-96; Amended in Rule Making 97000002, eff 7-1-97; Amended in Rule Making 200000002, eff 7-1-2000]

165:10-5-7. Monitoring and reporting requirements for wells covered by 165:10-5-1

(a) **Scope.** This Section applies to:
(1) Notice of Commencement of Injection and Disposal Operations on Forms 1012 and 1072.
(2) Annual Report of Injection Projects, saltwater disposal wells and LPG storage wells on Form 1012.
(3) Notice of Voluntary Termination of Operations on Form 1072.
(4) Notice of mechanical failure or down-hole problems.

(b) **Annual report of enhanced recovery injection projects, saltwater disposal wells and LPG storage wells.**
(1) **Submit Form 1012 by April 1st.** Each operator of a saltwater disposal well, LPG storage well or an authorized waterflood, pressure maintenance project, gas repressuring project, or other enhanced recovery project shall submit annually Form 1012 for every well to the Conservation Division as follows:
(A) Form 1012 shall be submitted by April 1st for the previous calendar year for all noncommercial wells.
(B) For commercial disposal wells Form 1012 shall be submitted February 28 and August 31, for the previous six months.
(2) **Failure to submit Form 1012.** Any operator who fails to submit the report on Form 1012 as required by (c)(1) of this Section shall be subject to a fine of $500.00 and:
(A) Injection into the project is prohibited until the operator submits Form 1012 for each injection well.
(B) The order is voidable.
(3) **Required monthly monitoring.** On a monthly basis, the operator of each enhanced recovery injection well and disposal well and LPG storage well shall monitor and record the injection rate and surface injection pressure for the well.
(4) **All UIC wells.** Saltwater disposal wells, injection wells and storage wells shall be reported on Form 1012 individually according to the order authorizing disposal.

(c) **Monitoring requirements for commercial disposal well.**
(1) The operator of a commercial disposal well shall monitor and record the casing tubing annulus pressure and the injection pressure on a daily basis.
(2) The operator of a commercial saltwater disposal well shall make available upon request of the Commission a log of all loads of deleterious substances disposed at the well. The log shall be kept on file for a period of at least five (5) years. The log of record shall include at a minimum, the amount, the location of the source, and the operator and/or owner of the source of the deleterious substance.

(d) **Notice of voluntary termination.**
(1) If an operator permanently terminates injection into a well, the operator shall submit to the Conservation Division Form 1072 within 30 days after termination of injection. Form 1072 shall state:
(A) The legal description of the well.
(B) The reason for termination.
(C) The status of other wells, if the well is in an enhanced recovery project.
(2) Submission of Form 1072 to permanently terminate injection shall terminate the authority under the order.

(e) **Notice of mechanical integrity problem.**

(1) **Notice of mechanical failure or down-hole problem.** When a mechanical problem occurs, then:

(A) The well operator shall notify the Field Inspector for Conservation within 24 hours after discovery of the problem.

(B) Within five days after discovery of the problem, the well operator shall submit to the Manager of Underground Injection Control written notice of the failure and a plan to repair and/or retest the well.

(C) Repair shall be reported on the annual Form 1012 for the well.

(D) Any operator failing to timely notify the Commission shall be subject to a fine of $1,500.00.

(2) **Shutdown.**

(A) **Administrative shutdown.** The Conservation Division may shut down a well if a mechanical failure or down-hole problem indicates that injected substances are not or may not be entering the injection interval authorized by order of the Commission.

(B) **Administrative authority to recommence injection.**

(i) If a well is shut down under (1)(A) of this subsection, the well operator shall be responsible for proving to the satisfaction of the Manager of Underground Injection Control:

(I) The mechanical integrity of the well for injection.

(II) That the injected substances are going into and are confined to the permitted injection interval.

(ii) Upon submission of proper proof of the satisfactory capability of the well for injection, the Manager of Underground Injection Control may authorize recommencement of injection.

(C) **Resolution of disputes by order of the Commission.** In the event of a dispute between the Manager of Underground Injection Control and any person as to the suitability of a well for injection, the affected person may seek relief by order of the Commission. Upon application, notice, and hearing meeting the requirements of 165:5-7-27(c) and (d) for protested applications, the Commission may issue an order determining whether or not the well should be used for further injection.

(3) **Notice of unreported repairs.** Any prior unreported repair of the well shall be reported on the next annual Form 1012 to be submitted to the Manager of the UIC Department.

[SOURCE: Amended at 9 Ok Reg 2295, eff 6-25-92; Amended at 11 Ok Reg 3691, eff 7-11-94; Amended at 13 Ok Reg 2389, eff 7-1-96]

165:10-5-8. Liquid hydrocarbon storage wells

Authorization for storage wells will be granted by order of the Commission after notice and hearing, provided there is a finding that the proposed operation will not endanger fresh water strata.

165:10-5-9. Duration of underground injection well orders

(a) Subject to 165:10-5-10, orders authorizing injection into enhanced recovery injection wells and disposal wells shall remain valid for the life of the well, unless revoked by the Commission for just cause or lapses and becomes null and void under the provisions of 165:10-5-5(c) or 165:10-5-7(f).

(b) An order granting underground injection may be modified, vacated, amended, or terminated during its term for cause. This may be at the Commission's initiative or at the request of any interested person through the prescribed complaint procedure of the Conservation Division. All requests shall be in writing and shall contain facts or reasons supporting the request.

(c) An order may be modified, vacated, amended, or terminated after notice and hearing if:

(1) There is a substantial change of conditions in the enhanced recovery injection well or the disposal well operation, or there are substantial changes in the information originally furnished.

(2) Information as to the permitted operation indicates that the cumulative effects on the environment are unacceptable.

(d) If an operator fails to submit to the Conservation Division any initial report required by this Section within eighteen (18) months after the effective date of the order permitting the well, then the terms of the order permitting the well or enhanced recovery project shall expire.

[**Source:** Amended at 11 Ok Reg 3691, eff 7-11-94]

165:10-5-10. Transfer of authority to inject

(a) An order authorizing an enhanced recovery well(s), salt water disposal well, commercial salt water disposal well, or hydrocarbon storage well(s) shall not be transferred from one operator to another without the following:

(1) Notice in writing to the Commission on Form 1073I. For transfers involving more than ten (10) wells, a transferor and transferee may file a single Form 1073I with the Conservation Division indicating the transfer of multiple wells, provided that such multiple well transfer shall be accompanied by a well list containing the following information for each well transferred:

(A) API number of the well;

(B) Well name and number;

(C) Legal location of the well, described by section, township and range; and

(D) The Commission Order number(s) authorizing the injection, disposal, or hydrocarbon storage activity.

(2) The well list may be provided in spreadsheet form, if possible, and may be filed in digital format specified by the Conservation Division. In lieu of the information listed in subparagraphs (a)(1)(A) through (D), the transferor and transferee, at their option, may file one Form 1073I indicating the transfer of multiple wells with an OCC Form 1002A Completion Report attached for each well transferred. Upon review by the Conservation Division, it may require additional information from the transferor and/or the transferee to assist in identifying the specific well(s) being transferred. The additional information may include, but not be limited to, the quarter, quarter, quarter section calls, footages from the south and west quarter section lines, and the drilling and completion dates, and initial injection, disposal or storage dates.

(3) Notice in writing to the Commission on Form 1075 demonstrating that a mechanical integrity test was performed within one year prior to the date of transfer. For commercial disposal wells, the Mechanical Integrity Test shall be conducted within 30 days prior to the date of transfer.

(4) The performance of the mechanical integrity test required in (a)(2) of this subsection shall not apply to any operator transfer when the following conditions are present:

(A) The interest of the currently designated operator is transferred to its subsidiary or parent company, or a subsidiary of a parent company;

(B) The interest of the currently designated operator is transferred to a surviving or resulting corporation or business entity due to, respectively, a merger, consolidation or reorganization involving the transferor and transferee. As used in this subparagraph, "business entity" means a domestic or foreign partnership, whether general or limited; limited liability company; business trust; common law trust, or other unincorporated business; or

(C) The currently designated operator undergoes a name change. The relief afforded by this subparagraph is not applicable to situations where the name change involves the following conditions:

(i) The assignment of a new Federal Employer Identification number by the Internal Revenue Service to the new company;

(ii) The name change is accompanied by a change in the majority of partners in a partnership;

(iii) The name change is associated with a divorce between a husband and wife when the husband and wife comprise a partnership;

(iv) The name change is associated with the death of one spouse in a partnership comprised of a husband and wife;
(v) The name change involves a sole proprietorship; or
(vi) The name change is associated with such other circumstances where the Commission determines upon application, notice and hearing that the relief provided in this subparagraph is not applicable, or that an exception to any exclusion should be granted.
(vii) As used in this subparagraph, the term "partnership" means a domestic or foreign partnership, whether general or limited.

(b) The Commission shall, within 30 days therefrom, return a copy of Form 1073I to the new and previous operator, designating approval or denial of the transfer of authority to inject for the subject well(s).

[**SOURCE:** Amended at 13 Ok Reg 2390, eff 7-1-96; Amended in Rule Making 97000002, eff 7-1-97; Amended in Rule Making 200000002, eff 7-1-00]

165:10-5-11. Notarized reports

In lieu of notarization, all Conservation Division reports shall contain the following statement signed and dated by the responsible party representing the entity which is submitting the report:
"I declare that I have knowledge of the contents of this report, which was prepared by me or under my supervision and direction, with the data and facts stated herein to be true, correct, and complete to the best of my knowledge and belief".

165:10-5-12. Application for administrative approval for the subsurface injection of onsite reserve pit fluids

Except upon a case-by-case approval of the Commission pursuant to 165:10-5-13, the subsurface injection of reserve pit fluids is prohibited into:
(1) A newly drilled well which is to be plugged and abandoned, or
(2) The casing annulus of:
(A) A well being drilled.
(B) A recently completed well.
(C) A well which has been worked over.

165:10-5-13. Application for permit for one time injection of reserve pit fluids

(a) **General.**
(1) Injection of reserve pit fluids shall be limited to injection of only those fluids generated in the drilling, deepening, or workover of the specific well for which authorization is requested.
(2) An annular injection site shall be inspected by a duly authorized representative of the Commission prior to injection.
(3) The applicant shall file with the Underground Injection Control an affidavit of delivery or mailing not later than five days after the application is filed.
(4) An operator who disposes of drilling fluid into the surface casing or annulus without approval from the Manager of Pollution Abatement shall be fined $2,500.00.

(b) **Criteria for approval.**
(1) Casing string injection may be permitted if the following conditions are met and injection will not endanger treatable water:
(A) Surface casing injection may be authorized provided that surface casing is set and cemented at least 200 feet below the base of treatable water, except as otherwise provided by the Commission; or
(B) Intermediate casing injection may be authorized provided that intermediate casing is set at least 200 feet below the base of treatable water, except as otherwise provided by the Commission.

(2) Injection pressure shall be limited so that vertical fractures will not extend to the base of treatable water.
(3) **Required form and attachments.** Each application for annular injection shall be submitted to the UIC Department on Form 1015T in quadruplicate. The forms must be properly completed and signed. Attached to one copy of the form shall be the following:
(A) Affidavit of mailing a copy of the Form 1015T or Form 1000 to the landowner and to each operator of a producing lease within 1/2 mile of the subject well.
(B) Cement Bond Log of subject well (if run).
(4) **Expiration of the permit.** The permit shall expire on its own terms three months after the date of issuance of the permit.
(c) **Emergency authority to inject into the annulus.** The Manager of the UIC Department may grant emergency authority to inject pit fluids into the annulus provided an imminent environmental endangerment exists.
(d) **Protest period.** If no protest is received within 15 days of the mailing of Form 1015T, the application shall be submitted for administrative approval. If a protest is received within the protest period, the operator shall, within 30 days, set and give proper notice of a date for hearing on the Pollution Docket before an Administrative Law Judge.

[SOURCE: Amended at 9 Ok Reg 2295, eff 6-25-92; Amended at 13 Ok Reg 2390, eff 7-1-96]

165:10-5-14. Exempt aquifers
(a) Upon application after notice and hearing, the Commission may issue an order designating an underground source of drinking water (USDW) as an exempted aquifer if the USDW:
(1) Does not currently serve as a source of drinking water.
(2) Cannot now and has no reasonable future prospect of serving as a source of drinking water because:
(A) It is mineral, hydrocarbon or geothermal energy producing source; or
(B) It is situated at a depth or location which makes recovery of water for drinking water purposes economically or technologically impractical; or
(C) It is so contaminated that it would be economically or technologically impractical to render that water fit for human consumption.
(b) For purposes of 165:10-3-4 and 165:10-5-2 through 165:10-5-13, an exempted aquifer shall not be considered as productive of treatable water.
(c) Each application under subsection (a) of this Section shall comply with 165:5-7-28.
(d) Each order designating a USDW as an exempted aquifer shall be subject to approval by the U.S. Environmental Protection Agency.

165:10-5-15. Application for permit for simultaneous injection well.
(a) **General.**
(1) Simultaneous injection of salt water without a valid permit from the Underground Injection Control Department will be subject to a fine of up to $5,000 per day of operation.
(2) A simultaneous injection facility shall be inspected by a representative of the commission prior to operation.
(b) **Criteria for approval.**
(1) Simultaneous injection may be permitted if the following conditions are met and injection will not adversely affect offsetting production nor endanger treatable water.
(A) Injection zone is located below the producing zone in the borehole.
(B) Injection pressure is limited to less than the local fracture gradient.
(C) If injection is by gravity flow, no Area of Review will be required.

(D) If injection is by positive pump pressure, a 1/4 mile Area of Review will be required. If unplugged or mud-plugged boreholes are located within the 1/4 mile radius, the operator of the proposed simultaneous injection well will be required to reconcile these boreholes prior to a permit being issued.
(E) Simultaneous injectors must meet the requirements of 165:10-3-4 as they apply to producing wells.
(F) Simultaneous injectors may be authorized to accept produced water from other wells. The UIC Department will determine on a case-by-case basis whether such a well warrants designation as a simultaneous injector, or whether the well requires a Commission order.

(2) **Required form and attachments.** Each application for simultaneous injection shall be submitted to the UIC Department on Form 1015SI in quadruplicate. The forms must be properly completed and signed. Attached to one copy of the application form shall be the following:
(A) Affidavit of mailing a copy of the completed Form 1015SI to each operator of a producing lease within 1/2 mile of the subject well.
(B) Schematic diagram of the well showing all casing and tubing strings, packers, perforations and pumps.

(3) **Monitoring, testing and reporting requirements for simultaneous injection wells.**
(A) Upon receiving a permit, operator shall file an amended Completion Report Form 1002A within 30 days of recompletion.
(B) Mechanical integrity will be demonstrated by filing annual reports of surface casing pressure, production casing pressure and fluid level.
(C) Annual Report Form 1012 shall be submitted prior to April 1 of each year for the previous calendar year.

(4) If no protest is received within 15 days of the mailing of Form 1015SI, the application shall be submitted for administrative approval. If a protest is received within the protest period, the operator shall, within 30 days, set and give proper notice of a date for hearing on the Pollution Docket before an Administrative Law Judge.

(c) **Expiration of the permit.** The permit shall expire on its own terms if the subject well is not recompleted or if a revised Form 1002A is not submitted within 180 days from the date on the permit.

[SOURCE: Added at 13 Ok Reg 2391, eff 7-1-96]

SUBCHAPTER 7. POLLUTION ABATEMENT

PART 1. GENERAL PROVISIONS

PART 2. ANODE GROUNDBEDS

PART 3. STORAGE AND DISPOSAL OF FLUIDS

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PART 1. GENERAL PROVISIONS

165:10-7-1. Pollution abatement [RESERVED]

165:10-7-2. Administration and enforcement of rules

The Manager of Pollution Abatement shall supervise and coordinate the administration and enforcement of the rules of this Subchapter under the direction of the Director of Conservation and the Commission.

165:10-7-3. Cooperation with other agencies

(a) The rules of this Subchapter shall not be construed as modifying the rights, obligations, or duties of any person under any law of this State or under any order, rule, or regulation of the Oklahoma Water Resources Board, State Department of Health, Oklahoma Wildlife Conservation Commission, State Board of Agriculture, Department of Pollution Control, or any other agency of this State with respect to the pollution of fresh water.
(b) Whenever a written complaint against any person is filed with the Commission alleging pollution as prohibited by 165:10-7-5, the Manager of Pollution Abatement shall immediately initiate such action as may be necessary or appropriate to abate the pollution.
(c) OPERATORS TAKE NOTE: Federal statutes, such as the Bald Eagle Protection Act (16 U.S.C. Sections 668-668d), the Migratory Bird Treaty Act (16 U.S.C. Sections 703-711), the Endangered Species Act (16 U.S.C. Sections 1531-1542), and the Lacey Act Amendments of 1981 (16 U.S.C. Sections 3371-3378), dictate substantial fines and penalties for persons who allow birds of certain species to become fatally injured due to incidental contact with oil or oil by-products. These fines may be levied upon persons allowing such fatalities to occur, whether accidental or not. Misdemeanor and felony convictions may include imprisonment. Information on affected bird species, regulations under these Acts, and measures which can be taken to prevent such occurrences, such as the netting or covering of open-topped tanks and pits which contain oil or oil by-products, can be obtained from the U.S. Fish and Wildlife Service Office in Oklahoma City or the nearest Oklahoma Department of Wildlife Office.

165:10-7-4. Water quality standards

(a) **Scope.** The Commission hereby adopts the State water quality standards established and promulgated by the Oklahoma Water Resources Board (OWRB) or its successors effective October 7, 1987, and additions and revisions as lawfully published in the Oklahoma Register effective as provided by statute. The Commission's Oil and Gas Conservation Division (Conservation Division) shall implement the water quality standards with regard to its particular jurisdictional areas as referred to in (c).
(b) **General considerations.**
   (1) The primary goal of the implementation of the water quality standards in the context of a remediation project subject to Commission jurisdiction shall be the protection and/or restoration of the beneficial use of the land, the soil and any surface or subsurface waters of the State adversely impacted or impaired by pollution from a Commission regulated site or facility.
   (2) A remediation project utilizing the water quality standards shall adhere to the general practices appearing in the Conservation Division's *Oklahoma Water Quality Standards Implementation Plan (WQSIP)*.
   (3) Where appropriate, a remediation project utilizing the water quality standards shall follow the use support assessment protocols (OWRB-OAC 785:46-7) as specified in *Oklahoma Water Quality Standards Implementation Plan*.

(c) **Specific areas of Conservation Division jurisdiction.** Compliance with the water quality standards for specific areas of the Conservation Division's jurisdiction requires compliance with rules applicable to these operations, found in Oklahoma Corporation Commission Oil and Gas Conservation rules OAC 165, Chapter 10. Responsible parties shall refer to and comply with the rules in OAC 165:10 that pertain to each of the environmental jurisdictional areas listed below as (1) through (10). The completion of a remediation project pursuant to this paragraph and compliance with rules pertaining to specific areas of Conservation Division jurisdiction shall be considered compliance with the water quality standards. The partial listing of rules in the Commission's "Guidance Document of Technical Measures" for technology-based pollution prevention measures in areas of jurisdictional responsibility (1) through (8) and (10), listed below, is for guidance only and is not intended to be an exhaustive notation. Similar applicable rules for jurisdictional area (9), below, are listed in the WQSIP. Review of the Conservation Division rules will be made on a case by case basis to determine compliance:

(1) Field operations for geologic and geophysical exploration for oil, gas and/or brine, including seismic shot holes, stratigraphic test holes or other test wells.

(2) Exploration, drilling, development, production or processing of oil, gas and/or mineral brine at the lease site.

(3) The exploration, drilling, development and operation of wells used in connection with the recovery, injection, or disposal of mineral brines including construction, operation, maintenance, closure and abandonment of the facilities and activities.

(4) Reclaiming and/or recycling facilities associated with the exploration, drilling, development, production or transportation of oil and/or gas (including the processing of saltwater, crude oil, natural gas condensate, tank bottoms or basic sediment from crude oil tanks, pipelines, pits and equipment).

(5) Underground injection control pursuant to the federal Safe Drinking Water Act and 40 CFR parts 144 through 148 for Class II injection wells, Class V wells used for the recovery, injection or disposal or mineral brines as defined in the Oklahoma Brine Development Act.

(6) Tank farms for storage of crude oil and petroleum products located outside the boundaries of refineries, petrochemical manufacturing plants, natural gas liquid extraction plants, or other facilities that are not subject to the jurisdiction of the Oklahoma Department of Environmental Quality.

(7) Construction and operation of pipelines and associated rights-of-way, equipment, facilities or buildings used in the transportation of oil, gas, petroleum, petroleum products, anhydrous ammonia or mineral brine, or in the treatment of oil, gas or mineral brine during the course of transportation [not including pipelines in natural gas liquids extraction plants, refineries, or reclaiming facilities other than those specified in OAC 165:10-7-4(c)(6)].

(8) The handling, transportation, storage and disposition of saltwater, drilling fluids, mineral brines, waste oil and other deleterious substances produced from or obtained or used in connection with the drilling, development, production, and operation of oil and gas wells at any facility or activity specifically subject to Commission jurisdiction or other oil and gas extraction facilities and activities.

(9) Spills of deleterious substances associated with facilities and activities specified in OAC 165:10-7-4(c)(8) or otherwise associated with oil and gas extraction and transportation activities.

(10) Groundwater protection for activities subject to the jurisdictional areas of environmental responsibility of the Commission.

(d) **Monitoring of sites.** Before consideration for closure by the Conservation Division or the Commission, the responsible party shall monitor a remediation project subject to implementation of the water quality standards for a period of one (1) year, unless:

(1) Otherwise provided by Commission order, or

(2) As directed by the Manager of Pollution Abatement or designated Conservation Division staff.

(e) **Public participation; Resolution of complaint or disagreement with Conservation Division staff.**

(1) In any case where the Conservation Division determines the need for public participation in the resolution of a pollution complaint involving the implementation of the water quality standards or other issues relating to pollution, the Conservation Division may file an application and notice of hearing to request resolution of the complaint by adjudicative hearing and Commission order.

(2) In any case where a pollution complaint involving the implementation of the water quality standards or other issues relating to pollution cannot be resolved administratively between the responsible party and the complainant or because of a disagreement with the Conservation Division's Manager of Pollution Abatement, Manager of Field Operations, or other Conservation Division staff, regarding the complaint, the responsible party or the complainant may file an application and notice of hearing to request resolution of the complaint by adjudicative hearing and Commission order.

[**SOURCE:** Amended in Rule Making 200100005, eff 7-1-01]

165:10-7-5. Prohibition of pollution

(a) **General.** Pollution is prohibited. All operators, contractors, drillers, service companies, pit operators, transporters, pipeline companies, or other persons shall at all times conduct their operations in a manner that will not cause pollution.

(b) **Workable coal seams.** Sections 305, 306, 307, and 308 of Title 52, Oklahoma Statutes Annotated, governing the drilling, operations, and plugging of oil and gas wells in workable coal beds are hereby adopted as rules of the Commission as fully as if set out verbatim herein.

(c) **Reporting nonpermitted discharges (spills, etc.).**

(1) All operators, contractors, drillers, service companies, pit operators, transporters, pipeline companies, or other persons conducting operations regulated by the Commission shall:

(A) Report verbally, with respect to their operations, to the Commission District Office or Field Inspector within 24 hours of discovery:

(i) Any non-permitted discharge of deleterious substances of ten bbls. or more (single event) to the surface.

(ii) Any discharge of a deleterious substance, regardless of quantity, to the waters of the State.

(B) File a written or oral report with the District Office within ten working days specifying the following:

(i) Name of party reporting, firm name, and telephone number.
(ii) Legal location.
(iii) Lease or facility name.
(iv) Operator.
(v) Circumstances surrounding discharge and whether discharge was to water or soil.
(vi) Date of occurrence.
(vii) Volumes discharged.
(viii) Type of materials discharged.
(ix) Method of cleanup (if any) undertaken and completed.
(x) Volumes recovered.

(C) Maintain adequate records of each non-permitted discharge reflecting the information, time, and manner of reporting pursuant to this Section for a minimum of three (3) years.
Such documents shall be produced upon demand by an authorized representative of the Commission.

(D) Report hazardous substances that meet reportable quantities under Comprehensive Environmental Response Compensation and Liability Act (CERCLA) (40 C.F.R. Part 302) in the format as required under this subsection.

(2) Any operator, contractor, driller, service company, pit operator, transporter, or pipeline company who fails to comply with provisions of this rule may be fined $500.00 per incident.

[**SOURCE:** Amended at 9 Ok Reg 2295; Amended at 9 Ok Reg 2337, eff 6-25-92; Amended in Rule Making 97000002, eff 7-1-97]

165:10-7-6. Protection of municipal water supplies

The Commission, upon application of any municipality or other governmental subdivision, may enter an order establishing special field rules within a defined area to protect and preserve fresh water and fresh water supplies.

165:10-7-7. Informal complaints, citations, red tags, and shut down of operations

(a) This Section applies only to Field Operations Department of the Oil and Gas Conservation Division.

(b) For an alleged violation of an order or provision of this Chapter, a district manager or field inspector may attempt to contact the alleged violator or his agent, in person or by telephone. In addition, the district manager of field inspector may notify the alleged violator by mailing or delivering either Form 1036. The Form 1036 shall warn a person about an alleged violation, and it shall specify a time period for compliance. The Form 1036A shall be used for purposes of the monetary fines procedure in 165:10-7-9. Mailing of either form may be to the last known address of the alleged violator according to Commission records.

(c) Where surface or subsurface pollution is apparent, a district manager or field inspector may direct an alleged violator to take steps necessary to stop and/or clean up pollution. Said steps may include a temporary shut down of the lease or facility. If an alleged violator cannot be located, the district manager or field inspector may take emergency action necessary to abate pollution.

(d) If a district manager or field inspector issues a Form 1036, an inspection of the lease or facility shall be made after the compliance period shown on the form. If the inspection shows that the alleged violator failed to comply as directed, the district manager or field inspector may:

(1) Issue a Form 1036A, where applicable,

(2) Refer the matter to the Office of General Counsel for prosecution, and/or

(3) Temporarily shut down the lease or facility until further notice from the Commission.

(e) In shutting down a lease or facility, the district manager or field inspector shall affix at the site a red tag (directive to shut down). If the alleged violator removes or ignores a red tag, the Commission shall levy a monetary fine against him. The fine shall be $5,000.00.

[**Source:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended at 12 Ok Reg 2017, eff 7-1-95]

165:10-7-8. Inspection and enforcement [RESERVED]

165:10-7-9. Scheduled monetary fines

(a) **Scope.** This Section prescribes amounts and procedure for imposing monetary fines arising from the categories of rule violations shown on Schedules A and B, Appendix E and F, respectively to this Chapter.

(b) **Issuance of complaint-citations.**

(1) If the Conservation Division discovers an alleged violation in any category on Schedule A, it may issue a complaint-citation on Form 1036A.

Said form shall describe the alleged rule violation, and it shall prescribe a monetary fine.

(2) If the Conservation Division discovers an alleged violation in any category on Schedule B, it may issue a complaint-citation on Form 1036A. Said form shall describe the alleged rule violation. It shall establish a time period for compliance without a monetary fine. It shall prescribe a Schedule B fine if the alleged violator fails to comply with Commission rules within the specified time period for compliance.

(c) **Notice.** Any complaint-citation (OCC Form 1036A) issued under this Section shall be mailed or delivered to the alleged violator at the last known address shown on Commission records.

(d) **Hearing option.**

(1) Any alleged violator shall have the option to pay the prescribed fine or contest it at an evidentiary hearing. Payment of the fine within the time provided on the complaint-citation shall be considered and accepted as a plea of no contest.

(2) To obtain an evidentiary hearing, the alleged violator must request it at the preliminary hearing described on the complaint-citation. Failure to timely request an evidentiary hearing may result in an order assessing the fine prescribed by the complaint-citation.

(3) Appeal from any report of the Administrative Law Judge shall be to the panel of Commissioners in accordance with the Rules of Practice, OAC 165:5.

(e) **Payment of fines.** A person may pay a fine with cash, a money order, or check; provided, that any cash payment must be made at a Commission cashier's window. All checks must be made payable to the Oklahoma Corporation Commission. A copy of the complaint-citation must accompany payment to ensure proper credit.

(f) **Additional enforcement measures.**

(1) The Conservation Division and the Secretary of the Corporation Commission may issue one or more complaint-citations to a person who fails to bring a lease and/or facility into compliance with the rules of this Chapter.

(2) Until payment in full or payment schedule has been determined, the Conservation Division may shut-down any lease and/or facility associated with an overdue fine assessed by Commission order after notice and hearing.

[**SOURCE:** Added at 9 Ok Reg 2295, eff 6-25-92]

PART 2. ANODE GROUNDBEDS

165:10-7-14. Anode groundbeds

(a) **Definitions.** The following words or terms, when used in this Section, shall have the following meaning, unless the context clearly indicates otherwise:

(1) **"Anode"** means the electrode of an electrochemical cell at which oxidation occurs.

(2) **"Cathodic protection"** means a technique used to reduce the corrosion of a metal surface by making that surface the cathode of an electrochemical cell.

(3) **"Deep anode groundbed"** means one or more anodes installed vertically at a depth of fifty (50) feet or more below the earth's surface in a drilled hole for the purpose of providing cathodic protection.

(4) **"Shallow anode groundbed"** means one or more anodes installed either vertically or horizontally at a nominal depth of less than fifty (50) feet.

(5) **"Annular space"** means the space between the surface casing and the borewall or the space between two or more strings of casing placed in the borehole.

(6) **"Operator"** means the person who is duly authorized and in charge of the development of the operation of the pipeline or the development of a lease for the production of hydrocarbons.

(b) **Permit to drill.**

(1) The operator shall make application on Form 1000B and obtain a permit to drill a deep anode groundbed.
(2) A permit to drill shall be valid only for one or more deep anode groundbeds within a designated 10 acre tract.
(3) The Commission shall approve or deny the application within 30 days of date of receipt.
(4) Any contractor drilling a deep anode groundbed shall be licensed within the State of Oklahoma.
(5) Any operator who drills a deep anode groundbed without a permit shall be subject to a fine of one thousand dollars ($1,000.00).

(c) **Expiration.** A permit to drill shall expire six (6) months from the date of issuance, unless drilling operations are commenced.

(d) **Posting of permit to drill at the site.** During any activity subject to this Section the operator shall maintain at the site a legible copy of the permit to drill for inspection.

(e) **Notice.** The Commission's District Manager or Field Inspector shall be given at least twenty-four (24) hours notice prior to commencing drilling operations.

(f) **Notice of failure to comply with permit conditions.** The operator shall notify the district office or the field inspector within twenty-four (24) hours of any failure to comply with the construction requirements approved on the permit.

(g) **Deep anode groundbed abandonment.**
(1) In the event the hole is lost during drilling, the hole will be plugged as soon as possible.
(2) Upon abandonment of a deep anode groundbed, the hole shall be plugged within thirty (30) days of abandonment.

(h) **Construction standards.**
(1) **Shallow anode groundbeds.**
(A) Shallow anode groundbeds shall be constructed in order to prevent runoff water from entering the anode system or the commingling of water from separate groundwater bearing formations.
(B) Vertical shallow groundbeds shall be sealed by backfilling the hole with native cuttings or an approved sealing material.
(2) **Deep anode groundbeds.**
(A) Deep anode groundbeds shall be constructed in order to prevent runoff water from entering the anode system or the commingling of groundwater formations with different water quality.
(B) Surface casing shall be set a minimum of twenty (20) feet below ground level, or at a depth previously approved by the Oil and Gas Division's Technical Department.
(C) If surface casing is not placed in the hole, the hole shall be filled with bentonite or cement from the top of the Coke Breeze Column to three (3) feet below surface. Native cuttings or soil shall be used to fill the remaining portion of the hole.
(D) The annular space between the casing and drilled hole shall be a minimum of two (2) inches to allow for a proper seal.
(E) The sealing material for the annular space for surface casing shall be bentonite, cement or a material previously approved by the Oil and Gas Division's Technical Department.
(F) Centralizers shall be used at a minimum of one (1) for every twenty-five (25) feet of surface casing run in the hole unless previously approved by the Oil and Gas Division's Technical Department on form 1000B.
(G) The groundbed shall be capped to prevent the entry of foreign material. Allowances for a vent pipe will be approved.

(i) **Groundbed materials.** Groundbed materials that do not contaminate groundwater shall be required at all times.

(j) **Plugging requirements.**
(1) All wires and vent pipe must be cut off at the top of the ten (10) foot surface plug, and the vent pipe must be securely capped and plugged.
(2) Cased holes shall be filled to at least ten (10) feet from the surface with native cuttings, anode materials, cement or with a material approved by the Pollution Abatement Department.

(3) Cement or bentonite shall be placed in the hole at a minimum of ten (10) feet below the surface to within three (3) feet of the surface. The remainder of the hole shall be filled with native cuttings, soil or a material approved by the Pollution Abatement Department.
(4) If the standard method is inadequate to stop artesian flow, alternate remedies must be employed to do so.
(5) All holes shall be properly completed or plugged to protect groundwater.

[**SOURCE:** Added in Rule Making 97000002, eff 7-1-97]

PART 3. STORAGE AND DISPOSAL OF FLUIDS

165:10-7-15. Drilling or seismic activity near superfund sites or hazardous waste facilities

Any drilling or seismic activity related to oil or gas exploration or production shall be prohibited within 500 feet of the boundary of any superfund site pursuant to the Comprehensive Environmental Response Compensation and Liability Act (CERCLA), 42 U.S.C. Sections 9601, et. seq., or active hazardous waste treatment, storage, or disposal facility. A current listing of all superfund sites and active hazardous waste facilities is available from the Manager of Pollution Abatement. Seismic work, monitoring wells, or recovery wells necessary for identification, monitoring, or remediation of the superfund site or hazardous waste facility shall be exempt from this Section. Any request for exception to this Section shall comport with the requirements generally for filing of applications under the Commission's Rules of Practice (see 165:5-7-1); in addition, notice shall be given to the Oklahoma State Department of Health, 1000 Northeast Tenth Street, Oklahoma City, Oklahoma 73152.

165:10-7-16. Use of noncommercial pits

(a) **Scope.** This Section shall cover the permitting, construction, operation, and closure requirements for any noncommercial pit. A noncommercial pit is an earthen pit which is located either on-site or off-site and is used for the handling, storage, or disposal of drilling fluids and/or other deleterious substances produced, obtained, or used in connection with the drilling and/or operation of a well or wells, and is operated by the generator of the waste. This does not cover disposal well pits. (See 165:10-7-20 and 165:10-9-3.)
(b) **Liner requirements.**
(1) **Reserve/circulation and/or completion/fracture/workover pits.**
(A) To assist in determining the construction requirements for a particular proposed reserve/circulation pit, either on-site or an off-site, the operator of the pit shall indicate on Form 1000 the type of mud system(s) to be used, the maximum and average anticipated chloride concentration of the mud (based on drilling records in the area), whether or not pit fluids will be segregated, and shall furnish other information required by this Section or requested by the Commission's Technical Department.
(B) The Commission's Technical Department shall evaluate the site based upon Oklahoma Geological Survey maps and other pertinent information and shall assign one of the following categories to any proposed reserve/circulation pit, designating same on Form 1000 and indicating whether or not a liner is required:
(i) **Category 1A - Geomembrane liner.**
(I) **Water based drilling fluid containment and/or water-based completion/fracture/workover fluid containment located over a alluvial deposit or in a near surface static water level environment.** Any pit used to contain water-based drilling fluids, cuttings and/or completion/ fracture/ workover fluids located in alluvial deposit area or an area where the static water table is

within 10 feet of the surface shall utilize a geomembrane liner for all drilling fluids and cuttings and/or completion/ fracture/ workover fluids.

(II) **Water-based drilling fluid containment and/or water-based completion/fracture/workover fluid containment located within a wellhead protection area.** Any pit used to contain water-based drilling fluids, cuttings and/or completion/fracture/workover fluids located within a wellhead protection area (WPA) as identified by the Wellhead Protection Program (42 U.S.C. Section 300h-7, Safe Drinking Water Act), or within one mile of an active municipal water well for which the WPA has not been delineated, shall be required to have a geomembrane liner.

(ii) **Category 1B - Soil liner or geomembrane liner.**

(I) **Water-based drilling fluid containment and/or water-based completion/fracture/workover fluid containment located over a terrace deposit.** Any pit used to contain water-based drilling fluids, cuttings and/or completion/ fracture/ workover fluids located over a terrace deposit shall be required to have either a soil liner or a geomembrane liner.

(II) **Water-based drilling fluid containment and/or water-based completion/fracture/workover fluid containment located over a bedrock aquifier or Hydrologically Sensitive Area(HSA).** Any pit used to contain water-based drilling fluids, cuttings and/or completion/ fracture/workover fluids located over any bedrock aquifer or HSA and is used to contain water-based drilling fluids and/or cuttings and/or completion/fracture/workover fluids with chlorides in excess 5,000 mg/l shall be required to have a soil liner or a geomembrane liner. A separate unlined pit may be used to contain fluids and/or cuttings with a chloride content of less than of 5,000 mg/l.

(iii) **Category 2 - Water-based/other situations.** Any pit which is used to contain water-based drilling fluids, cuttings and/or completion/fracture/workover fluids with a set of conditions different from Categories 1A and 1B shall not be required to be lined.

(iv) **Category 3 - Oil-based.** Any pit used to contain oil-based drilling fluids, cuttings and/or completion/fracture/workover fluids shall be required to have a geomembrane liner.

(v) **Category 4 - Air-based.** Any pit used to contain the cuttings from an air-based system shall not be required to be lined.

(2) **Other type pits.**

(A) Any basic sediment pit shall be required to have a geomembrane liner.

(B) Any emergency pit shall not be required to be lined.

(C) Any flare pit shall not be required to be lined.

(D) Any recycling/reuse pit, spill containment pit, or remediation pit shall conform to the same criteria for determining liner requirements for reserve/circulation and/or completion/fracture/workover pits, pursuant to (b)(1) of this Section.

(3) **Converted pits.** Any pit that is to be converted from one use to another, e.g., reserve pit to completion or fracture pit, shall have the more stringent liner requirements, pursuant to (c)(6) and (c)(7) of this Section.

(4) **Offsite pits.** Any offsite pit shall conform to the liner requirements in this Section and will require a permit. The operator of the proposed pit shall submit Form 1014 in duplicate to the appropriate District Office for review and approval. No offsite reserve pit may be permitted or constructed at a spacing closer than one pit per governmental quarter quarter section and a distance less than 600 feet from any other pit. Any offsite reserve pit may be reclassified or considered as a commercial pit, pursuant to 165:10-9-1, if it is constructed or used at a spacing closer than one reserve pit per governmental quarter quarter section. Closure of any offsite reserve pit shall not warrant the permitting of another offsite reserve pit within the same governmental quarter quarter section. For use of a pit without a permit, the pit operator may be fined up to $1,000.00.

(5) **Variances.** Any variance from the liner requirements of this Section may be granted by the Manager of the Technical Department after receipt of a written request and supporting documentation required by the Department.

(c) **Construction requirements.**

(1) **Field or area rules.** Any noncommercial pit which is to be constructed or used in an area covered by a field or area rule shall be subject to the more stringent requirements of either this Section or the field or area rule.

(2) **Stockpiling of topsoil.** Prior to constructing any noncommercial pit, except an emergency pit, all top soil within the top twelve inches shall be stripped and stockpiled for use as the final cover of fill at the time of closure. The top soil may be stockpiled in the berms, provided it is not mixed with other materials and can be readily distinguishable from other materials at the time of closure.

(3) **Exclusion of runoff water.** Any noncommercial pit shall be constructed and maintained so that runoff water from outside the location is not allowed to enter it.

(4) **Flood protection.** Any noncommercial pit which is constructed in any area subject to frequent flooding according to the Soil Conservation Service County Soil Survey shall have berms substantial enough to prevent overtopping or washing out.

(5) **Constructing on fill.** Any noncommercial pit which requires a liner and is constructed on fill shall be constructed so that the maximum level of the solid contents will be maintained at least three feet below the natural ground level.

(6) **Soil liners.**

(A) Soil materials used or to be used in a soil liner shall undergo permeability testing either before or after construction, unless exempt pursuant to (B) of this paragraph.

(i) Pre-construction permeability testing shall consist of laboratory permeability tests on at least two specimens of representative soil liner materials compacted in the laboratory to approximately 90 percent of the material's Standard Proctor Density (ASTM D-698).

(ii) Post-construction permeability testing shall consist of at least two laboratory permeability tests on undisturbed samples of the completed soil liner or one field permeability test on the completed soil liner. Particular emphasis shall be placed on selecting the location(s) for permeability tests or test samples where nonuniformity in soil texture or color can be observed.

(iii) Laboratory permeability test procedures must conform to one of the methods described for fine-grained soils in the Corps of Engineers Manual EM-1110-2-1906 Appendix VII. In no case shall the pressure differential across the specimen exceed five feet of water per inch of specimen length. Field permeability tests shall be conducted only by the double ring infiltrometer method as described in ASTM D-3385. Permeability tests may be discontinued prior to flow stabilization upon satisfactory evidence that the permeability rate is less than 1.0×10^{-6} cm/sec.

(iv) If permeability testing shows that addition of bentonite or other approved material is needed to assist the native soils in meeting the permeability standard, it shall be applied at a minimum rate specified by the testing or engineering firm. Any bentonite used for liner material shall not have been previously used in drilling muds.

(B) Permeability testing requirements for soil materials may be exempt if laboratory testing of a minimum of two representative samples of the soil materials found throughout the entire depth of the proposed excavation indicates that the plasticity index is greater than 16 (ASTM D-4318) and that the amount passing the No. 200 U.S. standards sieve is greater than 60 percent (ASTM D-1140).

(C) Any soil liner shall be constructed by disturbing the soil to the depth of the bottom of the liner, applying fresh water as necessary to the soil materials to achieve a moisture content wet of optimum, then recompacting it with heavy construction equipment, such as a footed roller, until the required density is achieved, pursuant to (H) of this paragraph.

(D) Any soil liner shall cover the bottom and interior sides of the pit entirely.

(E) Any soil liner shall be installed on a slope no steeper than 3:1 (horizontal to vertical).

(F) Any soil liner shall have a minimum thickness of six inches (after compaction), and shall have a maximum coefficient of permeability of 1.0 x 10^{-6} cm/sec, unless it conforms to (G) of this paragraph.

(G) A soil liner may have a coefficient of permeability greater than 1.0 x 10^{-6} cm/sec if it is greater in thickness and constructed in accordance with the following:

(i) A minimum twelve inch compacted soil liner shall have a maximum coefficient of permeability of 2.0 x 10^{-6} cm/sec.

(ii) A minimum 18 inch compacted soil liner shall have a maximum coefficient of permeability of 3.0 x 10^{-6} cm/sec.

(iii) A compacted soil liner may not be constructed thicker than 18 inches for the purpose of meeting a coefficient of permeability greater than 3.0 x 10^{-6} cm/sec.

(iv) Any soil liner with a minimum twelve inch or 18 inch thickness shall be constructed in maximum lifts of six inches (after compaction). Each lift shall be scarified before placement of the next lift and shall conform to (H) of this paragraph.

(H) Any soil liner shall be field tested for compaction, unless a post-construction permeability test is performed, pursuant to (A)(ii) of this paragraph.

(i) A minimum of six compaction tests shall be performed on any soil liner; a minimum of four widely spaced tests in the bottom of the pit and two tests on different slopes of the pit are required, unless otherwise directed by a Field Operations representative. Particular emphasis shall be placed on selecting locations for compaction tests where nonuniformity in soil texture or color can be observed.

(ii) Compaction tests shall be conducted in accordance with ASTM methods D-2922 or D-1556.

(iii) The soil materials of any liner shall be compacted to at least 90 percent of the Standard Proctor Density (ASTM D-698).

(7) **Geomembrane liners.**

(A) Any geomembrane liner that is installed in a reserve/circulation pit, spill prevention pit, or remediation pit, completion/fracture/workover pit, basic sediment pit, or recycling/reuse pit shall have a minimum thickness of 20-mil.

(B) Any geomembrane liner used in a noncommercial pit shall be chemically compatible with the type of substances to be contained and shall have ultraviolet light protection.

(C) Any geomembrane liner shall be placed over a specially prepared, smooth, compacted surface void of sharp changes in elevation, rocks, clods, organic debris, or other objects.

(D) Any geomembrane liner shall be continuous, although it may include seams, and shall cover the bottom and interior sides of the pit entirely. The edges shall be securely placed in a minimum twelve inch deep anchor trench around the perimeter of the pit.

(8) **Certification of liner.** The operator of any noncommercial pit that is constructed with a soil or geomembrane liner shall secure an affidavit signed by the installer, certifying that the liner meets minimum requirements and was installed in accordance with Commission rules. It shall be the operator's responsibility to maintain the affidavit and all supporting documentation pertaining to the liner (e.g., permeability and compaction test results, bentonite receipts, and geomembrane liner specifications from the manufacturer), and shall make them available at all times for review by any representative of the Conservation Division.

(d) **Operation and maintenance requirements.**

(1) **Freeboard.** The fluid level of any noncommercial pit shall be maintained at all times at least 24 inches below the lowest elevation on the top of the berm.
(2) **Reserve/circulation pits.** The operator of any reserve/circulation pit shall limit its contents to the fluids and cuttings from a single well.
(3) **Off-site reserve pits.** A waterproof sign shall be posted within 25 feet of any off-site reserve pit and shall bear the name of the operator, legal description to the quarter quarter quarter section, permit number, and emergency telephone number.
(4) **Recycling/reuse pits.**
(A) Any pit permitted for drilling mud recycling or reuse may contain the fluids and cuttings from multiple wells, provided that those wells are operated by the pit operator.
(B) A waterproof sign shall be posted within 25 feet of any recycling/reuse pit and shall bear the name of the operator, legal description to the quarter quarter quarter section, permit number, and emergency telephone number.
(5) **Prevention of pollution.**
(A) All noncommercial pits shall be constructed, used, operated, and maintained at all times so as to prevent pollution. In the event of a nonpermitted discharge from a noncommercial pit, sufficient measures shall be taken by the operator to stop or control the loss of contents, and reporting procedures pursuant to 165:10-7-5(c) shall be followed. Any materials lost from a pit shall be cleaned up as directed by any Field Operations representative. For a willful non-permitted discharge from a noncommercial pit, the operator may be fined up to $2,000.00.
(B) The protection of migratory birds shall be the responsibility of the operator. Therefore, the Conservation Division recommends that to prevent the loss of birds, oil be removed or the surface area covered by the oil be protected from access to birds. [See Advisory Notice 165:10-7-3(c)].

(e) **Closure requirements.**
(1) **Designation of disposal method.** The operator of any reserve/circulation pit shall indicate the proposed method of disposal of drilling fluids and/or cuttings on Form 1000 as required by 165:10-3-1(f). Options shall be limited to the following, unless written approval is granted by a Field Operations representative:
(A) Evaporation/dewatering and backfilling.
(B) Chemical solidification of pit contents.
(C) Annular injection (requires permit).
(D) Land application (requires permit).
(E) Disposal in permitted commercial pit.
(F) Disposal at permitted commercial soil farming facility.
(G) Disposal at permitted recycling/reuse facility.
(2) **Trenching.**
(A) Before trenching, stirring or otherwise disturbing the bottom of any noncommercial pit, the pit shall be completely dewatered.
(B) Trenching, stirring, or other similar practice shall be prohibited for any lined pit.
(3) **Lined pits.**
(A) When closing any noncommercial pit with a soil or geomembrane liner, extreme care shall be taken to preserve the integrity of the liner.
(B) For any lined reserve/circulation pit, completion/fracture/workover pit, recycling/reuse pit, or basic sediment pit, all free liquids shall be removed or chemically solidified with nonhazardous material.
(C) For any lined oil-based reserve/circulation pit, all cuttings remaining in the pit shall be chemically solidified with nonhazardous material.
(D) Soil cover, pursuant to (5) of this subsection, shall follow.
(4) **Soil cover.** Closure procedures for any noncommercial pit shall include a minimum of three feet of soil cover over any remaining pit contents, with all stockpiled topsoil being applied last. The materials shall be mounded or sloped to encourage runoff. A variance from this provision may be granted by a Field Operations District Office for justifiable cause. A

written request and supporting documentation is required. The Field Operations office shall respond in writing within five working days either approving or disapproving the request.

(5) **Erosion control.** Any noncommercial pit shall be closed in such a manner that any future erosion will not cause the discharge of the pit contents. This may require vegetative cover and/or a diversion terrace(s).

(6) **Notification to District Office.** The operator of any noncommercial pit shall notify the appropriate Field Inspector or District Office at least 48 hours prior to commencing closure, and for reserve/circulation pits shall advise if the disposal method is different from that indicated on Form 1000. The operator shall also notify the Field Inspector or District Office within 48 hours after reclamation of the site has been completed.

(7) **Time limits.** Any noncommercial pit shall be closed within the time limits set forth in this paragraph. Any extension of time for pit closure must be requested by the operator, who shall file an application pursuant to OAC 165:5-7-33. A legal change of operator of any noncommercial pit shall not extend the time limit for closure. If a noncommercial pit is converted from one type of use to another, the last use shall determine the time limit for closure.

(A) Any Category 1A, 1B or ~~3~~ 2 reserve/circulation pit, either on-site or off-site, shall be closed within twelve months after drilling operations cease.

(B) Any Category 3 reserve/circulation pit, either on-site or off-site shall be closed within six months after drilling operations cease.

(C) Any Category 4 pit shall have closure procedures commenced within 30 days and completed within 90 days after drilling operations cease.

(D) **Completion/fracture/workover pits.**

(i) Any reserve/circulation pit converted to a completion/fracture/workover pit shall be closed within six (6) months after drilling operations cease. Upon request by the operator, a six (6) month extension shall be granted by the Conservation Division, after review by a field inspector to confirm the pit is in compliance with 165:10-7-16 (c) and (d)requirements.

(ii) Any completion/fracture/workover pit not converted from a reserve/circulation pit shall be closed within 60 days after completion, fracture, or workover operations cease.

(E) Any emergency pit shall be emptied of its contents as soon as possible and closed within 60 days after the emergency situation ceases to exist.

(F) Any flare pit shall be closed within 30 days of abandonment of a lease.

(G) Any spill containment pit shall be closed within 30 days of abandonment of a lease.

(H) Any basic sediment pit shall be closed within 60 days after use of the pit ceases.

(I) Any recycling/reuse pit shall be closed within twelve months after operations cease.

(J) Any remediation pit shall be closed immediately after receipt of all contaminated materials.

(8) For failure to comply with any closure requirement, the operator may be fined up to $1,000.00.

(9) **Waiver of closure requirements.** Exemption from closure and transfer of responsibility for any noncommercial pit to the surface owner or other party shall be requested by filing an application pursuant to OAC 165:5-7-34. No approval shall be granted unless the analyses of the fluids show that the following ranges or concentrations are not exceeded:

(A) pH - 6.0-9.5 s.u.
(B) Chlorides - 3500 mg/l
(C) Total Dissolved Solids (TDS) - 7000 mg/l
(D) Chromium (Total) - 10 mg/l
(E) Arsenic - 20 mg/l

[**Source:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended at 12 Ok Reg 2017, eff 7-1-95; Amended in Rule Making 980000035, eff 7-1-99]

165:10-7-17. Surface discharge of fluids

(a) **Scope.** This Section shall cover the surface discharge of hydrostatic test water, storm water from diked areas, and produced water from tanks or other containment vessels.

(b) **Discharge of hydrostatic test water.**

(1) Hydrostatic test water used in the testing of new pipeline segments, new casing, new tubing, new tanks and new vessels, may be discharged as necessary without a permit, notification to the Commission, or adherence to any other provisions of this Section, provided the following conditions are met:

(A) **Low chlorides.** Chloride concentration does not exceed 1000 mg/l.

(B) **Sheen.** There shall be no visible sheen or discoloration as a result of testing; however, certain dyes used to establish mechanical integrity may be approved.

(C) **Notice to District Office.** Any discharges exceeding 1,000 barrels shall require notification to the appropriate District Office.

(2) Hydrostatic test water used in the testing of existing tanks, vessel lines and transmission pipelines may be discharged upon notification to the Oklahoma Corporation Commission appropriate District Office on Form 1014HD provided that the following conditions are met:

(A) **Oil and grease.** The oil and grease content of the discharge water shall not exceed 15 mg/l.

(B) **Sheen.** There shall be no visible sheen or discoloration as a result of testing; however, certain dyes used to establish mechanical integrity may be approved.

(C) **Total Suspended Solids (TSS).** The TSS shall not exceed 45 mg/l.

(D) **pH.** The pH shall not be less than 6.5 nor exceed 9 s.u.

(E) **Foreign material.** The discharge must be free from foreign material such as welding scrap tank sediments or sand blasting waste material.

(F) **Soil erosion.** Standard soil erosion prevention procedures shall be required.

(3) Hydrostatic test water that meets the requirements listed in (b) (2) of this Section may be discharged in volumes less than 15 bbls without filing Form 1014HD.

(4) Hydrostatic test water that will be discharged to land and not directly into waters of the state and which may exceed the discharge parameters specified in (b) (2), shall be discharged only upon submission and approval by the Pollution Abatement Department of a plan for one-time discharge.

(5) Hydrostatic test water not covered under (b)(1) from transmission lines and tanks that contain waste products that are listed as hazardous waste under the Resource Conservation and Recovery Act and have not been cleaned or pigged must meet the following discharge requirements in addition to (b)(2) of this Section:

(A) The following parameters may not be exceeded: Benzene, .028 MG/L; toluene, .3 MG/L; phenol, .250 MG/L.

(B) EPA analytical method 8020 shall be used unless approved by the Manager of Pollution Abatement.

(c) **Discharge of storm water.** Storm water accumulations in any diked area built for the containment of tank battery spills may be discharged as necessary without a permit, notification to the Commission, or adherence to any other provisions of this Section, provided the following conditions are met:

(1) **No hydrocarbons.** A visual inspection of the storm water is made and there is no sheen or other visible evidence of hydrocarbons being present.

(2) **Low chlorides.** Chloride concentration does not exceed 1000 mg/l.

(3) **Conditions recorded.** The operator records the conditions required by (1) and (2) in this subsection for each discharge, maintains those records for a period of three (3) years, and makes them available upon request to any representative of the Field Operations Department.

(d) **Discharge of produced water.**

(1) **Site restrictions.** Discharge of produced water shall only occur on land having an Exchangeable Sodium Percentage (ESP) no greater than 15, pursuant to

(f)(3) of this Section, and all of the following characteristics as determined by the appropriate Soil Conservation District or by a qualified soils expert:

(A) A maximum slope of five percent.

(B) Depth to bedrock at least 20 inches.

(C) Slight salinity (defined as electrical conductivity less than 4,000 micromhos/cm) in the topsoil or upper six inches of the soil.

(D) A water table deeper than six feet from the soil surface, except a perched water table.

(E) A minimum distance of 100 feet from any stream designated by Oklahoma Water Quality Standards (available for viewing at the Commission's Oklahoma City Office and District Offices) or any fresh water pond, lake, or wetland (designated by the National Wetlands Inventory Map Series, prepared by the U.S. Fish and Wildlife Service and available for viewing at the Commission's Oklahoma City Office).

(2) **Water quality limitations.** A surface discharge permit shall not be issued if the produced water to be discharged exceeds either of the following concentrations:

(A) Total Dissolved Solids (TDS) - 5000 mg/l.

(B) Oil and Grease - 1000 mg/l.

(e) **Sampling requirements.**

(1) **Contact with District Office.** The appropriate District Office shall be contacted at least two working days prior to sampling to allow a Commission representative an opportunity to witness the sampling of the receiving soil and produced water to be discharged. A variance from this provision may be granted by a Field Operations office for justifiable cause. A written request and supporting documentation shall be required. The Field Operations office shall respond in writing within five working days after receipt, either approving or disapproving the request.

(2) **Produced water.** Produced water to be discharged shall be sampled using the following procedure, unless exempt pursuant to (f)(4) of this Section.

(A) Prior to sampling, fresh water shall not be added to any tank or other containment vessel for dilution or any other purpose.

(B) A sample of the produced water to be discharged shall be taken from the bottom of the tank or other containment vessel. A minimum two quart sample shall be placed into a foil or teflon covered, glass container. The container shall be filled completely to exclude air and delivered to the laboratory within seven days. No samples shall be altered in any way.

(C) Another sample of the produced water to be discharged (approximately one pint) shall be properly labeled and delivered or otherwise provided to a Field Operations office or Field Inspector, unless exempt by the District Manager.

(3) **Receiving soil.** Soil samples shall be taken from the proposed discharge area and analyzed, unless exempt pursuant to (f)(4) of this Section. A minimum of 20 representative surface core samples (0-6 inches) must be taken from each sample area, combined and thoroughly mixed, then a minimum one pint composite sample taken and placed in a clean container for delivery to the lab. No sample area shall exceed 40 acres.

(f) **Analysis requirements.**

(1) **Certified laboratory.** The samples of soil and produced water shall be analyzed by a laboratory operated by the State of Oklahoma or certified by the Oklahoma Water Resources Board, unless exempt pursuant to (4) of this subsection.

(2) **Parameters for produced water.** Parameters for analysis of the produced water shall include, but not be limited to, Total Dissolved Solids (TDS) and Oil and Grease.

(3) **Parameters for soil.** Parameters for analysis of the receiving soil shall include, but not be limited to, Electrical Conductivity or Total Soluble Salts (TSS) and Exchangeable Sodium Percentage (ESP).

(4) **Exemptions.** A Field Operations office may exempt the analysis of produced water if an analysis of the produced water from a well located within one mile and producing from the same formation has been previously submitted. Analysis of the receiving soil may be exempt if an analysis of the same soil type(s) within one mile of the proposed discharge site has been previously submitted.

(g) **Application for permit.**

(1) **Permit required.** No person shall discharge produced water from a tank or other containment vessel without applying for and obtaining a permit issued under this subsection. An operator discharging produced water without a permit shall be fined $1,000.00.

(2) **Who may apply.** Only the operator of the well associated with the tank or other containment vessel, the contents of which are sought to be discharged, may apply for a surface discharge permit.

(3) **Required form and attachments.** Each application for surface discharge of produced water shall be submitted to a Field Operations office on Form 1014D in quadruplicate. The forms shall be properly completed and signed. Attached to at least one of the forms shall be the following:

(A) A copy of written notice to the surface owner that the applicant intends to discharge produced water as per 165:10-7-17 to a specific portion of real property as designated by legal description.

(B) If the operator has an agent, a contractual agreement between the parties or an affidavit designating the contractor or agent.

(C) A well prepared map or diagram, drawn to scale, showing the proposed and potential discharge areas.

(D) Site suitability report, pursuant to (d)(1) of this Section, provided by a qualified soils expert (include qualifications).

(E) Analysis of produced water, unless exempt pursuant to (f)(4) of this Section.

(F) Soil analysis, unless exempt pursuant to (f)(4) of this Section.

(G) Other information as required by this Section or requested by a Field Operations office.

(4) **Review period.** The Field Operations office shall review the application, either approve or disapprove it, and return a copy of Form 1014D within five working days of submission of all required or requested information. If approved, a permit number shall be assigned to Form 1014D; if disapproved, the reason(s) shall be given. The applicant may make application for a hearing if it is not approved.

(h) **Maximum application rate.**

(1) **Soil loading standards.** The maximum application rate shall be calculated by the Field Operations office using the following soil loading standards. (Soil loading standards are based upon standards set forth in "Diagnosis and Improvement of Saline and Alkaline Soils," U.S. Agriculture Handbook 60. Pub. U.S. Salinity Laboratory, Riverdale, California, 1954. "Critical Concentrations for Irrigation Water Supplies," Water Quality Criteria, 1972 Ecological Research Series, EPA R2-73033, March, 1973).

(A) Total Soluble Salts - 6,000 lbs/acre (less TSS in soil).

(B) Oil and Grease - 500 lbs/acre.

(2) **Determination of most limiting parameter.** The maximum application rate shall be restricted by the most limiting parameter. It may require more than one application to achieve the maximum application rate while avoiding runoff. The Field Operations office shall indicate on the permit what the maximum application rate shall be after making the following calculations:

PROCEDURE FOR CALCULATING APPLICATION RATE OF TOTAL SOLUBLE SALTS (TSS)

______ppm TSS in soil[1] X 2 = ______lbs/ac TSS in soil

6000 lbs/ac TSS - ______ lbs/ac TSS in soil = Maximum TSS (lbs/ac) to be applied

Maximum TSS (lbs/ac) ______ ÷ (______ ppm TSS in water[1] X .000001) = Maximum lbs/ac of water to be applied ______

Maximum lbs/ac ______ ÷ ______lbs/bbl[2] = Maximum bbls/ac ______

PROCEDURE FOR CALCULATING APPLICATION RATE OF OIL AND GREASE

500 lbs/ac ÷ (______ppm in water X .000001) = Maximum lbs/ac of water to be applied ______

Maximum lbs/ac ______ ÷ ______ lbs/bbl[2] = Maximum bbls/ac ______

[1]Electrical Conductivity (EC expressed in micromhos/cm) may be used to estimate TSS: EC x 0.64 = ppm TSS.
[2]Based on documented weight of composite sample.

(i) **Conditions of permit.** Any discharge of produced water that is done under this Section shall be subject to the following conditions or stipulations of the permit.

(1) **Presence of representative.** A representative of the operator shall be on the discharge site at all times that water is being applied. A variance from this provision may be granted by a Field Operations office for justifiable cause. A written request and supporting documentation shall be required. The Field Operations office shall respond in writing within five working days after receipt, either approving or disapproving the request.

(2) **Weather restrictions.** Surface discharge shall not be done:

(A) During precipitation events or when precipitation is imminent.

(B) When the soil moisture content is at a level such that the soil would not readily take the addition of water.

(C) When the ground is frozen.

(D) By spray irrigation when the wind velocity is such that even distribution of water cannot be accomplished or the buffer zones, pursuant to (3) of this subsection, cannot be maintained.

(3) **Buffer zones.** Surface discharge shall not be done within the following buffer zones:

(A) Fifty feet of a property line boundary.

(B) Fifty feet of any stream not designated by Oklahoma Water Quality Standards.

(C) Three hundred feet of any actively-producing water well used for domestic or irrigation purposes.

(D) Eight hundred feet of any actively-producing water well used for municipal purposes.

(4) **Application rate.** The maximum application rate of produced water stipulated by the permit shall not be exceeded. Application of produced water outside the approved plot shall be prohibited. Accurate records shall be kept as to the quantities discharged and the dates of each discharge.

(5) **Discharge method.** Discharge of produced water shall be uniform over the approved discharge plot and shall be made by spray irrigation or other method approved by the Commission prior to use. The flood irrigation method shall be limited to those fields that normally are irrigated in that manner.

(6) **Runoff or ponding prohibited.** No runoff or ponding of discharged water shall be allowed during application.

(7) **Annual report.** An annual report shall be submitted by February 1 of each year and shall be made on Form 1014P. Attached to the annual report shall be current (within three months) analyses of the produced water and soil from the discharge plot, pursuant to (8) of this subsection.

(8) **Additional testing.** The produced water and soil shall be sampled and analyzed, pursuant to (e)(1) through (e)(3) and (f)(1) through (f)(3) of this Section, on an annual basis just prior to filing of the annual report. When a soil analysis indicates that 75 percent of the maximum application rate of TSS or Oil and Grease [(h) of this Section] has been applied or when the ESP exceeds 11, sampling shall be done quarterly or semiannually as determined by the Field Operations office.

(9) **Expiration of permit.** The permit shall expire by its own terms when testing, pursuant to (8) of this subsection, indicates that the concentration of TDS or Oil and Grease in the water exceeds the limitations of (d)(2) of this Section, or more than 98 percent of the maximum application rate of TSS or Oil and Grease [(h) of this Section] has been applied or the ESP exceeds 15.

(10) **Violations.** If the applicant violates the conditions of the permit or this Section, the surface discharge shall be discontinued and the Field Operations office shall be contacted immediately. The Field Operations office may revoke the permit and/or require the operator to do remedial work. If the permit is not revoked, surface discharge may resume with Field Operations' approval. If the permit is revoked, the operator may make application for a hearing to reinstate it.

[SOURCE: Amended at 9 Ok Reg 2295, eff 6-25-92; amended at 13 Ok Reg 2381, eff 7-1-96; Amended in Rule Making 97000002, eff 7-1-97]

165:10-7-18. Discharge to surface waters

Discharge of deleterious substances to streams or other surface waters is prohibited except by order of the Commission; unless permitted by a valid National Pollutant Discharge Elimination System (NPDES) Permit issued by U.S. EPA.

165:10-7-19. One-time land application of water-based fluids from earthen pits and tanks

(a) **Authority for land application.** No person shall land apply fluids except as provided by 165:10-9-2, 165:10-7-17, or this Section. Any operator failing to obtain a permit shall be fined $2,000.

(b) **Scope.** This Section shall cover the land application of water-based drilling fluids and cuttings from earthen pits, tanks, or other containment structures; however, this Section shall not be exclusive of other authorities for land application listed in (a) of this Section. Any land application made under this Section shall be done on a one-time basis from a single well to land that has not been previously permitted and used for this practice or similar practices.

(c) **Site suitability restrictions.** Land application shall only occur on land having all of the following characteristics below, as field verified by a soil scientist or other qualified person pre-approved by the Commission. Any variance from site suitability restrictions must be approved by the Oil and Gas Conservation Division (see (f)(2)(C) of this Section).

(1) **Maximum slope.**

(A) Five percent for all application methods except spray irrigation;

(B) Eight percent for the spray irrigation method.

(2) **Depth to bedrock.** Depth to bedrock must be at least 20 inches.

(3) **Soil texture.** A soil profile (as defined by USDA soil surveys) containing at least twelve inches (may be cumulative) of one of the following soil textures between the surface and the water table, unless a documented impeding layer of shale is present: loam, silt loam, silt, sandy clay loam, silty clay loam, clay loam, sandy clay, silty clay, or clay.

(4) **Salinity.** Slight salinity [defined as Electrical Conductivity (EC) less than 4,000 micromhos/cm] in the topsoil, or upper six inches of the soil, and a calculated Exchangeable Sodium Percentage (ESP) less than 10.0.

(5) **Depth to water table.** No evidence of a seasonal water table within six (6) feet of the soil surface as verified by field observation and published data.

(6) **Distance from water bodies.** A minimum distance of 100 feet from the land application site boundary to any perennial stream and 50 feet to any intermittent stream shown on the appropriate United States Geological Survey (U.S.G.S.) topographic map (available for viewing at the Commission's Oklahoma City Office and District Offices) and a minimum of 100 feet to any freshwater pond, lake, or wetland. [Designated by the National Wetlands Inventory Map Series, prepared by the U.S. Fish and Wildlife Service, available for viewing at the Commission's Oklahoma City Office (also, see (h)(6) of this Section)].

(7) **Site specific concerns.** Void of slick spots within or adjacent to the land application area, where subsurface lateral movement of water is unlikely, or areas void of concentrated surface flow such as gullies or waterways.

(d) **Sampling requirements.**

(1) **Notice to Field Inspector.** The appropriate Field Inspector shall be contacted at least two working days prior to sampling of the receiving soil and sampling of the drilling fluids and/or cuttings to be land applied from an earthen pit. This is to allow a Commission representative an opportunity to be present.

(2) **Receiving soil.** Sampling of the receiving soil shall be performed by, or under the supervision of, a soil scientist or other qualified person pre-approved by the Commission. Soil samples shall be taken from the proposed application area and analyzed. A minimum of four representative core samples from the surface (0-6 inches) and subsurface (14-20 inches) must be taken from each ten acres, or part thereof. Each group of surface core samples representative of a ten-acre area (or less) shall be combined and thoroughly mixed. A minimum one-pint composite sample shall be taken and placed in a clean container for delivery to the laboratory. Alternatively, soil samples may be composited by the laboratory. All subsurface samples shall be handled in the same manner.

(3) **Drilling fluids and/or cuttings.**

(A) **Earthen pits.** Drilling fluids and/or cuttings to be land applied shall be sampled using the following procedure:

(i) Prior to sampling, fresh water (except natural precipitation) shall not be added to any pit for dilution or any other purpose.

(ii) A minimum of four samples, each from different quadrants of the pit and representative of the materials to be land applied, must be taken if the volume to be land applied is 25,000 bbls. or less. If more than 25,000 bbls. are to be land applied, a minimum of four quadrant samples plus one sample for each 5,000 bbls. over 25,000 bbls. will be required. The samples shall be combined and thoroughly mixed, then a minimum two quart composite sample placed into a foil or teflon covered glass container. The container shall be filled completely to exclude air and delivered to the laboratory within seven days. No samples shall be altered in any way.

(iii) After samples have been taken for analysis from a pit, the operator shall not allow the addition of fluids or other materials, except natural precipitation or fresh water to decrease the viscosity of the fluid.

(B) **Tanks.** Sampling of the drilling fluids and/or cuttings shall occur after the application has been approved. A minimum of one representative sample must be taken from each tank or other containment structure, the contents of which are to be land applied.

(e) **Analysis requirements.**

(1) **Testing.**

(A) The composite sample(s) of soil shall be tested by a laboratory proficient in testing soils. Either a 1:1 extract or saturated paste extract shall be used for sample preparation.

(B) Methods of analysis.

(i) **Earthen pits.** The composite sample(s) of drilling fluids and/or cuttings shall be analyzed by a laboratory operated by the State of Oklahoma or certified by the Oklahoma Department of Environmental Quality.

(ii) **Tanks.** Samples of the drilling fluids and/or cuttings may be tested on-site. A filter press shall be used for preparation of samples. Tests must be performed by a person who is knowledgeable and experienced in the chemical testing of fluids. Acceptable on-site testing protocol may be obtained from a Field Operations office.

(2) **Parameters for receiving soil.** Parameters for analysis of the receiving soil shall include at a minimum EC and ESP.

(3) **Parameters for drilling fluids and/or cuttings.**

(A) **Earthen pits.** Parameters for analysis of the drilling fluids and/or cuttings shall include at a minimum EC and Oil and Grease (O&G). Dry Weight shall also be determined if a significant amount of solids will be land applied.

(B) **Tanks.** EC shall be a required parameter for analysis of drilling fluids and/or cuttings. Dry weight shall also be determined if a significant amount of solids will be land applied.

(f) **Application for permit.**

(1) **Who may apply.** Only the operator of a well or the operator's designated agent may apply for a land application permit under this Section, except that a commercial pit operator may also apply in case of emergency or for the purpose of facilitating repair or closure.

(2) **Required form and attachments.** Each application for land application of drilling fluids and/or cuttings shall be submitted to a Field Operations office on Form 1014S. An original and three copies shall be required. Attached to at least one of the copies shall be the following:

(A) Written permission from the surface owner to allow the applicant to land apply drilling fluids and/or cuttings. For purposes of obtaining such consent, the applicant shall use Form 1014L.

(B) A topographic map and the most recent aerial photograph (minimum scale 1:660) with the proposed and potential land application areas delineated as well as the location of cultural features such as buildings, water wells, etc. Both the topographic map and aerial photograph must show all areas within 1,320 feet of the boundary of the land application area.

(C) A site suitability report, pursuant to subsections (c) and (h)(6) of this Section, based on an on-site investigation and signed by a soil scientist or other qualified person. The report shall include detailed information concerning the site and shall discuss how all site characteristics were determined. Any requests for a variance to site suitability restrictions must be accompanied by a written justification that has been developed or approved by a soil scientist or other qualified person. The justification shall provide explanation as to safeguards which will assure that conditions of the permit will be met and there will be no adverse impacts from the land application.

(D) Analysis of drilling fluids and/or cuttings (for earthen pits only).

(E) Analyses of soil samples.

(F) Loading calculations.

(G) Copies of all chains-of-custody related to sampling.

(H) Manufacturer, model number, and specifications of testing equipment to be used (for tanks only).

(I) If there is an agent, a notarized affidavit designating same, signed by the operator.

(J) Other information as required by this Section or requested by a Field Operations office.

(3) **Review period.** The Field Operations office shall review the application, either approve or disapprove it, and return a copy of Form 1014S within five working days of submission of all required or requested information. If approved, a permit number shall be assigned to Form 1014S; if disapproved, the reason(s) shall be given. The applicant may make application for a hearing if it is not approved.

(g) **Calculating maximum application rate.**

(1) **Earthen pits.**

(A) The maximum application rate shall be calculated by the applicant or the applicant's designated agent based on the analyses of the pit materials and the soil of the application area. The averaging of TDS values of soil sampling areas shall not be permitted. If the entire application area is larger than ten acres, requiring separate soil sampling areas, the applicant or the applicant's designated agent shall use the highest soil TDS value of any sampling area in calculating the maximum application rate for the entire application area, and shall also calculate the maximum application rate of each ten acre (or less) application area using the respective TDS values of each soil sampling area. The applicant or the applicant's designated agent shall decide which of the two loading rates to use and notify the District Office when notification of commencement of land application is given, pursuant to (h)(1) of this Section.

(B) Soil loading formulas contained in Appendix I shall be used.

(C) The maximum application rate shall be restricted by the most limiting parameter. The Field Operations office shall indicate on the permit the maximum application rate and the minimum acreage that must be used.

(2) **Tanks.**

(A) The applicant shall calculate the maximum application rate based on the analysis of each tank or other containment vessel to be land applied and the soil of the application area. The averaging of TDS values of soil sampling areas shall not be permitted. If the entire application area is larger than ten acres, requiring separate soil sampling areas, the applicant shall have the option of using the highest soil TDS value of any sampling area in calculating the maximum application rate for the entire application area, or calculating the maximum application rate of each ten-acre (or less) application area using the respective TDS value of each soil sampling area.

(B) Soil loading formulas contained in Appendix I shall be used.

(C) Based on the maximum application rate, the applicant or its designated agent shall determine where the fluids will be applied and supervise the land application process.

(h) **Conditions of permit.** Any land application which is performed under this Section shall be subject to the following conditions or stipulations of the permit:

(1) **Notice to Field Inspector.** The applicant shall notify the appropriate Field Inspector at least 24 hours prior to the commencement of land application to allow a Commission representative an opportunity to be present.

(2) **Compliance agreement.** Any person responsible for supervision of land application shall have signed a compliance agreement with the Commission.

(3) **Presence of representative.** A representative of the applicant shall be on the land application site at all times during which fluids and/or cuttings are being applied. The representative shall be an employee of the applicant, designated agent, contractor, or other person pre-approved by the Commission.

(4) **Materials to be land applied.** Land application shall be limited to water-based drilling fluids and/or cuttings.

(5) **Weather restrictions.** Land application, including incorporation, shall not be done:

(A) During precipitation events or when precipitation is imminent.

(B) When the soil moisture content is at a level such that the soil cannot readily take the addition of drilling fluids.

(C) When the ground is frozen.

(D) By spray irrigation when the wind velocity is such that even distribution of materials cannot be accomplished or the buffer zones, pursuant to (6) of this subsection, cannot be maintained.

(6) **Buffer zones.** Land application shall not be done within the following buffer zones, as identified in the site suitability report:

(A) Fifty feet of a property line boundary.

(B) Three hundred feet of any actively producing water well used for domestic or irrigation purposes.

(C) One-quarter (1/4) mile of any actively producing water well used for municipal purposes.

(7) **Land application rate.** The maximum calculated application rate of drilling fluids and/or cuttings shall not be exceeded. It may require more than one pass to achieve the maximum application rate while avoiding runoff or ponding, pursuant to (9) of this subsection. Application of drilling fluids and/or cuttings outside the approved plot shall be prohibited.

(8) **Land application method.**

(A) Application of drilling fluids and/or cuttings shall be uniform over the approved land application plot, shall not be applied at a rate to cause permanent vegetation damage, and shall be made by a method approved by the Commission prior to use. The flood irrigation method shall be limited to those fields that normally are irrigated in that manner.

(B) For earthen pits, if more than 500 lbs/acre of Oil and Grease or 50,000 lbs/acre of Dry Weight materials are applied, the materials shall be incorporated into the soil by use of the injection method, or by disking or use of some other method approved by the Commission prior to use within 15 days after application.

(9) **Runoff or ponding prohibited.** No runoff of land applied materials shall be allowed during application. Ponding is prohibited, except where the flood irrigation method is approved. In order to comply with this rule, some applications will require the use of more than the minimum calculated acreage and/or a drying period between applications.
(10) **Vegetative cover.** If the vegetative cover is destroyed or significantly damaged by disking, injection, or other practice associated with land application, a bona fide effort shall be made to restore or reestablish the vegetative cover within 180 days after the land application is completed. Additional efforts shall be made until the vegetative cover is fully restored or reestablished.
(11) **Time period.**
(A) **Earthen pits.** Land application shall be completed within 90 days from the date of the permit. At the end of the 90 day period, the permit shall expire by its own terms. To renew the permit, the applicant shall resample the fluids and/or cuttings to be land applied, submit a new analysis, and receive a notification of renewal from a Field Operations office.
(B) **Tanks.** Land application shall be completed within 180 days after drilling ceases.
(12) **Post-application report.** A post-application report shall be submitted by the operator or the operator's agent to the Manager of Field Operations within 30 days of the completion of land application. The report shall give specific details of the land application, including test results of materials applied and loading rate calculations (for tanks only), volumes of materials applied, and an aerial photograph (minimum scale 1:660) delineating the actual area where materials were applied. The report shall contain a statement certifying that the land application was done in accordance with the approved permit.
(13) **Violations.** If the applicant violates the conditions of the permit or this Section, the land application shall be discontinued and the Field Operations office shall be contacted immediately. The Field Operations office may revoke the permit and/or require the operator to do remedial work. If the permit is not revoked, land application may resume with Field Operations' approval. If the permit is revoked,` the operator may make application for a hearing to reinstate it.
(14) **Requirements to close pit.** Neither filing an application nor receiving a permit under this Section shall extend the time limit for closing a reserve pit pursuant to 165:10-7-16, or a commercial pit pursuant to 165:10-9-1.
(i) **Variances.** A variance from the time provisions of (d)(1), (h)(1), (h)(8)(B) or (h)(10) of this Section may be granted by a Field Operations office for justifiable cause. A written request and supporting documentation shall be required. The Field Operations office shall respond in writing within five working days after receipt, either approving or disapproving the request.

[**SOURCE:** Amended in Rule Making 97000002, eff 7-1-97]

165:10-7-20. Noncommercial disposal or enhanced recovery well pits used for temporary storage of saltwater
(a) **Scope.** This Section shall apply to any production operation_where a pit is used for temporary storage of saltwater, except (c)(7) of this Section, which shall apply to any noncommercial well, regardless of whether or not a pit is used.
(b) **Construction requirements.**
(1) **Splash pad/apron.** A splash pad/apron shall be constructed at the unloading area of any noncommercial disposal well or enhanced recovery pit to the design and dimensions necessary to contain and direct all materials unloaded into the pit, unless the pit is of such design that discharge directly into it presents no spill potential.
(2) **Pit specifications.** Except as provided by (4)(A) of this subsection, any noncommercial disposal or enhanced recovery well pit shall be constructed of concrete or steel or be lined with a geomembrane liner according to the following:

(A) Concrete pits must be steel reinforced and have a minimum wall thickness of six inches.
(B) Steel pits must have a minimum wall thickness of three-sixteenths (3/16) inch. A previously used steel pit may be installed, provided it is free of corrosion or other damage.
(C) Geomembrane liners must:
(i) Have a minimum thickness of 30 mils, be chemically compatible with the type of wastes to be contained, and have ultraviolet light protection.
(ii) Be placed over a specially prepared, smooth, compacted surface void of sharp changes in elevation, rocks, clods, organic debris, or other objects.
(iii) Be continuous (may include seams) and cover the bottom and interior sides of the pit entirely. The edges must be securely placed in a minimum twelve inch deep anchor trench around the perimeter of the pit.

(3) **Certification of liner.** The operator of any saltwater storage pit that is constructed with a geomembrane liner shall secure an affidavit signed by the installer, certifying that the liner meets minimum requirements and was installed in accordance with Commission rules. It shall be the operator's responsibility to maintain the affidavit and all supporting documentation pertaining to the liner, such as geomembrane liner specifications from the manufacturer, etc., and shall make them available to a representative of the Conservation Division upon request.

(4) **Monitoring of site.**
(A) If not constructed according to one of the three methods in (2) of this subsection, any noncommercial disposal or enhanced recovery well pit shall be required to have a leachate detection system or at least one monitor well, unless it can be shown that the pit is not located over a hydrologically sensitive area, i.e., a principal bedrock aquifer, the recharge or potential recharge area of a principal bedrock aquifer, or an unconsolidated alluvium or terrace deposit, according to the Oklahoma Geological Survey "Maps Showing Principal Groundwater Resources and Recharge Areas in Oklahoma" (available for viewing at the Commission's Oklahoma City Office or District Offices). The District Manager may require more than one monitor well if he has reason to believe one would not be sufficient to adequately monitor the site.
(B) Any monitor well shall be installed within 100 feet of the pit. An existing nearby water well may be used as a monitor well upon written approval by the District Manager or Manager of Field Operations.
(C) Any new monitor well shall be drilled through the first aquifer encountered, but need not extend below 100 feet if no aquifer is encountered, and shall be completed by a licensed monitor well driller. If documentation can be submitted prior to drilling to show that no water will be encountered within 100 feet, the District Manager may allow the monitor well(s) to be drilled to a lesser depth or eliminated.
(D) Any new monitor well shall have:
(i) A minimum two inch diameter PVC casing with a sealing cap on the bottom.
(ii) Casing consisting of a slotted liner in the saturated zone, or bottom ten feet if none is encountered, and be gravel packed or sand packed as appropriate to the installation.
(iii) Bentonite placed in the annular space of the well above the slotted liner for an interval of at least two feet to form an adequate seal.
(iv) Well cuttings returned to the annular space above the bentonite seal for well stability.
(v) A minimum of two of the top six feet of annular space around the casing filled with cement.
(vi) A minimum three inch thick concrete apron placed at the surface to a minimum two foot radius from the casing.
(vii) A removable and lockable cap placed on top of the casing. The cap must remain locked at all times, except when a well is being sampled.

(E) Within 30 days of installation, construction details for any leachate detection system or specific completion information for any monitor well and a diagram of the location of any monitor well in relation to the pit shall be submitted to the Manager of Field Operations.

(c) **Operation and maintenance requirements.**

(1) **Fencing.** All noncommercial disposal or enhanced recovery well surface facilities that have a pit shall be completely enclosed by a minimum four strand barbed wire fence or equivalent protection as approved by the District Manager. Said fence shall be constructed in such a manner as to prevent livestock from entering the pit area.

(2) **Site maintenance.** The normal access surface of any well site that has a pit, including the access road(s), shall be maintained in a condition that will safely and easily allow access.

(3) **Exclusion of runoff water.** No pit shall be allowed to receive runoff water.

(4) **Freeboard.** The fluid level in any concrete or steel noncommercial disposal or enhanced recovery well pit shall be maintained at all times at least six inches below the top of the pit wall. Any geomembrane lined pit shall have a minimum of 18 inches of freeboard at all times.

(5) **Temporary storage only.** No pit shall be used as permanent storage for salt water.

(6) **Sampling of monitor wells or leachate detection systems.**

(A) Sampling of monitor wells and leachate detection systems shall occur once every six months, during the months of January and July.

(B) The appropriate District Manager shall be notified at least 24 hours in advance of sampling to allow a Commission representative an opportunity to witness the sampling.

(C) Samples shall be collected, preserved, and handled by the operator according to EPA approved standards (RCRA Groundwater Monitoring Technical Enforcement Guidance Document, EPA, OSWER-9950.1, September, 1986, pp. 99-107) and analyzed for pH, chlorides (Cl^-) and total dissolved solids (TDS) by a laboratory certified or operated by the State of Oklahoma. Analysis of additional parameters may be required as determined by the District Manager or Manager of Field Operations. A copy of each analysis and a statement as to the depth to groundwater encountered in each well, or an affidavit that no water was encountered, shall be forwarded to the Manager of Field Operations, within 30 days of sampling.

(7) **Prevention of pollution.** All noncommercial disposal or enhanced recovery wells shall be maintained at all times so as to prevent pollution. In the event of a nonpermitted discharge from surface facilities, sufficient measures shall be taken immediately to stop, contain, and control the loss of materials. Reporting of said discharge shall be in compliance with 165:10-7-5(c). Any materials lost due to such discharge shall be cleaned up as directed by a representative of the Conservation Division of the Commission.

(8) **Oil film.** The operator of a saltwater pit shall be responsible for the protection of migratory birds. Therefore, the Conservation Division recommends that to prevent the loss of birds due to oil films, all open top tanks and pits containing fluid be kept free of oil films or sludge or be protected from access to birds. [See Advisory Notice 165:10-7-3(c)]

(d) **Closure requirements.**

(1) **Time limit.** Within 180 days of the cessation of operations, all associated pits shall be emptied of all contents, and either removed or filled with soil. All monitor wells shall be plugged with bentonite or cement, unless exempt in writing by the District Manager or Manager of Field Operations. The site shall be revegetated within one (1) year.

(2) **Burial.** If any concrete, steel, geomembrane, or other materials associated with the site are to be left on-site, they shall be buried under a minimum soil cover of three feet, pursuant to 165:10-3-17.

(e) **Prospective application to existing facilities.** All provisions of this Section, except those in (b)(2) and (b)(3), shall apply to all existing pits within the scope of this Section which are, or have been, in operation prior to the effective date of this Section. Operators shall have one (1) year from the effective date of this Section in which to bring their facilities into compliance with the applicable provisions of this Section. Failure to comply with any applicable provision may result in revocation of the authority to operate.

(f) **Variances.**

(1) A variance from the time requirements of (c)(6), (d)(1), or (e) of this Section may be granted by the District Manager or Manager of Field Operations for justifiable cause. A written request and justifiable explanation is required. The District Manager or Manager of Field Operations shall respond in writing within five working days, either approving or disapproving the request.

(2) Any variance from the liner requirements as required under (b)(2) of this Section may be granted by the manager of Field Operations after receipt of a written request and supporting documentation required by the department.

[**SOURCE:** Amended in Rule Making 980000034, eff 7-1-99]

165:10-7-21. Refining and processing of oil and gas

(a) All deleterious substances obtained or used in the processing and refining of oil and gas shall be disposed of in a manner that will prevent the pollution of fresh water.

(b) Chemicals, gasolines, oil, and other deleterious substances shall be stored, where necessary, in tanks or containers of a material and of a construction and in a manner that will prevent the escaping, seepage, or draining of such liquids into any fresh water.

165:10-7-22. Permits for County Commissioners to apply waste oil, waste oil residue, or crude oil contaminated soil to roads

(a) **Prohibition against application of waste oil, waste oil residue, or crude oil contaminated soil without permit.** This Section prohibits any Board of County Commissioners from applying waste oil, waste oil residue, or crude oil contaminated soil to a street or road without a permit.

(b) **Permit by District Office.** A District Manager for the Conservation Division may issue to a Board of County Commissioners for a county within the district a permit to apply waste oil, waste oil residue, or crude oil contaminated soil to a street or road within the county.

(c) **Permit requirements.**

(1) **Use of Form 1014W.** The application and permit to apply waste oil, waste oil residue, or crude oil contaminated soil shall be made on Form 1014W.

(2) **Telephone permits.** In case of emergency, a District Manager may issue a permit by telephone. If an applicant obtains a permit by telephone, then the applicant shall file Form 1014W and attachment within five working days after receipt of the permit by telephone.

(3) **Conditions for permit.**

(A) Waste oil, waste oil residue, and contaminated soils applied under this Section shall consist of crude oil and materials produced with crude oil only and shall not contain any refined oils such as motor oils, lubricants, compressor oils or hydraulic fluids.

(B) If required by the District Manager, a hydrocarbon analysis shall be submitted with Form 1014W. The analysis shall be performed by a state-certified laboratory in accordance with OCC-approved methods.

(C) Waste oil, waste oil residue, and crude oil contaminated soil shall be applied in such a manner that pollution of surface or subsurface waters will not likely occur and public and private property adjoining the street or road will be protected.

(D) During operations for road oiling, all necessary signs, lights, and other safety and warning devices shall be used to alert road users to

conditions. A sign shall be posted with the contractor or authority's name and phone number to contact in case of emergency.
(E) Following completion of the project there shall be a uniform soil/oil base (all liquid worked in), with no visible free-standing oil.
(F) Proper care shall be taken to avoid runoff of oil or water into borrow ditches or adjacent areas.
(G) No road oiling shall be conducted:
(i) When the temperature is less than 45° F.
(ii) In any area where water collects and stands.
(iii) Where soil moisture content or road conditions such as soil type, tight soil conditions, packed soil conditions, or grade limits prevent rapid absorption of the oil.

(d) **Notice to District Office.** The Board of County Commissioners receiving the permit shall notify the District Office at least two days prior to commencement of road oiling under a permit.
(e) **Site inspection.** At his discretion, a District Manager may request a Field Inspector of the Conservation Division or an Enforcement Officer of the Transportation Division to inspect the site at any time during the road oiling operation to ensure compliance with this Section.
(f) **Duration of permit.** The permit shall state the duration of the permit, and it shall also state that if the application fails to comply with either the terms of the permit or the terms of this Section, then the permit shall terminate automatically.
(g) **Disapproval or cancellation of permits.**
(1) If a District Manager receives a complaint about a road oiling permit, he shall cause an investigation of the complaint to be made as soon as practicable. During the investigation, the District Manager may direct the applicant to cease road oiling under a permit. If necessary, the District Manager may verbally revoke the permit.
(2) If a District Manager disapproves an application or cancels a permit, the applicant may apply to the Commission for an order under OAC 165:5-7-41.

[**Source:** Amended at 12 Ok Reg 2017, eff 7-1-95]

165:10-7-23. Disposal of waste oil

(a) All waste oil and waste oil residue shall be disposed of in one of the following ways:
(1) Transfer or sale to a reclaimer or transporter.
(2) Transfer or sale to County Commissioners.
(3) Administrative approval from the Conservation Division.

(b) All operators or owners of pits, tanks, commercial disposal operations, or reclaimers shall maintain books and records describing the disposition of all waste oil or waste oil residue. A copy of the run or load ticket will satisfy this requirement if the information required in (c) of this Section is contained therein.
(c) The following information shall be contained in said books and records and subject to audit and inspection by representatives of the Commission for a minimum period of three years:
(1) The amount of waste oil or waste oil residue removed.
(2) The location of the waste oil or waste oil residue prior to disposal.
(3) The destination of waste oil or waste oil residue as reported by transporter.
(4) The name of the transporter of waste oil or waste oil residue.

165:10-7-24. Waste management practices reference chart

(a) **Scope.** This Section provides reference guidelines for the disposal of wastes under the jurisdiction of the Commission which are generated by oil and gas operators and pipeline companies. Hazardous waste as defined at 40 CFR 261.3 is regulated by the Oklahoma Department of Environmental Quality.

(b) **Waste materials and disposal options.** Consistent with EPA's policy on source reduction, recycling, treatment and proper disposal, operators shall use waste management practices as listed in (c) of this Section which describes the various management practices for the following waste materials. For any of the following waste materials where option (16) of subsection (c) is listed, option (16) shall be considered before any other option.

(1) Produced water: Options 1, 7 & 9
(2) Weighted water: Options 1 & 7
(3) Used treatment fluids and other flowback wastes: Options 1, 2, 5 & 7
(4) Water based mud: Options 1, 2, 5, 6, 7, 8 & 19
(5) Water based mud cuttings: Options 1, 2, 3, 4, 5, 6, 7, 8, 12 & 19
(6) Oil based mud: Options 1, 2, 3, 5, 7 & 22
(7) Oil based mud cuttings: Options 1, 2, 3, 4, 5, 7, 8, 12 & 14
(8) Crude oil: Options 1, 4, 12, 13 & 14
(9) Used motor, gear, lube, compressor and hydraulic oils: Options 1, 15 & 16
(10) Used solvents: Options 1, 15 & 16
(11) Oily debris: Options 1, 3, 13 & 20
(12) Filter media and backwash: Options 1, 3, 7, 15, 16 & 20
(13) Glycol, amine, and caustic wash: Options 1 & 7
(14) Iron sponge: Options 3 & 20
(15) Molecular sieve: Options 3 & 20
(16) Produced sand/sediment: Options 3, 7, 8, 17 & 20
(17) Tight emulsions: Options 1, 4, 8, 12, 14 & 17
(18) Unused treatment chemicals: Options 1, 15 & 16
(19) Tank bottoms from E&P: Options 1, 3, 4, 7, 8, 10, 12, 14 & 17
(20) Paraffin: Options 1, 3, 4, 12, 14, 15, 16 & 20
(21) Asbestos insulation: Options 3 & 15
(22) Non-asbestos insulation: Options 3, 15 & 20
(23) Used batteries: Options 1, 3, 15 & 16
(24) Oils containing PCBs: Option 11
(25) Oils not containing PCBs: Options 1, 15 & 16
(26) Empty oil and chemical drums: Options 1, 3 & 15
(27) Salt contaminated soils: Options 5, 6, 8 & 17
(28) Crude oil contaminated soils: Options 1, 3, 4, 8, 10, 12, 14, 17 & 22
(29) Pit sludges from wellsites, disposal well pits and gathering systems: Options 1, 3, 4, 7, 8, 12, 17 & 20
(30) Gathering line pigging wastes: Options 1, 3, 7 & 20
(31) Gas plant sweetening wastes: Options 1, 3, 7 & 20
(32) Gas plant dehydration wastes: Options 1, 3 & 7
(33) Cooling tower blowdown from gas plants: Options 7 & 15
(34) Wastes from subsurface natural gas storage: Options 1, 3, 7 & 20
(35) Wastes other than refined product removed from produced water and other well fluids prior to injection or disposal: Options 1, 7, 8, 17 & 20
(36) Gases removed from the production stream: Options 1, 7, 13 & 18
(37) Waste crude oil and light hydrocarbons (gas condensate) in reserve pits, other impoundments or tankage at wellsites: Options 1, 7, 8, 13 & 17
(38) Contaminated ground water (except refined products): Options 1, 7, 21 & 22
(39) Pipeline sludge and other deposits removed from pipe or equipment on E&P gathering systems: Options 1, 3, 7, 8, 10, 17 & 20
(40) Residues and truckwash from inside the tank of trucks used to transport saltwater, drilling mud or spent completion fluids: Options 1, 3, 7 & 20
(41) Sewage and wastes from portable toilets: Option 15
(42) Crude pipeline pigging wastes, contaminated soil and residue from transmission and trunk lines: Options 1, 3, 4, 8, 12, 15, 16, 17 & 22
(43) Water or soil contaminated by refined product from E&P operations: Options 1, 16, 21 & 22
(44) Rigwash and supply water: Options 1, 5, 7 & 8
(45) Storm water and hydrostatic test water from E&P operations: Options 1, 7, 9 & 22
(46) Spent filters: Options 1 & 3
(47) Trash and debris: Options 15 & 20
(48) Refined petroleum product releases: Options 1, 3, 8, 13, 16, 17 & 22

(49) Refined petroleum product pigging wastes: Options 1, 3, 8, 15, 16, 17 & 22
(50) Water or soil contaminated by refined products from pipelines: Options 1, 16, 21 & 22
(51) Hydrostatic test water from pipelines: Options 1, 9, 16 & 22
(52) Tank bottoms from crude pipeline facilities: Options 1, 3, 4, 8, 10, 12, 14, 16, 17 & 22
(53) Tank bottoms from refined product pipeline facilities: Options 1, 3, 14, 15, 16, 17 & 22

(c) **Disposal options and rule reference guide.** The following waste disposal options are referenced in (b) of this Section:
(1) Reclaim and/or recycle.
(2) Burial (in accordance with 165:10-7-16).
(3) Landfills regulated by the Oklahoma Department of Environmental Quality.
(4) Road applications by County Commissioners (in accordance with 165:10-7-22 and 165:10-7-28).
(5) Noncommercial pits (in accordance with 165:10-7-16).
(6) Commercial mud disposal pits (in accordance with 165:10-9-1).
(7) Underground injection (in accordance with 165:10-5-1 through 165:10-5-14).
(8) Land application (in accordance with 165:10-7-19 and 165:10-7-26).
(9) Discharge (in accordance with 165:10-7-17).
(10) Reclaim and/or recycle (in accordance with 165:10-7-23).
(11) In accordance with EPA; Code of Federal Regulations (CFR), Title 40, Part 761.60 through 761.79.
(12) Application to lease roads, well locations, and production sites (in accordance with 165:10-7-27 and 165:10-7-29).
(13) Open burning in accordance with Oklahoma Department of Environmental Quality regulations.
(14) Disposal of waste oil as specified in 165:10-7-23.
(15) Disposal in accordance with Oklahoma Department of Environmental Quality regulations.
(16) If the waste is determined to be a hazardous waste under the Federal Resource Conservation and Recovery Act (RCRA), disposal will be determined by the Oklahoma Department of Environmental Quality; if a non-hazardous waste, Option 17 may be used or other disposal option as approved by the Commission.
(17) On-site or in-situ bioremediation/remediation.
(18) Flaring or venting (in accordance with 165:10-3-15).
(19) Commercial soil farming (in accordance with 165:10-9-2).
(20) Burial as approved by the Commission.
(21) Surface discharge as approved by the Commission.
(22) Land application as approved by the Commission.

[**Source:** Amended at 12 Ok Reg 2039, eff 7-1-95; Amended in Rule Making 97000002, eff 7-1-97; Amended in Rule Making 200200017, eff 7-1-02]

165:10-7-25. One-time land application of water-based fluids from tanks or other containment vessels [REVOKED]

[SOURCE: Amended at 9 Ok Reg 2295, eff 6-25-92; Revoked in Rule Making 97000002, eff 7-1-97]

165:10-7-26. One-time land application of contaminated soils and petroleum hydrocarbon based drill cuttings

(a) **Authority for land application.** No person shall land apply soils or drill cuttings contaminated by salt or petroleum hydrocarbons except as provided by this Section. Any operator failing to obtain a permit shall be fined $2,000.00.

(b) **Scope.** This Section shall cover the land application of soils and drill cuttings contaminated by salt and/or petroleum hydrocarbons. Petroleum hydrocarbon-contaminated soils land applied under this Section shall meet the

RCRA criteria for exempt or non-exempt/nonhazardous waste. [Reference 40 CFR Subtitle C and EPA publication EPA530-K-95-003 "Crude Oil and Natural Gas Exploration and Production Wastes: Exemption from RCRA Subtitle C Regulation]. Hazardous waste as defined at 40 CFR 261.3 is regulated by the Oklahoma Department of Environmental Quality. Any land application made under this Section shall be done on a one-time basis to land that has not been previously used for this practice or similar practices.

(c) **Receiving site suitability restrictions.** Land application shall only occur on land having all of the characteristics below, as field verified by a soil scientist or other qualified person pre-approved by the Commission~~:~~. Any variance from site suitability restrictions must be approved by the Oil and Gas Conservation Division (see (g)(2)(C) of this Section).

(1) **Maximum slope.** A maximum slope of five percent for all application methods.

(2) **Depth to bedrock.** Depth to bedrock will be at least 40 inches if crude oil contaminated soils or petroleum hydrocarbon-based drill cuttings are to be applied; 20 inches if salt contaminated soils are to be applied.

(3) **Soil texture.** A soil profile (as defined by USDA soil surveys) containing at least twelve inches (may be cumulative) of one of the following soil textures between the surface and the water table, unless a documented impeding layer of shale is present: loam, silt loam, silt, sandy clay loam, silty clay loam, clay loam, sandy clay, silty clay, or clay.

(4) **Salinity.** Slight salinity [defined as Electrical Conductivity (EC) less than 4,000 micromhos/cm] in the topsoil, or upper six inches of the soil, and a calculated Exchangeable Sodium Percentage (ESP) less than 10.0.

(5) **Depth to water table.** No evidence of a seasonal water table within six (6) feet of the soil surface as verified by field observation and published data.

(6) **Distance from water bodies.** A minimum distance of 100 feet from the land application site boundary to any perennial stream and 50 feet to any intermittent stream found on the appropriate United States Geological Survey (U.S.G.S.) topographic map (available for viewing at the Commission's Oklahoma City Office and District Offices); and a minimum of 100 feet to any freshwater pond, lake, or wetland designated by the National Wetlands Inventory Map Series, prepared by the U.S. Fish and Wildlife Service (available for viewing at the Commission's Oklahoma City Office). Also, see (h)(6) of this Section.

(7) **Site specific concerns.** Void of slick spots within or adjacent to the land application area, where subsurface lateral movement of water is unlikely, or areas void of concentrated surface flow such as gullies or waterways.

(d) **Sampling requirements.**

(1) **Notice to Field Inspector.** The appropriate Field Inspectors shall be contacted at least two working days prior to sampling of the receiving soil and materials to be land applied. This is to allow a Commission representative an opportunity to be present.

(2) **Receiving soil.** Sampling of the receiving soil shall be performed by, or under the supervision of, a soil scientist or other qualified person pre-approved by the Commission. Soil samples shall be taken from the proposed application area and analyzed. A minimum of four representative surface core samples from the surface (0-6 inches) and subsurface (14-20 inches) must be taken from each ten acres, or part thereof. Each group of surface core samples representative of a ten-acre area (or less) shall be combined and thoroughly mixed. A minimum one pint composite sample shall be taken and placed in a clean container for delivery to the laboratory. Alternatively, soil samples may be composited by the laboratory. All subsurface samples shall be handled in the same manner.

(3) **Materials to be land applied.** Representative samples of the materials to be land applied shall be taken, composited into a minimum one-pint sample, and placed in a clean container for delivery to the laboratory. Alternatively, materials to be land applied may be composited by the laboratory.

(e) **Analysis requirements.**

(1) **Salt contaminated soils or drill cuttings.** Analysis requirements will be dependent upon the loading method that is chosen. For most applications, loading based on Total Dissolved Solids (TDS) will be most appropriate. However, applicants proposing to land apply on a site in western Oklahoma, where the soils commonly contain moderate to high levels of gypsum, may benefit from using the loading formula based on Chlorides (Cl).

(A) Samples of soil and materials to be land applied shall be tested by a laboratory proficient in testing soils. Either a 1:1 extract or saturated paste extract shall be used for sample preparation for TDS or Cl loading. A saturated paste moisture equivalent is necessary where the saturated paste sample preparation method is used.

(B) Parameters for analysis of the receiving soil shall include at a minimum EC, TDS, and ESP for TDS loading. For Chloride loading, parameters shall include Chlorides (dry weight basis) and ESP.

(C) Parameters for analysis of soils or drill cuttings contaminated by salt shall include at a minimum EC for TDS loading and both EC and Cl for Chloride loading.

(2) **Soils and drill cuttings contaminated by petroleum hydrocarbons.**

(A) Samples of soil and materials to be land applied shall be tested by a laboratory proficient in testing soils.

(B) Parameters for analysis of the receiving soil shall include at a minimum EC and ESP.

(C) Parameters for analysis of soils or drill cuttings contaminated by petroleum hydrocarbons shall include at a minimum a test of the appropriate carbon range(s), which is determined by the nature of the waste material. These include Gasoline Range Organics (GRO) - C6 to C10 (EPA test method 8015/8020 M), Diesel Range Organics (DRO) - C10 to C28 (extractable procedure), and Oil and Grease - C20 to C50+ (EPA test method 1664).

(f) **Application rates.**

(1) **Calculations.** The maximum application rate for TDS (or Cl) and GRO, DRO, or O & G shall be calculated by the applicant based upon the analyses of the materials to be land applied and the soil of the application area. For salt contaminated soils or drill cuttings, if the application area encompasses more than one soil sampling area, the rate shall be calculated in one of two ways, depending on how the application will be made. The applicant may either calculate the maximum application rate for the entire application area based upon the highest soil TDS (or Cl) value of any sampling area (averaging not allowed), or calculate it for each ten acre (or less) application area using the respective soil TDS (or Cl) values of each sampling area.

(2) **Soil loading formulas.** The maximum application rate for any application area shall be restricted by the most limiting parameter. To determine this, the soil loading formulas in Appendix I of this Chapter shall be used as applicable.

(3) **Variances.** In special situations, a request for a variance relating to soil loading of petroleum hydrocarbons may be administratively approved by the Manager of Field Operations. The applicant shall submit a written request explaining the circumstances or conditions which warrant a variance and shall also submit a management plan for reducing the petroleum hydrocarbon content in the soil to two percent or less.

(g) **Application for permit.**

(1) **Who may apply.** Only the operator responsible for generating the waste to be land applied or the operator's designated agent may apply for a land application permit, except that the Oklahoma Energy Resources Board or its designated contractor may make application to land apply materials for which there is no responsible party.

(2) **Required form and attachments.** Each application for land application of soils contaminated by salt and/or crude oil or petroleum hydrocarbon-containing deleterious substances shall be submitted to a Field Operations office on Form 1014S. An original and three copies shall be required. Attached to at least one of the copies shall be the following:

(A) Written permission from the surface owner to allow the applicant to land apply, incorporate, and fertilize materials. For purposes of obtaining such consent, the applicant shall use Form 1014L.
(B) A topographic map and the most recent aerial photograph (minimum scale 1:660) with the proposed and potential land application areas delineated as well as the location of cultural features such as buildings, water wells, etc. Both the topographic map and aerial photograph must show all areas within 1320 feet of the boundary of the land application area.
(C) Receiving site suitability report, pursuant to subsections (c) and (h)(6) of this Section, based on an on-site investigation and signed by a soil scientist or other qualified person. The report shall include detailed information concerning the site and shall discuss how all site characteristics were determined. Any requests for a variance to site suitability restrictions must be accompanied by a written justification that has been developed or approved by a soil scientist or other qualified person. The justification shall provide explanation as to safeguards which will assure that conditions of the permit will be met and there will be no adverse impacts from the land application.
(D) Analyses of receiving soil samples.
(E) Analyses of contaminated soil or petroleum hydrocarbon-based drill cuttings.
(F) For contaminated soils, an investigation report and diagram, drawn to scale, detailing the areal extent and depth of the contamination; and sampling procedures which were used to assure that representative samples were taken.
(G) Loading calculations.
(H) Copies of all chains-of-custody related to sampling.
(I) If there is an agent, a notarized affidavit designating same, signed by the operator.
(J) Other information as required by this Section or requested by a Field Operations office.

(3) **Review period.** The Field Operations office shall review the application, either approve or disapprove it, and return a copy of Form 1014S within five working days of submission of all required or requested information. If approved, a permit number shall be assigned to Form 1014S; if disapproved, the reason(s) shall be given. The applicant may make application for a hearing if it is not approved.

(h) **Conditions of permit.** Any land application which is performed under this Section shall be subject to the following conditions or stipulations of the permit:

(1) **Notice to Field Inspector.** The applicant shall notify the appropriate Field Inspector at least 24 hours prior to the commencement of land application to allow a Commission representative an opportunity to be present.
(2) **Compliance agreement.** Any person responsible for supervision of land application shall have signed a compliance agreement with the Commission.
(3) **Presence of representative.** A representative of the applicant shall be on the land application site at all times during which materials are being applied. The representative shall be an employee of the applicant, designated agent, contractor, or other person pre-approved by the Commission.
(4) **Materials to be land applied.** Land application under this Section shall be limited to soils and drill cuttings contaminated by salt and/or petroleum hydrocarbons. Petroleum hydrocarbon-contaminated soils or drill cuttings land applied under this Section shall meet the RCRA criteria for exempt or non-exempt/nonhazardous waste. Hazardous waste as defined at 40 CFR 261.3 is regulated by the Oklahoma Department of Environmental Quality.
(5) **Weather restrictions.** Land application, including incorporation, shall not be done:

(A) During precipitation events or when precipitation is imminent.
(B) When the soil moisture content is at a level such that the soil cannot readily take the addition of materials.
(C) When the ground is frozen.

(6) **Buffer zones.** Land application shall not be done within the following buffer zones, as identified in the site suitability report:
(A) Fifty feet of a property line boundary.
(B) Three hundred feet of any actively producing water well used for domestic or irrigation purposes.
(C) One-quarter (1/4) mile of any actively producing water well used for municipal purposes.
(7) **Land application rate.** The maximum calculated application rate of materials shall not be exceeded. Under no circumstances shall land applied materials exceed a two inch depth. Furthermore, no runoff or ponding of land applied materials shall be allowed. It may require more than one pass or lift to achieve the maximum application rate while avoiding runoff or ponding.
(8) **Land application method.** Application of materials shall be uniform over the approved land application area, and shall be made by a method approved by the Commission prior to use. Land applied materials shall be incorporated into the soil by disking or chiseling during or immediately after application to a minimum depth of two times the depth of ~~a~~ applied materials; however, if any contaminated sandy soil~~s~~ is applied to any clayey soil, incorporation shall be to a minimum depth of four times the depth of the applied materials.
(9) **Fertilizer.** For any land application involving petroleum hydrocarbon-contaminated soils and/or drill cuttings, fertilizer shall be applied at an appropriate rate as indicated by soil testing for available N-P-K to adjust the average carbon-nitrogen ratio in order to enhance biodegradation of the petroleum hydrocarbons and assist in reestablishing vegetation. In the absence of soil testing, Nitrogen, Phosphorus, and Potassium shall be applied at a rate of 160-40-40 lbs. per acre (actual N-P-K).
(10) **Vegetative cover.** A bona fide effort shall be made to restore or reestablish the vegetative cover within 180 days after the land application is completed. Additional efforts shall be made until the vegetative cover is fully restored or reestablished.
(11) **Time period.** Land application shall be completed within 30 days of the anticipated completion date shown on the approved application form.
(12) **Post-application report.** A post-application report shall be submitted by the operator or the operator's agent to the Manager of Field Operations within 30 days of the completion of land application. The report shall give specific details of the land application, including volumes of materials applied and an aerial photograph (minimum scale 1:660) delineating the actual area where materials were applied. The report shall contain a statement certifying that the land application was done in accordance with the approved permit.
(13) **Violations.** If the applicant violates the conditions of the permit or this Section, the land application shall be discontinued and the Field Operations office shall be contacted immediately. The Field Operations office may revoke the permit and/or require the operator to do remedial work. If the permit is not revoked, land application may resume with Field Operations' approval. If the permit is revoked, the operator may make application for a hearing to reinstate it.

(i) **Variances.** A variance from the time provisions of (d)(1), (h)(1), (h)(10) or (h)(11) of this Section may be granted by a Field Operations office for justifiable cause. A written request and supporting documentation shall be required. The Field Operations office shall respond in writing within five working days after receipt, either approving or disapproving the request.

[**Source:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended at 12 Ok Reg 2039, eff 7-1-95; Amended in Rule Making 97000002, eff 7-1-97]

165:10-7-27. Application of waste oil, waste oil residue, or crude oil contaminated soil by oil and gas operators and pipeline companies

(a) **Scope.** This Section shall cover the application of waste oil, waste oil residue, or crude oil contaminated soil by oil and gas operators and pipeline companies to lease roads, pipeline service and tank farm roads, well locations,

and production sites. Hazardous waste as defined at 40 CFR 261.3 is regulated by the Oklahoma Department of Environmental Quality.
(b) **Permit by District Office.** A District Manager for the Conservation Division may issue to an oil or gas operator or pipeline company within the District a permit for road application of waste oil, waste oil residue, or crude oil contaminated soil to lease roads, pipeline service and tank farm roads, well locations, and production sites within the District. This subsection prohibits any operator from applying waste oil, waste oil residue, or crude oil contaminated soil without a permit. Any operator or pipeline company violating this subsection shall be fined $2,000.00.
(c) **Permit requirements.**
(1) **Use of Form 1014X.** The application to apply waste oil, waste oil residue, or crude oil contaminated soil shall be made on Form 1014X. The original and one copy are required.
(2) **Landowner permission.** Attached to the application shall be a copy of written permission by the surface owner to allow the operator or pipeline company to apply waste oil, waste oil residue, or crude oil contaminated soil as per this Section to a specific portion of real property as designated by legal description. For purposes of obtaining such consent, the applicant shall use Form 1014L.
(3) **Telephone permits.** In case of an emergency, a District Manager may issue a permit by telephone. If an operator or pipeline company obtains a permit by telephone, the operator or pipeline company shall file Form 1014X and attachments within five working days after receipt of the permit by telephone.
(4) **Conditions for permits.**
(A) Waste oil, waste oil residue, and contaminated soils applied under this Section shall consist of crude oil and materials produced with crude oil only. Hazardous waste as defined at 40 CFR 261.3 is regulated by the Oklahoma Department of Environmental Quality.
(B) If required by the District Manager, a hydrocarbon analysis shall be submitted with Form 1014X. The analysis shall be performed by a state-certified laboratory in accordance with OCC-approved methods.
(C) Waste oil, waste oil residue, and crude oil contaminated soil shall be applied in such a manner that pollution of surface or subsurface waters will not likely occur and public and private property adjoining the application area will be protected.
(D) During application, any necessary signs, lights and other safety and warning devices shall be used as traffic requires to alert users to conditions. A sign shall be posted with the contractor's or operator's name and phone number to contact in case of an emergency.
(E) No application shall be conducted:
(i) When the temperature is less than 45° F.
(ii) In any area where water collects and stands.
(iii) Where conditions such as grade, soil moisture content, soil type, tight soil conditions, or packed soil conditions cause runoff or prevent rapid absorption of the oil.
(F) Following completion of the project, there shall be a uniform soil/oil base (all liquids worked in), with no visible free-standing oil.
(G) Proper care shall be taken to avoid runoff of oil into borrow ditches or adjacent areas.
(d) **Notice to Field Inspector.** The operator or pipeline company receiving the permit shall notify the appropriate Field Inspector at least two days prior to commencement of application.
(e) **Site inspection.** At his discretion, a District Manager may request a Field Inspector of the Conservation Division or an Enforcement Officer of the Transportation Division to inspect the site at any time during the application operation to ensure compliance with this Section.
(f) **Duration of permit.** The permit shall state the duration of the permit, not to exceed 60 days. If a complaint is received or the operator or pipeline company fails to comply with either the terms of the permit or this Section, the District Manager may direct the operator or pipeline company to cease application until the problem is resolved. If necessary, the District Manager may verbally revoke the permit and/or require the operator or pipeline company to perform remedial work.

If a District Manager disapproves an application or cancels a permit, then the applicant may apply to the Commission for an order under 165:5-7-41.

[**Source:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended at 12 Ok Reg 2017, eff 7-1-95; Amended in Rule Making 97000002, eff 7-1-97]

165:10-7-28. Application of freshwater drill cuttings by County Commissioners

(a) **Scope.** This Section shall cover the one-time application of freshwater drill cuttings by a Board of County Commissioners to a street or road.

(b) **Permits by District Office.** A District Manager for the Conservation Division may issue to any Board of County Commissioners within the District a permit for road application of freshwater drill cuttings to a street or road within the county. This Section prohibits any Board of County Commissioners from applying freshwater drill cuttings without a permit.

(c) **Site restrictions.** Application of freshwater drill cuttings shall only occur on sites having an:

(1) Electrical Conductivity (EC) no greater than 6,000 micromhos/cm; and

(2) Exchangeable Sodium Percentage (ESP) less than 15.0.

(d) **Sampling requirements.**

(1) The appropriate Field Inspector shall be contacted at least two working days prior to sampling to allow a Commission representative an opportunity to witness the sampling of the receiving soil and freshwater drill cuttings to be applied.

(2) The receiving soil shall be sampled using the following procedure:

(A) A minimum of five samples shall be taken for each one-half (1/2) mile section of road (or borrow ditch) and composited into one sample for analysis.

(B) Sampling shall be to a minimum depth of six inches.

(3) The freshwater cuttings shall be sampled by taking a minimum of one representative sample for every five cubic yards of freshwater cuttings to be applied and composited into one quart sample for analysis.

(e) **Analysis requirements.**

(1) The composite samples of soil and drill cuttings shall be analyzed by a laboratory which tests soils.

(2) The parameters for the receiving soil shall include ESP and either EC or Total Dissolved Solids (TDS).

(3) The parameters for the drill cuttings shall include TDS.

(f) **Maximum application rate.**

(1) The maximum application rate shall be calculated by the Board of County Commissioners using the following formula:

PROCEDURE FOR CALCULATING APPLICATION RATE OF TOTAL DISSOLVED SOLIDS (TDS)

______ ppm TDS in receiving soil x 2 = ______ lbs/ac TDS in receiving soil.

10,000 lbs/ac TDS - _______ lbs/ac TDS in receiving soil = Maximum TDS (lbs/ac) to be applied _________.

Maximum TDS (lbs/ac) to be applied ________ ÷ (_______ ppm TDS in cuttings x .000001) = Maximum lbs/ac of cuttings to be applied _______.

Actual weight of drill cuttings ________ lbs/cu ft x 27 = ________ lbs/cu yd.

Maximum lbs/ac to be applied _______ ÷ _______ lbs/cu yd = ________ cu yds/ac to be applied.

Total volume _______ cu yds ÷ _______ cu yds/ac = Minimum acres required ________.

(2) Calculations shall be submitted with the application.

(g) **Permit requirements.**

(1) **Use of Form 1014W.** The application to apply freshwater drill cuttings shall be made on Form 1014W. The original and one copy are required.
(2) **Telephone permits.** In case of an emergency, a District Manager may issue a permit by telephone. If any Board of County Commissioners obtains a permit by telephone, the applicant shall file Form 1014W within five working days after receipt of the permit by telephone.
(3) **Conditions for permits.**
(A) The method to be used for application of freshwater drill cuttings shall not pollute surface or subsurface waters and shall protect public and private property adjoining the application area.
(B) During application, any necessary signs, lights and other safety and warning devices shall be used to alert users to conditions. A sign shall be posted with the contractor's or authority's name to contact in case of an emergency.
(C) All free liquids shall be removed before cuttings are applied.
(D) Following completion of the project, there shall be a uniform soil/cuttings base.
(h) **Notice to Field Inspector.** The Board of County Commissioners receiving the permit shall notify the appropriate Field Inspector at least two days prior to commencement of the application.
(i) **Site inspection.** At his discretion, a District Manager may request a Field Inspector of the Conservation Division or an Enforcement Officer of the Transportation Division to inspect the site at any time during the application operation to ensure compliance with this Section.
(j) **Duration of permit.** The permit shall state the duration of the permit, not to exceed 60 days. If a complaint is received or the Board of County Commissioners fails to comply with either the terms of the permit or this Section, the District Manager may direct the Board of County Commissioners to cease application until the problem is resolved. If necessary, the District Manager may verbally revoke the permit and/or require the Board of County Commissioners to perform remedial work. If a District Manager disapproves an application or cancels a permit, then the applicant may apply to the Commission for an order under 165:5-7-41.

165:10-7-29. Application of freshwater drill cuttings by oil and gas operators
(a) **Scope.** This Section shall cover the one-time application of freshwater drill cuttings by oil and gas operators to private access areas, well locations, and production sites.
(b) **Permits by District Office.** A District Manager for the Conservation Division may issue to an operator within the District a permit for application of freshwater drill cuttings to private access areas, well locations, and production sites within the District. This Section prohibits any operator from applying freshwater drill cuttings without a permit. Any operator violating this subsection shall be fined $2,000.00.
(c) **Site restrictions.** Application of freshwater drill cuttings shall only occur on sites having an:
(1) Electrical Conductivity (EC) no greater than 6,000 micromhos/cm; and
(2) Exchangeable Sodium Percentage (ESP) less than 15.0.
(d) **Sampling requirements.**
(1) The appropriate Field Inspector shall be contacted at least two working days prior to sampling to allow a Commission representative an opportunity to witness the sampling of the receiving soil and freshwater drill cuttings to be applied.
(2) The receiving soil shall be sampled using the following procedure:
(A) A minimum of five samples shall be taken for each one-half (1/2) mile section of road (or borrow ditch), well location, or production facility and composited into one sample for analysis.
(B) Sampling shall be to a minimum depth of six inches.
(3) The freshwater cuttings shall be sampled by taking a minimum of one representative sample for every five cubic yards of freshwater cuttings to be applied and composited into one quart sample for analysis.

(e) **Analysis requirements.**
(1) The composite samples of soil and drill cuttings shall be analyzed by a laboratory which tests soils.
(2) The parameters for the receiving soil shall include ESP and either EC or Total Dissolved Solids (TDS).
(3) The parameters for the drill cuttings shall include TDS.
(f) **Maximum application rate.**
(1) The maximum application rate shall be calculated by the operator using the following formula:

PROCEDURE FOR CALCULATING APPLICATION RATE OF TOTAL DISSOLVED SOLIDS (TDS)

_______ ppm TDS in receiving soil x 2 = ________ lbs/ac TDS in receiving soil.

10,000 lbs/ac TDS - ______ lbs/ac TDS in receiving soil = Maximum TDS (lbs/ac) to be applied _______.

Maximum TDS (lbs/ac) to be applied _______ ÷ (_______ ppm TDS in cuttings x .000001) = Maximum lbs/ac of cuttings to be applied _______.

Actual weight of drill cuttings _______ lbs/cu ft x 27 = _______ lbs/cu yd.

Maximum lbs/ac to be applied _______ ÷ _______ lbs/cu yd = _______ cu yds/ac to be applied.

Total volume _______ cu yds ÷ _______ cu yds/ac = Minimum acres required _______.

(2) Calculations shall be submitted with the application.
(g) **Permit requirements.**
(1) **Use of Form 1014X.** The application to apply freshwater drill cuttings shall be made on Form 1014X. The original and one copy are required.
(2) **Landowner permission.** Attached to the application shall be a copy of written permission by the surface owner to allow the operator to apply freshwater drill cuttings as per this Section to a specific portion of real property as designated by legal description.
(3) **Telephone permits.** In case of an emergency, a District Manager may issue a permit by telephone. If an operator obtains a permit by telephone, the applicant shall file Form 1014X within five working days after receipt of the permit by telephone.
(4) **Conditions for permits.**
(A) The method to be used for application of freshwater drill cuttings shall not pollute surface or subsurface waters and shall protect public and private property adjoining the application area.
(B) During application, any necessary signs, lights, and other safety and warning devices shall be used as traffic requires to alert users to conditions. A sign shall be posted with the contractor's or operator's name to contact in case of an emergency.
(C) All free liquids shall be removed before cuttings are applied.
(D) Following completion of the project, there shall be a uniform soil/cuttings base.
(h) **Notice to Field Inspector.** The operator receiving the permit shall notify the appropriate Field Inspector at least two days prior to commencement of the application.
(i) **Site inspection.** At his discretion, a District Manager may request a Field Inspector of the Conservation Division or an Enforcement Officer of the Transportation Division to inspect the site at any time during the application operation to ensure compliance with this Section.
(j) **Duration of permit.** The permit shall state the duration of the permit, not to exceed 60 days. If a complaint is received or the operator fails to comply with either the terms of the permit or this Section, the District Manager may direct the operator to cease application until the problem is resolved. If necessary, the District Manager may verbally revoke the permit

and/or require the operator to perform remedial work. If a District Manager disapproves an application or cancels a permit, then the applicant may apply to the Commission for an order under 165:5-7-41.

[**SOURCE:** Amended at 9 Ok Reg 2295, eff 6-25-92]

165:10-7-30. Enhanced recovery project surface facilities [REVOKED]

[**SOURCE:** Added at 9 Ok Reg 2337, eff 6-25-92; Revoked in Rule Making 980000034, eff 7-1-99]

165:10-7-31. Seismic and stratigraphic operations

(a) **Scope.**

(1) This Section shall cover the permitting, bonding, and plugging requirements for seismic exploration activities and stratigraphic test holes. Check-shots and vertical seismic profiles or other downhole wellbore seismic operations are excluded from this Section.

(2) For the purposes of this Section, seismic operation shall mean the drilling of seismic shot holes and use of surface energy sources such as weight drop equipment, thumpers, hydro pulses and vibrators. This definition does not include surveying of the seismic area or the activity of conducting private negotiations between parties.

(3) For the purposes of this Section, technical information and data shall be defined as pre-plats as referenced in (b)(2)(B) and post-plats as referenced in subsection(e).

(b) **Seismic and stratigraphic test permitting.**

(1) Before commencing any seismic or stratigraphic test hole operations in the State of Oklahoma, those companies who actually do the work in the field, hereinafter referred to as the applicant, shall:

(A) Be duly registered with the Commission, including provision of a permanent address.

(B) Post a financial surety guarantee with the Commission.

(C) Provide to the Commission the name and business or field address of the contractor responsible for the operations being conducted.

(D) Notify all surface owners of property where seismic or stratigraphic test operations will occur at least fifteen (15) days prior to commencement of operations. It shall be sufficient notice pursuant to this Section when notice is given to the current surface owner(s) as shown by the records of the applicable county treasurer's office. If the applicant has obtained from the surface owner specific written permission to conduct such operations prior to commencement of operations, such action shall be considered sufficient notification for the purposes of this Section and the 15 day notice requirement shall not be required. Notification by U.S. mail shall be sufficient for the purposes of this Section, provided the notice is postmarked at least fifteen (15) days prior to commencement of any seismic or stratigraphic test operations.

(E) The notice shall include a copy of the oil or gas lease or seismic permit or other legal instrument of similar nature authorizing the use of the surface for seismic or stratigraphic test hole operation(s) and shall contain the following information:

(i) Name of the company for whom the applicant is conducting the seismic or stratigraphic test operation(s) and

(ii) Anticipated date of commencement of operation(s).

(F) Applicants must obtain a permit from the Conservation Division for each seismic or stratigraphic test operation.

(2) The applicant shall make application on the Commission's Form 1000S.

(A) The permit shall be valid for only one operation as approved on Form 1000S.

(B) A pre-plat of the operation area shall be attached to the application showing the location of the operation area delineated to the nearest section.

(C) Post a performance bond in the amount of $50,000, or other form of surety in an amount as approved by the Conservation Division. The performance bond may be filed for each operation, or may be filed on an annual basis to cover all operations that may be undertaken during the year. If the performance bond is filed for a single operation, the amount may be approved by the Conservation Division for less than $50,000 or in another form of financial surety guarantee, depending on the nature of the seismic or stratigraphic operation involved, the number of shot holes or surface energy source points, the cost of the operation and the size of the applicant's business. The form of surety shall not include letters of credit or financial statements. Such bond(s) or other surety may be released upon request made no sooner than thirty (30) days subsequent to the completion of the applicant's operation(s), which have been permitted under such bond(s) or other surety, upon satisfactory inspection or review by Conservation Division personnel.

(D) The permit shall expire twelve (12) months from the issue date, unless operations are commenced.

(E) The Conservation Division shall approve or deny the application within thirty (30) days of receipt of the application. The Conservation Division may act upon an application or amended application on an expedited basis.

(F) During any activity subject to this subsection, the applicant shall maintain at the site a copy of the approved permit, Form 1000S, for inspection.

(G) All technical information, excluding the Form 1000S, but including any plats, relative to the permitted operation shall remain confidential or the Conservation Division shall destroy the records. The plats and any other technical data submitted, shall be filed in the Technical Services Department of the Conservation Division. Upon request of the Manager of Field Operations, the technical data may be reviewed by Field Operations to ensure compliance with Commission rules.

(3) Unless the applicant can demonstrate to the Conservation Division's District Office that another method will provide sufficient protection to groundwater supplies and long term land stability, the following guidelines shall be observed:

(A) Standard plugging method. All holes shall be filled to within four feet from the surface with bentonite, native cuttings, or an appropriate substitute. The remainder of the shot hole shall be filled and tamped with native cuttings or soil.

(B) Special methods. In areas where the standard plugging method has been shown to be inadequate for the prevention of groundwater contamination, the Conservation Division may designate the area as a special problem area. In such event, the Conservation Division will provide to the best of its ability, a clear geographical description of such area and the recommended, or required, hole plugging methods. Should the applicant encounter conditions such that the standard method appears inadequate for the prevention of groundwater contamination, the applicant shall inform the Conservation Division.

(i) Artesian flow. If the standard method is inadequate to stop artesian flow, alternate remedies must be employed to do so.

(ii) Water well conversion. Applicants are prohibited from allowing the conversion of seismic shot holes or stratigraphic test holes to water wells.

(iii) Groundwater protection. Alternative plugging procedures and materials may be utilized when the applicant has demonstrated to the Conservation Division's satisfaction that the alternatives will protect usable quality water.

(iv) Timeliness. All seismic shot holes or stratigraphic test holes shall be plugged as soon as possible and shall not remain unplugged for a period of more than 30 days after the drilling of the hole.

(c) No seismic shot hole blasting shall be conducted within two hundred (200) feet of any habitable dwelling, building, or water well without written permission from the owner of the property or within 500 feet of any superfund site or hazardous waste facility.
(d) Any person, firm, corporation or entity which conducts any seismic or stratigraphic test hole operations without a permit as provided in this Section, or in any other manner violates the rules of the Commission governing such operation shall be subject to a penalty up to One Thousand Dollars ($1,000.00) per violation per day after completion of the informal complaints procedure provided in OAC 165:10-7-7 and notice and hearing pursuant to the Commission's contempt proceedings.
(e) Within 30 days after completing a seismic or stratigraphic test hole operation, the applicant receiving the permit shall submit a copy of the approved Form 1000S certifying the plugging of all seismic shot holes or stratigraphic test holes in compliance with Section (b)(3)(A) or Section (b)(3)(B) above. In addition to the Form 1000S, a post-plat or acceptable form of survey showing the actual location of all seismic shot holes or all stratigraphic test holes shall be included.
(f) **Complaints.** A complaint alleging violations of this Section may be filed with the Commission against any person, firm or corporation conducting seismic and stratigraphic operation(s). The Commission may determine if and when a complaint has been adequately resolved, pursuant to the informal complaints process of OAC 165:10-7-7, and, if an environmental complaint, pursuant to the citizen complaint procedure of OAC 165:5-1-25.

[**SOURCE:** Added in Rule making 980000034, eff 7-1-99]

165:10-7-32. Application to reclaim and/or recycle produced water for surface activities related to drilling, completion, workover, and production operations from oil and gas wells

(a) **Authority to reclaim and/or recycle produced water.** No person shall use produced water for any other purpose except as provided by this section. Any operator failing to obtain a permit may be fined up to $500.00.
(b) **Scope.** This Section shall cover the reclaiming and/or recycling of produced water from oil and gas wells for a single well location for the purpose of water supply for surface activities used for a specific permitted use. This does not include the use of produced water for down- hole operations referred to as weighted water under OAC 165:10-7-24(b)(2).
(c) **Quality of produced water.** For the purposes of this rule shall be limited to Total Dissolved Solids (TDS) content not to exceed 5,000 mg/l and oil and grease content not to exceed 1,000 mg/l.
(d) **Storage of produced water.** If the produced water is stored in tanks, the tanks shall be legibly marked "recycle" water.
(e) **Log of load tickets.** The operator shall maintain copies of the load tickets from wells that the produced water was obtained. Such copies shall be made available to the OCC Inspector upon request.
(f) **Notification to OCC District Office.** The Operator shall orally notify the District Office when produced water is to be initially hauled to the permitted facility.
(g) **Application for permit.**
  (1) The operator of the well must apply for the permit for the reclamation of produced water.
  (2) Required Application. Each application for the reclaiming and/or recycling of produced water shall be submitted to the Field Operations District office on Form 1014D.
  (3) A copy of written notice to the surface owner that the applicant intends to use produced water as per 165:10-7-32 to a specific portion of their real property as designated by legal description. For purposes of notice, a written waiver from the surface owner may also be submitted.

[**SOURCE:** Added in Rule making 200300001, eff 7-1-03]

SUBCHAPTER 8. COMMERCIAL RECYCLING
PART 1. HYDROCARBON RECYCLING/RECLAIMING FACILITIES

Section

PART 3. DRILLING WASTE RECYCLING/RECLAIMING FACILITIES

[**Authority:** 52 O.S. Sections 139 and 141 (Supp. 1993)]

[**Source:** Codified 7-11-94]

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PART 1. HYDROCARBON RECYCLING/RECLAIMING FACILITIES

165:10-8-1. Scope

This Part shall cover the permitting, construction, operation, and closure requirements for any recycling/reclaiming facility.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-2. Definitions

The following words and terms, when used in this Subchapter, shall have the following meaning, unless the context clearly indicates otherwise:

"Tank bottom hydrocarbon recycling/reclaiming facility" means a recycling/reclaiming operation at a tank bottom reclaiming facility which is authorized by the Commission to recycle and/or reclaim marketable crude oil or condensate produced or used in the exploration or production of oil and gas. The facility shall comply with OAC 710:45-15-3.

"Hydrocarbon recycling/reclaiming facility at a saltwater disposal site" means a recycling/reclaiming operation at a Class II saltwater disposal site which is authorized by the commission to recycle and/or reclaim marketable crude oil or condensate produced or used in the exploration or production of oil and gas. The facility shall comply with OAC 710:45-15-3.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Amended in Rule Making 200000002, eff 7-1-00]

165:10-8-3. Permit required

(a) **Who may apply.** The applicant for a recycling/reclaiming facility shall be the owner and/or lease holder of the site.
(b) **Compliance with Part.** Before issuance of a permit, the applicant shall comply with this Part and if pits are to be used for storage, the applicant shall comply with 165:10-9-1, except at Class II saltwater disposals.
(c) **OCC Form 1020A.** Application shall be filed on OCC Form 1020A.
(d) **An Oklahoma Tax Commission Reclaimer License.** The applicant shall have obtained a reclaimer license number under OAC 710:45-15-2. This number will be used by the Corporation Commission for its permit number.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Amended in Rule Making 200000002, eff 7-1-00]

165:10-8-4. Application requirements

(a) **Permit required.** No recycling/reclaiming facility shall be constructed, enlarged, or used without approval on Form 1020A.
(b) **Site limitations.** Recycling/reclaiming facilities shall not be restricted by site limitations unless pits are to be used.
  (1) Tank bottom hydrocarbon recycling/reclaiming facilities with pits that are to be used for storage in the operation shall comply with OAC 165:10-9-1.
  (2) Hydrocarbon recycling/reclaiming facilities at a saltwater disposal site with pits that are used for unloading saltwater shall comply with OAC 165:10-9-3.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Amended in Rule Making 200000002, eff 7-1-00]

165:10-8-5. Surety requirements for reclaimers

(a) **Agreement to close.** Any operator of a recycling/reclaiming facility shall file with the Oil and Gas Conservation Division an agreement to properly close and reclaim the site in accordance with approved closure and reclamation procedures upon termination of recycling/reclaiming operations. The agreement shall be on forms available from the Conservation Division and shall be accompanied by surety. The agreement shall provide that if the Commission finds that the operator has failed or refused to close the facility or take remedial action as required by law and the rules of the Commission, the surety shall pay to the Commission the full amount of the operator's obligation up to the limit of the surety.

(b) **New facilities.** Category A (165:10-1-11) or Category B (165:10-1-13) surety shall be required for coverage of the closure costs, including well pluggings and general site restoration. These costs shall be calculated upon the projected costs of closure for the facility, based on estimated costs of earth work, remediation, revegetation, plugging, etc. Such information shall be provided by the applicant and reviewed, adjusted and ordered by the Commission.

(c) **Existing facilities.** For facilities in operation prior to the effective date of this Part, the Commission can require, by order, the establishment of an escrow account to cover the costs of closure, by using a per barrel fee to be deposited into the account. Any interest the account earns until the total amount is collected shall be reinvested in the account. Any interest accrued after the account balance is full shall be returned to the operator.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-6. Design and construction requirements

(a) **Spill prevention.** Each facility shall be designed and constructed utilizing good engineering practices. Design and construction standards shall be determined on a case-by-case basis by the Commission. Each such facility shall be designed and constructed to prevent escape of deleterious substances.

(b) **Unloading pits or sumps.** All unloading areas at tank bottom hydrocarbon recycling/reclaiming facilities that use a pit to receive fluids and skimming pits shall be approved on OCC Form 1014.

(c) **Required exhibits.** Complete construction plans, drawings, and written specifications for the proposed facility shall be submitted to the Manager of Pollution Abatement for review and approval. Design and construction standards shall be determined on a case-by-case basis by the Commission. Applicants shall consult with the Commission prior to the construction of the proposed facility. The Commission may apply existing technological standards and/or establish new standards, as it deems appropriate to the proposed site and activities. All plans, drawings, and specifications shall be prepared by or under the supervision of a qualified expert.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Amended in Rule Making 200000002, eff 7-1-00]

165:10-8-7. Operation and maintenance requirements

(a) **Fencing.** All recycling/reclaiming facilities shall be completely enclosed by a fence at least four feet in height. No livestock shall be allowed inside the fence. Final construction is subject to approval by the Manager of Pollution Abatement.

(b) **Sign.** A waterproof sign bearing the name of the operator, legal description, permit number, and emergency phone number shall be posted within 25 feet of the entrance gate to the facility and shall be readily visible.

(c) **Site security.** Receiving of any recycling/reclaiming material shall occur only when there is an attendant on duty. All sites shall be secured by a locked gate when an attendant is not on duty. A key or combination to the lock shall be provided to the appropriate Field Inspector for the purpose of carrying out inspections.

(d) **Acceptable materials.** Operators of a recycling/reclaiming facility shall only receive substances as defined in 165:10-1-2 "Deleterious substances."
(e) **Oil film.** OPERATORS TAKE NOTE: Federal statutes, such as the Bald Eagle Protection Act (16 U.S.C. Sections 668-668d), the Migratory Bird Treaty Act (16 U.S.C. Sections 703-711), the Endangered Species Act (16 U.S.C. Sections 1531-1542), and the Lacey Act Amendments of 1981 (16 U.S.C. Sections 3371-3378), dictate substantial fines and penalties for persons who allow birds of certain species to become fatally injured due to incidental contact with oil or oil by-products. These fines may be levied upon persons allowing such fatalities to occur, whether accidental or not. Misdemeanor and felony convictions may include imprisonment. Information on affected bird species, regulations under these Acts, and measures which can be taken to prevent such occurrences, such as the netting or covering of open-topped tanks and pits which contain oil or oil by-products, can be obtained from the U.S. Fish and Wildlife Service Office in Oklahoma City or the nearest Oklahoma Department of Wildlife Office.
(f) **Aesthetics.**
(1) All surface trash, debris, junk and scrap or discarded material connected with the operations of the facility shall be removed from the premises. With written permission from the surface owner, the operator may, without applying for an exception to 165:10-3-17(b), bury all nonhazardous material at a minimum depth of three feet; cement bases are included.
(2) The District Office or field inspector may issue a Form 1085 for any alleged violation of this subsection. If the operator fails to conduct cleanup as directed, the Commission may fine the operator $500.00 for a first offense. For a subsequent offense, the fine shall be $1,000.00, and the facility shall be shut down until completion for cleanup operations.
(g) **Structural integrity.** All recycling/reclaiming facilities shall be used, operated, and maintained at all times so as to prevent the escape of their contents. Any condition that threatens the structural stability of any diked portion or the storage facility shall be repaired in a timely manner.
(h) **Prevention of pollution.** All recycling/reclaiming facilities shall be used, operated, and maintained at all times so as to prevent pollution. In the event any non permitted discharge occurs, sufficient measures shall be taken to stop or control the loss of materials, and reporting procedures in accordance with 165:10-7-5(c) shall be followed. Any materials lost due to such discharge shall be cleaned up as directed by a representative of the Conservation Division.
(i) **Fines.** For a willful non-permitted discharge from the facility, the operator shall be fined $5,000.00.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Amended in Rule Making 200000002, eff 7-1-00]

165:10-8-8. Reporting
(a) **Annual report on Form 1014A.** The operator of any recycling/reclaiming facility shall submit an annual report on Form 1014A to the Manager of Pollution Abatement, by February 1 of each year. In lieu of Commission Form 1014A, operators may submit Oklahoma Tax Commission Form 323A for the twelve calendar months of the previous year by February 1st.
(b) **Daily log for tank bottom at a hydrocarbon recycling/reclaiming facility.** The operator shall maintain a daily log and at a minimum shall include the date, volume, source (generator) and type of material. In addition, copies of any chemical analysis of materials or material safety data sheets shall be maintained.
(c) **Daily load tickets for hydrocarbon recycling/reclaiming facilities at salt water disposal facilities.** The operator shall keep the load tickets for saltwater and other deleterious substances received at the saltwater disposal facilities for a minimum of three years at the operator's office.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Amended in Rule Making 200000002, eff 7-1-00]

165:10-8-9. Closure requirements

(a) **Notification.** The Manager of Pollution Abatement Department shall be notified in writing whenever a recycling/reclaiming facility shall be closed, or portions thereof, or becomes inactive unless it is shut down by the Commission.

(b) **Closed facility.** A recycling/reclaiming facility may be considered closed or inactive if the operator closes the facility, the operator is unable to furnish documentation to show that there has been receipt of deleterious substances during the last twelve months, the facility has been shut down by the Commission, or authority to operate has lapsed or is vacated by Commission order.

(c) **Closure plan.** An approved closure plan shall be submitted to the Pollution Abatement Department. Estimate of cost of closure shall be made part of the plan.

(d) **Monitor wells.** Monitor wells, if required, shall be plugged with bentonite or cement, upon approval in writing by the Manager of Pollution Abatement.

(e) **Pits.** When closing any pit with a geomembrane liner, extreme care shall be taken to preserve the integrity of the liner. All free liquids and sediments shall be removed.

(f) **Burial.** If any concrete, steel, geomembrane, or other materials associated with the site are to be left on-site, they shall be buried under a minimum soil cover of three (3) feet, pursuant to 165:10-3-7.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-10. Additional requirements

The requirements set forth in this Part are minimum requirements. Additional requirements may be made upon a showing of good cause.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-11. Variances

Except as otherwise provided in this Subchapter, variances from provisions of this Part may be granted by the Manager of Pollution Abatement or by order after application, notice, and hearing.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

PART 3. DRILLING WASTE RECYCLING/RECLAIMING FACILITIES

165:10-8-25. Scope

This Part shall cover the permitting, construction, operation, and closure requirements for any drilling waste recycling/reclaiming facility.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-26. Definitions

The following words and terms, when used in this Subchapter, shall have the following meaning, unless the context clearly indicates otherwise:

"Drilling waste recycling/reclaiming facility" means a recycling/reclaiming operation which is authorized by the Commission to recycle and/or reclaim drilling waste produced or used in the exploration or production of oil and gas into a marketable product for resale which has undergone at least one treatment process and is to be used for something other than drilling or plugging mud.

This definition does not?include the reuse of drilling mud used in drilling or plugging operations.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-27. Pit requirements
(a) **Who may apply.** The applicant for a drilling waste recycling/reclaiming facility shall be the owner and/or lease holder of the site.
(b) **Compliance with Part.** Before issuance of a permit, the applicant shall comply with this Part and if pits are to be used for storage, the applicant shall also comply with 165:10-9-1.
(c) **OCC Form 1020A.** Application shall be filed on OCC Form 1020A.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-28. Application requirements
(a) **Permit required.** No drilling waste recycling/reclaiming facility shall be constructed, enlarged, reconstructed, or used without approval on Form 1020A.
(b) **Site limitations.** Drilling waste recycling/reclaiming facilities shall not be restricted by site limitations unless pits are to be used. If pits are to be used for storage in the operation, the applicant shall also comply with 165:10-9-1.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-29. Surety requirements for reclaimers
(a) **Agreement to close.** Any operator of a drilling waste recycling/reclaiming facility shall file with the Oil and Gas Conservation Division an agreement to properly close and reclaim the site in accordance with approved closure and reclamation procedures upon termination of drilling waste recycling/reclaiming operations. The agreement shall be on forms available from the Conservation Division and shall be accompanied by surety. The agreement shall provide that if the Commission finds that the operator has failed or refused to close the facility or take remedial action as required by law and the rules of the Commission, the surety shall pay to the Commission the full amount of the operator's obligation up to the limit of the surety.
(b) **New facilities.** For new facilities, a Category A (165:10-1- 11) or Category B (165:10-1-13) surety shall be required for coverage of the closure costs, including well pluggings and general site restoration. These costs shall be calculated upon the projected costs of closure for the facility, based on estimated costs of earth work, remediation, revegetation, plugging, etc. Such information shall be provided by the applicant and reviewed, adjusted if necessary, and ordered by the Commission.
(c) **Existing facilities.** For facilities in operation prior to the effective date of this Section, the Commission can require, by order, the establishment of an escrow account to cover the costs of closure, by using a per barrel fee to be deposited into the account. Any interest the account earns until the total amount is collected shall be reinvested in the account. Any interest accrued after the account balance is full shall be returned to the operator.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-30. Design and construction requirements
(a) **Spill prevention.** Each facility shall be designed and constructed utilizing good engineering practices. Design and construction standards shall

be determined on a case-by-case basis by the Commission. Each facility shall be designed and constructed to prevent escape of deleterious substances.
(b) **Unloading pits or sumps.** All unloading areas that use a pit to receive fluids and skimming pits shall be approved on OCC Form 1014.
(c) **Required exhibits.** Complete construction plans, drawings, and written specifications for the proposed facility shall be submitted to the Manager of Pollution Abatement for review and approval. Design and construction standards shall be determined on a case-by-case basis by the Commission. Applicants shall consult with the Commission prior to construction of the proposed facility. The Commission may apply existing technological standards and/or establish new standards, as it deems appropriate to the proposed site and activities. All plans, drawings, and specifications shall be prepared by or under the supervision of a qualified expert.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-31. Operation and maintenance requirements
(a) **Fencing.** The drilling waste recycling/reclaiming facility shall be completely enclosed by a fence at least four feet in height. No livestock shall be allowed inside the fenced area. Final construction is subject to approval by the Manager of Pollution Abatement.
(b) **Sign.** A waterproof sign bearing the name of the operator, legal description, permit number, and emergency phone number shall be posted within 25 feet of the entrance gate to the facility and shall be readily visible.
(c) **Site security.** Receiving of any drilling waste recycling/reclaiming material shall occur only when there is an attendant on duty. All sites shall be secured by a locked gate when an attendant is not on duty. A key or combination to the lock shall be provided to the appropriate Field Inspector for the purpose of carrying out inspections.
(d) **Acceptable materials.**
(1) Operators of a drilling waste recycling/reclaiming facility shall only receive substances as defined in 165:10- 1-2 "Deleterious Substances."
(2) Water based mud shall be stored separately from oil based mud.
(e) **Open pits.** Any open recycling pit or tank shall be covered to prevent access to birds.
(f) **Aesthetics.**
(1) All surface trash, debris, junk and scrap or discarded material connected with the operations of the facility shall be removed from the premises. With written permission from the surface owner, the operator may, without applying for an exception to 165:10-3-17(b), bury all nonhazardous material at a minimum depth of three feet; cement bases are included.
(2) The District Office or field inspector may issue a Form 1036 for any alleged violation of this subsection. If the operator fails to conduct cleanup as directed, the Commission may fine the operator $500.00 for a first offense. For a subsequent offense, the fine shall be $1,000.00, and the facility shall be shut down until completion for cleanup operations.
(g) **Structural integrity.** All drilling waste recycling/reclaiming facilities shall be used, operated, and maintained at all times so as to prevent the escape of their contents. Any condition that threatens the structural stability of any diked portion or the storage facility shall be repaired in a timely manner.
(h) **Prevention of pollution.** All drilling waste recycling/reclaiming facilities shall be used, operated, and maintained at all times so as to prevent pollution. In the event any non permitted discharge occurs, sufficient measures shall be taken to stop or control the loss of materials, and reporting procedures in accordance with 165:10-7-5(c) shall be followed. Any materials lost due to such discharge shall be cleaned up as directed by a representative of the Conservation Division.
(i) **Fines.** For a willful non-permitted discharge from the facility, the operator shall be fined $5,000.00.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-32. Reporting

(a) **Annual report on Form 1014A.** The operator of any drilling waste recycling/reclaiming facility shall submit an annual report on Form 1014A to the Manager of Pollution Abatement, by February 1 of each year.
(b) **Daily log.** The operator shall maintain a daily log that at a minimum shall contain the date, volume, source (generator) and type of material and in addition copies of any chemical analysis or materials or D.O.T. material safety data sheets.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-33. Closure requirements

(a) **Notification.** The Manager of Pollution Abatement Department shall be notified in writing whenever a drilling waste recycling/reclaiming facility shall be closed, or portions thereof, or becomes inactive unless it is shut down by the Commission.
(b) **Closed facility.** A drilling waste recycling/reclaiming facility may be considered closed or inactive if the operator closes the facility, the operator is unable to furnish documentation to show that there has been receipt of deleterious substances during the last twelve months, the facility has been shut down by the Commission, or authority to operate has lapsed or is vacated by Commission order.
(c) **Closure plan.** An approved closure plan shall be submitted to the Pollution Abatement Department. Estimate of cost of closure shall be made part of the plan.
(d) **Monitor wells.** Monitor wells, if required, shall be plugged with bentonite or cement, upon approval in writing by the Manager of Pollution Abatement.
(e) **Pits.** When closing any pit with a geomembrane liner, extreme care shall be taken to preserve the integrity of the liner. All free liquids and sediments shall be removed.
(f) **Burial.** If any concrete, steel, geomembrane, or other materials associated with the site are to be left on-site, they shall be buried under a minimum soil cover of three (3) feet, pursuant to 165:10-3-7.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-34. Additional requirements

The requirements set forth in this Part are minimum requirements. Additional requirements may be made upon a showing of good cause.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-35. Variances

Except as otherwise provided in this Subchapter, variances from provisions of this Part may be granted by the Manager of Pollution Abatement or by order after application, notice, and hearing.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

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SUBCHAPTER 9. COMMERCIAL DISPOSAL FACILITIES

Section

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165:10-9-1. Use of commercial pits

(a) **Scope.** This Section shall cover the permitting, construction, operation, and closure requirements for any commercial pit. A commercial pit is a disposal facility which is authorized by Commission order and used for the disposal, storage, and handling of deleterious substances or soils contaminated by deleterious substances produced, obtained, or used in connection with drilling and/or production operations. This does not cover disposal well pits. (See 165:10-9-3 and 165:10-7-20.)

(b) **Application requirements.**

(1) **Who may apply.** The applicant for a commercial pit shall be the owner of the land (or person having a written firm option to purchase the land at the time the application is filed) on which the proposed pit is to be located: if leased, both the owner and lessee shall be joint applicants.

(2) **Compliance with rules.** Before issuance of an order, the applicant shall comply with Commission Rules of Practice 165:5-7-1, 165:5-7-35, 165:5-3-1, and this Section.

(3) **Exhibits.** Two complete sets of all exhibits which shall be relied upon by the applicant shall be submitted to the Pollution Abatement Department of the Commission, pursuant to 165:5-7-35. Those exhibits shall include, but are not limited, to the following:

(A) A lithologic log of test borings, identifying the subsurface materials encountered and the depth at which groundwater was encountered pursuant to (c)(2)(D) of this Section.

(B) Results of permeability tests of the proposed liner materials, pursuant to (e)(7) of this Section.

(C) A topographic map of the commercial pit site.

(D) The appropriate Soil Conservation Service (SCS) soil survey aerial photo and legend.

(E) A detailed drawing of the site, with complete construction plans drawn to scale by or under the supervision of a registered professional engineer.

(F) A plan for closure of the pit(s) which shall provide for a minimum three feet of soil cover and shall specifically state how all aspects of closure shall be accomplished, including volume and fate of liquids and solids, earthwork to close the pit(s) (including placement of stockpiled topsoil), and revegetation of the site.

(G) An itemization of projected hauling, closure, reclamation, maintenance, and monitoring costs.

(H) A plan for post-closure maintenance and monitoring which shall address maintenance of the site as well as monitoring and plugging of wells. Exemption from the plugging of monitor wells may be obtained upon written request and approval of the Manager of Pollution Abatement.

(I) A plan for operation which shall address the method(s) by which excess water will be disposed.

(c) **Restrictions.**

(1) **Order required.** No commercial earthen pit shall be constructed, enlarged, reconstructed, or used without a Commission order.

(2) **Site limitations.**

(A) No commercial earthen pit shall be constructed or used unless an investigation of the soils, topography, geology, and hydrology conclusively shows that storage of water-based drilling fluids and/or cuttings at the site will not be harmful to groundwater, surface water, soils, plants, or animals in the surrounding area. No abandoned mine, strip pit, quarry, canyon, or streambed shall be used for disposal of oilfield wastes, nor shall a pit be constructed or used in such a setting.

(B) No commercial pit shall be constructed or used on any site that is located within a 100-year flood plain.

(C) No commercial pit shall be constructed or used within a wellhead protection area (WPA) as identified by the Wellhead Protection Program (42 USC Section 300h-7, Safe Drinking Water Act), or within one mile of an active municipal water well for which the WPA has not been delineated.

(D) No commercial pit shall be constructed unless it can be shown that there will be a minimum of 25 feet between the bottom of the pit and the groundwater level of the first aquifer. To ascertain this and to demonstrate the subsurface profile of the site, a minimum of three test borings (the exact number of locations to be determined by the Pollution Abatement Department) shall be drilled to a minimum depth of 25 feet below the proposed bottom of the pit and into the first aquifer encountered. Test borings need not extend deeper than 50 feet below the bottom of the pit if an aquifer has not been encountered before that depth. All boreholes converted to monitor wells shall conform to (e)(15) of this Section. All boreholes not converted to monitor wells shall be plugged from top to bottom with bentonite, cement, and/or other method approved by the Pollution Abatement Department within 30 days of drilling completion.

(E) After July 1, 1992, no commercial pit shall be constructed or used within the following distances from the city limits of an incorporated municipality unless previously authorized by Commission order:

(i) Three miles if population is 20,000 or less.

(ii) Five miles if population is greater than 20,000.

(3) **Means of water disposal.** No commercial pit shall be constructed or used unless the operator can show that there will be an ongoing means of disposal of excess water pursuant to (b)(3)(I) of this Section.

(d) **Surety requirements.**

(1) **Agreement with Commission.** Any operator of a commercial pit shall file with the Manager of Document Handling for the Conservation Division an agreement to properly close and reclaim the site in accordance with approved closure and reclamation procedures upon termination of disposal operations due to abandonment, shutdown, full pits, or other reason. The agreement shall be on forms available from the Conservation Division and shall be accompanied by surety. The agreement shall provide that if the Commission finds that the operator has failed or refused to close the pits or take remedial action as required by law and the rules of the Commission, the surety shall pay to the Commission the full amount of the operator's obligation up to the limit of the surety.

(2) **Surety amount and type.** The Commission shall establish the amount of security in the order for the authority to construct, enlarge, or operate a commercial pit. The amount of security shall be based on factors such as dimensions of the pit and costs of hauling, closure, reclamation, and monitoring. The amount may be subject to change for good cause. Upon approved closure of a pit, the Manager of Pollution Abatement may administratively reduce the surety requirement to an amount which would cover the cost of monitoring the site and plugging the monitor wells. Security shall be maintained for as long as monitoring is required. The type of security shall be a corporate surety bond, certificate of deposit, irrevocable letter of credit, or other type of security approved for the pit by order of the Commission. Any type of surety that expires shall be renewed prior to 30 days before the expiration date. All joint escrow accounts shall be made current every 30 days.

(3) **Posting surety before permit is issued.** An operator shall post surety with the Commission before a construction permit is issued, pursuant to (e)(1) of this Section.

(e) **Construction requirements.**

(1) **Permit required.** Prior to constructing any pit, a commercial pit operator shall obtain a permit from the Manager of Pollution Abatement. Application shall be made on Form 1014N. For use of a commercial pit without a permit, the pit operator shall be fined $5,000.00.

(2) **Runoff water prohibited.** No runoff water from surrounding land surfaces shall be allowed to enter a pit.

(3) **Stockpiling of topsoil.** Prior to constructing a pit, all topsoil within the top twelve inches of soil on the site shall be stockpiled for use as the final cover at the time of closure. The topsoil may be stockpiled in the outside slopes of the berms, provided it is not used for structural purposes and can be readily distinguishable from other soil materials at the

time of closure. In cases where topsoil is stockpiled in the berms, it shall be shown in the as-built drawings pursuant to (e)(16) of this Section.

(4) **Monitoring by engineer.** A registered professional engineer or an engineer-in-training working under the supervision of a registered professional engineer (RPE) shall monitor the construction of any commercial pit to assure that approved design specifications and Commission rules are adhered to. A minimum of three on-site visits to the site shall be made; one pre-construction, one during construction, and one post-construction. At least the post-construction on-site visit shall be made by the RPE.

(5) **Maximum fluid depth.** Any pit shall be constructed to contain a maximum fluid or sediment depth of seven feet, with a minimum freeboard of three feet.

(6) **Maximum dimensions.** Any pit shall not be constructed to dimensions greater than that approved in the order. Furthermore, the maximum width of a pit or pit cell shall not exceed 175 feet if closure must be accomplished from one side or two adjacent sides; 350 feet if closure can be accomplished from at least two opposite sides or three adjacent sides. Pit dimensions shall be measured at the maximum allowable fluid level.

(7) **Soil liners.**

(A) Soil materials to be used in a soil liner shall undergo permeability testing before construction. Pre-construction permeability testing shall consist of laboratory permeability tests on at least two specimens of representative soil liner materials compacted in the laboratory to approximately 95 percent of the material's Standard Proctor Density (ASTM D-698).

(B) Laboratory permeability test procedures must conform to one of the methods described for fine-grained soils in the Corps of Engineers Manual EM-1110-2-1906 Appendix VII. In no case shall the pressure differential across the specimen exceed five feet of water per inch of specimen length.

(C) If permeability testing shows that addition of bentonite or other approved material is needed to assist the native soils in meeting the permeability standard, it shall be applied at a minimum rate specified by the testing or engineering firm. Any bentonite used for liner material shall not have been previously used in drilling muds.

(D) Any soil liner shall be constructed by disturbing the soil to the depth of the bottom of the liner, applying fresh water as necessary to the soil materials to achieve a moisture content wet of optimum, then recompacting it with heavy construction equipment, such as a footed roller, until the required density is achieved, pursuant to (H) of this paragraph. The liner shall be constructed in maximum six inch lifts (after compaction), with each lift being scarified before placement of the next lift.

(E) Any soil liner shall cover the bottom and interior sides of the pit entirely.

(F) Any soil liner shall be installed on a slope no steeper than 3:1 (horizontal to vertical).

(G) Any soil liner shall have a minimum thickness of 18 inches (after compaction) and shall have a maximum coefficient of permeability of 1.0×10^{-7} cm/sec.

(H) Any soil liner shall be field tested for compaction, unless a post-construction permeability test is performed pursuant to (I) of this paragraph.

(i) A minimum of six compaction tests shall be performed on any soil liner; a minimum of four widely spaced tests in the bottom of the pit and two tests on different slopes of the pit are required, unless otherwise directed by a Conservation Division representative. Particular emphasis shall be placed on selecting locations for compaction tests where nonuniformity in soil texture or color can be observed.

(ii) Compaction tests shall be conducted in accordance with ASTM methods D-2922 or D-1556.

(iii) The soil materials of any liner shall be compacted to at least 95 percent of the Standard Proctor Density.

(I) Post-construction permeability testing shall consist of at least two laboratory permeability tests on undisturbed samples of the completed soil liner.

(i) Particular emphasis shall be placed on selecting the location(s) for permeability tests or test samples where nonuniformity in soil texture or color can be observed.

(ii) Field permeability tests shall be conducted only by the double ring infiltrometer method as described in ASTM D-3385. Permeability tests may be discontinued prior to flow stabilization upon satisfactory evidence that the permeability rate is less than 1.0×10^{-7} cm/sec.

(8) **Geomembrane liners.**

(A) Any geomembrane liner that is installed in a commercial pit shall have a minimum thickness of 30 mil.

(B) Any geomembrane liner used in a commercial pit shall be chemically compatible with the type of substances to be contained and shall have ultraviolet light protection.

(C) Any geomembrane liner shall be placed over a specially prepared, smooth, compacted surface void of sharp changes in elevation, rocks, clods, organic debris, or other objects.

(D) Any geomembrane liner shall be continuous, although it may include seams, and shall cover the bottom and interior sides of the pit entirely. The edges shall be securely placed in a minimum twelve inch deep anchor trench around the perimeter of the pit.

(9) **Width of the crown.** The crown (top) of any berm shall be a of minimum eight feet in width.

(10) **Slopes.** The inside slope of any exterior berm (having fluid on one side) shall not be steeper than 3:1 (horizontal to vertical) and the outside slope 2.5:1. The slopes of any interior berm (having fluid on both sides) shall not be steeper than 3:1.

(11) **Earthwork compaction.** All earthwork, except as noted in (7)(H)(iii) of this subsection, shall be compacted to achieve a minimum 90% Standard Proctor Density and shall be applied in lifts where some method of bonding is achieved between lifts, with each lift not to exceed eight inches prior to compaction.

(12) **Pipe installation.** Any pipe, tinhorn, culvert, or conduit in the berm between two adjoining pits shall be placed so that there is a minimum of 36 inches between the top of the pipe, tinhorn, culvert, or conduit and the lowest point in the top of the berm separating the pits.

(13) **Splash pad.** All pits which receive fluids directly from a vacuum truck shall have a splash pad at the point where fluids are received unless a waiver is obtained from the Manager of Pollution Abatement by showing that erosion of the liner will not occur. The pad must be constructed of materials and to the dimensions necessary to effectively prevent the liner from eroding.

(14) **Fluid level marker.** A minimum of one stationary fluid level marker shall be erected in each pit or cell. The marker shall be erected in a location within the pit or cell where it can be easily observed. The marker shall be of such design that the maximum fluid level at any time may be clearly identified. The marker shall be mounted on a suitable post set in concrete or other method approved by the Manager of Pollution Abatement. That portion of the post hole which lies in the soil liner zone shall be backfilled with bentonite pellets. Details of the proposed marker installation shall be approved by the Manager of Pollution Abatement prior to installation. Markers shall be installed under the supervision of a registered professional engineer, licensed land surveyor, or other person approved by the Manager of Pollution Abatement prior to installation.

(15) **Monitor wells.** All commercial pits shall have a minimum of three monitor wells; one upgradient and two downgradient. The exact number and location of wells shall be approved by the Pollution Abatement Department prior to installation. No monitor well shall be installed more than 250 feet from a commercial pit, nor shall any existing water well be used as a monitor well unless approved by the Manager of Pollution Abatement. Monitor wells installed prior to the effective date of this Section may be accepted

by the Manager of Pollution Abatement if it can be shown that they adequately monitor a site. All new monitor wells shall be drilled through the first aquifer encountered, but need not extend more than 50 feet below the bottom of a pit if no aquifer is encountered, and shall be completed by a licensed monitor well driller. If documentation can be submitted prior to drilling to show that no water will be encountered within 50 feet below the bottom of the pit, the Manager of Pollution Abatement may require that monitor wells be drilled to a lesser depth. All new monitor wells shall meet the following requirements:

(A) A minimum two inch diameter PVC casing shall be used with a sealing cap on the bottom.

(B) The casing shall consist of a slotted liner in the saturated zone, or bottom ten feet if none is encountered, and shall be gravel-packed or sand-packed as appropriate to the installation.

(C) Bentonite shall be placed in the annular space of the well above the slotted liner for an interval of at least two feet to form an adequate seal.

(D) Uncontaminated well cuttings may be returned to the annular space above the bentonite seal for well stability.

(E) A minimum of two of the top six feet of the annular space around the casing shall be filled with cement.

(F) A minimum three inch thick concrete apron shall be placed at the surface to a minimum two foot radius from the casing.

(G) A removable and lockable cap shall be placed on top of the casing. The cap shall remain locked at all times, except when the well is being sampled.

(H) Within 30 days of installation, specific completion information for all monitor wells shall be submitted to the Manager of Pollution Abatement.

(16) **As-built drawing.** A detailed, as-built drawing of the pit(s) and monitor wells by or under the supervision of a registered professional engineer shall be submitted to the Manager of Pollution Abatement before operation of the pit(s) commences.

(17) **Liner certification.** An affidavit signed by the person who was responsible for installing the pit liner, certifying that the liner meets minimum requirements and was installed in accordance with Commission rules, shall be submitted to the Manager of Pollution Abatement before operation of the pit commences. Supporting documentation shall also be submitted, such as post-construction permeability or compaction test results, bentonite receipts, and geomembrane liner specifications from the manufacturer.

(18) **Pit approval.** Acceptance of fluids into a pit shall not commence until a representative of the Conservation Division has inspected and approved the pit.

(19) **Hydrologically sensitive areas.** If the proposed site is known to be located over a hydrologically sensitive area (hydrologically sensitive areas and hydrologically very sensitive areas are determined by the Technical Department and based upon Oklahoma Geological Survey maps), in addition to the foregoing construction requirements, the additional requirements shall apply:

(A) The total depth of a pit shall not exceed eight feet, and the total designed fluid or sediment depth shall not exceed five feet.

(B) A soil liner having a minimum thickness of three feet and a coefficient of permeability no greater than 1.0×10^{-8} cm/sec or a minimum 60-mil geomembrane liner shall be required.

(C) The Manager of Pollution Abatement shall determine the minimum depth of all monitor wells.

(f) **Operation and maintenance requirements.**

(1) **Vegetative cover.** Vegetative cover shall be established on all areas of earthfill immediately after pit construction or during the first planting season if pit construction is completed out of season. The cover shall be sufficient to protect those areas from soil erosion and shall be maintained.

(2) **Fencing.** All commercial pits shall be completely enclosed by either a woven wire fence at least four feet in height or a woven wire fence at least

three feet in height with two strands of barbed wire. No livestock shall be allowed inside the fence.
(3) **Sign.** A waterproof sign bearing the name of the operator, legal description, most current order number, and emergency phone number shall be posted within 25 feet of the entrance gate to any commercial pit and shall be readily visible.
(4) **Site security.** Dumping into a commercial pit shall occur only when there is an attendant on duty. All sites shall be secured by a locked gate when an attendant is not on duty. A key or combination to the lock shall be provided to the appropriate Field Inspector for the purpose of carrying out inspections.
(5) **Fluid level.** Drilling fluids and/or cuttings shall not be accepted into a commercial pit unless the fluid level can be maintained at an elevation no higher than the maximum level of the fluid level marker.
(6) **Acceptable materials.**
(A) No operator of a commercial pit shall receive any substances other than water-based drilling fluids and/or cuttings or salt contaminated soils.
(B) No operator of a pit permitted prior to July 9, 1987, shall receive fluids and/or cuttings with a chloride content greater than 3500 mg/l. No operator of a pit permitted after July 9, 1987, shall receive fluids and/or cuttings with a chloride content greater than 5000 mg/l.
(C) A sample from each incoming load shall be collected, filtered using a standard API filter press, and tested for chlorides.
(D) The date, volume, source, and chloride level of each load received shall be entered into a log book. The log book shall be available for inspection by a representative of the Conservation Division of the Commission at all times. Log books shall be kept for a minimum of five years after closure is completed.
(7) **Pit contents.** No pit permitted prior to July 9, 1987, shall contain fluids and/or cuttings with a chloride content greater than 5,000 mg/l. No pit permitted after July 9, 1987, shall contain fluids and/or cuttings with a chloride content greater than 10,000 mg/l. The contents of each pit or pit cell shall be sampled and analyzed by the operator at least once every six months (during January and July) after operations commence. More frequent sampling may be required by the Manager of Pollution Abatement. The following procedures shall be used:
(A) The appropriate Field Inspector shall be notified at least 24 hours in advance of sampling to allow a Commission representative an opportunity to witness the sampling.
(B) Samples shall be collected and handled by the operator according to EPA-approved standards. (RCRA Groundwater Monitoring Technical Enforcement Guidance Document, EPA, OSWER-9950.1, September 1986, pp. 99-107.)
(C) A minimum of five samples per 50,000 bbls., or part thereof, is required for each pit or pit cell. Samples must be taken from different horizontally and vertically distributed locations in each pit or pit cell.
(D) The samples shall be combined and thoroughly mixed, then a minimum two pint composite sample taken for analysis.
(E) If requested by a representative of the Conservation Division, each composite sample shall be split and an adequate portion (approximately one pint) shall be properly labeled and delivered or otherwise provided to the appropriate District Office or Field Inspector.
(F) All samples delivered to the laboratory shall be accompanied by a chain of custody form.
(G) All composite samples must be analyzed for chlorides by a laboratory certified by the Oklahoma Water Resources Board or operated by the State of Oklahoma. Analysis of additional parameters may be required, as determined by the Manager of Pollution Abatement.
(H) A copy of each analysis shall be forwarded to the Pollution Abatement Department within 30 days of sampling.
(8) **Oil film.**

(A) No commercial pit shall contain an oil film covering more than one acre or more than ten percent of the surface area of the pit, whichever is less.

(B) The protection of migratory birds shall be the responsibility of the operator. Therefore, the Conservation Division recommends that to prevent the loss of birds, oil films be removed, or the surface area covered by the film be protected from access to birds. (See Advisory Notice in 165:10-7-3(c).)

(9) **Aesthetics.** All commercial pit sites shall be maintained so that there is no junk iron or cable, oil or chemical drums, paint cans, domestic trash, or debris on the premises.

(10) **Structural integrity.** All commercial pits shall be used, operated, and maintained at all times so as to prevent the escape of their contents. All erosion, cracking, sloughing, settling, animal burrows, or other condition that threatens the structural stability of any earthfill shall be repaired immediately upon discovery.

(11) **Monitor wells.** Sampling of monitor wells shall begin prior to accepting any drilling fluids and/or cuttings into a new facility and within 30 days of drilling completion on existing facilities, and shall be done at least once every six months (during January and July) after operations commence until three years after closure is completed. Sampling of greater frequency of duration may be required by the Manager of Pollution Abatement. The following procedures shall be used:

(A) The appropriate Field Inspector shall be notified at least 24 hours in advance of sampling to allow a Commission representative an opportunity to witness the sampling.

(B) Samples shall be collected and handled by the operator according to EPA-approved standards. (RCRA Groundwater Monitoring Technical Enforcement Guidance Document, EPA, OSWER-9950.1, September 1986, pp. 99-107.)

(C) If requested by a representative of the Conservation Division, an adequate portion of each sample (approximately one pint) shall be properly labeled and delivered or otherwise provided to the appropriate District Office or Field Inspector.

(D) All samples delivered to the laboratory shall be accompanied by a chain of custody form.

(E) All samples must be analyzed for pH and chlorides by a laboratory certified by the Oklahoma Water Resources Board or operated by the State of Oklahoma. Analysis of additional parameters may be required, as determined by the Manager of Pollution Abatement.

(F) A copy of each analysis and a statement as to the depth to groundwater encountered in each well, or an affidavit that no water was encountered, shall be forwarded to the Pollution Abatement Department within 30 days of sampling.

(12) **Prevention of pollution.** All commercial pits shall be used, operated, and maintained at all times so as to prevent pollution. In the event of a nonpermitted discharge from a commercial pit, sufficient measures shall be taken to stop or control the loss of materials, and reporting procedures in 165:10-7-5(c) shall be followed. Any materials lost due to such discharge shall be cleaned up as directed by a representative of the Conservation Division. For a willful non-permitted discharge, the pit operator shall be fined $5,000.00.

(g) **Annual report.** The operator of any commercial pit shall submit an annual report on Form 1014A to the Manager of Pollution Abatement, by February 1 of each year.

(h) **Closure requirements.**

(1) **Notification.** The Manager of Pollution Abatement shall be notified in writing whenever a commercial pit becomes inactive, is abandoned, full of sediment, or operation of the pit ceases for any reason. A commercial pit may be considered to be inactive by the Commission if:

(A) The pit has been shut down by the Commission because of a violation which results in the filing of an application for an order to vacate the operator's authority.

(B) The authority to operate has been terminated by failure to comply with (j) of this Section.
(C) The operator is unable to furnish documentation to show that there has been receipt of drilling fluids and/or cuttings into the pit during the previous twelve months.

(2) **Time limit.** Closure of all commercial pits shall be commenced within 60 days and completed within one year of cessation of pit operations, pursuant to (1) of this subsection. In cases where extenuating circumstances arise, one extension of six months may be administratively approved in writing by the Manager of Pollution Abatement. Closure shall be in accordance with an approved closure plan. A progress report shall be submitted to the Manager of Pollution Abatement, every three months (during January, April, July, and October) after cessation of pit operations until closure is completed.

(3) **Restrictive covenant.** A restrictive covenant shall be filed with the County Clerk of the county in which a commercial pit is located. The document shall accurately describe the pit location and shall specifically restrict the current or future landowners of the pit site from puncturing the final cover of the pit or otherwise disturbing the site to the extent that pollution could occur.

(4) **Penalty for failure to meet closure requirements.** An operator failing to meet the closure requirements set out in this subsection shall be fined $1,000.00.

(i) **Additional requirements.** The requirements set forth in this Section are minimum requirements. Additional requirements may be made upon a showing of good cause that an operator has a history of complaints for failure to comply with Commission rules and regulations, the site has certain limitations, or other conditions of risk exist.

(j) **Application to existing pits.** Subsections (a), (c)(1), (d), (e), (f), (g), (h), and (i) of this Section shall apply to all commercial pits permitted or ordered prior to the adoption of this Section. All pits permitted, but yet to be constructed as of the effective date of this Section, shall be subject to all of the construction requirements under (e) of this Section.

(k) **Variances.** Except as otherwise provided in this Section, variances from provisions of this Section may be granted for good cause by order after application, notice, and hearing.

[**SOURCE:** Amended at 9 Ok Reg 2295; Amended at 9 Ok Reg 2337, eff 6-25-92]

165:10-9-2. Commercial soil farming

(a) **Order and permit required.** No person shall conduct commercial soil farming without an order of the Commission and an approved permit.

(b) **Site suitability restrictions.** Commercial soil farming shall only occur on a tract of land having all of the following characteristics [paragraphs (1) through (5) shall be determined by the appropriate Soil Conservation District or a qualified soils expert]:

(1) A maximum slope of five percent.
(2) Depth to bedrock no less than 20 inches.
(3) A soil profile containing at least twelve inches of one of the following U.S.D.A. soil textures:
(A) loam
(B) silt loam
(C) silt
(D) sandy clay loam
(E) clay loam
(F) silty clay loam
(G) sandy clay
(H) silty clay or clay
(4) No flooding potential.
(5) Slight salinity (defined as electrical conductivity less than 4,000 micromhos/cm) in the topsoil or upper six inches of the soil.
(6) An Exchangeable Sodium Percentage (ESP) less than 15.

(7) A water table deeper than 25 feet from the soil surface, excluding perched water tables (submit basis for this determination).
(8) A minimum distance of 100 feet from any stream designated by Oklahoma Water Quality Standards or any fresh water pond, lake, or wetland (available for viewing at the Commission's Oklahoma City or District Offices).

(c) **Application requirements.**
(1) **Who may apply.** The applicant or joint applicant for commercial soil farming shall be the owner of the land (or person having a firm option, in writing, to purchase the land) which is to be used for soil farming.
(2) **Order required.** The Commission may issue an order upon compliance with Commission Rules of Practice 165:5-7-1, 165:5-7-35, 165:5-3-1, and this Section.
(3) **Required exhibits.** All exhibits intended to support an application shall be filed pursuant to 165:5-7-35. The exhibits shall include the following:
(A) A site suitability report, pursuant to (b) of this Section, provided by the appropriate Soil Conservation District or a qualified soils expert (include qualifications). The report must contain a U.S.D.A. Soil Survey map, or when Soil Survey map does not have adequate detail, a map prepared by a qualified soils expert. A legend and soil type description shall be attached.
(B) Plan of conservation management practices covering needs of storm water disposal and erosion control.
(C) A well-prepared map or diagram, drawn to scale, showing the size and configuration of the individual soil farming plots.
(D) A topographic map of the subject area.
(E) Initial soil analysis.
(F) A detailed discussion of the method of application and provisions for preventing runoff from the application area.

(d) **Sampling requirements.**
(1) **Contact with District Office.** The District Office shall be contacted at least two working days prior to sampling to allow a Commission representative an opportunity to witness the sampling of the receiving soil and pit(s) to be soil farmed.
(2) **Receiving soil.** Subsequent to the preparation of a conservation plan or site suitability report, soil samples shall be taken from the proposed soil farming plot and analyzed. Analysis shall be submitted pursuant to (c)(3)(E) of this Section. Soil sampling shall follow this procedure:
(A) If the site contains soil types from different parent material, separate areas shall be established for soil sampling and loading calculations.
(B) A sample area shall not exceed 40 acres.
(C) A minimum of 20 representative surface core samples (0-6 inches) and 20 representative subsurface core samples (18-30 inches) must be taken from each sample area. The samples shall be composited for analysis of a single surface core sample and a single subsurface core sample.
(3) **Pit materials.** Pit materials to be soil farmed shall be sampled using the following procedure:
(A) A minimum of five samples per 50,000 bbls., or part thereof, each representative of the materials to be soil farmed, is required for each pit or pit cell. Samples must be taken from different horizontally and vertically distributed locations in each pit or pit cell.
(B) The samples shall be combined and thoroughly mixed, then a minimum two pint composite sample shall be taken for TDS analysis, a minimum three pint composite sample taken for oil and grease analysis, and a minimum two pint composite sample taken for heavy metal analysis.
(C) If requested by a representative of the Conservation Division, each composite sample for TDS analysis shall be split and an adequate portion (approximately one pint) properly labeled and delivered or otherwise provided to the appropriate District Office or Field Inspector.
(D) After samples have been taken for analysis from a pit or pit cell which is the subject of a soil farming application, the operator shall not allow the addition of fluids or other materials, except natural precipitation or fresh water, to decrease the viscosity of the fluid.

(e) **Analysis requirements.**

(1) **Approved laboratory.** Soil and pit samples shall be analyzed by a laboratory operated by the State of Oklahoma or certified by the Oklahoma Water Resources Board.

(2) **Soil.** Parameters for analysis of soil shall include, but are not limited to pH, Total Soluble Salts (TSS) or Electrical Conductivity, and Exchangeable Sodium Percentage (ESP).

(3) **Pit contents.** Parameters for analysis of pit contents shall include, but are not limited to, the following: pH, Total Dissolved Solids (TDS), Electrical Conductivity, Arsenic, Chromium and Oil and Grease. Arsenic and Chromium may be analyzed by either Nitric Acid Extraction or Acetic Acid Extraction ("Test Methods for Evaluating Solid Waste," SW846, second edition, U.S. EPA). The analysis shall specify which method of extraction was used.

(f) **Maximum application rate.**

(1) **Loading limits.**

(A) The maximum application rate (loading limit) shall be calculated by the operator using the calculations in (g) of this Section and the following soil loading standards:

(i) Total Soluble Salts: 6,000 lbs/acre (less TSS in soil).

(ii) Arsenic: 80 lbs/acre.

(iii) Chromium: 40 lbs/acre.

(iv) Oil and Grease: 40,000 lbs/acre.

(v) Total Dry Weight: 200,000 lbs/acre.

(B) Limitations in (A) of this paragraph are based upon standards set forth in the following publications:

(i) "Diagnosis and Improvement of Saline and Alkaline Soils," U.S. Agriculture Handbook, No. 60, U.S. Salinity Laboratory, Riverdale, California, 1954

(ii) "Critical Concentrations for Irrigation Water Supplies," Water Quality Criteria, 1972 Ecological Research Series, EPA-R2-73-033, March, 1973

(iii) H.R. Moseley, "Summary and Analysis of API Onshore Drilling Mud and Produced Water Environmental Studies," American Petroleum Institute Bulletin, No. D-19, 1983

(2) **Determination of most limiting parameter.** The maximum application rate shall be restricted by the most limiting parameter. It may require more than one application to achieve the maximum application rate while avoiding runoff. The operator shall indicate on Form 1014CS the maximum application rate and the minimum acreage that will be used.

(3) **Records required.** Accurate records shall be kept for each parameter as to when, where (which application area), and how much is applied. The operator shall make such records available at all times for inspection by a representative of the Conservation Division. Additionally, an annual report shall be submitted to the Manager of Pollution Abatement, pursuant to (k) of this Section.

(4) **Additional soil sampling required.** Additional soil sampling and analysis of a plot shall be done prior to each soil farming application when records show that 60 percent of the maximum application rate in (1) of this subsection of any parameter except total weight is reached. Requirements of (d) and (e) of this Section shall be met. Soil farming shall not be permitted on a plot if the analysis indicates that more than 95 percent of the maximum application rate of any parameter has been reached or if the ESP is greater than 15.

(g) **Calculations.** The procedures described in Appendix H of this Chapter shall be used in calculating the maximum application rate.

(h) **Operation requirements.**

(1) **Surety required.**

(A) Any operator of a commercial soil farming site shall file with the Manager of Document Handling for the Conservation Division an agreement to clean up pollution, restore the site, and/or plug monitor wells, if necessary, upon termination of operations. The agreement shall be on forms available from the Conservation Division and shall be accompanied by surety. The agreement shall provide that if the Commission finds that the operator has failed or refused to comply with the rules or take remedial action as required by law and this Section, the surety shall pay to the Commission the full amount of the operator's obligation up to the limit of the surety.

(B) The Commission shall establish the amount of security in the order for the authority to operate a commercial soil farming site. The security shall be based upon $10,000 per 40 acres, or part thereof. The amount may be subject to change for good cause. The security shall be maintained for as long as monitoring is required. The type of security shall be a corporate surety bond, certificate of deposit, irrevocable letter of credit, or other type of security approved by order of the Commission. Any type of surety that expires shall be renewed prior to 30 days before the expiration date. All joint escrow accounts shall be made current every 60 days.

(2) **Sign required.** A waterproof sign bearing the name of the operator, legal description, order number, and emergency phone number shall be posted within 25 feet of the entrance to any commercial soil farming site and shall be readily visible.

(3) **Monitor wells.**

(A) Any commercial soil farming operation shall be required to have a minimum of two monitor wells, one upgradient and one downgradient, unless it can be shown that the site is not located over a hydrologically sensitive area, i.e., a principal bedrock aquifer, the recharge or potential recharge area of a principal bedrock aquifer, or an unconsolidated alluvium or terrace deposit, according to the Oklahoma Geological Survey "Maps Showing Principal Groundwater Resources and Recharge Areas in Oklahoma" (available for viewing at the Commission's Oklahoma City Office and District Offices) or other maps approved by the Commission. The exact number and location of wells shall be established by the Pollution Abatement Department.

(B) No monitor well shall be installed more than 250 feet from a commercial soil farming operation, nor shall any existing water well be used as a monitor well, unless approved by the Manager of Pollution Abatement. Monitor wells installed prior to the effective date of this Section may be accepted by the Manager of Pollution Abatement if it can be shown that they adequately monitor a site.

(C) All new monitor wells shall be drilled through the first aquifer encountered, but need not extend below 100 feet if no aquifer is encountered, and shall be completed by a licensed water well driller. If documentation can be submitted prior to drilling to show that no water will be encountered within 100 feet, then the District Manager may require that monitor wells be drilled to a lesser depth.

(D) All new monitor wells shall meet the following requirements:

(i) A minimum four inch diameter PVC casing shall be used with a sealing cap on the bottom.

(ii) The casing shall consist of a slotted liner in the saturated zone, or bottom ten feet if none is encountered, and shall be gravel-packed or sand-packed as appropriate to the installation.

(iii) Bentonite shall be placed in the annular space of the well above the slotted liner for an interval of at least two feet to form an adequate seal.

(iv) Well cuttings shall be returned to the annular space above the bentonite seal for well stability.

(v) A minimum of two of the top six feet of the annular space around the casing shall be filled with cement.

(vi) A minimum three inch thick concrete apron shall be placed at the surface to a minimum two foot radius from the casing.

(vii) A removable and lockable cap shall be placed on top of the casing. The cap shall remain locked at all times, except when the well is being sampled.

(E) Within 30 days after installation, specific completion information for all monitor wells and a diagram of their locations in relation to the soil farming site shall be submitted to the Manager of Pollution Abatement.

(4) **Sampling of monitor wells.** Sampling of monitor wells shall begin prior to the first soil farming application and shall be done once every six months (during January and July) after operations commence until one year after the last application is made, then once every year for three years according to the following:

(A) The appropriate District Manager shall be notified at least 24 hours in advance of sampling to allow a Commission representative an opportunity to witness the sampling.

(B) Samples shall be collected and handled by the operator according to EPA-approved standards ("RCRA Groundwater Monitoring Technical Enforcement Guidance Document," EPA, OSWER-9950.1, September, 1986, pp.99-107.)

(C) If requested by a representative of the Conservation Division, an adequate portion of each sample (approximately one pint) shall be properly labeled and delivered or otherwise provided to the appropriate District Office or Field Inspector.

(D) All samples must be analyzed for pH and chlorides by a laboratory certified by the Oklahoma Water Resources Board or operated by the State of Oklahoma. Analysis of additional parameters may be required, as determined by the Manager of Pollution Abatement.

(E) A copy of each analysis and a statement as to the depth to groundwater encountered in each well, or an affidavit that no water was encountered, shall be forwarded to the Pollution Abatement Department within 30 days of sampling.

(i) **Conditions of permits.** Each permit issued under this Section shall be subject to the following conditions:

(1) **Required form.** A completed Form 1014CS shall be submitted to the Manager of Pollution Abatement for approval prior to commencement of soil farming. A new Form 1014CS shall be submitted each time that soil farming is proposed to be done. Approval or disapproval shall issue on Form 1014CS within ten days of submission.

(2) **Notice to Commission.** The applicant, by agreement with the appropriate District Office, shall schedule the commencement of soil farming no less than 24 hours prior thereto, to allow a Commission representative to be present to witness the work. The applicant shall also notify the appropriate District Office of completion of each soil farming application within 24 hours. Written notice of commencement and completion shall be submitted to the Manager of Pollution Abatement within 48 hours.

(3) **Presence of representative.** A representative of the applicant shall be on the soil farming site at all times during application of the pit materials to the land.

(4) **Type muds to be soil farmed.** Commercial soil farming is limited to water-based type muds and/or cuttings. Soil farming of oil-based muds and/or cuttings shall be prohibited.

(5) **Weather restrictions.** Commercial soil farming shall not be done:

(A) During precipitation events or when precipitation is imminent.

(B) When the soil moisture content is at a level such that the soil would not readily take the addition of drilling fluids.

(C) When the ground is frozen.

(D) By spray irrigation when the wind velocity is such that even distribution of materials cannot be accomplished or the buffer zones, pursuant to (6) of this subsection, cannot be maintained.

(6) **Buffer zones:** No commercial soil farming shall be done within the following buffer zones:

(A) One hundred feet of a property line boundary.

(B) Fifty feet of any stream not designated by Oklahoma Water Quality Standards.

(C) Three hundred feet of any actively-producing water well used for domestic, irrigation or industrial purposes.

(D) One thousand three hundred feet of any actively-producing water well used for municipal purposes.

(7) **Application rate.** The maximum application rate of drilling fluids and/or cuttings stipulated by the permit shall not be exceeded. Furthermore, the minimum required acreage within the approved soil farming

plot, as designated by the permit, shall be fully utilized. Application of drilling fluids and/or cuttings outside the approved plot shall be prohibited.

(8) **Soil farming method.**

(A) Application of pit contents shall be uniform over the soil farming plot and shall be made by injection, spray irrigation, or other method approved by the Commission prior to use. The flood irrigation method shall be limited to those fields that normally are irrigated in that manner.

(B) An application of more than 50,000 lbs/acre of dry weight materials or more than 500 lbs/acre of oil and grease shall be incorporated into the soil by injection, disking, or other method approved by the Commission. If the injection method is not used, incorporation must be made within a reasonable time period after completion of application, not to exceed 14 days unless extended by the Pollution Abatement Department pursuant to a written request.

(C) When the spray irrigation method is used and solids eventually accumulate on the soil surface to a one-eighth (1/8) inch depth, then the materials shall be incorporated prior to subsequent soil farming.

(9) **Runoff or ponding prohibited.** No runoff or ponding of soil farmed materials shall be allowed during application.

(10) **Automatic termination.**

(A) If the applicant violates the order, permit, or this Section, soil farming shall be discontinued and the Pollution Abatement Department shall be contacted immediately. The Pollution Abatement Department may revoke the permit and/or require the operator to do remedial work. If the permit is not revoked, soil farming may resume with the approval of the Pollution Abatement Department.

(B) Soil farming shall be carried out within two months from the date of approval of the permit. At the end of the two month period, the permit shall expire by its own terms. The Manager of Pollution Abatement may, upon written request, separately grant up to two extensions of the permit for periods of two months each.

(11) **Prevention of pollution.** All commercial soil farming facilities shall be operated and maintained at all times so as to prevent pollution. In the event of a nonpermitted discharge from a commercial soil farming facility, sufficient measures shall be taken to stop or control the loss of materials and reporting procedures in 165:10-7-5 (c) shall be followed. Any materials lost due to such discharge shall be cleaned up as directed by a representative of the Conservation Division.

(12) **Vegetative cover.** If the vegetative cover is destroyed or significantly damaged by disking, injection, or other practice associated with soil farming, the vegetative cover shall be reestablished within one year after the last soil farming application.

(j) **Additional requirements.** The requirements set forth in this Section are minimum requirements. Additional requirements may be made upon a showing of good cause that an operator has a history of complaints for failure to comply with Commission rules, or the site has certain limitations, or other conditions of risk exist.

(k) **Annual report.** The operator of any commercial soil farming facility shall submit an annual report on Form 1014A to the Manager of Pollution Abatement by February 1 of each year.

(l) **Prospective application to existing operations.** Subsections (d), (e), (f), (g), (h), (i), (j), (k) and (m) of this Section shall apply to all commercial soil farming operations for which an order or permit was obtained prior to the adoption of this Section. All affected operators shall have their facility in compliance with all of the noted subsections by December 31, 1988. Failure to be in compliance by that date shall result in termination of the authority to operate.

(m) **Variances.** Except as provided in this Section, variances from provisions of this Section may be granted for good cause by order after application, notice, and hearing.

[**Source:** Amended at 12 Ok Reg 2017, eff 7-1-95]

165:10-9-3. Commercial disposal well surface facilities

(a) **Scope.** This Section shall apply to the surface facilities of any commercial disposal well.

(b) **Site restriction.** No commercial disposal well pit shall be constructed in any area that floods according to the Soil Conservation Service County Soil Survey (available for viewing at the Commission's Oklahoma City Office or District Offices).

(c) **Construction requirements.**

(1) **Dikes.** A dike shall be constructed and maintained around any storage tank or group of tanks. The diked area shall be capable of totally containing at least one and one-half (1 1/2) times the volume held by the largest storage tank.

(2) **Leak containment.** A means for containing leaks shall be provided at all pumps and connections.

(3) **Splash pad/apron.** A splash pad/apron shall be constructed at the unloading area of any pit to the design and dimensions necessary to contain and direct all materials unloaded into the pit. If a pit is not used, an apron shall be constructed at the unloading area to the design and dimensions necessary to direct any spills into containment.

(4) **Pit specifications.** Any commercial disposal well pit shall be constructed of concrete or steel or shall be lined with a geomembrane liner. The following specifications shall be met:

(A) Any concrete pit shall be steel-reinforced and have a minimum wall thickness of six inches.

(B) Any steel pit shall have a minimum wall thickness of three-sixteenths (3/16) inch. If a previously used steel pit is installed, it shall be free of corrosion or other damage.

(C) Any geomembrane liner shall meet these requirements:

(i) The geomembrane liner shall have a minimum thickness of 30-mils, shall be chemically compatible with the type of wastes to be contained, and shall have ultraviolet light protection.

(ii) The geomembrane liner shall be placed over a specially prepared, smooth, compacted surface void of sharp changes in elevation, rocks, clods, organic debris, or other objects.

(iii) The geomembrane liner shall be continuous (may include seams) and shall cover the bottom and interior sides of the pit entirely. The edges shall be securely placed in a minimum twelve inch deep anchor trench around the perimeter of the pit.

(5) **Certification of liner.** The operator of any commercial disposal well pit that is constructed with a geomembrane liner shall secure an affidavit signed by the installer, certifying that the liner meets minimum requirements and was installed in accordance with Commission rules. It shall be the operator's responsibility to maintain the affidavit and all supporting documentation pertaining to the liner, such as geomembrane liner specifications from the manufacturer, etc., and shall make them available to a representative of the Conservation Division upon request.

(6) **Monitor wells or leachate detection system.**

(A) Any commercial disposal well pit shall be required to have a leachate collection system or a minimum of three monitor wells, one upgradient and two downgradient.

(B) No monitor well shall be installed more than 100 feet from a commercial disposal well pit, nor shall any existing water well be used as a monitor well, unless written approval is given by the District Manager or Manager of Field Operations.

(C) All new monitor wells shall be drilled through the first aquifer encountered, but need not extend below 100 feet if no aquifer is encountered, and shall be completed by a licensed water well driller. If documentation can be submitted prior to drilling to show that no water will be encountered within 100 feet, the District Manager may require that monitor wells be drilled to a lesser depth.

(D) All new monitor wells shall meet the following requirements:

(i) A minimum four inch diameter PVC casing shall be used with a sealing cap on the bottom.
(ii) The casing shall consist of a slotted liner in the saturated zone, or bottom ten feet if none is encountered, and shall be gravel-packed or sand-packed as appropriate to the installation.
(iii) Bentonite shall be placed in the annular space of the well above the slotted liner for an interval of at least two feet to form an adequate seal.
(iv) Well cuttings shall be returned to the annular space above the bentonite seal for well stability.
(v) A minimum of two of the top six feet of annular space around the casing shall be filled with cement.
(vi) A minimum three inch thick concrete apron shall be placed at the surface to a minimum two foot radius from the casing.
(vii) A removable and lockable cap shall be placed on top of the casing. The cap shall remain locked at all times, except when a well is being sampled. A key to each well shall be made available to the appropriate District Manager or Field Inspector upon request.

(E) Within 30 days of installation, construction details for any leachate detection system or specific completion information for all monitor wells and a diagram of their locations in relation to the pit they monitor shall be submitted to the Manager of Field Operations.

(d) **Operation and maintenance requirements.**

(1) **Sign.** A waterproof sign shall be erected and maintained within 25 feet of the entrance road to any commercial disposal well, shall be readily visible, and shall contain the name of the operator, order number, legal description, and emergency phone number.

(2) **Fencing.** All commercial disposal well surface facilities that have a pit shall be completely enclosed by a minimum four strand barbed wire fence or equivalent protection using woven wire and/or barbed wire. No livestock shall be allowed inside the fence.

(3) **Site maintenance.** The normal access surface of any commercial disposal well site, including the access road(s), shall be maintained in a condition that will safely and easily accommodate a passenger car during all weather conditions.

(4) **Exclusion of runoff water.** No commercial disposal well pit shall be allowed to receive runoff water.

(5) **Freeboard.** The fluid level in any concrete or steel commercial disposal well pit shall be maintained at all times at least 6 inches below the top of the pit wall. Any geomembrane lined pit shall have a minimum of 18 inches freeboard at all times.

(6) **Temporary storage only.** No pit shall be used as permanent storage for salt water.

(7) **Sampling of monitor wells.**

(A) Sampling of monitor wells shall occur once every six months, during the months of January and July.

(B) The appropriate District Manager shall be notified at least 24 hours in advance of sampling to allow a Commission representative an opportunity to witness the sampling.

(C) Samples shall be collected, preserved, and handled by the operator according to EPA-approved standards (RCRA Groundwater Monitoring Technical Enforcement Guidance Document, EPA, OSWER-9950.1, September, 1986, pp. 99-107) and analyzed for pH, chlorides and Total Dissolved Solids (TDS) by a laboratory certified by the Oklahoma Water Resources Board or operated by the State of Oklahoma. Analysis of additional parameters may be required, as determined by the District Manager or Manager of Field Operations.

(D) If requested by the District Manager, each sample shall be split and an adequate portion (approximately one pint) properly labeled and delivered upon request or otherwise provided to the appropriate District Office or Field Inspector. A copy of each analysis and a statement as to the depth to groundwater encountered in each well, or an affidavit that no water was encountered, shall be forwarded to the Manager of Field Operations, within 30 days of sampling.

(8) **Prevention of pollution.** All commercial disposal well pits shall be used, operated, and maintained at all times so as to prevent pollution. In the event of a nonpermitted discharge from surface facilities of a commercial disposal well, sufficient measures shall be taken to stop or control the loss of materials and reporting procedures in 165:10-7-5(c) shall be followed. Any materials lost due to such discharge shall be cleaned up as directed by a representative of the Conservation Division.

(9) **Oil film.** The operator of a saltwater disposal system shall be responsible for the protection of migratory birds. Therefore, the Conservation Division recommends that to prevent the loss of birds due to oil films, all open top tanks and pits containing fluid be kept free of hydrocarbons, or be protected from access to birds. [See Advisory Notice 165:10-7-3(c).]

(e) **Closure requirements.**

(1) **Time limit.** Within 90 days of the cessation of operation of any commercial disposal well, all associated pits shall be emptied of all contents and filled with soil. All monitor wells shall be plugged with bentonite or cement, unless exempt in writing by the District Manager or Manager of Field Operations. The site shall be revegetated within 180 days.

(2) **Geomembrane-lined pits.** When closing any commercial disposal well pit with a geomembrane liner, extreme care shall be taken to preserve the integrity of the liner. All free liquids shall be removed or chemically solidified. A geomembrane cap shall be placed over the top of any remaining contents to completely encapsulate them. Any geomembrane cap shall have a minimum thickness of twelve mils and shall be chemically compatible with the type of substances to be encapsulated. Burial, pursuant to (3) of this subsection, shall follow.

(3) **Burial.** If any concrete, steel, geomembrane, or other materials associated with a commercial disposal well site are to be left on-site, they shall be buried under a minimum soil cover of three feet, pursuant to 165:10-3-17.

(f) **Prospective application to existing facilities.** All provisions of this Section except (4) and (5) of subsection (c) shall apply to all existing commercial disposal well pits which are, or have been, in operation prior to the effective date of this Section. Operators shall have 180 days from the effective date of this Section in which to bring their facilities into compliance with the applicable provisions of this Section. Failure to comply with any applicable provision may result in revocation of the authority to operate.

(g) **Variances.** A variance from the time requirements of (d)(7) or (e)(1) of this Section may be granted by the District Manager or Manager of Field Operations for justifiable cause. A written request and supporting documentation is required. The District Manager or Manager of Field?Operations shall respond in writing within five working days, either approving or disapproving the request.

[**Source:** Amended at 11 Ok Reg 3691, eff 7-11-94]

SUBCHAPTER 11. PLUGGING AND ABANDONMENT

Section

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165:10-11-1. License for pulling pipe and plugging wells

(a) No person shall contract to pull casing or plug oil, gas, injection, disposal, or other service wells, or contract to salvage casing therefrom, or purchase wells for the purpose of salvaging casing therefrom until a license has been secured from the Commission.

(1) The application for such license shall state:

(A) The name of the applicant.

(B) The names and addresses of all partners, chief officers, and directors.

(C) The experience of applicant.

(D) Evidence of financial responsibility of the applicant.

(E) The counties in which the applicant will operate.

(2) Notice that an application has been filed shall be published by the applicant in a newspaper of general circulation in Oklahoma County and in the county where the applicant's principal place of business is located. The applicant shall file proof of publication prior to the hearing or administrative approval. The notice shall include:

(A) The name of the applicant.

(B) Generally what operations the applicant intends to conduct for which applicant is financially responsible.

(C) The counties in which applicant will operate.

(3) If a written objection to the application is filed within 15 days after the application is published or if a hearing is required by the Commission, the application shall be set for hearing and notice thereof shall be given as the Commission shall direct. If no objection is filed and the Commission does not require a hearing, the matter shall be presented administratively to the Manager of Field Operations who shall file a report and make recommendations to the Commission.

(b) The license shall not be transferable and may at any time be revoked by the Commission upon complaint, notice, and hearing.

(c) Any person violating this Section may be fined up to $2,500.00. Any operation in violation of this Section shall be shut down pending compliance with this Section.

[**SOURCE:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended in Rule Making 97000002, eff 7-1-97]

165:10-11-2. Operating requirements for licensees

(a) This Section shall apply to each licensee under 165:10-11-1.

(b) If a licensee prepares the Notice of Intent to Plug (Form 1001 and/or the Plugging Report (Form 1003), then the licensee shall:

(1) Include the following on any submitted form:

(A) The name and address of the well operator if the licensee is serving as a contractor for the operator of the well.

(B) The name and address of the person or entity hiring the licensee if the licensee is serving as the contractor for any person who is not an operator of the well.

(C) That he is acting independently if the licensee either purchased the well for salvage or contracted with the landowner to plug the well in exchange for casing and/or other well equipment.

(2) Mail a copy of Form 1001 to the last known operator of the well to be plugged, as shown by the records of the Conservation Division.

(c) For purposes of this subsection, the term "plugged well" shall refer to a well for which the Conservation Division has a plugging record. A licensee shall comply with the requirements of 165:10-1-10 and 165:10-3-1 before entering a plugged well if:

(1) The licensee is not hired by the operator of the well to conduct the re-entry operation.

(2) The owner of the well is either the licensee or the surface owner of the tract on which the well was drilled.

(3) The Commission has not contracted with the licensee to replug the well.
(d) A licensee shall be responsible for the plugging of a well if:
(1) The licensee is the owner of the well or the licensee is the operator of the well.
(2) The licensee enters a well without having contracted with the operator or with a party other than the operator who has authority to authorize the licensee to enter the well on behalf of such party.
(e) Any violation of this Section will subject licensee to a fine, to suspension or revocation of licensee's license issued pursuant to 165:10-11-1, and to proceedings as authorized by statute in the district court.

[**SOURCE:** Amended in Rule Making 97000002, eff 7-1-97]

165:10-11-3. Duty to plug and abandon

(a) **Scope.** This Section applies to:
(1) Joint and several liability of the owners and operator of a well for plugging.
(2) Time periods for plugging wells:
(A) Without casing.
(B) With only surface casing and cement.
(C) With production casing.
(3) Wells exempted from plugging.
(4) Notice of Temporary Exemption from Plugging granting permission to postpone plugging of a well.
(b) **Joint and several liability of owners and operators.** Any working interest owner and operator of any oil, gas, disposal, injection, or other service well or any seismic, core, or other exploratory hole, whether cased or uncased, shall be jointly and severally liable and responsible for the plugging thereof in accordance with this Subchapter.
(c) **Time period for plugging well without casing.** Each well in which neither production casing nor surface casing has been run shall be properly plugged within 72 hours after drilling or testing is completed. However, should the lack of production and surface casing create a fire hazard or a risk of contaminating the environment or formations containing oil, gas, or known treatable water, said well shall be properly plugged within 24 hours after drilling and testing is completed. The well marker requirement described in 165:10-3-4 (e) shall be followed.
(d) **Time period for plugging well with only surface casing and cement.** Each well in which only surface casing has been run and cemented in conformance with 165:10-3-4 shall be properly plugged within 90 days after drilling or testing is completed unless the lack of production or intermediate casing creates a fire hazard or risk of contaminating the environment or formations containing oil, gas, or known treatable water, in which case or cases the well shall be plugged within 24 hours.
(e) **Time period for plugging well with production casing.** Unless exempted under provisions contained elsewhere in this Section, any well which has production casing in place shall be plugged within one year after the latter of:
(1) Cessation of drilling if the well was not completed or tested; or
(2) Cessation of the latter of completion or testing if the well has not produced; or
(3) Cessation of production.
(4) From April 1, 1998, to March 31, 1999, the time period for plugging of any producing well with production casing in place that has ceased production shall be two years. The Commission shall review the need for the continued effectiveness of this provision during the time period set forth above on a quarterly basis. This provision shall not apply to any well that poses a public health, safety or pollution threat to the environment and surface or subsurface waters of the state.
(f) **Operators failing to commence timely plugging operations.** An operator who fails to commence plugging operations as required in (c), (d), and (e) of this Section after due notice from the District Office or the appropriate field inspector may be fined up to $1,000.00.

(g) **Wells exempted from plugging**. The following wells which have production casing in place shall be exempt from (e) of this Section:

(1) Shut-in gas wells, for the purpose of this Section, shall be considered producing wells in operation.

(2) Any well for which a written order of the Commission granting a specific exception to plugging is in full force and effect.

(3) Supply wells or wells authorized by order of the Commission for injection or disposal purposes and are in compliance with the rules of the Commission.

(4) Any well for which a temporary exemption from the plugging rules has been approved.

[**SOURCE:** Amended at 9 Ok Reg 2295; Amended at 9 Ok Reg 2337, eff 6-25-92; Amended in Rule Making 97000002, eff 7-1-97; Amended in Rule Making 980000035, eff 7-1-99]

165:10-11-4. Notification and witnessing of plugging

(a) **Wells without production casing.** The Conservation Division shall be notified at least 12 hours prior to commencement of plugging operations and a plugging procedure agreed upon for any well without production casing. Each plugging operation may be witnessed by an authorized representative of the Conservation Division.

(b) **Wells with production casing.** A separate Notification of Intention to Plug (Form 1001) for each well with production casing shall be filed, in duplicate, with the Conservation Division at least five days prior to the commencement of plugging operations. The five day notice requirement may be reduced or waived:

(1) If a qualified representative of the Conservation Division is available to witness the plugging operation.

(2) At the discretion of the District Manager of the District in which the well is located or his supervisor.

(c) **Penalty.** An operator or licensed plugger plugging a well without notifying and agreeing on a plugging procedure with the District Office may be fined up to $1,000.00 and may be required by the appropriate District Manager to reenter and replug the well.

[**Source:** Amended at 11 Ok Reg 3691, eff 7-11-94; Amended in Rule Making 97000002, eff 7-1-97]

165:10-11-5. Supervision and witnessing [REVOKED]

[**SOURCE:** Amended at 9 Ok Reg 2295, eff 6-25-92; Revoked in Rule Making 97000002, eff 7-1-97]

165:10-11-6. Plugging and plugging back procedures

(a) **Scope.** This Section establishes minimum standards for plugging and plugging back wells. The standards apply to:

(1) Wells drilled for the production of oil or gas.

(2) Wells drilled or used for disposal or enhanced recovery injection.

(3) Wells used in subsurface gas storage units.

(4) Monitoring wells in enhanced recovery projects or subsurface gas storage units.

(5) Wells plugged back for:

(A) Oil or gas production.

(B) Disposal or injection.

(C) Conversion to a water well.

(6) "Rat hole" or "mouse holes" used in rotary drilling of wells.

(7) Wells used for geophysical or geological exploration.

(8) Wells used for other service operations.

(b) **Alternate plugging materials and procedures**

(1) The Manager of Field Operations, or other designated Conservation Division staff member, may approve the use of an alternate material other than cement or in combination with cement for wells listed in subsection (a), provided alternate plugging materials shall not be used to plug or plug back wells listed in subsection (a)(2), wells drilled or used for disposal or enhanced recovery injection, subsection (a)(3), wells used in subsurface gas storage units, subsection (a)(5)(B), wells plugged back for disposal or injection, and underground injection wells authorized under the Oklahoma Brine Development Act, 17 O.S. Section 500 *et seq*.

(2) The Director of Oil and Gas Conservation, in consultation with the Conservation Division's Field Operations staff and the public, shall develop specific plugging criteria for any type of alternate plugging material authorized for use instead of cement or in combination with cement. The plugging criteria for approved alternate material shall be available to the public for review and copying at the Conservation Division's offices and on the Commission's Internet website.

(3) A District Manager may approve alternate plugging procedures for the use of alternate plugging materials.

(4) A detailed description of the alternate plugging operation shall be included with the Plugging Report (Form 1003).

(5) The District Manager shall note his approval of the alternate plugging procedure on the well's Plugging Report (Form 1003).

(6) Any alternate plugging material or procedure shall conform to the minimum plugging standards relating to formations or depths set forth in the Sections below. Provided, based upon the type of alternate plugging material being utilized, the District Manager approving the alternate procedure may authorize variances to the plugging standards delineated in this Section otherwise applicable to the use of cement, where such variances are necessary to ensure an effective well plugging.

(c) **Application and cross references:**

(1) Subsection (n) of this Section provides for administrative approval of alternative plugging procedures if downhole problems in a wellbore prevent an operator from complying with the minimum standards established by this Section.

(2) Subsection (o) of this Section applies to plugging of "rat holes" and "mouse holes" used at the surface during rotary drilling.

(3) OAC 165:10-11-8 establishes additional procedures for identification and control of wellbores in which certain logging tools have been abandoned.

(4) OAC 165:10-7-31 establishes the minimum standards for plugging wellbores used in seismic exploration.

(5) Subsections (d) through (p) of this Section establish plugging and plug back standards for all other wellbores subject to this Section.

(d) **Formations to be plugged.**

(1) Except as provided in (2) of this subsection, for cased formations, if the operator plugs or plugs back a well, the operator shall plug any formation or formations in communication with a formation that:

(A) Bears H_2S;

(B) Bears oil or gas;

(C) Bears treatable water;

(D) Was used in the wellbore for injection as part of a saltwater disposal well or enhanced recovery injection well; or

(E) Is open in the wellbore below either the shoe of the casing or the base of the liner to be left in the well after plugging.

(2) Paragraph (1) of this subsection shall not apply to any formation behind the pipe left in the hole, unless a formation endangers a treatable water formation or any oil and gas bearing formation.

(e) **Mud requirements.** Before running a plug, the operator shall remove or displace all oil and saltwater in the wellbore, and the operator shall fill the wellbore with drilling mud. The minimum mud weight shall be nine pounds per gallon. The minimum viscosity for the drilling mud shall be 36 (API Full Funnel Method). If the operator removes casing from the wellbore, the operator shall keep the wellbore filled with drilling mud meeting or exceeding the weight and viscosity requirements of this subsection.

(f) **Approved cementing methods.**
(1) **Cement plugs.**
(A) To plug or plug back a well, either the tubing and pump method or the pump and plug method shall be used.
(B) Surface pumping and shut in pressures shall be of sufficient pressure to:
(i) Squeeze off perforations in the casing.
(ii) Prevent the plug from floating upward in the wellbore.
(2) **Bridge plugs.** The operator may run by the bailer method cement required in the casing above a bridge plug as provided by (g) of this Section.
(g) **Use of bridge plugs.**
(1) **Permitted use.** Except as provided in (2) of this subsection for top plugs, a bridge plug may be used to permanently plug off a formation if:
(A) The only openings from the formation into the wellbore are perforations in the casing.
(B) The annulus between the casing and the formation is filled with cement from a depth 50 feet below the base of the formation to a depth 50 feet above the top of the formation.
(C) The bridge plug is set above the top of the perforations in the cemented interval described in (B) of this paragraph.
(D) Sufficient cement is placed on top of the bridge plug to fill the casing from the top of the bridge plug to a depth ten feet above the top of the bridge plug.
(2) **Prohibited use for top plug.** A bridge plug may not be used for a top plug described in (j) of this Section.
(h) **Cement plug for uncased hole below the casing or liner.** If any production casing or liner is to be left in the wellbore, then any uncased hole below the casing or liner shall:
(1) Be filled with cement:
(A) **From** a depth which is the lesser of total depth of the well or 50 feet below the lower of shoe of the casing or base of the liner.
(B) **To** a depth of 50 feet above the lower of the casing shoe or the base of the liner; or
(2) Have a cast iron bridge plug set above the top of the liner with cement.
(i) **Intermediate cement plugs.** If a bridge plug and cement are not used, a cement plug shall be run over any other formation required to be plugged off by this Section. To plug off a formation, the wellbore shall be filled with cement from a depth at least 50 feet below the base of the formation to a depth at least 50 feet above the top of the formation.
(j) **Cement top plug.**
(1) **No treatable water exists.** If no treatable water exists, the wellbore shall be filled with cement from a depth of at least 30 feet to a depth of three feet from the surface.
(2) **Treatable water exists.** Except as provided in (p) of this Section for converting a well to a water well, the wellbore shall be filled with cement as follows:
(A) If there is no surface casing or the base of the surface casing is 25 feet or further above the base of the treatable water, the wellbore shall be filled with cement from a depth of at least 50 feet below the base of the treatable water to a depth the lesser of:
(i) Fifty feet above the base of treatable water; or
(ii) Three feet below surface.
(B) If the surface casing is set at or below the base of the treatable water, the wellbore shall be filled with cement from a depth of at least 50 feet below the base of the surface casing to a depth the lesser of:
(i) Fifty feet above the base of the surface casing; or
(ii) Three feet below surface.
(C) If the cement plug prescribed by (2) of this subsection is not sufficient to bring the level of cement to within three feet from the surface, then the wellbore shall be filled with cement from a depth of at least 30 feet to a depth of three feet from the surface.
(k) **Cutting off surface pipe and identification of the abandoned wellbore.**

(1) This subsection applies to a wellbore plugged for abandonment. It does not apply to a wellbore plugged back for conversion to a water well under (p) of this Section.
(2) After setting the top plugs in a well, the operator shall cut off the casing left in the wellbore three feet below surface, and the operator shall cap the casing in the wellbore with a steel plate.
(3) The operator shall inscribe or embed the well number and date of plugging on the steel plate.

(l) **Tagging the top of the plug.** The Field Inspector for the Conservation Division may require the operator to determine the depth of the top of a plug by running a wireline or tubing string.

(m) **Fall back of cement.** If the cement for a plug falls back during setting below the top depth required by this Section, the operator shall run additional cement until the plug meets the minimum requirements of this Section.

(n) **Alternative plugging procedure for down-hole problems.**
(1) In plugging a well, if the operator encounters a downhole problem which prevents the operator from complying with the standards of this Section, the District Manager may prescribe an alternative plugging procedure provided that the alternative plugging procedure prevents the vertical migration in the wellbore of oil, gas, saltwater, H_2S, and other deleterious substances into a formation bearing oil, gas, or treatable water.
(2) The District Manager shall note his approval of the alternative plugging procedure on the well's Plugging Report (Form 1003).

(o) **Plugging of rat holes and mouse holes.** If a rat hole or mouse hole was used at the surface for drilling the well, it shall be plugged as follows.
(1) The hole shall be filled with drilling mud from bottom to a depth eight feet below the surface.
(2) The operator shall fill the hole with cement from a depth of eight feet to a depth of three feet below the surface.
(3) The operator shall fill the hole with dirt from a depth of three feet to surface.

(p) **Plug back for conversion to a water well.** The District Manager may permit a well operator to plug back a well for permanent use as a water well by:
(1) Setting any bottom hole and intermediate plugs required by this Section.
(2) Setting a top cement plug from the base of treatable water to 50 feet below the base of treatable water.
(3) Obtaining written permission from the owner of the ground water rights for conversion of the well to a water well.
(4) Submitting under 165:10-11-7, a Plugging Report (Form 1003) noting the conversion of the well with a copy of the written permission from the owner of the ground water rights for conversion of the well to a water well.

[**SOURCE:** Amended at 13 Ok Reg 2395, eff 7-1-96; Amended in Rule Making 97000002, eff 7-1-97; Amended in Rule Making 980000013, eff 7-15-98; Amended in Rule making 980000034, eff 7-1-99; Amended in Rule Making 200200017, eff 7-1-02]

165:10-11-7. Plugging record

(a) Within 30 days after plugging a well, the owner or operator of the well shall submit for the well in duplicate to the appropriate District Office of the Conservation Division:
(1) Plugging Record (Form 1003).
(2) Cementing Report (Form 1003C) to accompany Plugging Record (Form 1003).
(3) If a Completion Report (Form 1002A) has not been submitted for the well, Form 1002A shall be attached to the Form 1003.

(b) Any operator failing to comply with this Section may be fined up to $500.00.

[**SOURCE:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended in Rule Making 97000002, eff 7-1-97]

165:10-11-8. Procedures for identification and control of wellbores in which radioactive sources have been abandoned

(a) **Notice and permission to abandon.**

(1) When a radioactive source has been lost and abandoned in a well bore, the operator shall immediately notify the appropriate District Office and request permission to plug or plug-back and/or bypass to conform to the conditions set out in this Section. The District Manager or his designee may exercise the option of witnessing the procedure.

(2) A radioactive source shall not be considered abandoned until all reasonable efforts have been expended to retrieve the source.

(b) **Method of plugging.**

(1) Wells in which radioactive sources have been abandoned shall be mechanically equipped and plugged in such a manner so as to prevent either accidental or intentional mechanical disintegration of the radioactive source.

(2) When a radioactive source has been lost in a well bore and cannot be recovered, the tool shall be covered with a 100 foot plug consisting of standard oil field cement with an approved deflection tool cemented in place at the top of the plug. An additional 100 foot plug colored by red iron oxide shall be run on top of the deflection tool.

(c) **Approval for alternate plugging method.** When an operator, after expending all reasonable efforts, finds that it is not possible to abandon the source as prescribed in (d) of this Section, an alternate plugging procedure must be approved by the Commission prior to use.

(d) **Markers for wells in which a radioactive source has been abandoned.** Upon abandonment of a well in which a radioactive source has been abandoned, and the abandonment procedure has been approved by the Commission, the operator shall cause a permanent plaque to be attached to casing remaining in the well. The plaque shall be attached in such a manner that reentry could not be accomplished without disturbing it. The plaque shall be constructed of a long lasting material and shall contain the following information:

(1) Lease name and well number.
(2) Name of operator.
(3) The source material abandoned.
(4) Total depth of the well.
(5) The depth of the abandoned source.
(6) The date of abandonment.
(7) The activity of the source.
(8) Trefoil radiation symbol with a radioactive warning.

(e) **Plugging reports of wells with lost radioactive sources.** Two copies of the plugging report shall be submitted to the Conservation Division of the Commission. The well operator shall forward one copy to the Radiation Management Section of the Oklahoma Department of Environmental Quality. The report shall contain all of the information required in (d) of this Section. The fact that a radioactive source was abandoned in the wellbore shall be noted under remarks on the Form 1002A.

(f) **Record of abandoned radioactive sources.** The Commission will maintain a current listing of all wells in which radioactive sources have been abandoned.

[**SOURCE:** Amended at 9 Ok Reg 2337, eff 6-25-92; Amended in Rule Making 97000002, eff 7-1-97]

165:10-11-9. Temporary exemption from plugging requirements

(a) **Scope.** The Commission may permit any well which is required to be properly abandoned pursuant to OAC 165:10-11-3 and OAC 165:10-11-5, at the request of an operator, to be temporarily abandoned.

(b) **Application.** An application for a permit to temporarily exempt a well from the plugging requirement shall be made on Form 1003A completed in its entirety, and submitted to the appropriate Conservation Division's District Office.

(c) **Permit.**

(1) Any operator seeking approval for temporary abandonment shall submit a notice of intent to temporarily abandon the well, Form 1003A, to the

appropriate District Office describing the temporary abandonment procedure used.

(2) The permit will be valid for a period of five (5) years. At least 30 days prior to the expiration of any approved temporary abandonment permit, the operator shall return the well to beneficial use in accordance with Commission rules, permanently plug and abandon said well, or apply for a new permit to temporarily abandon the well.

(3) No temporary abandonment will be approved that does not prevent the contamination of treatable water and/or other natural resources and the leakage of any substance at the surface.

(4) If the well fails the tests required herein the problem shall be found, corrected and a new test successfully conducted within 30 days or the well shall be plugged and abandoned in accordance with Commission rules.

(5) Upon successful completion of the work on the temporarily abandoned well, the operator will submit a new request for temporary abandonment to the appropriate District Office.

(d) **Protection of treatable water.** The treatable water shall be protected by one or more of the following:

(1) A drillable, retrievable or temporary bridging plug set above the producing interval and below the top of the cement. The surface shall be capped with a valve in operational condition. A pressure test may be required by the appropriate District Office.

(2) A packer run on tubing and set above the producing interval and below the top of the cement. The well shall be equipped with suitable wellhead packoff equipment and be closed to the atmosphere.

(3) A fluid level test determined by use of equipment approved by the Conservation Division’s Field Operations Department. The fluid level must be no higher than 150 feet below the base of the treatable water. The Field Inspector shall be notified at least 48 hours beforehand to be afforded the opportunity of witnessing the procedure. Fluid level tests must be conducted annually each of the five (5) years during the anniversary month of the permit. Additional tests may be required at any time at the request of the Conservation Division’s Field Operations Department. The wellhead shall be closed to the atmosphere.

(4) A casing inspection log confirming the mechanical integrity of the production casing submitted to the appropriate Conservation Division’s District Office.

(5) Alternate methods of testing may be approved by the Conservation Division’s Field Operations Department by written application and upon showing that such a test will provide information sufficient to determine that the well does not pose a threat to natural resources.

(e) **Surface facilities.** The well site of a well with temporary exemption from the plugging requirements shall be kept in a neat and orderly manner with a legible sign showing the name of the operator, operator telephone number, well name, number, and the legal location.

(f) **Termination of permit.** The permit for a temporary exemption from plugging shall terminate and plugging operations shall commence within 30 days after:

(1) The time interval set has lapsed and a renewal has not been granted.

(2) The lease or unit on which the exempted well was located has become nonproductive.

(3) The fluid level has risen to a point less than 150 feet below the base of the treatable water.

(4) The Conservation Division’s Field Operations Department has determined that the surface area or wellhead equipment requirement does not meet the standards required by the Commission.

(g) **Exception to termination of permit.** An exception to the termination of an exemption from the plugging requirements shall be allowed if:

(1) An application to convert the well to a disposal, injection, or supply well has been filed with the Commission, and proper notice, according to OAC 165:5, has been met.

(2) An application requesting an exception to the plugging rules has been filed with the Commission and an exception has been granted by an order of the Commission.

[**SOURCE:** Added at 9 Ok Reg 2337, eff 6-25-92; Amended in Rule Making 97000002, eff 7-1-97]

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SUBCHAPTER 13. DETERMINATION OF ALLOWABLES – OIL AND GAS WELLS

Section

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165:10-13-1. Oil and gas production [RESERVED]

165:10-13-2. Classification of wells for allowable purposes

(a) For purposes of this Subchapter the terms gas, oil, and gas-oil ratio are defined in 165:10-1-2.
(b) Any well having a gas-oil ratio of 15,000 to one or more shall be classified as a gas well for allowable purposes.
(c) Any well having a gas-oil ratio of less than 15,000 to one shall be classified as an oil well for allowable purposes.
(d) If a well is a multiply completed well under 165:10-3-35, then each zone of the completion shall be classified separately for allowable purposes.
(e) If a well is commingled under 165:10-3-39, the classification of the well for allowable purposes shall be determined by the gas-oil ratio of the commingled production.

165:10-13-3. Production tests on new, re-entered, and recompleted wells

(a) On all new wells, re-entered wells, and recompleted wells classified as oil wells for allowable purposes, in any regular spacing unit(s) and reservoir dewatering oil spacing unit(s), initial production tests shall be performed and reported to the Commission on Form 1029A unless otherwise specified by order of the Commission. The test shall not commence until after recovery of a volume of oil equivalent to or greater than the amount of load oil or other liquids introduced into the well.
(b) On all new wells, re-entered wells, and recompleted wells classified as gas wells for allowable purposes, initial production tests shall be performed and reported to the Commission on Form 1016 unless otherwise specified by order of the Commission.
(c) If special pool rules prescribe, by order of the Commission, the manner in which production tests are to be performed in any separate common source of supply, the production or gas-oil ratio test shall be performed and reported to the Commission in accordance with such special pool rules.

[**SOURCE:** Amended in Rule Making 200100009, eff 7-1-02]

165:10-13-4. Reservoir performance tests

The Commission may require, from time to time, the presentation of such data and facts as may be necessary to indicate reservoir performance and conditions in any oil or gas pool. The Commission may witness or supervise the taking of such reservoir performance tests and keep such records as it deems necessary to properly regulate the operation of any oil or gas pool. Any test requested by the Commission may be witnessed by any operator in the pool. When special pool rules require bottom hole pressure tests, the tests shall be reported to the Conservation Division on Form 1027.

165:10-13-5. Most efficient rate

Subject to the procedural requirements of 165:5-7-12, the Commission may issue an order increasing or decreasing the rate of oil and gas production in an oil pool to correspond to the most efficient rate of production which is consistent with sound engineering and conservation practices as may be justified by the circumstances and evidence submitted.

165:10-13-6. Load oil

Load oil used in well completions which is not produced from the same lease or spacing unit shall not be charged against the well, lease, or unit. The well shall be allowed to produce such load oil in addition to the current monthly allowable. Operators claiming credit for load oil for allowable purposes may file Oklahoma Tax Commission Form 317 not more than 6 months after treating the well.

[**SOURCE:** Amended in Rule Making 980000033, eff 7-1-99]

165:10-13-7. Production from different pools

(a) In the event there are two or more common sources of supply produced through a well or wells on the same lease or drilling and spacing unit and which are not commingled under 165:10-3-39, the production from each common source of supply shall be separately produced, measured, and/or accounted for to the Commission.

(b) If one or more of the zones produced are classified as oil for allowable purposes, the operator of the well shall submit to the Conservation Division a multi-zone report on Form 1011 showing the production from each oil-bearing common source of supply on or before the last day of the succeeding proration period.

165:10-13-8. Transfer of allowables

Subject to the procedural requirement of 165:5-7-12, the Commission may issue an order transferring, after proper adjustment, all or part of an allowable from a well with a high gas-oil ratio or high water-oil ratio to a well having a lower gas-oil ratio or water-oil ratio, if:

(1) The wells produce from the same common source of supply.

(2) The wells are located on the same lease or in the same drilling and spacing unit.

165:10-13-9. Allowable for increased density well

(a) **Allowable production.** Except as otherwise provided by rule or order of the Commission, the allowable production for permitted wells within a drilling and spacing unit producing from the same common source(s) of supply shall be determined as follows:

(1) Each individual well shall be classified for allowable purposes by gas-oil ratio under 165:10-13-2.

(2) Permitted wells of the same classification for allowable purposes shall share a single well allowable.

(3) Permitted wells of different classifications for allowable purposes shall receive allowables as provided by the order of the Commission authorizing the additional well(s).

(b) **Shared single allowable.** If two or more wells in a single drilling and spacing unit are classified as gas wells for allowable purposes, the shared single allowable for the unit shall be determined by the greater of:

(1) A minimum allowable; or

(2) A normal allowable based on the wellhead absolute open flow potential of the best well in the drilling and spacing unit producing from the same common source of supply.

(c) **Additional well.** If an additional well is not of the same classification as any prior permitted well, it shall receive an allowable as provided by the order permitting the well.

(d) **Effect of penalties.** If the allowable for a well in a drilling and spacing unit is subject to a percentage penalty or lid on production, the penalty or lid on production shall apply to the ratable share of production of the shared single allowable for the penalized well as opposed to the entire shared single allowable for the unit.

(1) The ratable share of production of the shared single allowable for an unallocated gas well is that volume of gas which bears the same ratio to the shared single allowable as the wellhead absolute open flow potential for the well bears to the sum of the wellhead absolute open flow potentials for all wells in the drilling and spacing unit of the same classification for allowable purposes.
(2) The ratable share of production of the shared single allowable for a special allocated gas well is that volume of gas which bears the same ratio to the shared single allowable as the unpenalized monthly allowable the well would receive if it were the only well in the unit bears to the sum of such allowables for all the wells in the drilling and spacing unit of the same classification for allowable purposes.
(3) No special allocated well shall receive an allowable less than the defined minimum unit allowable divided by the number of wells in the drilling and spacing unit of the same classification for allowable purposes.
(4) The ratable share of production of the shared single allowable for an oil well is that volume of oil which bears the same ratio to the shared single allowable as the potential for the well bears to the sum of the potentials for all wells in the drilling and spacing unit of the same classification for allowable purposes. If the oil well was assigned a separate allowable under (c) of this Section, the penalty shall apply to the allowable assigned to the well.
(5) The portion of the shared single allowable representing the reduction in the allowable for the penalized well is not allocable to other wells in the drilling and spacing unit.

(e) **Which operator shall file required tests.** If the operators of the wells in a drilling and spacing unit cannot agree as to which operator shall file the required tests and production reports for the unit or as to what proportion of a shared single allowable shall be attributable to each well of the same classification for allowable purposes, the Commission may, after application, notice, and hearing, issue an order determining which operator shall file the tests and reports or what the proportional share of the shared single allowable is attributable to each well or the maximum rate of allowable production for each well.

(f) **Wellhead absolute open flow potential.** For the purpose of this Section, the wellhead absolute open flow potential for a test exempt gas well shall be presumed to equal:
(1) The average daily production for the previous calendar year (or that portion of the previous calendar year if the first sales date was after January 1 of that year), or the minimum allowable that would otherwise be assigned to an unallocated gas well under applicable rules of the Commission as if such well were the only well in the unit, whichever is less, for an unallocated well; or
(2) The product of two multiplied by the monthly allowable for the well under 165:10-17-9 for a special allocated well.

(g) **Testing or reporting requirements.** This Section shall not exempt any well from any testing or reporting requirement imposed by rule or order of the Commission.

[**SOURCE:** Amended at 9 Ok Reg 2337, eff 6-25-92; Amended in Rule Making 980000033, eff 7-1-99]

165:10-13-10. Applications for reinstatement of cancelled underage for oil wells and for unallocated gas wells

(a) **Oil well.**
(1) With respect to an oil well, all underage for the proration period in excess of 15 percent of the allowable shall be automatically cancelled at the end of the proration period, except underage accrued under (4) of this subsection because of the failure to split a tank.
(2) A producer may apply to reinstate cancelled underage if the well is capable of producing in excess of its allowable. The procedure for applying for reinstatement of cancelled underage is described in (c) of this Section.

(3) Except in situations where the operator has failed to comply with applicable well testing and reporting requirements of the Commission, failure or refusal of the purchaser to take the allowable shall be grounds for reinstatement of any underage accumulated because of such failure or refusal. Underage of this nature may be accumulated until balanced by future runs.
(4) The operator shall not be required to sell less than a full stock tank of oil by the end of the proration period to avoid cancellation of underage. Instead, such underage may be accrued until the operator accumulates and sells a volume of oil from the tank amounting to a full tank, and the sale of oil representing such underage shall not be considered as overage.

(b) **Unallocated gas well.**
(1) With respect to any unallocated gas well, of the total underage for the well or unit existing at the end of the proration period, 75% shall be automatically cancelled and 25% shall be automatically carried forward to the next prorationing period.
(2) Said underage carried forward to the next balancing period must be utilized in said balancing period, with that amount of underage carried forward but not used, to be cancelled at the end of the prorationing period.

(c) **Procedure for reinstatement of cancelled underage.**
(1) The operator of an oil well may apply for reinstatement of cancelled underage by application for administrative approval on Form 1010 within 90 days after cancellation of the underage.
(2) If the Conservation Division declines to approve the Form 1010 application, the applicant shall be notified in writing that application, notice, and hearing under 165:5-7-1 are necessary to obtain reinstatement of cancelled underage.

[**SOURCE:** Amended in Rule Making 980000033, eff 7-1-99]

SUBCHAPTER 15. OIL WELL PRODUCTION AND ALLOWABLES

Section

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165:10-15-1. Classification of oil pools and projects

(a) **Types of oil pools.** Each producing oil pool shall be classified by the Commission into one of the following categories:

(1) Discovery oil pool (165:10-15-5).
(2) Allocated oil pool (165:10-15-9).
(3) Unallocated oil pool (165:10-15-12).
(4) Enhanced oil recovery project (165:10-15-14).
(5) Excessive water exempt oil project (165:10-15-16).
(6) Reservoir dewatering oil spacing unit (165:10-15-18).

(b) **Treatment of an oil well located in a gas pool.** An oil well located in a gas pool shall be treated as an unallocated oil well, unless the oil well is subject to one of the following:

(1) Pool rules controlled by volumetric withdrawal.
(2) Discovery oil pool rules.
(3) Allocated oil pool rules.
(4) Some other order of the Commission.

(c) **Discovery oil pools.**

(1) A new oil pool which has complied with the provision of 165:10-15-5 may be granted discovery allowable production rates, administratively, subject to either:
(A) Spacing requirements.
(B) Order of the Commission.

(2) Each permitted discovery oil well shall be subject to discovery oil pool rules until either:
(A) Expiration of the discovery allowable period.
(B) Reclassification of the well or pool.

(d) **Allocated oil pool.**

(1) The Commission shall classify an oil pool as an allocated oil pool when:
(A) At any market demand hearing the total production from an oil pool or from any well within the pool needs to be regulated; or
(B) For good cause shown, upon application, notice, and hearing.

(2) A gas well located in an allocated oil pool that is reclassified as an oil well for allowable purposes shall be subject to allocated oil pool rules.

(3) Each allocated oil well shall be subject to the allocated oil pool rules until the Commission reclassifies the well or pool.

(e) **Unallocated oil pools.**

(1) Classification of unallocated oil pool:
(A) Any pool or area which does not require specific regulation and control by the Commission to restrict production to the market demand, aid in the prevention of waste, assure the maximum ultimate recovery of oil and gas from the pool, or protect correlative rights shall be classified as an unallocated pool.
(B) The Commission shall determine which discovery and allocated pools will be placed in the unallocated classification at each market demand hearing.

(2) Each unallocated oil well shall be subject to unallocated oil pool rules until the Commission reclassifies the well or pool.

(f) **Enhanced oil recovery projects.**

(1) **Authorized pressure maintenance.** The Commission may, upon application, notice, and hearing, authorize the pressure maintenance of a pool or the production of oil by the injection of fluid, fluids, gas, gases, or other material into a common source of supply or a portion thereof, whether unitized or not, where substantial quantities of additional oil may be recovered which could not be recovered under ordinary primary depletion methods. When so authorized, the project will be classified as an Enhanced Oil Recovery Project with one of the following classifications:
(A) Pressure Maintenance Project
(B) Gas Repressuring Project
(C) Waterflood Project
(D) Other Enhanced Recovery Projects

(2) **Status of a gas well reclassified as an oil well.** If a well classified as a gas well in an enhanced oil recovery project is reclassified as an oil

well for allowable purposes, the well shall be subject to the appropriate enhanced oil recovery project rules.

(3) **Termination of enhanced oil recovery status.** Each enhanced oil recovery well shall be subject to enhanced oil recovery project rules until one of the following occurs:

(A) Termination of the enhanced oil recovery project.

(B) The well is reclassified as a gas well for allowable purposes.

(C) The Commission issues an order reclassifying the well or project.

(D) The well is abandoned.

(g) **Excessive water exempt oil projects.**

(1) **Oil production rates.** The Director of Conservation may administratively authorize the production of oil at rates greater than the normal allowable provided the water-oil ratio of the well and/or pool is greater than or equal to 3:1. All applications shall comply with 165:5-7-12.

(2) **Status of a gas well reclassified as an oil well.** If a well classified as a gas well in an excessive water exempt oil project is reclassified as an oil well for allowable purposes, the well shall be subject to excessive water exempt oil project rules.

(3) **Termination of excessive water exempt status.** Each excessive water exempt well shall be subject to excessive water exempt oil project rules until at least one of the following occurs:

(A) The water-oil ratio declines below 3:1.

(B) Termination of the excessive water exempt oil project.

(C) The well is reclassified as a gas well.

(D) The Commission issues an order reclassifying the well or project.

(h) **Allowable for reservoir dewatering oil spacing unit.**

(1) **Oil production rates.** To set an allowable for a well in a reservoir dewatering oil spacing unit, the operator shall refer to Appendix J and submit the appropriate forms and/or application as provided in OAC 165:10-15-18.

(2) **Reclassification of oil well as gas well.** If a well in a reservoir dewatering oil spacing unit is later subject to reclassification as a gas well for allowable purposes, such reclassification will be determined according to general classification procedures based on the its gas/oil ratio pursuant to OAC 165:10-1-6(d) and (e) and 165:10-13-2. If the subject well is designated an excessive water exempt oil project pursuant to OAC 165:10-15-1(g) and 165:10-15-16, reclassification shall be determined by OAC 165:10-15-1(g)(2). If the subject well is assigned an allowable based upon its most efficient rate pursuant to OAC 165:10-13-5, such allowable shall remain in effect under the order establishing the production rate, so that the well will not be reclassified, until its status is modified or terminated by the terms of the instant or a subsequent Commission order.

(3) **Termination of reservoir dewatering oil spacing unit allowable.** The oil allowable assigned a reservoir dewatering oil spacing unit shall remain in effect until one of the following occurs:

(A) The subject well is reclassified as a gas well pursuant to OAC 165:10-1-6 and 165:10-13-2.

(B) The subject well's status as an excessive water exempt oil project is terminated pursuant to OAC 165:10-15-1(g)(3).

(C) The subject well's status under a most efficient rate order is modified or terminated by the terms of the instant or a subsequent Commission order.

[**SOURCE:** Amended in Rule Making 200100009, eff 7-1-02]

165:10-15-2. Overage adjustments for oil wells

No well, lease, unit, or project shall be overproduced in excess of 15 percent of the allowable for the proration period. All overage accrued at the end of the proration period shall be deducted from the allowable for the second succeeding proration period.

165:10-15-3. Effect of percentage penalty on oil wells

If a percentage penalty has been assigned to an oil well, the penalty shall, depending on the status of the well, be subtracted from:

(1) **Discovery status.** The applicable allowable from the Discovery Allowable Table (Appendix B to this Chapter) or the capacity of the well to produce as reported on Form 1029A or the annual Form 1008A, whichever is less.

(2) **If allocated or unallocated per-well status.** The applicable allowable from the Allocated Well Allowable Table (Appendix A to this Chapter) multiplied by the current market demand factor or the capacity of the well to produce as reported on the initial Form 1029A or the annual Form 1008A, whichever is less.

(3) **If unallocated per-lease status.** The shallowest ten acre or less allowable from the Allocated Well Allowable Table (Appendix A to this Chapter) multiplied by the current market demand factor for the penalized well only. The penalty shall be subtracted from the lease allowable.

165:10-15-4. Discovery oil pools [RESERVED]

165:10-15-5. Discovery oil allowables

(a) **Number of barrels of oil per day and duration of the discovery allowable period.** The maximum number of barrels of oil per day and the duration of the discovery allowable period shall be determined from the Discovery Allowable Table (Appendix B to this Chapter) or the Allocated Well Allowable (Appendix A to this Chapter), whichever is greater, provided that the well is in compliance with the other provisions of this Section and other rules pertaining to allowables. If the well is not capable of producing at the discovery rate without causing preventable waste, the temporary discovery allowable shall be the capacity of the well to produce as reported on Form 1029A or the annual Form 1008A, unless otherwise limited by the Commission.

(b) **Effective date of discovery allowable.**

(1) The discovery allowable period for the pool shall begin with the date of first completion of the discovery well of the pool and extend as provided in the Discovery Well Allowable Table (Appendix B to this Chapter).

(2) The discovery allowable period for each well in the pool shall run from the date specified under 165:10-15-7 for each well to the date of termination of the pool, if granted administratively.

(3) If application, notice, and hearing are required, the effective date of the discovery allowable period shall be specified by an order of the Commission, provided that such date shall not precede the date of filing of the application. The date of expiration of the discovery allowable shall still be determined as set forth in (1) of this subsection.

(c) **Gross allowable production.** The gross allowable production for any proration period from a well in a discovery pool may, at the option of the operator, be produced at any time during the proration period; however, in no event shall the production exceed the maximum efficient rate of flow.

165:10-15-6. Production tests and reports for discovery oil pools

(a) **Initial test requirements.** The operator of each well in each discovery pool shall perform an initial potential test and furnish the Conservation Division the results of such test on Form 1029A not later than 30 days after completion of each well. Each individual well shall be tested for not less than six hours and not more than 24 hours with the production calculated and reported at a daily rate (24 hours).

(b) **Witnessing of tests.**

(1) With respect to initial test, the operator shall give twenty-four (24) hour notice of the opportunity to witness said test to the Conservation

Division and the offset operator(s) producing from the same pool, but no waiver or signature of Conservation Division personnel is required on Form 1029A.
(2) Any operator in the pool may witness any official test for any well in the pool. However, any person other than a Commission employee witnesses a test at their sole risk and expense.

[**SOURCE:** Amended at 9 Ok Reg 2337, eff 6-25-92; Amended in Rule Making 980000033, eff 7-1-99]

165:10-15-7. Procedure for obtaining discovery allowable
(a) Any operator desiring a discovery allowable shall file Form 1028 with the material and information specified below:
(1) A resistivity and a porosity type wireline survey of the well in question, if run.
(2) A Completion Report (Form 1002A) and Cementing Report (Form 1002C), completed in detail.
(3) A Potential Test (Form 1029A), completed in detail.
(4) A plat of the area showing all of the following information for each well within one and one-half (1 1/2) miles of the subject well:
(A) Operator.
(B) Well name and number.
(C) Total depth.
(D) Current status of the well (dry, oil, gas, injection, disposal, temporarily abandoned).
(E) Name of interval open, if any.
(F) Perforations, top and bottom, if any.
(G) Average daily production.
(5) An isopach contour map of the productive interval and/or a structural contour map of a nearby marker bed or formation, not separated from the producing interval by an unconformity, which is commonly used in the area. The Conservation Division may require either or both types of maps to determine the discovery status. The Commission may also require additional geological and/or engineering data, such as: stratigraphic cross-sections, structural cross-sections, production, and pressure information.
(b) The Conservation Division may administratively designate a discovery allowable for a well when the operator furnishes the Technical Department with the information specified in (a) of this Section. If the information is provided within 30 days of the date of first production and the application is approved, the effective date of the discovery allowable shall be the date of first production. If the information is provided more than 30 days after the date of first production and the application is approved, the discovery allowable shall be effective the date of filing.
(c) If a gas well in a discovery oil pool is reclassified as an oil well for allowable purposes, the operator must file the appropriate form, information and material specified in (a) of this Section within 30 days of reclassifying the well to obtain a discovery allowable. The allowable shall be effective the date the well was reclassified as an oil well as indicated on Form 1002A. If the application is not received within the specified time period, the application will be processed in accordance with (b) of this Section.

165:10-15-8. Allocated oil pools [RESERVED]

165:10-15-9. Allocated oil allowables
(a) **Effective date of allowables.** The allowable for an allocated well completed or recompleted on or after the first day of the proration period shall become effective the date of completion of the well, provided the operator has complied with the provisions of this Section and other rules governing

allowables. In situations where the operator fails to comply, the allowable shall become effective the date the operator complies with this Section and other rules governing allowables.
(b) **Allowables in allocated pools.** Allowables in allocated pools shall be granted on an individual well basis, subject to appropriate spacing requirements, unless otherwise specified by order of the Commission. The allowable for each allocated well shall be determined as if the well was an unallocated well operating under 165:10-15-12(b) or 165:10-15-12(c)(1), whichever is appropriate, unless adjusted by order of the Commission. The operator shall produce the allowable on each well from that well and no part thereof from any other well.
(c) **Application.** Upon application by the Director of Conservation or any interested party, and after notice and hearing, the Commission may order the wells in a common source of supply to be produced under allowables established by special pool rules in lieu of the provisions of this Section. All requirements as to production tests and allowables shall be set forth by the order of the Commission establishing such special pool rules.

165:10-15-10. Production tests and reports for allocated oil wells

All production tests and reports shall be filed as if the allocated well were an unallocated well operating on a per-well basis allowable under 165:10-15-13(a).

165:10-15-11. Unallocated oil pools [RESERVED]

165:10-15-12. Unallocated oil allowables

(a) **Effective date of allowable.** The allowable for a well completed or recompleted on or after the first day of a proration period shall become effective the date of completion of the well, provided the operator has complied with the provisions of this Section and other rules governing allowables. In situations where the operator fails to comply, the allowable shall become effective the date the operator complies with this Section and other rules governing allowables.
(b) **Well in an unallocated pool.** Each well in an unallocated pool in which drilling and spacing units have been established shall be assigned the applicable allowable on a per-well basis from the Allocated Well Allowable Table (Appendix A to this Chapter) multiplied by the current market demand factor unless adjusted by order of the Commission. The production from each well shall be separately accounted for to the Commission.
(c) **Lease in an unallocated pool.** Each individual lease in an unallocated pool in which drilling and spacing units have not been established shall be assigned allowables, at the option of the operator, on either of the following basis:

(1) **A per-well basis.** If the operator elects to accept the per-well basis allowable, each well on the lease shall be assigned an allowable applicable to a ten-acre or less allowable at the appropriate depth from the Allocated Well Allowable Table (Appendix A to this Chapter) multiplied by the current market demand factor unless adjusted by order of the Commission. The production from each well shall be separately accounted for to the Commission.

(2) **A per-lease basis.** If the operator elects to accept the per-lease basis allowable, the allowable for the lease shall be the shallowest ten-acre or less allowable from the Allocated Well Allowable Table (Appendix A to this Chapter) multiplied by the current market demand factor multiplied by the number of wells on the lease unless adjusted by order of the Commission. The production from each lease shall be separately measured and accounted for to the Commission.

165:10-15-13. Production tests and reports for unallocated oil wells

(a) **Per-well basis allowable.**

(1) If the well is an allocated well, or an unallocated well located on lands in which drilling and spacing units have not been established and the operator elected to accept allowables on a per-well basis, or an unallocated well located on lands in which drilling and spacing units have been established, the operator shall file a production test on Form 1029A no later than 30 days after the earlier of:

(A) Making the election,

(B) Completion of the well, or

(C) Recompletion of the well.

Each individual well shall be tested for not less than six hours and not more than 24 hours with the production calculated and reported at a daily rate (24 hours).

(2) Each new well shall be given an allowable equal to the allowable for an unallocated per-well basis well until the production test has been performed with the results reported to the Conservation Division on Form 1029A. The allowable shall be effective for a period not longer than 30 days from completion of the well. No further allowable shall be assigned to the well until compliance with this subsection.

(3) Until an operator submits the required test results for any well, as provided in subsection (a)(1), no allowable shall be assigned to the well. If said test results are filed late, then the allowable shall be effective the first day of the following month after the Conservation Division accepts the test.

(4) All initial tests shall be conducted in the manner set forth in (1) of this subsection.

(5) Annual testing shall not be required.

(b) **Per-lease basis allowables.**

(1) If the well is an unallocated well located on lands in which drilling and spacing units have not been established and the operator elects to accept allowables on a per-lease basis, the operator shall file a production test on Form 1029A with the Conservation Division not later than 30 days after:

(A) Making the election,

(B) Completion of the initial well on the lease,

(C) Completion of a subsequent well on the lease,

(D) Recompletion of any well on the lease, or

(E) Retesting of any well on the lease.

Each well on the lease shall be tested for not less than six hours and not more than 24 hours with the production calculated and reported at a daily rate (24 hours).

(2) Each lease shall be given an additional allowable equivalent to the shallowest ten-acre or less allowable from the Allocated Well Allowable Table (Appendix A to this Chapter) multiplied by the current market demand factor for each new producing well added to the lease until the production test has been performed with the results reported to the Conservation Division on Form 1029A. The additional allowable shall be effective for a period not longer than 30 days from completion of the well. No further additional allowable shall be assigned to the lease until compliance with this subsection.

(3) If an operator fails to submit the required test results for any lease with allowables calculated on a per-lease basis, no allowable shall be assigned to the lease. The operator may submit the results of the test to the Conservation Division on Form 1029A to reinstate the allowable. The allowable shall be effective the first day of the following month after the Conservation Division accepts the test.

(4) No lease shall be granted underage resulting from failure to perform a required test in compliance with this Section.

(5) All initial tests, annual tests and retests shall be conducted in the manner set forth in (1) of this subsection.

[**SOURCE:** Amended at 9 Ok Reg 2337, eff 6-25-92; Amended in Rule Making 980000033, eff 7-1-99]

165:10-15-14. Enhanced oil recovery project allowables

(a) **Effective date of allowable.** The allowable for an enhanced oil recovery project shall be effective on the date operations commenced or the date specified by order of the Commission authorizing the project, whichever is later, provided the operator has complied with the provisions of this Section and other rules governing allowables. In situations where the operator fails to comply, the allowable shall become effective the date the operator complies with this Section and other rules governing allowables.

(b) **Qualification for enhanced oil recovery allowable.** For any project to qualify for an enhanced oil recovery allowable, an order of the Commission authorizing the project must be obtained.

(c) **Allowable for enhanced oil recovery project.** The allowable for an enhanced oil recovery project shall be on a project basis and shall be the capacity of the project to produce.

(d) **Wells on a project producing from another reservoir.** Oil wells within the boundaries of a project which do not produce from the project shall not be permitted to produce any portion of the allowable of such enhanced oil recovery project. The oil produced by non-project wells shall be separately produced, measured, and reported.

165:10-15-15. Production tests and reports for enhanced oil recovery projects

(a) Within 30 days of commencement of any enhanced oil recovery project, the operator shall file with the Conservation Division an inventory of all the wells located within the boundaries of the project completed in the approved common source of supply showing the name of the project and the new OTC Production Unit Number (including merge number) and the following for each well:

(1) Previous OTC Production Unit Number.
(2) API Number.
(3) Well Name and Number.
(4) Legal location, including quarter quarter quarter quarter section.
(5) Current status (producer, injector, observation, or temporarily abandoned).

The inventory shall also include the current daily (24 hour) production and injection rates for the project.

(b) The operator shall notify the Conservation Division in writing within 30 days of the completion of any new well or the change in status of any existing well in the project.

(c) Until the operator submits the required test results for any enhanced oil recovery project as provided in subsection (a), no allowable shall be assigned to the project. If said test results are filed late, then the allowable shall be effective the first day of the following month after the Conservation Division accepts the tests.

(d) All initial tests shall be conducted as set forth in subsection (a).

(e) Annual testing shall not be required except as provided in OAC 165:10-1-6.

[**SOURCE:** Amended in Rule Making 980000033, eff 7-1-99]

165:10-15-16. Excessive water exempt oil project allowables

(a) **Effective date of allowables.** The allowable for an excessive water exempt oil project shall be on a well or a project basis and shall be effective when the Conservation Division receives and accepts the production test of, Form 1013, unless otherwise specified by order of the Commission.

(b) **Qualification for excessive water exempt oil project.** For any project or well to qualify for excessive water exempt allowable, an order of the Commission authorizing the well or project must be obtained.

(c) **Allowable for excessive water exempt oil project.** The allowable for a well or project which has received a special excessive water exempt allowable shall be the capacity of the well or project to produce without causing preventable waste unless otherwise adjusted by the Director of Conservation. The production from a well which has received a special excessive water exempt allowable under this Section shall be separately produced, measured, and accounted for to the Commission from the oil produced from the remainder of the lease.

165:10-15-17. Production tests and reports for excessive water exempt oil projects

(a) The operator of each individual well with an excessive water exempt allowable shall file an initial production test, in duplicate, on Form 1013 with the Conservation Division. Each individual well shall be tested for seven consecutive days, and the amount of oil and the amount of water produced each day shall be reported on Form 1013. With respect to the initial test, the operator shall give twenty-four (24) hour notice of the opportunity to witness said test to the Conservation Division and the offset operator(s) producing from the same formation, but no waiver or signature of Conservation Division personnel is required on Form 1013.
(b) Each individual well shall be given an initial allowable equal to the unallocated per-well basis allowable until the production test has been performed with the results reported to the Conservation Division on Form 1013. The allowable shall be effective for a period not longer than 30 days from completion of the well. No further allowable shall be assigned to the well until compliance with this subsection.
(c) Until the operator submits the required test results for any excessive water exempt well or project, as provided in subsection (a), no allowable shall be assigned to the well or project. If said test results are filed late, the allowable shall be effective the first day of the following month after the Conservation Division accepts the test.
(d) All initial tests shall be conducted as set forth in (a) of this Subsection.
(e) Annual testing shall not be required except as provided in OAC 165:10-1-6.

[**SOURCE:** Amended in Rule Making 980000033, eff 7-1-99]

165:10-15-18. Production tests and reports for reservoir dewatering oil spacing units

(a) **Effective date for oil allowable.** To establish the commencement date of an allowable for an oil well in a reservoir dewatering oil spacing unit, the operator shall file Forms 1002A and 1013, in lieu of the Form 1029A, with the Commission according to OAC 165:10-13-3 within thirty (30) days after the completion date of the well. The allowable will commence on the date of first production.
(b) **Qualification for reservoir dewatering unit.** Proof of fifty percent (50%) water saturation presented at the time of a hearing to establish dewatering oil spacing may entail calculations from logs or core data from wells within the common source of supply covered by the application or an analogous common source of supply, or an actual production test from a well in the common source of supply covered by the application. To qualify for the reservoir dewatering spacing unit allowable provided on Appendix J, the Form 1013 must provide data that verifies that the water-oil ratio is greater than 1:1. If the water-oil ratio is less than 1:1, then the oil allowable shall be the appropriate allowable for the depth of the top of the formation and the maximum acreage provided in Appendix A.
(c) **Allowable rate not provided for in Appendix J.** To establish an allowable other than that specified in Appendix J, the operator shall file a Form 1030 with the Commission to adjust the allowable.
(d) **Record of annual production rates.** The operator shall maintain production records on an annual basis. Operators shall make these records available to the Conservation Division staff upon the request of the Manager of the Technical Department. Annual testing shall not be required except as provided in OAC 165:10-1-6.

[**SOURCE:** Amended in Rule Making 200100009, eff 7-1-02]

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SUBCHAPTER 17. GAS WELL OPERATIONS AND PERMITTED PRODUCTION

Section

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165:10-17-1. Gas production from gas pools [RESERVED]

165:10-17-2. Classification of gas pools

(a) **Types of gas pools.** Each gas pool shall be classified by the Commission into one of the following categories:
(1) Allocated Gas Pool.
(2) Special Allocated Gas Pool.
(3) Unallocated Gas Pool.

(b) **Treatment of gas well in an oil pool.** If a well in an oil pool is classified as a gas well for allowable purposes, the well shall be treated as if it were in an unallocated gas pool, unless the well is subject to pool rules which establish allowables by volumetric withdrawal.

(c) **Allocated gas wells.**
(1) **Classification of pool by order.** Upon application, notice, and hearing, the Commission may issue an order establishing allowables for gas wells in a pool by the allocated gas pool rules in 165:10-17-8.
(2) **Status of an oil well reclassified as a gas well.** If a well classified as an oil well in an allocated gas pool is reclassified as a gas well for allowable purposes, the well shall be subject to allocated gas pool rules.
(3) **Termination of allocated status.** Each allocated gas well shall be subject to allocated gas pool rules until:
(A) The Commission establishes special allocated gas pool rules for the common source of supply.
(B) The well is reclassified as an oil well for allowable purposes.
(C) The Commission issues an order reclassifying the well as an unallocated gas well.
(D) The well becomes the only gas well in the pool.
(E) The well is abandoned.

(d) **Special allocated gas pools.** Each gas pool for which special pool allocation rules (field rules) are or have been established by the Commission shall be classified as a special allocated gas pool. Each gas well in a special allocated gas pool shall be referred to as a special allocated gas well for allowable purposes.

(e) **Unallocated gas pools.** Each gas pool not classified as an allocated gas pool or as a special allocated gas pool shall be classified as an unallocated gas pool. Each gas well in an unallocated gas pool shall be referred to as an unallocated gas well for allowable purposes.

165:10-17-3. Effective date of allowables

A gas well shall be assigned an allowable as of the date it is connected into a pipeline and the first delivery is made if the Notice of Intention to Drill (Form 1000) is valid, the Completion Report (Form 1002A) is filed with attachments, if required, and all required tests are run within 30 days from the date of first sales and are filed within 45 days of the date of first sales, and special reports have been filed with the Conservation Division.

[**SOURCE:** Amended in Rule Making 980000033, eff 7-1-99]

165:10-17-4. Standard gas measurement law

Sections 471 through 477, inclusive, of Title 52, Oklahoma Statutes Annotated, cited as the "Standard Gas Measurement Law", are hereby adopted as rules of the Commission as fully as if set out verbatim herein.

165:10-17-5. Meters and recorders
(a) **Requirement of a gas meter and recorder.**
(1) For allowable, allocation or custody transfer purposes, each well producing natural gas other than a shut-in gas well shall have a gas meter and recorder for the gathering line; provided, if two or more wells share a single allowable, a single meter and recorder may be used to measure gas production, unless a special order of the Commission or either 165:10-13-9 or 165:10-3-39 require allocation of gas production on a per well basis.
(2) For purposes of (1) of this subsection, the term "recorder" refers to a circular gas chart recorder or other type of recording device which has been mutually agreed upon by the gas seller and the gas purchaser.
(3) For purposes of (1) of this subsection, an offsite recorder shall be permitted provided:
(A) There is compliance with the requirements of (2) of this subsection.
(B) The recording device is made available for inspection by the Conservation Division to determine that the recorder is functioning properly.
(4) Offsite recordation under (1) and (3) of this subsection shall be treated as wellsite metering for purposes of the reporting requirements of 165:10-1-47.
(5) Use of electronic gas measurement and recording devices that meet industry standards of (b)(2) of this Section are permitted for allowable, allocation, custody transfer, and well testing.
(b) **Standards for meters and recorders.**
(1) Each meter and recorder shall be properly constructed, maintained, repaired, and operated to continually and accurately register the quantity of gas produced from the well into a gathering line.
(2) The meter and recorder shall be installed, used, and operated according to the natural gas industry standards and guidelines promulgated by the American Gas Association, the American Petroleum Institute, and the Gas Processors Association, in effect at the time of installation of the meter and recorder. If there are conflicting standards, then the most current American Petroleum Institute standard shall apply.
(c) **Prohibited meter bypasses.** For each meter measuring production at the wellsite, use of piping to bypass the meter is prohibited. Gas meters with internal bypasses are permitted.
(d) **Reporting of estimated volume if the meter or recorder fails.**
(1) **Seventy-two hours to repair equipment.** If a meter or recorder at the wellsite malfunctions, then the malfunctioning equipment shall be repaired within 72 hours after discovery of the malfunction.
(2) **Reporting of estimated volumes while the meter or recorder is down.** If the well continues to produce gas while the meter or recorder is malfunctioning or being repaired, estimated gas volumes shall be reported to the Conservation Division for purposes of 165:10-1-47.

[**Source:** Amended at 12 Ok Reg 2017, 7-1-95]

165:10-17-6. General well testing requirements
(a) All single-point and multi-point potential tests shall be calculated for all gas wells in a uniform manner with respect to the following:
(1) The potential shall be the calculated wellhead absolute open flow potential of the well determined by obtaining a static column wellhead flowing pressure and shall indicate the capacity of the well to produce against zero psia at the wellhead.
(2) All pressures used in test calculations shall be corrected to pounds per square inch absolute, using 14.4 psia as the average barometric pressure.
(3) The static column wellhead pressure, either measured or calculated as reported in the potential test, shall be no more than 90 percent of the wellhead shut-in pressure. If data cannot be obtained in accordance with the foregoing provisions, an assumed static column wellhead pressure of 90

percent of the wellhead shut-in pressure shall be used to calculate the results of the test. This paragraph supersedes any contrary provision in special pool rules.

(b) The operator of a well shall be responsible for testing the well and submitting the test results to the Conservation Division. The results of a potential test shall be filed with the Conservation Division on Form 1016. If the operator wishes to obtain a copy of the approved Form 1016, he shall enclose with the original form a self-addressed stamped envelope and one additional copy of the test and/or form. The Conservation Division shall acknowledge such requests within 15 days, stating either the date of acceptance of the test results or rerunning the original test if it has been rejected. If any order or rule of the Conservation Division requires witnessing of a test, the operator of the well shall be responsible for securing the presence of an authorized Conservation Division representative to witness the test and sign the Form 1016 for the test.

(c) Unless otherwise prescribed by special pool rules, field testing procedure shall be performed in accordance with the procedures set out in Oklahoma Corporation Commission Manual of Back-Pressure Testing of Gas Wells, Parts I and II, utilizing the specified tables in the Interstate Oil and Gas Compact Commission Manual of Back-Pressure Testing. A gas turbine meter may be used in lieu of an orifice meter for flow measurements in gas well testing.

(d) The initial test for all gas wells shall be run into the pipeline within 30 days and test results filed within 45 days after the date of first sales of gas. Any test filed after the 45 day limit will not be made effective until the first of the month following the date of acceptance of the test. With regard to initial tests for special allocated gas wells, the operator of the well shall provide twenty-four (24) hours notice to the Conservation Division of its intent to run an initial test in order to give the Conservation Division the opportunity to witness said test, but in no case shall the operator be precluded from performing said test and filing the results as provided for in subsection (b). Initial tests for special allocated gas wells need not be witnessed, nor signatures obtained, if witnessed, in order for the Conservation Division to assign an allowable to said well. Initial tests for unallocated gas wells with calculated open flow of less than two million cubic feet per day are exempt from witnessing by Conservation Division personnel under 165:10-17-7(b)(1).

(e) The annual test for all gas wells shall be run into a pipeline in accordance with this Section or applicable pool rules. Any annual test for a well in a special allocated pool, filed late shall not be made effective until the first of the month following the date of acceptance of the test.

(f) Wells in allocated pools shall be tested in accordance with the requirements for wells in unallocated pools, unless superseded by specific field rules. Form 1016 shall be used to report shut-in pressure tests on wells in allocated and special allocated pools, except for the Guymon-Hugoton Pool #182 which shall use a form 1017 Deliverability Gas Test.

[**SOURCE:** Amended in Rule Making 980000033, eff 7-1-99]

165:10-17-7. Well tests

(a) **Wells in special allocated pools.**

(1) An initial test shall be filed for each newly completed gas well in each special allocated pool. The well shall be tested into a pipeline no later than 30 days after the date of the first sale of gas. Test procedures shall be those specified in the applicable pool rules subject to the uniform requirements of 165:10-17-6.

(2) An annual test shall be filed in accordance with the requirements of the applicable pool rules, subject to the following provisions specific to the Guymon-Hugoton special allocated pool.

(3) **Wells in the Guymon-Hugoton special allocated pool.**

(A) The Conservation Division staff will not be required to witness any well test on any well in the Guymon-Hugoton special allocated gas pool unless requested to do so by an offset operator. Operators have a right to witness any well test on any well offsetting said operator's well in the pool. Operators of offsetting wells will be given sufficient prior notice of testing to allow for a representative to be present to witness testing, and will be provided access to the designated witness throughout testing.

(B) Wells in the Guymon-Hugoton special allocated gas pool which are not capable of producing 450 Mcf/day will be exempt from biannual deliverability tests. Operators shall have the right to elect to receive the minimum allowable by deciding not to conduct well deliverability tests on any such wells in the pool. No well shall be exempt from the annual wellhead shut-in pressure test requirements. For the purpose of the annual wellhead shut-in pressure test, the shut-in pressure shall be measured after the well has been shut-in for approximately 48 hours. In no case shall the well have been shut-in for less than 44 hours at the time the shut-in pressure is taken.

(b) **Wells in unallocated pools.**

(1) **Testing of newly completed wells.**

(A) An initial test shall be submitted to the Conservation Division for each newly completed gas well in an unallocated gas pool under 165:10-17-2. The well shall be tested into a pipeline no later than 30 days after the date of first sale of gas into a pipeline. The flow period for the initial test shall be 24 hours. It shall not be necessary for the operator to submit the initial flow potential test for an unallocated well with a calculated open flow of less than 2,000,000 cubic feet per day, only the wellhead shut-in pressure taken for a minimum of 24 hours for the well is required, unless requested by the Commission. All tests and initial shut-in pressures shall be submitted to the Conservation Division on Form 1016 and, at the operator's discretion, in digital magnetic form in a format prescribed by the Commission. The form shall contain complete and accurate information.

(B) If said initial test is taken between the first day of January and the thirty-first day of July of the calendar year, the test shall be used for allowable purposes for the calendar year unless the operator later submits a retest which is accepted by the Conservation Division.

(C) The well shall also be tested during the annual test period between the first day of May and the thirty-first day of October, but no sooner than three months after the initial test. Said test shall be used for the annual test to determine permitted production for the following calendar year unless the well is later retested.

(D) If the test used for the following year cannot be submitted during the annual test period, the Conservation Division may grant administratively a written extension of time up to 30 days beyond the thirty-first day of October for running the test.

(2) **Annual test period for other wells.** An annual potential test shall be run on each gas well in each unallocated pool between May 1, and November 30, and must be accepted by the Commission no later than December 15, except for wells exempt under (4) of this subsection. The annual potential test shall be effective January 1 of the succeeding calendar year (annual accounting period) unless superseded by a later test. The Director of Conservation may require additional tests at any time. Retests become effective the first day of the month following acceptance of the test by the Conservation Division.

(3) **One-point tests.** The potential test required for each gas well in each unallocated pool shall use the one-point back pressure method and an assumed flow characteristic of 0.85 shall be used in establishing the wellhead absolute open flow. The test shall be governed by the requirements of OAC 165:10-17-6.

(4) **Minimum well exemption from annual tests.** Each gas well in each unallocated pool having a tested potential of 2,000,000 cubic feet of gas per day, or less, shall thereafter be exempt from the annual potential test, and the operator of the well shall report annually the results of an annual wellhead shut-in pressure test taken for a minimum of 24 hours on Machine Accounting Form 1007A and, at the operator's discretion, in digital magnetic form in a format prescribed by the Commission unless the Director of

Conservation waives in writing the pressure test requirement. Machine Accounting Form 1007A, when received by the operator, shall be used to report shut-in pressure tests and gas sales from the previous calendar year on wells in unallocated pools. Wellhead shut-in pressure just for minimum wells may be taken any time during the year, but must be taken at least six months after the test submitted for the prior year.

(5) **Retests.** Retests may be run at any time and shall become effective the first day of the month following acceptance of the test by the Conservation Division. Retests submitted during the unallocated gas well testing period of May 1, through October 31, will also be classified as annual-status tests to establish the allowable for the following year.

(6) **Minimum compliance.** Each operator shall be responsible for conducting and submitting the required potential tests on the applicable form and for the annual reporting of all required information on Machine Accounting Form 1007A and, at the operator's discretion, in digital magnetic form in a format prescribed by the Commission. All submitted tests and 1007A forms must contain complete and accurate information. Permitted production rates will be granted only to those wells which meet this requirement and all other rules or orders of the Commission.

[**SOURCE:** Amended in Rule Making 97000002, eff 7-1-97; Amended in Rule Making 97000011, eff 7-1-98; Amended in Rule Making 980000033, eff 7-1-99]

165:10-17-8. Allocated pools

(a) The current monthly allowable for each allocated pool shall be equal to the total production from the pool during the current month.

(b) The current allowable for each capable drilling and spacing unit within the pool shall be that proportion of the pool allowable that the acreage of the drilling and spacing unit bears to the total developed acreage in the pool, adjusted in accordance with any order of the Commission imposing an allowable adjustment. The current allowable for each limited drilling and spacing unit shall be equal to the current production from the unit. A unit shall be deemed limited when its underage is cancelled under this Section until it thereafter produces a current allowable for any one month.

(c) Accrued underage shall be carried forward as a cumulative credit by adding it to the unit's current allowable until the underage has been produced. If the unit's cumulative underage exceeds six times the allowable assigned to it for the preceding January, all of the underage will be cancelled, the unit shall be classified as "limited", and the unit shall not thereafter accumulate underage until such time as the unit produces a current allowable for any one month. All cancelled underage shall be distributed to the capable drilling and spacing units within the pool in the proportion that the acreage of each unit bears to the total capable acreage in the pool, adjusted in accordance with any order of the Commission imposing an allowable adjustment. A capable unit shall be any nonlimited unit. Cancelled underage may be reinstated administratively by the Director of Conservation to any capable unit in an overproduced status within six months after cancellation by application on Form 1010.

(d) Accrued overage shall be carried forward as a cumulative charge against the unit by subtracting it from the unit's current allowable until the overage has been made up. If the cumulative overage exceeds six times the current allowable assigned for the preceding January, the Director of Conservation shall notify the operator in writing, and the unit shall thereafter be permitted to produce not more than 25 percent of its current allowable until all of the overage in excess of six times the well's current allowable for the preceding January has been made up. In the event the operator fails to limit production as herein provided, the well shall be ordered shut-in by the Commission upon application of the Director of Conservation and after notice and hearing.

(e) If a unit did not have a current allowable assigned to it on a full month's basis for the preceding January, the first current allowable assigned to the unit on a full month's basis shall be used as reference for the purpose of limiting underage and overage.

165:10-17-9. Special allocated gas pools

(a) **Scope.** This Section applies to special allocated gas pools except any special allocated gas pool with allowables based upon volumetric withdrawals.

(b) **Minimum unit allowable of 150 mcf/d.** For all special allocated gas pools except the West Cheyenne Upper Morrow, Purvis Chert, Guymon-Hugoton, Custer City N. Hunton, Sharon W. Morrow, Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro, the minimum allowable for a drilling and spacing unit in the pool shall be 150 MCF/D regardless of the amount of any location exception penalty charged against a unit well. For purposes of this Section, the net minimum allowable shall be the gross minimum allowable adjusted for overage or underage according to this Section.

(c) **Minimum unit allowable of 450 mcf/d for the Guymon-Hugoton pool.**

(1) For the Guymon-Hugoton Special Allocated Gas Pool, minimum allowables shall be determined as follows: The minimum allowable shall be the lesser of 450 mcf/d or the drilling and spacing unit's capability. Capability shall be defined as the average of the highest three (3) of the last twelve (12) months of production. A drilling and spacing unit receiving a minimum allowable shall not accrue underage. The minimum allowables under this Section shall not affect the calculation of capable well allowables. The field monthly allowable shall be equal to total nominations and not adjusted for underage or overage.

(2) The deliverability standard pressure (DSP) to be used in the application of special allocated rules (field rules) shall be defined as 25 pounds less than the average shut-in wellhead pressure of the pool.

(3) The Corporation Commission shall calculate and publish reports of allowable and production quarterly.

(d) Minimum unit allowable of 2,000 mcf/d for the Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro Pools. For the Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro Pools (Pool Nos. 456, 457 and 458) located in Latimer and LeFlore Counties, Oklahoma, the minimum allowable for a drilling and spacing unit in each pool shall be 2,000 mcf/d. For purposes of this Section, the net minimum allowable shall be the gross minimum allowable adjusted for overage or underage according to this Section.

(e) **Double minimum allowable of 300 mcf/d.**

(1) **Compressor and application required.** For all special allocated gas pools except the West Cheyenne Upper Morrow, Purvis Chert, Guymon-Hugoton, Custer City N. Hunton, Sharon W. Morrow, Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro, if a drilling and spacing unit has a minimum allowable under (b) of this Section, the operator of a well in the drilling and spacing unit may obtain for the unit a double minimum allowable regardless of any location penalty against a well by installing a compressor on a unit well and applying for a double minimum allowable under (2) of this subsection.

(2) **Request for administrative approval.** To apply for a double minimum allowable, the operator shall submit to the Manager of Production Allowables for the Conservation Division a letter requesting a double minimum allowable and stating the factual basis for the request and the legal description of the well with the compressor.

(f) **Basic allowable.**

(1) **Use of basic allowable for determining overage and underage.** For purposes of determining the amount of overage or underage accrued by a well or drilling and spacing unit, the Conservation Division shall establish on a yearly basis a status factor known as the basic allowable.

(2) **Apportionment of basic allowable.**

(A) **Increased density unit without apportionment of the allowable.** If neither OAC 165:10-13-9 nor an order of the Commission require specific allocation of the unit allowable to each unit well, overage and underage shall be carried on a unit basis.

(B) **Increased density unit with ratable allowables.** If either OAC 165:10-13-9 or an order of the Commission require specific allocation of the unit allowable to each unit well, overage and underage shall be carried on a per well basis. For purposes of computing overage and underage, the basic allowable shall be apportioned to each unit well using the formula for determining each well's ratable allowables for the applicable month under (3) of this subsection. The term "ratable allowables" refers to a well's share of the unit allowable under the formula apportioning the allowable amongst the unit wells.

(3) **Computation of the basic allowable.** Except as provided in (C) of this paragraph for basic allowable changes, the basic allowable for the calendar year shall be computed as follows:

(A) **For all pools except the Red Oak Pools.** For all pools except the Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro, the basic allowable shall equal the drilling and spacing unit's January allowable for the calendar year.

(B) **For the Red Oak Pools.** For the Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro, the basic allowable shall equal the drilling and spacing unit's March allowable for the calendar year.

(C) **Changes in the basic allowable.**

(i) **Test exempt minimum allowable.** If a drilling and spacing unit receives test exempt minimum allowable status as provided in this Section, then the basic allowable shall be a minimum allowable.

(ii) **Test exempt double minimum allowable.** If a drilling and spacing unit receives a test exempt double minimum allowable as provided in this Section, then the basic allowable for the unit shall be a double minimum allowable.

(iii) **Retests.** If the well operator submits to the Conservation Division a retest which is approved by the Conservation Division, then the Conservation Division shall recompute the basic allowable using the retest. Retests are permitted at any time and become effective the first day of the month after acceptance by the Conservation Division.

(g) **Determination of overage and underage.**

(1) **Overage.**

(A) **Drilling and spacing unit without ratable allowables.** If no well in a drilling and spacing unit is subject to a ratable allowable, the current monthly allowable shall be compared with the second prior month's unit production. Production in excess of the current monthly allowable is overage. Aside from any adjustment to the pool allowable required by pool rules, overage shall not reduce any subsequent monthly allowable until accumulated overage exceeds the applicable overage limit under (h) of this Section.

(B) **Drilling and spacing unit subject to ratable allowables.** If any well in a drilling and spacing unit is subject to a ratable allowable, the current monthly ratable allowable for the well shall be compared with the second prior month's production from the well. Production in excess of the ratable allowable is overage. Aside from any adjustment to the pool allowable required by pool rules, the well's overage shall not reduce any subsequent monthly ratable allowable until accumulated overage exceeds the well's overage limit under (h) of this Section.

(2) **Underage.**

(A) **Drilling and spacing unit without ratable allowable.** If no well in a drilling and spacing unit is subject to a ratable allowable under OAC 165:10-13-9, the current monthly allowable for the unit shall be compared with the second prior month's unit production. If production is less than the allowable, the difference between the production and the unit allowable is underage. Aside from any adjustment to the pool allowable required by pool rules, only reinstated cancelled underage under (k) of this Section shall increase any subsequent monthly allowable.

(B) **Drilling and spacing unit with ratable allowables.** In a drilling and spacing unit with ratable allowables, the current monthly ratable allowable for a well shall be compared with the second prior month's production from the well. If production was less than the current monthly ratable allowable, the difference between the production and the ratable allowable is underage. Aside from any adjustment to the pool allowable required by pool rules, only reinstated cancelled underage under (k) of this Section shall increase any subsequent monthly ratable allowable for the well.

(h) **Overage limits.**

(1) **For all pools Except the Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro.** For all pools except the Red Oak Fanshawe, Red Oak Red Oak, and the Red Oak Spiro, the overage limit is six times:

(A) The basic allowable for the drilling and spacing unit, if the overage carried on a unit basis; or

(B) The well's share of the basic allowable for the drilling and spacing unit, if the well receives a ratable allowable.

(2) **For the Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro Pools.** For the Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro Pools, the overage limit is 168 times:

(A) The basic allowable for the drilling and spacing unit, if the overage is carried on a unit basis; or

(B) The well's share of the basic allowable for the drilling and spacing unit, if the well receives a ratable allowable.

(3) **Mandatory curtailment for excessive overage.**

(A) **Single well drilling and spacing unit.** If accumulated overage from a single well drilling and spacing unit exceeds the applicable overage limit, production from the unit shall be curtailed to 25 percent of the monthly allowable until accumulated overage is reduced below the overage limit.

(B) **Multiple well unit without ratable allowables.** In a multiple well drilling and spacing unit without ratable allowables, if accumulated overage for the unit exceeds the applicable overage limit, the unit production shall be curtailed to 25 percent of its monthly allowable until the accumulated overage is reduced below the overage limit.

(C) **Multiple well unit with a ratable allowable.** In a multiple well drilling and spacing unit with one or more wells subject to a ratable allowable, if the accumulated overage for a well exceeds its overage limit, production from the well shall be curtailed to 25 percent of its monthly ratable allowable until the well's accumulated overage is reduced below its overage limit.

(i) **Underage limits.**

(1) **For the Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro Pools.** For the Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro Pools (Pool Nos. 456, 457 and 458) located in Latimer and LeFlore Counties, Oklahoma, the underage limit is three times the status factor for:

(A) The drilling and spacing unit,

(i) If the unit has only one well, or

(ii) If the unit has multiple wells but no unit well has a ratable allowable; or

(B) The well, if a well has a ratable allowable.

(2) **For all other special allocated gas pools subject to this Section.** For all other special allocated gas pools subject to the Section, the underage limit is six times the status factor for:

(A) The drilling and spacing unit, if the status factor is determined on a unit basis; or

(B) The well, if the well is subject to a ratable allowable.

(j) **Cancellation of underage.**

(1) **Underage in excess of the underage limit.** If accumulated underage exceeds the applicable underage limit, the accumulated underage shall be cancelled.

(2) **Subsequent underage.** After cancellation, underage shall not accrue until after:

(A) The drilling and spacing unit produces a current monthly allowable, if the unit wells share a unit allowable; or

(B) A well with a ratable allowable produces a current monthly ratable allowable.

(k) **Reinstatement of cancelled underage.**

(1) The operator may apply for reinstatement of cancelled underage by:

(A) An application for administrative approval on Form 1010, if filed within six months after cancellation of underage; or

(B) Application, notice, and hearing under OAC 165:5-7-1.

(2) Reinstated cancelled underage shall be available to increase the monthly allowable or ratable allowable for up to one year without cancellation. If reinstated underage is cancelled, the operator may reapply under (1) of this subsection.

(3) For the Guymon-Hugoton special allocated gas pool, the operator of any drilling and spacing unit in such pool which unit has accumulated cancelled underage credited thereto on the records of the Commission prior to July 1, 1998 shall have until January 1, 2000 to file an application with the Commission pursuant to OAC 165:5-7-1 for the reinstatement of such accumulated cancelled underage as credited to such unit prior to July 1, 1998. Upon the filing of such an application, the cause seeking reinstatement of such accumulated cancelled underage shall be diligently prosecuted. In such proceeding for the reinstatement of such accumulated cancelled underage credited to such drilling and spacing unit prior to July 1, 1998, the Commission shall determine the portion of such accumulated cancelled underage which is proper and valid under the special pool allocation rules (field rules) applicable to the Guymon-Hugoton special allocated gas pool and shall reinstate only such portion that is determined to be proper and valid under such special pool allocation rules (field rules). If an application for reinstatement of any such accumulated cancelled underage credited to a drilling and spacing unit on the records of the Commission prior to July 1, 1998 is not filed with the Commission on or before January 1, 2000, such accumulated cancelled underage shall be permanently deleted from the records of the Commission and shall not thereafter be able to be reinstated or used for any other purpose under the special pool allocation rules (field rules) applicable to the Guymon-Hugoton special allocated gas pool.

(l) **Effect of reinstatement of underage on pool allowables.** If cancelled underage has been distributed among the capable wells in the pool, reinstated underage shall not be deducted for the allowables of the capable wells which received distributed cancelled underage.

(m) **Test exempt status.**

(1) **No allowable without test.** For all pools except West Cheyenne Upper Morrow and Purvis Chert, no allowable shall be assigned unless:

(A) **Single well drilling and spacing unit.** The operator submits the required test or the unit has test exempt status under this Section.

(B) **Multiple well drilling and spacing unit.** In a multiple well drilling and spacing unit, the operator of at least one well in the unit submits the required test in accordance with applicable pool rules or the unit is granted test exempt status under this Section.

(2) **Automatic test exempt status.**

(A) **For the West Cheyenne Upper Morrow and Purvis Chert Pool.** For the West Cheyenne Upper Morrow and Purvis Chert, a drilling and spacing unit shall have test exempt status as follows:

(i) **Single well drilling and spacing unit.** In a single well drilling and spacing, the well operator does not submit either an initial or an annual test.

(ii) **Multiple well drilling and spacing unit.** In a multiple well drilling and spacing unit, none of the well operators in the unit submit either an initial or annual test. A test exempt drilling and spacing unit on the West Cheyenne Upper Morrow and Purvis Chert Pools shall have a minimum allowable under the applicable orders establishing and modifying pool rules as opposed to (b) of this Section.

(3) **Test exempt status upon requests for all other pools.** For all other pools except Guymon-Hugoton a drilling and spacing unit shall be test exempt upon written request to the Conservation Division if the potential for the unit does not exceed:

(A) The applicable minimum allowable under this Section.

(B) A double minimum allowable, if the Conservation Division has granted a double minimum to the unit.

(4) **Termination of requested test exempt status.**

(A) **Automatic termination.** Requested test exempt status shall terminate upon:

(i) **Submission of a retest.** Submission of a retest showing that the well has a potential in excess of a test exempt allowable, or;

(ii) **Overproduction.**

(I) **Single well drilling and spacing unit.** If gas production from a single well drilling and spacing unit exceeds a test exempt allowable during any month while the well has test exempt status, the unit shall lose test exempt status beginning with next month following the month with overproduction.

(II) **Multiple well drilling and spacing unit.** If total gas production from a multiple well drilling and spacing unit exceeds the minimum allowable during any month while the unit has test exempt status, the unit shall lose test exempt status beginning with the next month following the month with overproduction.

(B) **Reinstatement of test exempt status after automatic termination.** After termination of test exempt status for overproduction, the Conservation Division shall not reinstate test exempt status until:

(i) The operator requests test exempt status; and

(ii) The allowable year during which overproduction occurred expires.

[**SOURCE:** Amended in Rule Making 970000011, eff 7-1-98; Amended in Rule Making 980000033, eff 7-1-99; Amended in Rule Making 200100006, eff 7-1-01; Amended in Rule Making 200400006, eff 7-1-04]

165:10-17-10. Unallocated pools [RESERVED]

165:10-17-11. Maximum permitted rates of production for unallocated gas wells

(a) **Scope.**

(1) This Section shall apply to each gas well in unallocated status except as otherwise provided by Commission order. The Commission may establish different production rates by:

(A) Location exception order.

(B) Establishment of pool rules for the common source of supply.

(C) Other order adjusting gas production from the well.

(2) For purposes of this Section, the term "well" shall include any drilling and spacing unit with multiple unallocated gas wells, which do not receive separate maximum permitted rates of production by Commission order.

(3) For the purposes of this Section, the term "allowable formula" shall mean the formula used by the Commission for the determination of the daily rates for capable and minimum wells.

(4) For purposes of this Section, the term "capable well" shall refer to those unallocated gas wells having a wellhead absolute flow potential of 2000 mcf/d or greater. All other wells are minimum wells.

(5) For purposes of this Section, the term "daily natural flow" means the wellhead absolute open flow potential determined in the manner described in OAC 165:10-17-6 and OAC 165:10-17-7.

(b) **Commission authority and responsibility.** Production shall be governed by the provisions of 52 O.S. Section 29. Pursuant to said statute, the Commission has the power and authority to adjust allowables to meet reasonable market demand. The Commission, upon its own application, after notice and hearing, shall establish allowables which may be greater or lesser than those set forth in 52 O.S. Section 29.

(c) **Procedure.**

(1) Allowables for wells other than those provided in subsections (a), (e), (f), and (g) of this Section shall be determined pursuant to a proration hearing held at least semiannually for the proration periods of April through September and October through March. The Commission may hold additional proration hearings at shorter intervals if necessary. At least 15 days prior to scheduled semiannual hearings, the Commission shall publish

in a newspaper of general circulation in Oklahoma County, the proposed allowable formula for the next proration period. The semiannual proration hearings shall be held at least 30 days prior to the proration period for which the allowable is being determined. Such hearing shall be for the purpose of gathering comments and hearing testimony from all interested parties concerning the determination of reasonable market demand for the next proration period. As a guideline, but not to the exclusion of any other information that the Commission deems pertinent, the following may be considered by the Commission in determining reasonable market demand and corresponding allowables:

(A) Production from prior years.

(B) Production from the most recent proration period.

(C) Wellhead open flow potentials.

(D) New wells, recompletions, temporarily abandoned wells and plugged wells.

(E) Gas which is available but is not being produced at the present time.

(F) Changes in existing gas markets, forecasts, and new markets for Oklahoma gas.

(G) State-wide gas production and the portion thereof attributable to unallocated gas wells.

(H) Overproduction and underproduction from the preceding proration period.

(2) After a proration hearing, the Commission shall publish in a newspaper of general circulation in Oklahoma County, the allowable formula, no later than 15 days prior to the proration period for which the allowable formula is determined.

(d) **Emergency allowables.**

(1) When the Commission determines that an emergency gas supply situation exists, the Commission may establish an emergency allowable. The emergency allowable shall provide for the protection of correlative rights including those relating to minimum wells and penalized wells.

(2) The Commission may extend or change the emergency allowable for as long as an emergency exists. However, any authorized extension of the emergency allowable shall be by order after notice and hearing.

(e) **Exceptions.** Upon application, notice, and hearing, the Commission may establish a different allowable for good cause shown.

(f) **Exclusion for hardship and distressed wells.** The allowable established under this Section shall not limit rates established by special order for those wells classified as hardship or distressed wells.

(g) **Discovery gas well.**

(1) For thirty (30) months from the date of first production, a discovery gas well, as defined in this subsection, subject to the provisions of this Section, shall have a production allowable which shall be the greater of one thousand three hundred (1,300) mcf/d or sixty-five percent (65%) of the absolute open flow (AOF) as specified by the Corporation Commission. Such discovery well allowable shall not be available for any discovery gas well wherein two (2) or more separate common sources of supply are commingled and one (1) common source of supply would not qualify a new gas well as a discovery gas well, as defined in this Section.

(2) Drilling and spacing units which are downspaced after June 1, 1997, shall not qualify for the discovery gas well allowable.

(3) For purposes of this subsection, "discovery gas well" shall mean a new gas well, which is not an off-pattern well, is the first well completed in a common source of supply within a drilling and spacing unit and is at least one (1) mile from all existing gas wells which are completed in the same common source of supply. In the absence of spacing, a discovery well shall be the first well in the governmental section completed in a common source of supply, provided that the discovery gas well shall not be drilled closer than one thousand three hundred twenty (1,320) feet from the boundaries of the governmental section and is at least one (1) mile from all existing gas wells which are completed in the same common source of supply.

(h) **Minimum compliance.**

(1) The Conservation Division shall monitor well production at least annually. The allowable for a well shall be based on the product of the number of days in the proration period, multiplied by the applicable allowable formula, provided that said product shall be reduced for overproduction as provided by this Section or by any penalty or limitation on production imposed by applicable Commission order.
(2) Any overproduction existing at the end of the calendar year shall be applied against the allowable for the next calendar year. Furthermore, the overproduced well shall be required to make up overproduction within the first six months of the next calendar year. If the overproduction is not made up within that time period, the flow rate shall not exceed ten percent of the then current allowable until the overproduction is made up.

[**Source:** Amended at 9 Ok Reg 3969, eff 8-28-92 (emergency); Amended at 10 Ok Reg 1275, eff 9-25-92 (emergency); Amended at 10 Ok Reg 1579, eff 5-13-93; Amended in Rule Making 97000002, eff 7-1-97; Amended in Rule Making 980000011, eff 7-1-98; Amended in Rule Making 200200017, eff 7-1-02]

165:10-17-12. New proposed well classification for the priority schedule
(a) Any common purchaser as defined in 52 O.S. 1981, Section 240 shall purchase all the gas which may be offered for sale and which may reasonably be reached by its trunk lines or gathering lines, without discrimination in favor of one producer as against another or in favor of any one source of supply as against another, except as authorized by the Commission under (b) of this Section.
(b) In the interest of the prevention of waste and protection of correlative rights, the following priority schedule shall be implemented by any first purchaser of gas whenever the permitted production from all wells in any common source of supply in its system in this State, including gas which is processed, is in excess of that purchaser's reasonable market demand; provided, however, if the first purchaser does not contractually control wellhead production, the first taker of gas shall be responsible for implementation of the following priority schedule.
(1) Priority One - Hardship and distressed wells.
(2) Priority Two - Enhanced recovery wells.
(3) Priority Three - Wells producing casinghead gas and associated gas.
(c) With respect to all gas not identified in (b) of this Section, the collective market demand of multiple common purchasers on each pipeline system for natural gas production from each well and each common source of supply in this state shall be deemed adequate to meet statutory purchasing requirements unless the Commission, upon its own motion or upon verified application by any interested party and after notice and hearing, as hereinafter provided, shall determine that differing obligations shall be imposed upon any common purchaser in order to protect correlative rights, the interest of the public or otherwise meet the requirements of applicable law.
(d) When permitted production of gas from all Priority 1, 2, and 3 wells from which a purchaser or taker is required to take exceeds the market demand of said purchaser or taker, all reductions in gas purchases or takes from wells in each priority shall be ratable. All production from the lower priority wells shall be shut-in before production from any well in the next higher priority is curtailed.
(e) Any well which meets the definition of more than one priority shall be assigned the higher priority.
(f) When there is more than one purchaser or taker involved in the taking of gas from a well into any purchaser's system, all purchasers and takers within that system shall be responsible for compliance with this Section.
(g) Upon a verified application of the Director of the Conservation Division or any other person, the Commission, after notice and hearing, may determine if gas has been ratably purchased or taken from a common source of supply on a system-wide basis in accordance with this Section without avoidable waste and

with equitable participation in production and markets by all operators and other interested parties.
(h) First purchasers or takers of gas produced from Priority 1, 2, or 3 wells, who anticipate curtailing production from such wells, shall file by the twentieth day of each month nominations of requirements for gas to be purchased and/or used by them during the following month (Form 1004B). Nominations shall be made according to priorities established in (b) of this Section. Curtailments of production and acceptance of deliveries of gas shall be performed in accordance with (a) and (b) of this Section.
(i) Any interested party may file an application requesting that the Commission, for good cause shown, authorize limited deviation from the general priority schedule provided under (b) of this Section. The Commission, on its own motion, may initiate a review of the continued need for such a limited deviation. After notice and hearing, the Commission may authorize limited deviation upon finding that the same is necessary in order to prevent waste, protect correlative rights, and is otherwise required by the public interest or authorized by law.

[**Source:** Amended at 12 Ok Reg 2045, eff 7-1-95]

165:10-17-13. Use of gas for carbon black
Gas may not be used for the manufacture of carbon black or similar products predominately carbon, except as specifically authorized by the Commission after notice and hearing.

165:10-17-14. Waste of tail gas at gasoline plants
The duty, obligation, and jurisdiction of the Commission to prevent waste of tail gas where an additional market is available shall not be circumvented by any exclusive provisions in private contracts between the owners and the purchasers of tail gas.

165:10-17-15. Gas removed from storage
The rules relating to gas production from pools shall not apply to gas being removed from storage except and unless waste is involved.

165:10-17-16. Reports
A calendar year shall constitute the accounting period for each unallocated gas well. At the end of each calendar year, the Conservation Division will mail an original and one copy of Machine Accounting Form 1007A (Unallocated Gas Well Survey) to the operator, and the operator shall complete and file the original form with the Conservation Division on or before the following February 15th and retain the copy for his own use.

[**Source:** Amended in Rule Making 200200017, eff 7-1-02]

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SUBCHAPTER 19. NATURAL GAS POLICY ACT DETERMINATION [REVOKED]

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165:10-19-1. Definitions [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2401, eff 7-1-96]

165:10-19-2. Applications for NGPA determination [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2401, eff 7-1-96]

165:10-19-3. Application for additional well in existing proration unit [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2401, eff 7-1-96]

165:10-19-4. Notice of application; service of notice [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2401, eff 7-1-96]

165:10-19-5. Procedures for protest, administrative consideration, and hearing [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2401, eff 7-1-96]

165:10-19-6. Stripper well determination [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2401, eff 7-1-96]

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SUBCHAPTER 21. APPLICATIONS FOR TAX EXEMPTIONS

SUBCHAPTER 21. APPLICATIONS FOR TAX EXEMPTIONS

PART 1. TERTIARY RECOVERY PROJECT [REVOKED]

165:10-21-1. Tertiary recovery project certification [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2933, eff 7-11-96]

PART 2. ENHANCED RECOVERY PROJECT [REVOKED]

165:10-21-2. Gross production tax exemption for enhanced recovery project [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2933, eff 7-11-96]

PART 3. HORIZONTALLY DRILLED PRODUCTION WELLS [REVOKED]

165:10-21-3. Qualification and application for exemption from the levy of gross production tax on horizontally drilled production wells [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2933, eff 7-11-96]

PART 4. DELETERIOUS SUBSTANCES

165:10-21-4. Recycling, reuse, and ultimate destruction of deleterious substances [REVOKED**]**

[SOURCE: Revoked in rule making 200000009, eff 5-11-01]

PART 6. PRODUCTION ENHANCEMENT PROJECTS

165:10-21-21. General

Exemption from the levy of gross production tax on the incremental production which results from a production enhancement project with a project beginning date on or after July 1, 1994, and prior to July 1, 2006 shall be determined according to the provisions of this Part, which have been jointly adopted by the Oklahoma Corporation Commission and Oklahoma Tax Commission pursuant to 68 O.S. Section 1001(M)(1).

[SOURCE: Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Amended at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01, Amended in Rule Making 200400006, eff 7-1-04]

165:10-21-22. Definitions

The following words and terms, when used in this Part, shall have the following meaning, unless the context clearly indicates otherwise:

"Base production" means the average monthly amount of production for the twelve-month (12) period immediately prior to the commencement of the project or the average monthly amount of production for the twelve-month period immediately prior to the commencement of the project less the monthly rate of production decline for the project for each month beginning one hundred eighty (180) days prior to the commencement of the project. The monthly rate of production decline shall be equal to the average extrapolated monthly decline rate for the twelve-month period immediately prior to the commencement of the project based on the production history of the well. If the well or wells covered by the application had production for less than the full twelve-month period prior to the filing of the application for the production enhancement project, the base production shall be the average monthly production for the months during that period that the well or wells produced.

"Effective date" means the project beginning date for the production enhancement project.

"Exemption period" means a period of twenty-eight (28) months from the date of first sale after completion of the production enhancement project.

"Incremental production" means the amount of crude oil, natural gas or other hydrocarbons which are produced as a result of the production enhancement project in excess of the base production.

"Production enhancement project" means: for production enhancement projects having a project beginning date prior to July 1, 1997, any workover as defined in this Section, recompletion as defined in this Section, or fracturing of a producing well; for production enhancement projects having a project beginning date on or after July 1, 1997, and prior to July 1, 2006, "production enhancement project" means any workover as defined in this Section, recompletion as defined in this Section, reentry of plugged and abandoned wellbores, or addition of well or field compression.

"Recompletion" means: for production enhancement projects having a project beginning date prior to July 1, 1997, any downhole operation in an existing oil or gas well that is conducted to establish production of oil or gas from any geological interval not currently completed or producing in such existing oil or gas well; for production enhancement projects having a project beginning date on or after July 1, 1997, and prior to July 1, 2006, "recompletion" means any downhole operation in an existing oil or gas well that is conducted to establish production of oil or gas from any geologic interval not currently completed or producing in such existing oil or gas well within the same or a different geologic formation.

"Workover" means any downhole operation in an existing oil or gas well that is designed to sustain, restore or increase the production rate or ultimate recovery in a geologic interval currently completed or producing in said existing oil or gas well. For production enhancement projects having a project beginning date prior to July 1, 1997, "workover" includes, but is not limited to, acidizing, reperforating, fracture treating, sand/paraffin removal, casing repair, squeeze cementing, or setting bridge plugs to isolate water productive zones from oil or gas productive zones, or any combination thereof. For production enhancement projects having a project beginning date on or after July 1, 1997, and prior to July 1, 2006, "workover" includes, but is not limited to, the following: acidizing; reperforating; fracture treating; sand/paraffin/scale removal or other wellbore cleanouts; casing repair; squeeze cementing; installation of compression on a well or group of wells or artificial lifts on oil and/or gas wells, including plunger lifts, rod pumps, submersible pumps and coiled tubing velocity strings; downsizing existing tubing to reduce well loading; downhole commingling; bacteria treatments; upgrading the size of pumping unit equipment; setting bridge plugs to isolate water production zones; or any combination thereof. "Workover" shall not mean the routine maintenance, routine repair, or like-for-like replacement of downhole equipment such as rods, pumps, tubing, packers, or other mechanical devices.

[**SOURCE**: Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Amended at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 97000025, eff 7-1-98; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200400006, eff 7-1-04]

165:10-21-23. Qualification procedure

The well operator or one of the working interest owners in the well, on behalf of the well operator and the other owners of the well, shall apply for qualification of the production enhancement project and incremental production, at the Oklahoma Corporation Commission on OCC Form 1534.

(1) OCC Form 1534 shall be completed in its entirety, and together with supporting documentation, shall be submitted to the Technical Services Department of the Conservation Division of the Oklahoma Corporation Commission for review.
(2) If the Department approves the application, an order of the Oklahoma Corporation Commission shall be issued, and a copy of the order shall be forwarded to the operator.
(3) If the application is denied or refused, or approval is delayed beyond sixty (60) days, the applicant may seek review by application, notice and hearing.

[SOURCE: Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Amended at 13 Ok Reg 2933, eff 7-11-96]

165:10-21-24. Rebates - Refund procedure
(a) **Request to Oklahoma Tax Commission for a tax refund.** If the Oklahoma Corporation Commission grants the application, the operator or one of the working interest owners in the well, on behalf of the well operator and the other owners of the well, shall make its request for refund by letter to the Audit Division, Oklahoma Tax Commission. Such letter request shall state the reason for refund and the amount claimed and must be accompanied by the following:
(1) A Corporation Commission order certifying the well as production enhanced.
(2) A Copy of OCC Form 1534 submitted to the Corporation Commission.
(3) A properly completed OTC Form 328 Gross Production 841/495 Refund Report.
(4) If the refund request is filed by any person other than the party named in the Oklahoma Corporation Commission order, a notarized affidavit, signed by the party named in the order must be filed, authorizing the applicant to apply for the refund.
(b) **No time limitation on rebate for prior periods; claim limitation after July 1, 2003.** Approval of a "Production Incentive" for production periods prior to July 1, 2003 shall not be time-barred by either the date of certification or the date of filing a claim for refund of the rebate of gross production tax. Effective July 1, 2003, claims for rebate filed with the Oklahoma Tax Commission shall be subject to a time limitation pursuant to Title 68 O.S., Section 1001(L).
(c) **Method of appeal.** If the refund is denied, the applicant may file an appeal under the provisions of Title 68, Sections 227 and 228 of the Oklahoma Statutes.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04]

PART 7. RE-ESTABLISHMENT OF PRODUCTION FROM AN INACTIVE WELL

165:10-21-35. General
Exemption from the levy of gross production tax on the re-establishment of production from an inactive well shall be determined according to the provisions of this Part, which have been jointly adopted by the Oklahoma Corporation Commission and Oklahoma Tax Commission pursuant to 68 O.S. Section 1001(M)(1).

[SOURCE: Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Amended at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01]

165:10-21-36. Definitions

The following words and terms, when used in this Part, shall have the following meaning, unless the context clearly indicates otherwise:

"Effective date" means the date on which the reestablishment of production has occurred.

"Exemption period" means a period of twenty-eight (28) months from the date upon which production from an inactive well is reestablished.

"Inactive well" means a well which may be defined under one (1) of the following three (3) categories:

(A) A well which after July 1, 1997 experiences mechanical failure or loss of mechanical integrity, as defined by the Corporation Commission, including but not limited to, casing leaks, collapse of casing or loss of equipment in a wellbore, or any similar event which causes cessation of production, shall be considered an inactive well. For use within this sub-paragraph "mechanical failure" means a well which experiences mechanical failure or loss of mechanical integrity because of, but not limited to, casing leaks, collapse of casing or loss of equipment in a wellbore, or any similar event which results in a workover of the well and cessation of production as evidenced by the use of a workover rig or other mechanical device being placed over the well to repair the well or equipment.

(B) A well on which work to reestablish production commenced on or after July 1, 1997, and on or before June 30, 2006, that has not produced oil, gas or oil and gas for a period of not less than one (1) year as evidenced by the appropriate forms on file with the Oklahoma Corporation Commission reflecting the well.

(C) A well on which work to reestablish production commenced on or after July 1, 1994, and on or before June 30, 1997, that has not produced oil, gas or oil and gas for a period of not less than two (2) years as evidenced by the appropriate forms on file with the Oklahoma Corporation Commission reflecting the well's status.

[**SOURCE:** Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Amended in Rule Making 97000025, eff 7-1-98; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200400006, eff 7-1-04]

165:10-21-37. Qualification procedure

The well operator or one of the working interest owners, on behalf of the well operator and the other owners of the well, shall apply for qualification of the well and production at the Oklahoma Corporation Commission on OCC Form 1534.

(1) OCC Form 1534 shall be completed in its entirety, and together with supporting documentation, shall be submitted to the Technical Services Department of the Conservation Division of the Oklahoma Corporation Commission for review.

(2) If the Department approves the application, an order of the Oklahoma Corporation Commission shall be issued, and a copy shall be forwarded to the operator.

(3) If the application is denied or refused, or approval is delayed beyond sixty (60) days, the applicant may seek review by application, notice and hearing.

[SOURCE: Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Amended at 13 Ok Reg 2933, eff 7-11-96]

165:10-21-38. Rebates - Refund procedure

(a) **Request to Oklahoma Tax Commission for a tax refund.** If the Oklahoma Corporation Commission grants the application, the operator or one of the working interest owners in the well, on behalf of the well operator and the other owners of the well, shall make its request for refund by letter to the

Audit Division, Oklahoma Tax Commission. Such letter request shall state the reason for refund and the amount claimed and must be accompanied by the following:

(1) A Corporation Commission order certifying the well as an inactive well for which production has been reestablished.

(2) A copy of OCC Form 1534 submitted to the Corporation Commission.

(3) A copy of an approved OTC Form 320C that shows the date of the re-establishment of production of oil and/or gas.

(4) A properly completed OTC Form 328 Gross Production 841/495 Refund Report.

(5) If the refund request is filed by any person other than the party named in the Oklahoma Corporation Commission order, a notarized affidavit, signed by the party named in the order must be filed, authorizing the applicant to apply for the refund.

(b) **No time limitation on rebate for prior periods; claim limitation after July 1, 2003.** Approval of a "Reestablished Incentive" for production periods prior to July 1, 2003 shall not be time-barred by either the date of certification or the date of filing a claim for refund of gross production tax. Effective July 1, 2003, claims for rebate filed with the Oklahoma Tax Commission shall be subject to a time limitation pursuant to Title 68 O.S., Section 1001(L).

(c) **Method of appeal.** If the refund is denied, the applicant may file an appeal under the provisions of Title 68, Sections 227 and 228 of the Oklahoma Statutes.

[**SOURCE:** Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04]

PART 8. DEEP WELLS

165:10-21-45. General

(a) **General provisions.** Exemption from the levy of gross production tax on the production of gas, oil, or gas and oil from wells certified as being "Deep Wells" set out in 68 O.S. §.1001(H).shall be determined according to the provisions of this Part, which have been jointly adopted by the Oklahoma Corporation Commission and the Oklahoma Tax Commission pursuant to 68 O.S. § 1001(M)(1).

(b) **Definitions.** For purposes of qualifying for the exemption, **"depth"** means the length of the maximum continuous string of drill pipe utilized between the drill bit face and the drilling rig's kelly bushing.

(c) **Exemption for wells spudded between July 1, 1994, and June 30, 2000, to a depth of fifteen thousand (15,000) feet or greater.** Deep wells spudded between July 1, 1994, and June 30, 2000, and drilled to a depth of fifteen thousand (15,000) feet or greater shall be exempt from the gross production tax, beginning from the date of first sale, for a period of twenty-eight (28) months.

(d) **Exemption for wells spudded between July 1, 1997, and June 30, 2006, to a depth of twelve thousand five hundred (12,500) feet.** Deep wells spudded between July 1, 1997, and June 30, 2006, and drilled to a depth of twelve thousand five hundred (12,500) feet or greater shall be exempt from the gross production tax, beginning from the date of first sale, for a period of twenty-eight (28) months.

(e) **Exemption for wells spudded between July 1, 2002, and June 30, 2006.** Deep wells spudded between July 1, 2002, and June 30, 2006, shall be eligible for an exemption from the gross production tax which shall begin from the date of first sale, and vary as to duration in relation to the depth of the well.

(1) **12,500 to 14,999 feet.** The duration of the exemption for wells drilled to this depth is twenty-eight (28) months.

(2) **15,000 to 17,499 feet.** The duration of the exemption for wells drilled to this depth is forty-eight (48) months.

(3) **17,500 feet or greater.** The duration of the exemption for wells drilled to this depth is sixty (60) months.

[SOURCE: Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Amended at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 970000025, eff 7-1-98; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04]

165:10-21-46. Definitions [REVOKED]

[SOURCE: Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Amended at 13 Ok Reg 2933, eff 7-11-96; Revoked in Rule Making 97000025, eff 7-1-98]

165:10-21-47. Qualification procedure

The well operator or one of the working interest owners, on behalf of the well operator and the other owners of the well, shall apply for qualification of the well at the Oklahoma Corporation Commission on OCC Form 1534.

(1) OCC Form 1534 shall be completed in its entirety, and together with supporting documentation, shall be submitted to the Technical Services Department of the Conservation Division of the Oklahoma Corporation Commission for review.

(2) If the Department approves the application, an order of the Oklahoma Corporation Commission shall be issued, and a copy shall be forwarded to the operator.

(3) If the application is denied or refused, or approval is delayed beyond sixty (60) days, the applicant may seek review by application, notice and hearing.

[SOURCE: Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Amended at 13 Ok Reg 2933, eff 7-11-96]

165:10-21-47.1. Rebates-Refund procedure

(a) **Request to Oklahoma Tax Commission for a tax refund.** If the Oklahoma Corporation Commission grants the application, the operator or one of the working interest owners in the well, on behalf of the well operator and the other owners of the well, shall make its request for refund by letter to the Audit Division, Oklahoma Tax Commission. Such letter request shall state the reason for refund and the amount claimed and must be accompanied by the following:

(1) A Corporation Commission order certifying the well as a well spudded within the applicable time periods and drilled to the prescribed depths provided in OAC 165:10-21-45.

(2) A copy of OCC Form 1534 submitted to the Corporation Commission.

(3) A copy of an approved OTC Form 320A that shows date of first sale of production.

(4) A properly completed OTC Form 328 Gross Production 841/495 Refund Report.

(5) If the refund request is filed by any person other than the party named in the Oklahoma Corporation Commission order, a notarized affidavit, signed by the party named in the order must be filed, authorizing the applicant to apply for the refund.

(b) **No time limitation on rebate for prior periods; claim limitation after July 1, 2003.** Approval of a "Deep Well Incentive" for production periods prior to July 1, 2003 shall not be time-barred by either the date of certification or the date of filing a claim for refund of the rebate of gross production tax. Effective July 1, 2003, claims for rebate filed with the Oklahoma Tax Commission shall be subject to a time limitation pursuant to Title 68 O.S., Section 1001(L).

(c) **Method of appeal.** If the refund is denied, the applicant may file an appeal under the provisions of Title 68, Sections 227 and 228 of the Oklahoma Statutes.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04]

165:10-21-48. Audit requirements [REVOKED]

[SOURCE: Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Revoked in Rule Making 200300001, eff 7-1-03]

165:10-21-49. Certificate of investment to be filed by the operator [REVOKED**]**

[SOURCE: Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Revoked at 13 Ok Reg 2933, eff 7-11-96]

PART 9. NEW DISCOVERY WELLS

165:10-21-55. General
(a) Exemption from the levy of gross production tax on the production of gas, oil, or gas and oil from wells spudded or reentered between July 1, 1995 and July 1, 2006, which qualify as a new discovery well pursuant to Title 68, Section 1001(I), shall be determined according to the provisions of this Part, which have been jointly adopted by the Oklahoma Corporation Commission and the Oklahoma Tax Commission pursuant to Title 68, Section 1001(M)(1).
(b) **"New discovery"** means production of oil, gas or oil and gas from:
(1) A well spudded or reentered prior to July 1, 1997, which discovers crude oil in paying quantities and is located more than one mile from the nearest oil well producing from the same interval.
(2) A well, spudded or reentered on or after July 1, 1997, and prior to July 1, 2006, which discovers crude oil in paying quantities and is located more than one mile from the nearest oil well producing from the same interval of the same formation.
(3) A well, spudded or reentered prior to July 1, 1997, which discovers crude oil in paying quantities beneath current production in a deeper producing formation located more than one mile from the nearest oil well producing from the same deeper interval.
(4) A well, spudded or reentered on or after July 1, 1997, and prior to July 1, 2006, which discovers crude oil in paying quantities beneath current production in a deeper producing interval located more than one mile from the nearest oil well producing from the same deeper interval.
(5) A well, spudded or reentered, prior to July 1, 1997, which discovers natural gas in paying quantities and is located more than two miles from the nearest gas well producing from the same producing interval.
(6) A well, spudded or reentered, on or after July 1, 1997, and prior to July 1, 2006, which discovers natural gas in paying quantities and is located more than two miles from the nearest gas well producing from the same producing interval.
(7) A well, spudded or reentered, prior to July 1, 1997, which discovers natural gas in paying quantities beneath current production in a deeper producing interval that is more than two miles from the nearest gas well producing from the same deeper interval.
(8) A well, spudded or reentered, on or after July 1, 1997, and prior to July 1, 2006, which discovers natural gas in paying quantities beneath current production in a deeper producing interval that is more than two

miles from the nearest gas well producing from the same deeper producing interval.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 97000025, eff 7-1-98; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200400006, eff 7-1-04]

165:10-21-56. Definitions

The following words and terms, when used in this Part, shall have the following meaning, unless the context clearly indicates otherwise:

"Effective date" means the date the well was spudded or the beginning date for a re-entered well.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 97000025, eff 7-1-98]

165:10-21-57. Qualification procedure

The well operator or one of the working interest owners, on behalf of the well operator and the other owners of the well, shall apply for qualification of the well at the Oklahoma Corporation Commission on OCC Form 1534.

(1) OCC Form 1534 shall be completed in its entirety, and together with supporting documentation, shall be submitted to the Technical Services Department of the Oklahoma Corporation Commission for review.

(2) If the Department approves the application, an order of the Oklahoma Corporation Commission shall be issued, and a copy shall be forwarded to the operator.

(3) If the application is denied or refused, or approval is delayed beyond sixty (60) days, the applicant may seek review by application, notice and hearing.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96]

165:10-21-58. Rebates - Refund procedure

(a) **Request to Oklahoma Tax Commission for a tax refund.** If the Oklahoma Corporation Commission grants the application, the operator or one of the working interest owners in the well, on behalf of the well operator and the other owners of the well, shall make its request for refund by letter to the Audit Division, Oklahoma Tax Commission. Such letter request shall state the reason for refund and the amount claimed and must be accompanied by the following:

(1) A Corporation Commission order certifying the well as a new discovery well spudded or re-entered between July 1, 1995 and June 30, 2006.

(2) A copy of OCC Form 1534 submitted to the Corporation Commission.

(3) A copy of an approved OTC Form 320A that shows date of first sale of production.

(4) A properly completed OTC Form 328 Gross Production 841/495 Refund Report.

(5) If the refund request is filed by any person other than the party named in the Oklahoma Corporation Commission order, a notarized affidavit, signed by the party named in the order must be filed, authorizing the applicant to apply for the refund.

(b) **No time limitation on rebate for prior periods; claim limitation after July 1, 2003.** Approval of a "New Discovery Incentive" for production periods prior to July 1, 2003 shall not be time-barred by either the date of certification or the date of filing a claim for refund of the rebate of gross production tax. Effective July 1, 2003, claims for rebate filed with the Oklahoma Tax Commission shall be subject to a time limitation pursuant to Title 68 O.S., Section 1001(L).

(c) **Method of appeal.** If the refund is denied, the applicant may file an appeal under the provisions of Title 68, Sections 227 and 228 of the Oklahoma Statutes.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04]

165:10-21-59. Audit requirements [REVOKED]

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Revoked in Rule Making 200300001, eff 7-1-03]

PART 11. HORIZONTALLY DRILLED PRODUCING WELLS

165:10-21-65. General

Exemption from the levy of Gross Production Tax on horizontally drilled producing wells set out in 68 O.S. § 1001(E) shall be determined according to the provisions of this Part, which have been jointly adopted by the Oklahoma Corporation Commission and the Oklahoma Tax Commission pursuant to law. [See: 68 O.S. §1001(M)(1)]

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03]

165:10-21-66. Definitions

In addition to terms defined in 165:10-1-2, the following words and terms, when used in this Part, shall have the following meaning, unless the context clearly indicates otherwise:

"Angle of deviation" means that angle in which a wellbore may deviate from the vertical.

"Date of completion of a gas well" means the date that gas is capable of being delivered to a pipeline purchaser.

"Date of completion of an oil well" means the date that the well first produces into the lease tanks through permanent well head equipment.

"Effective date" means that the first production must have commenced after July 1, 1995 and before July 1, 2006.

"Horizontal displacement" means that distance drilled into the pay zone of a formation at an angle exceeding seventy (70) degrees.

"Horizontally drilled payout" means the point at which gross working interest revenue from the horizontally drilled well equals the cost of drilling and completing such well.

"Horizontally drilled well" means an oil, gas, or oil and gas well drilled or completed in a manner which encounters and subsequently produces from a geological formation at an angle in excess of seventy (70) degrees from the vertical and which laterally penetrates a minimum of one hundred and fifty (150) feet into the pay zone of the formation.

"True vertical depth" means that depth measured from the surface perpendicular to the surface.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 97000025, eff 7-1-98; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200400006, eff 7-1-04]

165:10-21-67. Qualification procedure

The well operator or one of the working interest owners in the well, on behalf of the well operator and the other owners of the well, shall apply for qualification of the production from horizontally drilled wells, at the Oklahoma Corporation Commission on OCC Form 1534.

(1) OCC Form 1534 shall be completed in its entirety, and together with supporting documentation, shall be submitted to the Technical Services Department of the Conservation Division of the Oklahoma Corporation Commission for review.

(2) If the Department approves the application, an order of the Oklahoma Corporation Commission shall be issued, and a copy of the order shall be forwarded to the operator.

(3) If the application is denied or refused, or approval is delayed beyond sixty (60) days, the applicant may seek review by application, notice and hearing.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96]

165:10-21-68. Rebates - Refund procedure

(a) **Request to Oklahoma Tax Commission for a tax refund.** If the Commission grants the application, the well operator or one of the working interest owners in the well, on behalf of the well operator and the other owners of the well, shall make its request for refund by letter to the Audit Division, Oklahoma Tax Commission. Such letter request shall state the reason for refund and the amount claimed and must be accompanied by the following:

(1) A Corporation Commission order certifying the well as a horizontally drilled well.

(2) A copy of OCC Form 1534 submitted to the Corporation Commission.

(3) A copy of an approved OTC Form 320A that shows the date of initial production.

(4) A properly completed OTC Form 328 Gross Production 841/495 Refund Report.

(5) If the refund request is filed by any person other than the party named in the Oklahoma Corporation Commission order, a notarized affidavit, signed by the party named in the order must be filed, authorizing the applicant to apply for the refund.

(b) **No time limitation on rebate for prior periods; claim limitation after July 1, 2003.** Approval of a "Horizontal Drilling Incentive" for production periods prior to July 1, 2003 shall not be time-barred by either the date of certification or the date of filing a claim for refund of the rebate of gross production tax. Effective July 1, 2003, claims for rebate filed with the Oklahoma Tax Commission shall be subject to a time limitation pursuant to Title 68 O.S., Section 1001(L).

(c) **Method of appeal.** If the refund is denied, the applicant may file an appeal under the provisions of Title 68, Sections 227 and 228 of the Oklahoma Statutes.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04]

165:10-21-69. Time periods for exemption from gross production tax levied on horizontally drilled producing wells

(a) **General provisions.** The exemption for horizontally drilled wells qualified pursuant to this Part shall be determined from the project beginning date until project payback is achieved, and are limited in duration to the time periods set out in this Section.

(b) **Twenty-four (24) month exemptions.** For production described in this subsection, duration of the exemption may not exceed a period of twenty-four

(24) months commencing with the date of initial production from the horizontally drilled well.

(1) **Production prior to July 1, 1994.** Any incremental production which results from a horizontally drilled well producing prior to July 1, 1994.

(2) **Production prior to July 1, 2002, which commenced after July 1, 1995.** Any horizontally drilled well producing prior to July 1, 2002, which production commenced after July 1, 1995.

(c) **Forty-eight (48) month exemption.** For a horizontally drilled well producing prior to July 1, 2006, which production commenced after July 1, 2002, the duration of the exemption may not exceed a period of forty-eight (48) months commencing with the date of initial production from the horizontally drilled well. [See: 68 O.S. Supp. 2002, Section 1001(E)(1)]

[SOURCE: Added in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04]

PART 13. INCREMENTAL PRODUCTION FROM ENHANCED RECOVERY PROJECTS

165:10-21-75. General

Exemption from the levy of gross production tax on the incremental production of oil or other liquid hydrocarbons attributable to the working interest owners of an enhanced recovery project and property shall be determined according to the provisions of this Part.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01]

165:10-21-76. Definitions

The following words and terms, when used in this Part, shall have the following meaning, unless the context clearly indicates otherwise:

"Base production amount" means the average monthly amount of productions for the twelve (12) month period immediately prior to the project beginning date minus the monthly rate of production decline for the project or property for each month beginning one hundred eighty (180) days prior to the project beginning date.

"Completion date" means the date a well is first capable of being used for the injection of liquids, gases or other matter, or is capable of producing crude oil or other liquid hydrocarbons through permanent wellhead equipment.

"Enhanced recovery project costs" means the incremental project costs that are allowed as payback factors in determining the exemptions from the levy of gross production tax of project incremental production.

"Existing tertiary recovery project" means, for purposes of the exemption described in 68 O.S. Section 1001(D)(1), a tertiary recovery project whose beginning date is prior to October 16, 1987.

"Incremental production" means the amount of crude oil or other liquid hydrocarbons which are produced during an approved enhanced oil recovery operation and which are in excess of the base production amount of crude oil or other liquid hydrocarbons.

"Incremental working interest revenue" means the gross value of the incremental production, less the royalty interest therein.

"Monthly rate of production decline" means a rate equal to the average extrapolated monthly decline rate for the twelve (12) month period immediately prior to the project beginning date as determined by the Commission, based on the production history of the field, its current status, and sound reservoir engineering principles.

"New enhanced recovery project" means, for purposes of the exemption described in 68 O.S. Section 1001(D)(1), a secondary or tertiary recovery project whose beginning date is on or after October 16, 1987.

"Project beginning date" means the date on which the injection of liquids, gas or other matter begins on an enhanced recovery project.

"Project payback or payout" means that point at which the incremental working interest revenue from the enhanced recovery project equals the enhanced project costs.

"Secondary recovery properties" means secondary recovery properties approved or having an initial project beginning date on or after July 1, 2000 and before July 1, 2006, such that any incremental production attributable to the working interest which results from such secondary recovery property shall be exempt from the gross production tax levied pursuant to 68 O.S. Section 1001 for a period not to exceed five (5) years from the initial project beginning date or for a period ending upon the termination of the secondary recovery process, whichever occurs first. [Applicant may omit payback report for such secondary recovery properties.]

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04]

165:10-21-77. Qualification procedure

The provisions of this Section establish criteria for determining if an operator of an enhanced recovery project or property has met the required conditions to qualify the incremental production from such project or property for the exemption from the Gross Production Tax. [**See:** 68 O.S. §1001]

(1) **Application to Oklahoma Corporation Commission; determination; order.** An operator seeking an exemption of incremental production from the gross production tax shall make application to the Oklahoma Corporation Commission, as provided in OAC 165:5-7-14, for a determination that such project or property qualifies, a determination of the starting date, and of the base production amount.

(A) If the application is administratively approved, an order of the Oklahoma Corporation Commission shall be issued.

(B) To obtain the tax exemption, the operator shall forward a copy of the Oklahoma Corporation Commission order to the Oklahoma Tax Commission, together with any other data required by that agency.

(2) **Tax Commission approval of exemption.** An operator desiring an exemption from the gross production tax shall make application by letter to the Audit Division, Oklahoma Tax Commission. Such application shall be accompanied by:

(A) Corporation Commission Order approving such application and containing a determination of the project beginning date, base production amount and project payback.

(B) The ratio of working interest/royalty interest in the well. Only the incremental production attributable to the working interest owners shall be exempted from the gross production tax. For purposes of this exemption, overriding royalty shall be included in working interest.

(C) A schedule of production, by month, of the gross amounts of crude oil or other liquid hydrocarbons produced, and the gross values thereof, from the project beginning date until the date application is made to the Tax Commission.

(D) OTC Form 320A, 320C, and 320U, as are necessary, to set up the OTC Production Units, to request merge numbers, and to show the entity who will remit taxes.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01]

165:10-21-78. Recovery of costs allowed as payback factors

(a) **Enhanced recovery project, project beginning date between October 17, 1987 and June 30, 1990.** For any enhanced recovery project with a project beginning date between October 17, 1987, and June 30 1990, allowed enhanced recovery costs shall include only incremental capital costs and incremental operating expenses associated with enhanced recovery operations.

(b) **Enhanced recovery project, project beginning date between July 1, 1990 and June 30, 1993.** For any enhanced recovery project with a project beginning date between July 1, 1990, and June 30, 1993, allowable enhanced recovery project costs shall be limited to the incremental capital costs of project start up, including the cost of completing any well necessary to the project and of converting any existing well to handle secondary or tertiary injection of liquids, gas or other matter. With respect to completing or converting a well, no expenditure after completion or conversion for enhanced recovery purposes shall be included.
(c) **Secondary recovery project, project beginning date on or after July 1, 1993 and before July 1, 2000.** For any secondary recovery project with a project beginning date on or after July 1, 1993, and before July 1, 2000, allowed enhanced recovery project costs shall include only incremental capital costs and fifty percent (50%) of incremental operating expenses, provided however that the period for project payback shall not exceed a period of ten (10) years from the project beginning date.
(d) **Tertiary enhanced recovery project, project beginning date on or after July 1, 1993 and before July 1, 2006.** For any tertiary enhanced recovery project with a project beginning date on or after July 1, 1993, and before July 1, 2006, allowable enhanced recovery project costs shall include only incremental capital costs and incremental operating expenses, excluding administrative expenses. The capital expenses of pipelines constructed to transport carbon dioxide to a tertiary recovery project shall not be included in determining project payback. The period for project payback shall not exceed ten (10) years from the project beginning date.
(e) **Excluded costs.** The cost of tank batteries, meters, pipelines or other external equipment shall not be included in allowable enhanced recovery project costs. Allowable costs shall be determined using generally accepted accounting principles such as outlined in the "Council of Petroleum Accountants Society (COPAS) - Accounting Procedure Form for Joint Operations" and "COPAS Bulletin No. 16", or subsequent revisions thereto.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 97000025, eff 7-1-98; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04]

165:10-21-79. Responsibility for filing and payment of taxes
(a) **Responsibility for reporting; reporting; forms required.** The operator of a qualifying project will have primary responsibility for filing OTC Form 300-R-7-81, Gross Production Tax Monthly Tax Report, and for remitting gross production and petroleum excise taxes on project production controlled by the operator. Working interest owners who take-in-kind will be responsible for filing Gross production Monthly Tax Reports, unless the take-in-kind owner has made an agreement with his purchaser or the operator to report and remit on his behalf. A take-in-kind interest owner must submit, through the project operator, a Form 320, showing the disposition of his share of production. Purchasers may report taxes on project production with the approval of the Tax Commission, provided whenever there are multiple purchasers from a project, each reporting purchaser must report his allocated share of production, incremental production, and any exempt interest. All persons remitting taxes must comply with Tax Commission security requirements.
(b) **Valuation of incremental production.** When an operator or a single purchaser files the gross production tax reports and remits taxes, the incremental production will be valued at the volume-weighted average price per barrel of all crude oil or other liquid hydrocarbons produced from the project during the month. When multiple purchasers file the gross production tax reports and remit taxes, the incremental production will be valued at the volume-weighted average price per barrel purchased for the month, by each purchaser individually.
(c) **Method of computing production, base production amount and incremental production.**

(1) Frac oil recovered must be excluded as a Code 07 exemption. Frac oil will not be counted as part of the project base production amount, nor as incremental production.
(2) Incremental production will be deducted next as a Code 11 exemption.
(3) Exempt interests will be deducted next, in order of exemption code, as a decimal equivalent of the amount and value of production remaining after subtraction of the frac oil and incremental production.

(d) Well operators are advised to contact the Oklahoma Tax Commission concerning required annual reporting.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96]

165:10-21-80. Expiration of exemption for incremental production

For secondary recovery projects approved prior to July 1, 2000, and tertiary recovery projects approved prior to July 1, 2006, once the gross working revenue equals the enhanced recovery project cost, the exemption of incremental production shall end and the Oklahoma Tax Commission shall resume collection of the Gross Production Tax thereon.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200400006, eff 7-1-04]

PART 14. PRODUCTION OF OIL, GAS OR OIL AND GAS FROM ANY WELL LOCATED WITHIN BOUNDARIES OF A THREE-DIMENSIONAL SEISMIC SHOOT

165:10-21-82. General

Exemption from the levy of gross production tax on the production of oil, gas or oil and gas from a well, drilling of which is commenced on or after July 1, 2000, and prior to July 1, 2006, located within the boundaries of a three-dimensional seismic shoot and drilled based on three-dimensional seismic technology, shall be determined according to the provisions of this Part.

[SOURCE: Added in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200400006, eff 7-1-04]

165:10-21-82.1. Definitions

The following words and terms, when used in this Part, shall have the following meaning, unless the context clearly indicates otherwise:

"Three-dimensional seismic shoot" means any three-dimensional geophysical or seismic exploration activity conducted in the field for the purpose of drilling for and producing oil, gas or oil and gas from geological formations, intervals and/or common sources of supply.

"Three-dimensional seismic technology" means any three-dimensional geophysical or seismic equipment or instruments, data processing equipment, and/or data utilized to evaluate geological formations, intervals and/or common sources of supply in connection with a three-dimensional seismic shoot.

[SOURCE: Added in Rule Making 200000009, eff 5-11-01]

165:10-21-82.2. Qualification procedure

(a) **Applicable wells.** The provisions of this Section establish criteria for determining if an operator producing oil, gas or oil and gas from a well, drilling of which is commenced on or after July 1, 2000, and prior to July 1, 2006, located within the boundaries of a three-dimensional seismic shoot and drilled based on three-dimensional seismic technology, has met the required conditions to qualify the production from such a well for the exemption from the Gross Production Tax. [See: 68 O.S. §1001(J)]

(b) **Application to Oklahoma Corporation Commission; determination; order.** An operator seeking an exemption of the gross production tax on production from a well located within the boundaries of a three-dimensional seismic shoot and drilled based on such technology, shall make application to the Oklahoma Corporation Commission on a Form 1534 for a determination that the well qualifies for such exemption, as provided in 68 O.S. 2000 Supp. §1001(J).

(1) If the application is administratively approved, an order of the Oklahoma Corporation Commission shall be issued.

(2) To obtain the tax exemption, the operator shall forward a copy of the Oklahoma Corporation Commission order to the Oklahoma Tax Commission, together with any other data required by that agency pursuant to OAC 165:10-21-82.3.

(3) Any data, maps and other information submitted with the Form 1534 for determination that a well qualifies for the exemption provided in this paragraph shall be held as confidential information by the Conservation Division and/or Commission, and upon approval through issuance of a Commission order, shall be returned to the applicant or destroyed.

[SOURCE: Added in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04]

165:10-21-82.3. Rebates - Refund procedure

(a) **Request to Oklahoma Tax Commission for a tax refund.** If the Commission grants the application, the well operator or one of the working interest owners in the well, on behalf of the well operator and the other owners of the well, shall make its request for refund by letter to the Audit Division, Oklahoma Tax Commission. Such letter request shall state the reason for refund and the amount claimed and must be accompanied by the following:

(1) Corporation Commission order approving such application and containing a determination that the well meets the criteria of the statute insofar that its drilling was commenced on or after July 1, 2000, and prior to July 1, 2006, that it is located within the boundaries of a three-dimensional seismic shoot and was drilled based on such technology, and indicating whether the seismic shoot was shot either prior to or on or after July 1, 2000.

(2) A schedule of production, by month, of the gross amounts of oil, gas or oil and gas produced, and the gross values thereof, from the date of first sale until the date application is made to the Tax Commission.

(3) OTC Form 320A, 320C, and 320U, as are necessary, to set up the OTC Production Units, to request merge numbers, and to show the entity who will remit taxes.

(4) If the refund request is filed by any person other than the party named in the Oklahoma Corporation Commission order, a notarized affidavit, signed by the party named in the order must be filed, authorizing the applicant to apply for the refund.

(b) **No time limitation on rebate for prior periods; claim limitation after July 1, 2003.** Approval of a "Three-Dimensional Incentive" for production periods prior to July 1, 2003 shall not be time-barred by either the date of certification or the date of filing a claim for refund of the rebate of gross production tax. Effective July 1, 2003, claims for rebate filed with the Oklahoma Tax Commission shall be subject to a time limitation pursuant to Title 68 O.S., Section 1001(L).

(c) **Method of appeal.** If the refund is denied, the applicant may file an appeal under the provisions of Title 68, Sections 227 and 228 of the Oklahoma Statutes.

[SOURCE: Added in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04]

165:10-21-82.4. Time periods for exemption from gross production tax levied on oil, gas or oil and gas production from a well located within boundaries of three-dimensional seismic shoot

The exemption from gross production tax levied on oil, gas or oil and gas production from a well qualified pursuant to this Section shall be applied as follows:

(1) **Eighteen (18) month exemption.** For a well where the seismic shoot was shot prior to July 1, 2000, the well shall be exempt from the gross production tax levied from the date of first sales for a period of eighteen (18) months.

(2) **Twenty-eight (28) month exemption.** For a well where the seismic shoot was shot on or after July 1, 2000, the well shall be exempt from the gross production tax levied from the date of first sales for a period of twenty-eight (28) months.

[SOURCE: Added in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03]

PART 15. GENERAL PROVISIONS

165:10-21-85. Election of exemption

(a) **Election of exemptions generally.** Persons entitled to exemption based upon production from qualifying oil, gas, or oil and gas wells shall be entitled only to the exemption granted pursuant to:

(1) Incremental production from enhanced recovery projects, as authorized by 68 O.S. Supp. 2000 §1001(D) and Part 13 of this Subchapter; **or**,

(2) Horizontally drilled production wells, as authorized by 68 O.S. Supp. 2000 §1001(E) and Part 11 of this Subchapter; **or**,

(3) Reestablished production from inactive wells, as authorized by 68 O.S. Supp. 2000 §1001(F) and Part 7 of this Subchapter; **or**,

(4) Production enhancement projects, as authorized by 68 O.S. Supp. 2000 §1001(G) and Part 6 of this Subchapter; **or**,

(5) Production from deep wells, as authorized by 68 O.S. Supp. 2000 §1001(H) and Part 8 of this Subchapter; **or**,

(6) Production from new discovery wells, as authorized by 68 O.S. Supp. 2000 §1001(I) and Part 9 of this Subchapter; **or**,

(7) Production from wells located within the boundaries of three-dimensional seismic shoot, as authorized by 68 O.S. §1001(J) and Part 14 of this Subchapter.

(b) **Special provision.** Expiration of an exemption available for production from a qualifying well pursuant to one of Subsections (a)(2) through (a)(6) of this Section does not prohibit any person from qualifying for the exemption provided for in Subsection (a)(1).

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01]

PART 17. SALES TAX EXEMPTION FOR ELECTRICITY AND ASSOCIATED DELIVERY AND TRANSMISSION SERVICES SOLD FOR OPERATION OF RESERVOIR DEWATERING PROJECT AND/OR UNIT

165:10-21-90. General

(a) **Scope.** This Part deals with the classification by the Oklahoma Corporation Commission (Corporation Commission or Commission) of a reservoir dewatering project and/or unit for the purpose of an exemption, beginning January 1, 2004, from sales taxes levied on electricity and associated delivery and transmission services sold to an oil and gas operator for reservoir dewatering projects and associated operations commencing on or after July 1, 2003, as provided in 68

O.S. 2002 Supp., §1357(28).

(b) **Distinction from designation as reservoir dewatering oil spacing unit or other spacing application.** The classification of an area and reservoir(s) as a "reservoir dewatering project" and/or a "reservoir dewatering unit" pursuant to this Part shall be separate and distinct from the designation of a reservoir dewatering oil spacing unit for oil allowable purposes pursuant to OAC 165:10-15-18. Corporation Commission approval of an area and reservoir(s) for the instant sales tax exemption shall be made by application under this Part and not as a result of a spacing application filed for oil allowable purposes under OAC 165:10-15-1 and OAC 165:10-15-18, a spacing application filed for gas allowable purposes under OAC 165:10-17-2 through 10-17-16, a spacing application filed for horizontal drilling purposes under OAC 165:10-3-28, or any spacing application filed under OAC 165:10-1-22.

(c) **Reservoir Dewatering Projects for Oil Production.** Any reservoir that is the subject of an application pursuant to this Part, which produces predominantly oil, shall be evaluated to determine the initial water-to-oil ratio is equal to or greater than five-to-one (5-to-1).

(d) **Reservoir Dewatering Projects for Gas Production.** Any reservoir that is the subject of an application pursuant to this Part, which produces predominantly gas, shall be evaluated to determine the initial five-to-one (5-to-1) water-to-oil ratio using a gas conversion factor of one (1) barrel of oil converted to an MCF of natural gas based on an initial natural gas formation volume factor, BTU or price calculation or conversion accepted by the Conservation Division.

[**SOURCE:** Added in Rule Making 200300001, eff 7-1-03]

165:10-21-91. Definitions

The following words and terms, when used in this Part, shall have the following meaning, unless the context clearly indicates otherwise:

"Reservoir dewatering project" means an oil or gas production project covering a specified area and reservoir(s), which utilizes water recovery and disposal technology to increase water production in the initial phase of reservoir development, with the primary purpose of increasing oil or gas production from the reservoir(s) as a result of the dewatering process. For the purpose of qualification for the sales tax exemption pursuant to this Part, the definition of reservoir dewatering project shall require the proof that the reservoir's initial water-to-oil ratio is greater than or equal to five-to-one (5-to-1), or is greater than or equal to the appropriate gas-to-water ratio calculated using the gas conversion factor outlined in OAC 165:10-21-90(d). This definition shall not include enhanced recovery projects or secondary recovery properties, which are subject to gross production tax exemptions pursuant to 68 O.S. Section 1001 and Part 13 of this Subchapter, OAC 165:10-21-75 through 10-21-80.

"Reservoir dewatering unit" means an area and reservoir(s) designated a reservoir dewatering project where a reservoir dewatering process is conducted as defined in this Part.

[**SOURCE:** Added in Rule Making 200300001, eff 7-1-03]

165:10-21-92. Qualification procedure

(a) **Applicable operations.** The provisions of this Section establish criteria for determining if an area and reservoir(s) can be classified a reservoir dewatering project and/or a reservoir dewatering unit, beginning January 1, 2004, for the purpose of an exemption from sales taxes levied on electricity and associated delivery and transmission services sold to an oil and gas operator for a reservoir dewatering project and associated operations commencing on or after July 1, 2003.

(b) **Application to the Oklahoma Corporation Commission.** An oil and gas operator seeking the classification of an area and reservoir(s) as a reservoir dewatering project and/or reservoir dewatering unit pursuant to this Part shall file an application with the Corporation Commission on a Form 1535 for a determination that the project and/or unit qualifies for the exemption, as provided in 68 O.S. 2002 Supp., §1357(28). The operator shall attach to the Form 1535 a copy of the following information:

(1) A production test or other appropriate data showing the initial water-to-oil ratio is greater than or equal to five-to-one (5-to-1) or is greater than or equal to the appropriate gas-to-water ratio calculated using the gas conversion factor outlined in OAC 165:10-21-90(d). For this purpose, a Corporation Commission Form 1013 may be filed with the sales tax exemption application to demonstrate the initial 5-to-1 water-to-oil ratio for the reservoir.

(2) Geological structure and isopach maps for the applicable reservoir showing its geological characteristics; and any additional engineering and geological data or information deemed necessary by the Conservation Division to evaluate the application.

(3) A schematic diagram of the electrical grid and dewatering and water disposal equipment associated with the reservoir dewatering project covered by the application.

(c) **Administrative approval, determination and order.**

(1) If the application is administratively approved, an order of the Oklahoma Corporation Commission shall be issued.

(2) To obtain the tax exemption, the operator should contact the Director's Office, Taxpayer Assistance Division, Oklahoma Tax Commission, 2501 N. Lincoln Blvd., Oklahoma City, Ok. 73194.

(3) Any data, maps and other information submitted with the Form 1535 for determination that an area and reservoir qualify for the exemption provided in this Part shall be held as confidential information by the Conservation Division and/or Corporation Commission, and upon approval through issuance of a Commission order, shall be returned to the applicant or destroyed.

[**SOURCE:** Added in Rule Making 200300001, eff 7-1-03]

SUBCHAPTER 23. RATABLE SHARING OF REVENUE [REVOKED]

Section

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165:10-23-1. Definitions (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-2. General provisions for all interest owners in a well producing natural gas or casinghead gas (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-3. Revenue sharing in contract entered into on or after January 1, 1984; market by operator (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-4. Revenue sharing in contract entered into prior to May 3, 1983 (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-5. Revenue sharing in contract entered into on or after May 3, 1983, but prior to January 1, 1984 (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-6. Gas statements of production (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-7. Expiration of a gas contract (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-8. Special circumstances; parties selling under a joint operating agreement (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-9. Payments on production (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-10. Administrative expense (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-11. Commencement of an action (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-12. Other rights and remedies (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165-10-23-13. Crude oil (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-14. Liability (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-15. Severability (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

SUBCHAPTER 24. MARKET SHARING

Section

[**Authority**: 52 O.S. 1992, Section 581.1 et seq.]

[**Source**: Codified 6-25-93]

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165:10-24-1. Scope
(a) This Subchapter implements the Natural Gas Market Sharing Act of 1992, codified at 52 O.S. Section 581, et seq.
(b) This Subchapter establishes a procedure whereby an owner in a well may compel the well operator or other designated marketer to either sell gas on the owner's behalf or find a market for that owner's gas.
(c) This Subchapter shall apply to the sale of natural gas from a well except for:
(1) any sale under a gas contract for more than one year, entered into before January 1, 1985 (including any successor, replacement or roll-over contract entered into before January 1, 1990) provided that any participating mineral owners who were sharing in a contract on January 1, 1992, and continue to share in such a contract on September 1, 1992, are subject to this Subchapter;
(2) any sale under a contract which provides for:
(A) an initial term of more than three years; and
(B) a guarantee or warranty of delivery of fixed volumes without limitation on specified wells or reserves; and
(C) delivery of such volumes;
(3) any sale of natural gas liquids extracted by mechanical processing of the natural gas stream for removal of liquid components other than methane.
(d) Nothing in this Subchapter shall change the obligation of a first purchaser of production under an existing gas contract unless otherwise agreed to by the parties.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93; Amended at 11 Ok Reg 3699, eff 7-11-94]

165:10-24-2. Definitions
The following words or terms, when used in this Subchapter, shall have the following meaning, unless the context clearly indicates otherwise:
"Designated marketer" means the operator of the well or a producing owner substituted for the operator as provided in 165:10-24-5.
"Electing owner" means any owner who elects to produce and market its share of production pursuant to the provisions of this Subchapter.
"Nonexempt sales" means those gas sales which are subject to the provisions of this Subchapter and do not qualify for exemptions as set forth in 165:10-24-1(c) and 165:10-24-3(b).
"Overproduced owner" means an owner who has produced and sold a volume of gas in excess of his working interest percentage of cumulative sales from a well.
"Owner" means a person or persons who own a working interest in a well.
"Producing owner" means an owner who produces and sells gas from a well for its own account.
"Working interest" means the interest in a well, calculated prior to deduction for royalty, overriding royalty and other non-cost bearing interests burdening production, entitling the owner thereof to drill for and produce oil and gas, including the interest of a participating mineral owner to the extent set forth in Section 87.1 of Title 52 of the Oklahoma Statutes.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-24-3. Election to market share
(a) An owner eligible to market share as to a particular well, may elect to market share as to such well by sending written notice to the designated marketer for the well.
(b) An owner may not elect to market share as to a particular well if as to such well:

(1) said owner is subject to a balancing agreement (or other written agreement expressly providing for gas balancing or the taking, sharing, marketing of gas); or
(2) the term has yet to expire for a gas contract, where the owner terminated the contract for value received; or
(3) said owner terminated market sharing within the previous 12 months; or
(4) said owner is currently over-produced; or
(5) the designated marketer is relieved from the duty to market share pursuant to 165:10-24-4(g) or 165:10-24-4(i) and (j).

(c) An election to market share shall be effective on the first day of the month following 60 days from receipt of the election by the designated marketer.
(d) The well operator shall serve as the designated marketer until appointment of a substitute.
(e) An owner may terminate his election by sending writing notice to the designated marketer. Notice of termination is effective on the first day of the month following 60 days after receipt of the notice.
(f) Copies of all market sharing elections and notices shall be sent to the well operator, if said operator is not the designated marketer.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-24-4. Duties and accounting

(a) The designated marketer shall find an independent, non-affiliated purchaser for the electing owner's gas, or the designated marketer shall produce and sell said gas for the account of the electing owner.
(b) During market sharing, the designated marketer shall have the right to produce and sell and electing owner's gas, without further notice and consent except in those cases where the designated marketer has secured an independent non-affiliated purchaser for the gas production of such electing owner.
(c) If the designated marketer produces and sells the electing owner's gas for the account of the electing owner, the designated marketer shall account to the electing owner at the average price, weighted by volume, received by the marketer for all of the designated marketer's non-exempt sales from the well for that month, less post production cost and expenses required to render the gas marketable and to sell and deliver the gas to market, and net of all reasonable marketing costs, expenses and administrative fees. Volumetric allocation between the designated marketer and the electing owner shall be in proportion to their working interests in the well, with one exception. If the owner's proportionate production interest is different from his working interest, the proportionate production interest shall be used.
(d) Disbursement of gas sales proceeds shall be subject to the Production Revenue Standards Act of 1992 (52 O.S. Section 570.1, et seq.).
(e) The designated marketer shall not be considered as a fiduciary to any electing owner or to any owner with an interest burdening the electing owner's interest. The designated marketer shall not be liable for losses absent bad faith, gross negligence or willful misconduct.
(f) Market sharing according to this Subchapter shall not confer any contract rights to an electing owner or his assigns, either directly or as third party beneficiaries.
(g) For a gas contract with a term in excess of one year, the designated marketer may require an electing owner to either agree in writing to be bound by the contract terms or forego market sharing under that contract. Absent a confidentiality provision in said gas contract, the designated marketer shall send a copy of the gas contract to each electing owner.
(1) After receipt of the contract, the electing owner shall have 30 days in which to:
(A) send written consent to the contract terms, or
(B) provide a written termination of market sharing or
(C) elect a new designated marketer.
(2) If the electing owner fails to so respond, his election to market share shall be deemed terminated.

(h) If the designated marketer ceases to sell gas from the well and therefore has no sales, the designated marketer:

(1) may:

(A) notify the electing owners in writing that it has no sales and that the electing owners must elect a new designated marketer, or

(B) locate a non-affiliated purchaser for the electing owners.

(2) shall not be responsible for sharing sales with electing owners as it has no sales. If such a designated marketer again begins to produce and market gas from the well, then the electing owners may re-elect it as designated marketer.

(i) If the designated marketer provides the electing owner with a sales contract with a gas purchaser, the designated marketer shall be relieved of the duty to market share with the electing owner to the extent that the terms of said contract provide for the purchase of the electing owner's share of each withdrawal from the well during the contract period, provided:

(1) The designated marketer is not an affiliate of the gas purchaser: said term "affiliate" being defined at 18 O.S. Section 1148A(2); and

(2) The contract is of a type and with terms generally offered at the time to other producers for gas production from wells in the common source of supply; and

(3) If the designated marketer operates and controls a gathering line to the well, it does not prohibit access to downstream transportation or impose unjust or discriminatory gathering fees or tariffs upon the electing owner; and

(4) Before discontinuing market sharing if it had begun, the designated marketer provides the electing owner with at least thirty days in which to accept or reject the offer for said contract.

(j) In so far as the exemption established by subsection (i) of this Section, if the designated marketer fulfills each of the foregoing conditions, it shall be relieved from the duty to market share with the electing owner for a time period hereafter described as the "exemption period", calculated as follows:

(1) If the electing owner enters into said contract with said purchaser, then the exemption period shall be the duration of the contract as originally offered to the electing owner or the duration of the contract as entered into by the electing owner, whichever is greater;

(2) If the electing owner fails to enter into said contract for any reason, then the exemption period shall be the duration of the contract period as initially offered to the electing owner or twelve months, whichever is less.

(k) During the exemption period as determined in subsection (j) of this Section, failure to enter into said contract shall not be grounds for election or appointment of an additional designated marketer to market share with the electing owner with respect to volumes of gas which would have been purchased if the electing owner had entered into the said contract as initially offered to the electing owner.

(l) Upon request, the designated marketer or electing owner shall provide the first purchaser of production with information concerning the election to market share and the electing owner's share of monthly production.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-24-5. Replacement of the designated marketer

A new designated marketer may be appointed by a majority vote of the remaining market sharing owners. If an electing owner does not agree to the terms of a gas contract with a term greater than one year, the electing owner may elect a new designated marketer unless said election is prohibited by 165:10-24-4(i) and (j). Otherwise, substitution of the designated marketer shall occur not more than once every twelve months.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-24-6. Fees

(a) The designated marketer may charge each electing owner with an administrative fee for marketing the electing owner's share of production. Said fee shall be assessed monthly on a per-well basis. It shall be based on a formula described in this Section subject to annual adjustments as provided below. Said formula consists of 2.5% of the electing owner's monthly share of proceeds, but not less than twenty dollars nor more than seventy-five dollars, unless application of the annual adjustment factor provides a different maximum amount. The maximum amount of the fee permitted by this Section shall be adjusted as of the first day of May each year following May 1, 1993. The annual adjustment shall be computed by multiplying the rate currently in use by the percentage of increase or decrease in the annual overhead adjustment factor established by the Council of Petroleum Accountants Societies at its annual spring meeting for purposes of adjusting the combined fixed-rate overhead charges against joint operations in a well.

(b) If the designated marketer produces and sells gas for the account of the electing owner, the designated marketer may charge the electing owner or deduct said fee from the electing owner's share of the undistributed proceeds of production.

(c) Administrative fees under this Section shall be in addition to and separate from any and all post-production costs and expenses, including but not limited to reasonable marketing costs and expenses which may also be deducted from the proceeds payable to eligible electing owners.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

SUBCHAPTER 25. ESCROWED ACCOUNTS FOR POOLED MONIES

Section

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165:10-25-1. Definitions

The following words or terms, when used in this Subchapter, shall have the following meaning, unless the context clearly indicates otherwise:

"Escrow account" means an account established in a financial institution and held in the name of the holder and an escrow agent wherein each owner is federally insured to One Hundred Thousand Dollars ($100,000.00).

"Financial institution" means a federally or state chartered bank, savings and loan, or credit union.

"Holder" means any person in possession of royalties, bonus payments, or other monies directed to be paid under a Commission pooling order and which cannot be paid because the persons entitled thereto are unknown or cannot be located.

"Owner" means the last known record titleholder of a mineral interest which is subject to a Commission pooling order.

"Person" means any individual, partnership, joint stock associations, trust, cooperative, unincorporated association, or corporation.

165:10-25-2. Escrow account required

(a) Each pooling order which pools interest of unknown or unlocated owners shall contain language substantially similar to the following: "If any payment of bonus, royalty payments, or other payments due and owing under this order cannot be made because the person entitled thereto cannot be located or is unknown, then said bonus, royalty payments or other payments shall be paid into an escrow account in a financial institution within ninety (90) days after this order and shall not be commingled with any funds of the applicant or operator. Provided however, that the Commission shall retain jurisdiction to grant to financially solid and stable holders an exception to the requirement that such funds be paid into an escrow account with a financial institution and permit such holder to escrow such funds within such holder's organization. Responsibility for filing reports with the Commission as required by law and Commission rule as to bonus, royalty or other payments escrowed hereunder shall be with the applicable holder. Such escrowed funds shall be held for the exclusive use of, and the sole benefit of, the person entitled thereto. It shall be the responsibility of the operator to notify all other holders of this provision and of the Commission rules regarding unclaimed monies under pooling orders".

(b) Each pooling order issuing upon an application filed on or after July 1, 1984, shall contain, in addition to the foregoing language, an attached exhibit listing all parties or interests which are unknown or cannot be located, together with each party's last known address, if available.

165:10-25-3. Escrow account requirements

(a) Monies which are directed to be paid under a Commission pooling order and which cannot be paid because the persons entitled thereto are unknown or cannot be located shall be placed into escrow accounts in a financial institution. The holder shall choose the institution. The holder and the financial institution may make such arrangements as are necessary and appropriate for the establishment of the account. Service charges, fees, and costs may be deducted from any interest generated by the monies but in no event shall such charges, fees, and costs be deducted from the principal. Any financially solid and stable holder may apply to the Commission for an exception to the requirement to place monies into escrow accounts in a financial institution. The granting of an exception shall be within the sole discretion of the Commission and may only be granted upon the filing of a proper application therefor pursuant to notice given to the Manager of the Mineral Owners Escrow Account by mail at least ten days prior to the hearing and by publication one time at least 15 days prior to the hearing in a newspaper of general circulation in Oklahoma County and in a newspaper of general circulation in the county where the holder's principal

office in the state is located. The granting of an exception shall not exempt the holder from any other requirements set forth in this Subchapter.
(b) Only one account need be established by each holder. If only one account is established, a record shall be make of deposits and withdrawals for each person for whom monies are being held. Either the holder or the financial institution may keep the deposit/withdrawal record.
(c) An application for an exception under (a) of this Section shall state that the holder has proof by the holder's annual financial statement that it is a solid and stable holder. The holder must introduce its annual financial statement into evidence in the cause and the order, if one is issued, shall show that the annual financial statement was in fact introduced into evidence and considered by the Administrative Law Judge in making the determination to grant holder's request for an exemption under (a) of this Section, and holder shall submit a current financial statement on an annual basis thereafter.
(d) Withdrawals from such escrow account by the holder may only be made for the following purposes:
(1) To pay the rightful recipient of the monies upon presentation of a proper claim.
(2) To submit and pay to the Commission the principal of all monies placed in escrow pursuant to 165:10-25-6.
(3) To correct an overpayment or other mistake made in the distribution of monies by the holder.

[**SOURCE:** Amended at 9 Ok Reg 2337, eff 6-25-92]

165:10-25-4. Payment to owner

The holder shall have a designated officer or employee to whom claims upon the escrow account may be made. The holder shall promptly pay the appropriate sum to any person showing the holder sufficient proof of ownership and proof of identity as may be determined in good faith by the holder. The holder shall report any payments made on his annual report to the Commission.

165:10-25-5. Reports to the Commission

Each holder shall submit a report for persons who cannot be located or are unknown and for whom monies are being held in escrow no later than 30 days after such holder's annual reporting date. Each holder's initial report shall be filed no later than one year and 30 days after the date of the issuance of the first pooling order subject to this Subchapter. Such reports shall be filed each year that any monies are held in escrow, until the well is plugged.

165:10-25-6. Payment to the Commission

(a) No later than 30 days after the annual reporting date of each year, the holder shall submit to the Commission the principal of all monies placed in escrow accruing under the orders issued during the first year, and all subsequent years where the sum exceeds $100.00 for any one person.
(b) If the holder has placed in escrow less than $100.00 for any one person, the holder may follow the procedures for deposit, or maintain the funds in escrow. If the amount accumulates to over $100.00 for any one person after any annual reporting date, it shall be submitted to the Commission on the next annual reporting date.
(c) Payments shall be tendered to the Finance Office of the Commission. Payments shall be made by cashier's check, certified check, or money order made payable to the "Oklahoma Corporation Commission".

165:10-25-7. Affidavit of compliance

In addition to the Plugging Record (Form 1003) and Completion Report (Form 1002A) required under 165:10-11-7, the operator shall file a compliance affidavit. No plugging bond shall be released until after the compliance affidavit is filed.

165:10-25-8. Forms

The Commission may issue appropriate forms to implement the provisions of this Subchapter.

165:10-25-9. Release from liability

Any holder who pays or delivers monies to the Commission required to be paid under this Subchapter shall be relieved of all liability for the monies so paid or delivered for any claim which then exists or thereafter may arise or be made in respect to such monies.

165:10-25-10. Construction

This Subchapter shall not be construed as limiting the Commission's authority to grant an exception to any rule in this Subchapter, unless precluded by law.

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SUBCHAPTER 27. PRODUCTION REVENUE STANDARDS

Section

[**Authority:** 52 O.S. 1992, Section 570.13 et seq.]

[**Source:** Codified 6-25-93]

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165:10-27-1. Scope

This Subchapter implements the Production Revenue Standards Act of 1992, codified at 52 O.S. Section 570.1, et seq. It shall apply to all producing wells as set forth in the Production Revenue Standards Act of 1992. However, Sections 165:10-27-4 through 165:10-27-10 shall not apply to any well which is a part of a compulsory enhanced recovery project, or where royalty remittance is otherwise regulated by written agreement among all owners in the well. This Subchapter is intended to supplement and clarify as needed the language in the statutes.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-27-2. Effective date [Revoked]

[**Source:** Added at 10 OK Reg 2601, eff 6-25-93; Revoked at 11 Ok Reg 3699, eff 7-11-94]

165:10-27-3. Definitions

The following words or terms, when used in this Subchapter, shall have the following meaning, unless the context clearly indicates otherwise.

"Owner" means a person or governmental entity with a legal interest in the mineral acreage under a well which entitles that person or entity to oil or gas production or the proceeds or revenues therefrom.

"Produce", **"producing"** and **"production"** mean the physical act of severance of oil and gas from a well by an owner and includes but is not limited to the sale or other disposition thereof.

"Producing owner" means an owner entitled to produce who during a given month produces oil or gas for its own account or the account of subsequently created interests as they burden its interest.

"Proportionate production interest" means that interest in production which a working interest owner is entitled to produce in order to adjust for shifting of royalty burdens among working interest owners under the royalty provisions of 52 O.S. Sections 570.1, et seq., and is equal to the quotient of:

(A) the sum of a working interest owner's net revenue interest plus the net revenue interests of any subsequently created interests as they burden such owner's working interest,

(B) divided by the remainder of one (1) less the royalty share.

"Proportionate royalty share" means the percentage of the royalty share owned by a royalty interest owner calculated by dividing such owner's royalty interest in a well by the royalty share.

"Royalty interest" means the entirety of the percentage interest in production or proceeds therefrom:

(A) reserved or granted by a mineral interest owner exclusive of any interest defined as a working interest or a subsequently created interest, or

(B) otherwise provided or ascribed to a mineral interest owner by statute, rule, order or operation of law.

"Royalty interest in a well" means an owner's royalty interest multiplied by the quotient of:

(A) the gross mineral acres under the well attributable to such interest, divided by

(B) the total mineral acres under the well.

"Royalty proceeds" means the share of proceeds or other revenue derived from or attributable to any production of oil and gas attributable to the royalty share, but shall not include payments of bonus, delay rentals, shut-in royalties or any additional royalty payable to the Commissioners of the Land Office or other governmental entity, pursuant to and valued according to the terms of its oil and gas lease, which is calculated separately from the royalty portion of actual proceeds from the sale of oil or gas.

"Royalty share" means the percentage of the well equal to the sum of all royalty interests in the well.

"Share of production" means the monthly entitlement to produce belonging to a producing owner.

"Shipper" means any entity who contracts with a transporter to move gas through the transporter's system.

"Subsequently created interest" means any interest carved from a working interest other than a royalty interest. In addition to the royalty interest contained in a lease, a non-participatory interest created by a working interest owner for the benefit of a mineral interest owner in excess of a one-eighth (1/8) royalty interest may, by separate agreement other than the oil and gas lease, be a subsequently created interest and thereby not be communitized under the terms of the Production Revenue Standards Act only if there is clear and unambiguous language expressing that intent in the creating document. The additional royalty payable to the Commissioners of the Land Office or other governmental entity pursuant to and valued according to the terms of its oil and gas lease, which is calculated separately from the sale of oil or gas, shall also be a subsequently created interest and thereby shall not be communitized under 52 O.S. Section 570.1, et seq.

"Well" means an oil or gas well, and shall include:

(A) a well having uniform ownership as to all producing zones, or

(B) a drilling and spacing unit having uniform ownership wherein multiple wells producing gas are commonly metered, and

(C) each separately metered producing zone within a single wellbore wherein ownership varies by zone.

"Working interest" means the interest in a well entitling the owner thereof to drill for an produce oil and gas, including but not limited to the interest of a participating mineral owner to the extent set forth in Section 87.1 of Title 52 of the Oklahoma Statutes.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93; Amended at 11 Ok Reg 3699, eff 7-11-94]

165:10-27-4. Well operator records

Each well operator shall establish or cause to be established records showing the production allocations and payments to each interest owner in the well. For purposes of such records, the working interest owners shall provide the well operator with accounting and remittance information as required by statute. At a minimum, the required information shall consist of the name, address, interest amount and tax identification number of each royalty owner along with payment status. Each working interest owner shall provide said information in writing within 60 days of receipt of a written information request from the well operator. Updated information shall be provided by a working interest owner within 60 days after receipt of notice of a change.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93; Amended at 11 Ok Reg 3699, eff 7-11-94]

165:10-27-5. Pre-sale nominations

(a) Any producing owner marketing production separately from the well operator shall send pre-production nominations to the well operator for his withdrawals. A nomination shall be due five business days prior to the month in which the nomination is to be effective, but earlier if required by the first purchaser or transporter. The nomination shall consist of the name of the first purchaser or shipper, shipper contract number and the volumes of gas nominated for production for such producing owner's account.

(b) Nothing in this Section shall supersede or limit the operator's right to control gas nominations and allocations under a joint operating agreement, separate balancing agreement or Commission order.

(c) The owner of the gas meter shall confirm all nominations with the operator of the well no later than the last business day prior to the month in which production occurs.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93; Amended at 11 Ok Reg 3699, eff 7-11-94]

165:10-27-6. Entitlement

Each producing owner in a well shall be entitled to produce each month his proportionate production interest subject to balancing restrictions created by statute, rule, agreement or operation of law.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-27-7. Post-sale reports

(a) Within sixty days after the end of the month of production, each producing owner shall report and account to the operator of the well, the identity of the first purchaser or shipper of the gas and information specified in 165:10-27-13.
(b) Within fifteen days after the end of the month of production, each owner of a gas meter taking gas solely from a gathering system shall provide upon first request by the owner of such gathering system and thereafter, the gross volume of gas measured by such meter both in MCF and British Thermal Unit equivalent.
(c) Within twenty days after the end of the month of production, each owner of a gas meter shall provide or cause to be provided in writing to the operator of the well, the gross volume of gas measured by such meter, both in MCF and British Thermal Unit equivalent, and the volume of gas allocated at the meter to each first purchaser or shipper and each contracted producing owner that sold gas to the owner of the gas meter. Each meter owner shall, within the same time period, furnish each first purchaser or shipper the volume of gas allocated at the meter to that first purchaser or shipper. However, if the gas processing plant operator is performing the allocations, then within ten days after the end of the month of production, the owner of the pipeline residue gas meter shall provide, upon first request by the processing plant operator and thereafter, the volume in MCF and British Thermal Unit equivalent measured through its meter as required by the gas processing plant operator for its allocations under this subsection.
(d) As an alternative to supplying the operator with information in the manner prescribed by subsections (b) and (c) of this Section, the owner of a gas meter who has a contract with one or more producing owners, covering all of the gas flowing through its meter, may furnish monthly volume statements to the operator of the well, provided said owner of the gas meter has previously furnished the operator with names of the producing owners and the decimal interest owned by each such producing owner or owners or any method other than by decimal interest then in effect for allocating gas among the producing owners. After adopting alternative reporting under this subsection, the owner of the gas meter shall be required to supply the operator of the well with any change to the name of a producing owner, the decimal interest by a producing owner or the method, other than by decimal interest, for allocating gas among the producing owners: such change to reported by the owner of the gas meter to the operator of the well within thirty days after the owner of the gas meter receives notice of such change.
(e) Within thirty-five days after the end of the month of production, each first purchaser or shipper of gas from a gas meter shall furnish or cause to be furnished to the operator of the well, a volume allocation statement showing the volume of gas purchased from or shipper for each contracted producing owner. Within thirty days after making any retroactive gas volume adjustment for such well, the first purchaser or shipper shall furnish notice of such retroactive gas volume adjustment to the operator of the well.
(f) Any person subject to multiple reporting requirements under this Section shall not be required to re-report the same information to the operator if such

information has been previously provided by such person in a different report. Such person may consolidate the required information into a single report to the operator; provided, however, that all such reporting must comply with the applicable statutory time periods for the type of information being communicated to the operator.
(g) Any first purchaser, shipper or owner of a gas meter that does not provide the information required of it by this Section shall be subject to having its takes from the well suspended by the operator of the well pursuant to 165:10-27-8.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93; Amended at 11 Ok Reg 3699, 7-11-94]

165:10-27-8. Operator's option to confirm zero volume of gas sales because of noncompliance
(a) If a producing owner fails to timely provide the operator of the well with any of the information required by 165:10-27-4 and 165:10-27-7, or if the owner of a gas meter, first purchaser or shipper of gas fails to timely provide the operator of the well with any of the information required of it by 165:10-27-7 for the transfer, transportation, delivery or sale of gas by a producing owner, the operator of the well shall have the right, but not the obligation, to confirm zero volume of gas sales for such producing owner, and to make available for nomination and sale to other producing owners in the well, then in compliance with said Sections, all of such producing owner's share of production for the next subsequent calendar month and for each and every month thereafter of noncompliance. If the operator elects to make such producing owner's share of production available for nomination and sale, the operator shall immediately notify such producing owner by certified mail and inform such producing owner that such producing owner shall no longer have the right to nominate any volume of gas, until the next production month following the date of compliance, unless the operator of the well agrees to an earlier date. Such notice shall contain the lease or well identification, legal description, production months of noncompliance, a brief description of the noncompliance, and a provision stating that the operator is confirming zero volume of gas sales for such producing owner. The operator shall than immediately notify each producing owner then in compliance with the aforesaid Sections and inform said producing owner about additional gas volumes available for nomination and sale. In regard to the producing owner for which the operator has confirmed zero gas sales, the operator shall also immediately notify in writing such producing owner's first purchaser or shipper, and the owner of the gas meter, and such notice shall report that such producing owner does not have the right to nominate and sell or transport any volume of gas, until the next production month following compliance, unless the operator of the well agrees to an earlier date. Such notice shall also contain the lease or well identification, legal description, a brief description of the noncompliance, and the production months of noncompliance.
(b) As soon as a noncomplying party is in compliance, but no sooner than the next production month unless otherwise agreed to, the operator of the well shall give the affected producing owner the opportunity to nominate and sell gas subject to existing agreements or by common practice within the oil and gas industry.
(c) The first purchaser or shipper and the owner of the gas meter shall be entitled to rely on and shall incorporate on a prospective basis any nomination or allocation changes pursuant to such notification from the operator under this Section. Changes pursuant to such notification may be made on a retroactive basis if so agreed to by the operator, owner of the meter, the first purchaser or shipper.
(d) The remedies provided for in this Section shall not preclude any party from pursuing the remedies available to it through the district courts, as provided by existing law, including the right of offset.
(e) All elections and notices given pursuant to the provisions of this Subchapter shall become effective as of the first day of the month following the

end of any time period specified in the Production Revenue Standards Act as last amended, 52 O.S. Section 570.1, et seq.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93; Amended at 11 Ok Reg 3699, eff 7-11-94]

165:10-27-9. Designated payor for royalty distributions

(a) For royalty distributions, the well operator shall serve as payor for all proceeds of production, absent appointment of a substitute payor and/or election of a working interest owner to distribute royalties attributable to that working interest owner's sales.

(b) A substitute payor may be appointed by Commission order or by the owners owning a majority in interest of the working interest in the well. A substitute payor so appointed shall assume the rights and duties of the well operator concerning assessment of fees, royalty record maintenance and disbursement of royalties. A surety bond of $50,000 shall be required if the substitute payor is not a working interest owner, a first purchaser of production from the well, a bank or a trust company. Such bond shall be posted with the Surety Department of the Conservation Division before receipt of sales proceeds by the substitute payor. Any such bond shall be drafted so as to compensate royalty owners if the substitute payor defaults on his disbursement obligation.

(c) A producing owner may elect to distribute royalties from his sales subject to the following conditions:

(1) the producing owner shall provide 60 days written notice to the operator before starting or stopping the alternative procedure;

(2) the producing owner shall assume liability for its errors;

(3) the producing owner shall report payment information to the well operator within 30 days after each disbursement;

(4) the producing owner cannot re-start the alternative procedure within 12 months after terminating it.

(d) For good cause shown, the Commission may cancel a producing owner's election to separately distribute royalty. Cancellation shall occur only by order after application, notice and hearing.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-27-10. Administrative fees

(a) This Section prescribes fees which may be charged by the operator of a gas producing well or substitute payor, for administrative expenses generated by the Production Revenue Standards Act.

(b) Fees shall be assessed on a per-well basis against the cost-bearing working interests in a well according to respective gross working interest. They shall not be assessed against either royalty interests or non-cost bearing working interests in the well.

(c) A one-time implementation fee shall cover any cost associated with establishing or modifying the well operator's record keeping for the well, and it shall apply to any existing gas producing well with a date of first production occurring before September 1, 1992. If operations are transferred to a different operator after assessment of the one-time implementation fee, the successor operator may not assess another implementation fee against the working interests in the well.

(d) Should any working interest owner in a well producing gas fail to fully and timely comply with the requirements of 165:10-27-4, the well operator or substitute payor shall have the right to charge against said non-complying working interest owner a late fee of two hundred-fifty dollars per affected well.

(e) An annual maintenance fee shall cover any cost associated with record keeping, issuance of gas balancing statements and any election of a producing owner regarding separate distribution of royalty proceeds. Maintenance fees shall be calculated on an annual basis using the first day of May as the

anniversary date. Such fees may be prorated and billed on a monthly basis at the well operator's discretion. If a well has a date of first production after the first day of May of the calendar year, the annual maintenance fee shall be prorated based on the remaining number of months before the next anniversary date on the first day of May.
(f) No working interest owner other than the well operator shall be entitled to assess either an implementation fee or a maintenance fee.
(g) The rates for implementation fees and annual maintenance fees shall be based on the appropriate table values found in Appendix G to this Chapter, subject to annual adjustments as provided below. The appropriate table value shall be determined from a matrix using the number of working interest owners or royalty owners in a well. The table value shall be adjusted as of the first day of May each year following May 1, 1993. The annual adjustment shall be computed by multiplying the rate currently in use by the percentage of increase or decrease in the annual overhead adjustment factor established by the Council of Petroleum Accountants Societies at its annual spring meeting for purposes of adjusting the combined fixed-rate overhead charges against joint operations in a well.
(h) Any fee assessed under this Section may be billed or deducted from the working interest owner's share of undistributed proceeds of production.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-27-11. Balancing of royalty accounts
(a) In the event of a production imbalance among royalty owners in a well, the affected working interest owners may adopt a royalty payment method to balance the royalty accounts, provided it is used only to extent necessary to balance the cumulative accounts of the royalty owners, and prior notice of the plan is sent to the affected royalty owners and to the well operator along with any ongoing information necessary for said operator to discharge its duties.
(b) Nothing in this Section shall impair any balancing rights arising by contract or law.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-27-12. Record keeping
Any record required by this Subchapter shall be maintained for a period of at least five years. Upon reasonable request, the well operator or substitute payor shall make available to a royalty owner for confidential inspection a record of receipts and payment of proceeds to said royalty owner, as well as copies of information furnished to the well operator pursuant to the Production Revenue Standards Act.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-27-13. Check stub information
(a) With each royalty payment, the following information shall be provided:
(1) lease or well identification;
(2) month and year of sales included in the payment;
(3) total barrels or MCF attributed to such payment;
(4) price per barrel or MCF, including British Thermal Unit adjustment of gas sold;
(5) gross production and severance taxes attributable to said interest;
(6 net value of total sales attributed to such payment after deduction of gross production and severance taxes;
(7) owner's interest in the well expressed as a decimal;
(8) owner's share of the total value of sales attributed to such payment before any deductions;

(9) owner's share of the sales value attributed to such payment less owner's share of the production and severance taxes.

(b) Upon payee's request, the payor shall provide a list of any other deduction from such payment.

(c) All revenue decimals shall be calculated to at least six decimal places.

(d) Gas volumes shall be measured according to 52 O.S. Section 474.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

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APPENDIX A. ALLOCATED WELL ALLOWABLE TABLE*

The depth in feet from the surface of the ground to the top of the pay in the discovery oil well in each such pool will be the assumed average producing depth thereof.

AVERAGE DEPTH OF POOL/FEET**	ACREAGE 10 or less	20	40	80	160
To-3000		30	45	57	
3001-3200		31	45	57	
3201-3400		32	46	58	
3401-3600		33	47	59	
3601-3800		34	48	60	
3801-4000		35	49	61	
4001-4200		36	49	61	71
4201-4400		37	50	62	73
4401-4600		38	51	63	75
4601-4800		39	52	64	77
4801-5000		40	53	65	79
5001-5200		41	54	67	82
5201-5400		42	55	69	85
5401-5600		43	56	71	88
5601-5800		45	58	73	91
5801-6000		47	60	75	94
6001-6200		49	62	77	97
6201-6400		51	64	79	100
6401-6600		53	66	82	103
6601-6800		55	68	85	107
6801-7000		57	70	88	110
7001-7200		59	72	90	113
7201-7400		61	74	92	116
7401-7600		63	76	95	119
7601-7800		65	78	98	122
7801-8000		67	80	101	126
8001-8200		69	83	104	130
8201-8400		71	86	107	134
8401-8600		73	89	111	139

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AVERAGE DEPTH OF POOL/FEET**	**A C R E A G E** 10 or less	20	40	80	160
8601-8800	75	92	115	144	
8801-9000	77	95	119	149	
9001-9200	79	98	123	154	
9201-9400	81	101	127	159	
9401-9600	84	105	131	164	
9601-9800	87	109	136	170	
9801-10000	90	113	141	176	
10001-10200	95	119	148	185	333
10201-10400	100	125	156	195	351
10401-10600	105	131	164	205	369
10601-10800	110	137	172	215	387
10801-11000	115	144	180	225	405
11001-11200	122	153	190	239	431
11201-11400	129	162	202	254	458
11401-11600	137	171	214	269	485
11601-11800	145	181	226	284	512
11801-12000	153	191	239	299	539
12001-12200	163	203	254	318	573
12201-12400	173	215	269	338	609
12401-12600	183	228	285	358	645
12601-12800	193	241	301	378	681
12801-13000	203	254	317	398	717
13001-13200	213	266	333	416	749
13201-13400	223	278	349	436	785
13401-13600	233	290	365	455	819
13601-13800	243	303	380	475	855
13801-14000	253	316	395	494	890
14001-14200	263	328	410	514	926
14201-14400	273	340	426	534	962
14401-14600	283	353	441	554	998

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AVERAGE DEPTH OF POOL/FEET**	**A C R E A G E** **10 or less**	**20**	**40**	**80**	**160**
14601-14800	293	366	457	573	1032
14801-15000	303	379	473	593	1068

***** Allowables currently are established at 200 percent of market demand. To determine the allowable for any well, the number in the appropriate column of the chart in the appendix must be doubled (multiplied by 2). The minimum allocated well is therefore 60 BOPD (from the 10 acre column, depth to 3,000 feet, 30 BOPD times 2) (Market Demand).

****** The average producing depth of the pool is assumed to be the depth in feet from the surface of the ground to the top of pay in the discovery well in that pool.

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APPENDIX B. DISCOVERY WELL ALLOWABLE TABLE
(100 percent of market demand)

DEPTH*	BARRELS PER DAY	DAYS AFTER DISCOVERY
0-1000	100	365
1001-1200	105	391
1201-1400	110	416
1401-1600	115	442
1601-1800	120	467
1801-2000	125	493
2001-2200	130	518
2201-2400	135	545
2401-2600	140	569
2601-2800	145	596
2801-3000	150	621
3001-3200	155	647
3201-3400	160	672
3401-3600	165	698
3601-3800	170	723
3801-4000	175	749
4001-4200	180	774
4201-4400	185	800
4401-4600	190	825
4601-4800	195	851
4801-5000	200	876
5001-5200	205	910
5201-5400	210	942
5401-5600	215	975
5601-5800	225	1007
5801-6000	235	1041
6001-6200	245	1073
6201-6400	255	1107
6401-6600	265	1139
6601-6800	275	1172
6801-7000	285	1205
7001-7200	295	1245
7201-7400	305	1285
7401-7600	315	1326
7601-7800	325	1365

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DEPTH*	BARRELS PER DAY	DAYS AFTER DISCOVERY
7801-8000	335	1406
8001-8200	345	1445
8201-8400	355	1486
8401-8600	365	1526
8601-8800	375	1567
8801-9000	385	1606
9001-9200	395	1650
9201-9400	405	1694
9401-9600	420	1737
9601-9800	435	1781
9801-10000	450	1825
10001-10200	475	1837
10201-10400	500	1847
10401-10600	525	1859
10601-10800	550	1869
10801-11000	575	1880
11001-11200	610	1888
11201-11400	645	1895
11401-11600	685	1902
11601-11800	725	1910
11801-12000	765	1917
12001-12200	815	1917
12201-12400	865	1917
12401-12600	915	1917
12601-12800	965	1917
12801-13000	1015	1917
13001-13200	1065	1917
13201-13400	1115	1917
13401-13600	1165	1917
13601-13800	1215	1917

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DEPTH*	**BARRELS PER DAY**	**DAYS AFTER DISCOVERY**	
13801-14000		1265	1917
14001-14200		1315	1917
14201-14400		1365	1917
14401-14600		1415	1917
14601-14800		1465	1917
14801-15000		1515	1917

***** The depth of the discovery pool well is assumed to be the depth in feet from the surface of the ground to the top of the pay in the initial discovery well.

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APPENDIX C: TABLE HD

RECOMMENDED ALLOWABLE ON HORIZONTAL OIL WELLS
BASED ON DEPTH AND ACREAGE

UNIT SIZE	TRUE VERTICAL DEPTH	REQUIRED HORIZONTAL COMPONENT	BBLS/DAY ALLOWABLE	BONUS BBL/DAY PER FT. OF LATERAL
10 acre	0-4000'	150' - 467'	70	.2
20 acre	0-4000'	468' - 1044'	98	.2
40 acre	0-4000'	933' - 1400'	122	.2
80 acre	0-4000'	1401' - 2087'	244	.2
160 acre	0-4000'	1866' - 2800'	488	.2
320 acre	0-4000'	2801' - 4174'	976	.2
640 acre	0-4000'	3733' and over	1952	.2
10 acre	4001-8000'	150' - 467'	134	.3
20 acre	4001-8000'	468' - 1044'	160	.3
40 acre	4001-8000'	933' - 1400'	202	.3
80 acre	4001-8000'	1401' - 2087'	252	.3
160 acre	4001-8000'	1866' - 2800'	504	.3
320 acre	4001-8000'	2801' - 4174'	1008	.3
640 acre	4001-8000'	3733' and over	2016	.3
10 acre	8001-12000'	150' - 467'	306	.4
20 acre	8001-12000'	468' - 1044'	382	.4
40 acre	8001-12000'	933' - 1400'	478	.4
80 acre	8001-12000'	1401' - 2087'	598	.4
160 acre	8001-12000'	1866' - 2800'	1078	.4
320 acre	8001-12000'	2801' - 4174'	2156	.4
640 acre	8001-12000'	3733' and over	4312	.4

All oil produced and marketed during the drilling and completion operations shall be charged against the allowable assigned to the well upon completion. Effective date of the allowable shall be the date of first production.

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APPENDIX D. LIST OF NGPA FORMS [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2401, eff 7-1-96]

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APPENDIX E. SCHEDULE A FINES [REVOKED]

[**Source:** Revoked in Rule Making 200200017, eff 7-1-02]

APPENDIX E. SCHEDULE A FINES [NEW]

RULE	VIOLATION	FINE
165:10-3-1	Failure to obtain permit (Form 1000) to drill, re-enter, deepen or recomplete.	$1,000
165:10-3-3	Failure to report surface casing failure.	$1,000
165:10-3-4	Failure to set sufficient surface casing or circulate cement.	$5,000
165:10-3-4	Failure to run and cement surface well marker.	$1,000
165:10-5-2	Failure to obtain permit for injection or disposal well.	$5,000
165:10-5-13	Failure to obtain permit for annular injection of drilling fluids.	$2,500
165:10-7-14	Failure to obtain approval to drill deep anode groundbed.	$1,000
165:10-7-16	Failure to obtain permit for construction of off-site pit.	$1,000
165:10-7-16	Illegal discharge from noncommercial pit.	$2,000
165:10-7-17	Failure to obtain permit to discharge produced water to surface.	$1,000
165:10-7-19	Failure to obtain permit for one-time land application of water-based fluids from tanks/ earthen pits.	$2,000
165:10-7-26	Failure to obtain permit for a one-time land application of contaminated soils or petroleum hydrocarbon-based drill cuttings.	$2,000
165:10-7-27	Failure to obtain permit to apply waste oil, waste oil residue, or crude oil contaminated soil to lease roads, pipeline service roads, tank farm roads, well locations and production sites.	$2,000
165:10-7-29	Failure to obtain permit for a one-time application of freshwater-based drill cuttings to private access areas, well locations and production sites.	$2,000
165:10-9-1	Failure to obtain permit for construction and use of commercial pit.	$5,000
165:10-9-1	Illegal discharge from a commercial pit.	$5,000
165:10-11-1	Failure to acquire license to pull pipe and plug wells.	$2,500

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165:10-11-4	Failure to obtain plugging instructions and notify district office of time well is to be plugged.	$1,000

[**Source:** New in Rule Making 200200017, eff 7-1-02]

APPENDIX F. SCHEDULE B FINES [REVOKED]

[**Source:** Revoked in Rule Making 200200017, eff 7-1-02]

APPENDIX F. SCHEDULE B FINES [NEW]

RULE	VIOLATION	FINE
165:10-1-10	Failure to maintain current surety.	$500
165:10-3-4	Failure to protect treatable water or file for alternate casing procedure.	$2,500
165:10-3-17	Failure to remove trash, debris and junk from well site.	Up to $1,000
165:10-3-17	Failure to post lease sign or OTC number.	$50 per well/$500 per lease
165:10-3-25	Failure to file completion report, Form 1002A.	$250
165:10-3-26	Failure to submit required electric logs.	$250
165:10-3-35	Failure to obtain order for multiple completion.	$500
165:10-3-39	Failure to obtain order for commingling.	$500
165:10-5-6	Failure to conduct/perform mandatory initial mechanical integrity test within rule timeframe.	$500
165:10-5-6	Failure to perform subsequent mechanical integrity test.	$500
165:10-5-7	Failure to file fluid injection report, Form 1012.	$500
165:10-5-7	Failure to report loss of mechanical integrity on well.	$1,500
165:10-7-5	Failure to report non-permitted discharge.	$500
165:10-7-16	Failure to comply with any closure requirement for noncommercial pit.	$1,000
165:10-9-1	Failure to close commercial pit as required by rule.	$1,000
165:10-11-3	Failure to plug well in rule timeframe.	$1,000
165:10-11-7	Failure to file plugging and cementing report as required by rule.	$500

[**Source:** New in Rule Making 200200017, eff 7-1-02]

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APPENDIX G.

IMPLEMENTATION FEES (ONE - TIME)

No. of RIOs*	No. of Working Interest Owners 2-10	11-20	21+
2-30	$350	$500	$650
31-100	$500	$500	$650
100+	$650	$650	$650

MAINTENANCE FEES (ANNUAL)

No. of RIOs*	No. of Working Interest Owners 2-10	11-20	21+
2-30	$200	$325	$450
31-100	$325	$325	$450
100+	$450	$450	$450

* RIO = Royalty Interest Owners

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

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APPENDIX H. CALCULATIONS

PROCEDURE FOR CALCULATING LOADING RATE OF TOTAL SOLUBLE SALTS (TSS)

__________ ppm TSS in soil[1] X 2 = __________ lbs/ac TSS in soil

6,000 lbs/ac TSS – ________________ lbs/ac TSS in soil = Maximum TSS (lbs/ac) to be applied ____________

Maximum TSS (lbs/ac) ________ ÷ (________ ppm TSS in pit materials[1] X .000001) = Maximum lbs/ac of pit materials to be applied _________

Maximum lbs/ac ________ ÷ ________ lbs/bbl = Maximum bbls/ac _______

PROCEDURE FOR CALCULATING LOADING RATE OF HEAVY METALS AND OIL AND GREASE

OCC Standard for the parameter _______ lbs/ac ÷ (_______ ppm in pit materials X .000001) = Maximum lbs/ac of pit materials to be applied _________

Maximum lbs/ac _______ ÷ _______ lbs/bbl = Maximum bbls/ac ________

PROCEDURE FOR CALCULATING MAXIMUM DRY WEIGHT

Weight of drilling mud[2] ______ lbs/gal x 42 = ______ lbs/bbl

200,000 lbs ÷ ______ lbs/bbl = Maximum bbls/acre ______

PROCEDURE FOR CALCULATING VOLUME OF PIT CONTENTS

$$V = \frac{(W_t \times L_t) + (W_b \times L_b)}{2} \times D \times .1781$$

Where, V = volume

W_t = width of pit in feet at top of pit contents.

L_t = length of pit in feet at top of pit contents.

W_b = width of pit in feet at bottom of pit.

L_b = length of pit in feet at bottom of pit.

D = depth in feet of pit contents to be soil farmed.

[1]Electrical Conductivity (EC expressed in micromhos/cm) may be used to estimate TSS: EC x 0.64 = ppm TSS.

[2]Based on laboratory analysis of Dry Weight.

[**Source:** Added at 12 Ok Reg 2017, 7-1-95]

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APPENDIX I. SOIL LOADING FORMULAS

TOTAL DISSOLVED SOLIDS

EC of receiving soil ______ micromhos/cm x 0.64 = ______ ppm TDS. TDS in receiving soil ________ ppm x 2 = _______ lbs/ac TDS in receiving soil.

6,000 lbs/ac TDS* - _______ lbs/ac TDS in receiving soil = Maximum TDS (lbs/ac) to be applied _______.

EC of materials to be applied ________ micromhos/cm x 0.64 = _______ ppm TDS.

Maximum TDS (lbs/ac) to be applied _______ ÷ (TDS of materials to be applied ________ ppm x .000001) = Maximum weight of materials to be applied _______ lbs/ac.

FOR LIQUID MATERIALS:

Maximum weight of materials to be applied _______ lbs/ac ÷ (sample weight _______ lbs/gal** x 42) = Maximum loading _______ bbls/ac.

Total volume of materials to be applied _______ bbls ÷ Maximum loading ________ bbls/ac = Minimum acres required ________.

FOR SOLID MATERIALS:

Maximum weight of materials to be applied ________ lbs/ac ÷ (sample weight _______ lbs/gal** x 202) = Maximum loading ________ cu yds/ac.

Total volume of materials to be applied _________ cu yds ÷ Maximum loading ______ cu yds/ac = Minimum acres required _______.

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CHLORIDES

Cl in receiving soil _________ ppm x 2 = _________ lbs/ac Cl in receiving soil.

3500 lbs/ac Cl – ________ lbs/ac Cl in receiving soil = Maximum Cl (lbs/ac) to be applied _________.

Maximum Cl (lbs/ac) to be applied _________ ÷ (Cl of materials to be applied _________ ppm x .000001) = Maximum weight of materials to be applied _________ lbs/ac.

Maximum weight of materials to be applied _________ lbs/ac ÷ (sample weight _________ lbs/gal** x 202) = Maximum loading _________ cu yds/ac.

Total volume of materials to be applied _________ cu yds ÷ Maximum loading _________ cu yds/ac = Minimum acres required _________.

OIL AND GREASE[1]

40,000 lbs/ac O&G* ÷ (O&G of materials to be applied _________ ppm x .000001) = Maximum weight of materials to be applied ________ lbs/ac.

FOR LIQUID MATERIALS:

Maximum weight of materials to be applied ________ lbs/ac ÷ (sample weight __________ lbs/gal** x 42) = Maximum loading ________ bbls/ac.

Total volume of materials to be applied ________ bbls ÷ Maximum loading _________ bbls/ac = Minimum acres required _________.

Maximum bbls/ac ÷ 4.809 = Maximum cu yds/ac _________.

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FOR SOLID MATERIALS:

Maximum weight of materials to be applied _________ lbs/ac ÷ (sample weight _________ lbs/gal** x 202) = Maximum loading _________ cu yds/ac.

Total volume of materials to be applied ________ cu yds ÷ Maximum loading ________ cu yds/ac = Minimum acres required ________.

DRY WEIGHT

Wet weight of drilling mud**_________ lbs/gal x _________ % Dry weight = _________ lbs/gal Dry weight.

_________lbs/gal Dry weight x 202 = _________ lbs/cu yd.

200,000 lbs/ac Dry weight ÷ _________ lbs/cu yd = Maximum cu yds/ac _________.

Total volume of materials to be applied _________ cu yds ÷ Maximum cu yds/ac _________ = Minimum acres required _________.

*Soil loading standards are based upon standards set forth in "Diagnosis and Improvement of Saline and Alkaline Soils," U.S. Agriculture Handbook 60. Pub. U.S. Salinity Laboratory, Riverdale, California, 1954; Moseley, H.R., "Summary and Analysis of API Onshore Drilling Mud and Produced Water Environmental Studies," 1983, American Petroleum Institute Bulletin D-19.

**Based on actual weight of composite sample of materials.

[1] GRO or DRO may be substituted for oil and grease

[**SOURCE:** Added at 12 Ok Reg 2039, 7-1-95; Amended in Rule Making 97000002, eff 7-1-97

APPENDIX J. DEWATERING OIL ALLOWABLE TABLE

(100 percent of market demand)

Depth*	Barrels Per Day
To-3000	200
3001-4000	400
4001-5000	600
5001-6000	800
6001-7000	1000
7001-8000	1100
8001-9000	1200
9001-10000	1300
10001-	1400

* The depth in feet from the surface of the ground to the top of the producing formation in the oil well.

[**SOURCE:** Added in Rule Making 200100009, eff 7-1-02]

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Appendix E – Texas Regulatory Summary (General)

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Texas Administrative Code

TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.1	**Organization Report; Retention of Records; Notice Requirements**

(a) Filing requirements.

(1) Except as provided under subsection (d) of this section, no organization, including any person, firm, partnership, joint stock association, corporation, or other organization, domestic or foreign, operating wholly or partially within this state, acting as principal or agent for another, for the purpose of performing operations within the jurisdiction of the commission shall perform such operations without having on file with the commission an approved organization report and financial security as required by Texas Natural Resources Code §§91.103-91.1091. Operations within the jurisdiction of the commission include, but are not limited to, the following:

(A) drilling, operating, or producing any oil, gas, geothermal resource, brine mining injection, fluid injection, or oil and gas waste disposal well;

(B) transporting, reclaiming, treating, processing, or refining crude oil, gas and products, or geothermal resources and associated minerals;

(C) discharging, storing, handling, transporting, reclaiming, or disposing of oil and gas waste, including hauling salt water for hire by any method other than pipeline;

(D) operating gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance or repressurizing plants, or recycling plants;

(E) recovering skim oil from a salt water disposal site;

(F) nominating crude oil;

(G) operating a directional survey company;

(H) cleaning a reserve pit;

(I) operating a pipeline;

(J) operating as a cementer approved for plugging wells; or

(K) operating an underground hydrocarbon or natural gas storage facility.

(2) The Commission shall notify organizations that perform operations not included in paragraph (1)(A)-(K) of this subsection of any additional activities subject to the jurisdiction of the Commission which require the filing of the organization report. Such notification shall make the provisions of this section applicable to such activities.

(3) Each organization performing activities subject to the jurisdiction of the Commission shall maintain a current organization report with the Commission until all duties, obligations, and liabilities incurred

pursuant to Commission rules, the Natural Resources Code, Titles 3 (Subtitles A, B, C, and Chapter 111 of Subtitle D) and 5, and the Water Code, Chapters 27 and 29, are fulfilled.

(4) The organization report shall contain the following information:

(A) the name, street address, mailing address, telephone number, and emergency after-hours telephone number of the organization;

(B) the plan of the business organization;

(C) for each officer, director, general partner, owner of more than 25% ownership interest, or trustee (hereinafter controlling entity) of the organization:

(i) that entity's or individual's full legal name, the name(s) under which such entity or individual conducts business in the State of Texas, and all assumed names;

(ii) the following:

(I) if the entity is an individual, his or her social security number. Any individual who does not have a valid social security number shall submit, at that person's option, either his or her valid driver's license or Texas State Identification number;

(II) if the entity is not an individual, the name and, at that person's option, either the valid driver's license, social security, or Texas Identification number of each officer, director, or other person, who, under Texas Natural Resources Code, §91.114, holds a position of ownership or control of the organization, or an active P-5 number for that entity. All controlling entities connected to an organization which are not individuals shall provide the identification of the individuals in ownership or control of those entities.

(iii) a street address different than that of the organization; and

(iv) if different from the mailing address of the organization, a mailing address;

(D) if a foreign or nonresident organization, the name and street address of a resident agent.

(E) the name of any non-employee agent that the organization authorizes to act for the organization in signing Oil and Gas Division certificates of compliance which initially designate the operator or change the designation of the operator. Organizations may designate non-employee agents to execute subsequent organization reports. That designation shall be authorized by the organization and not by a non-employee agent.

(5) Any organization may designate a resident agent with a street address different than that of the organization in place of submitting the street addresses of the three (if applicable) primary controlling entities of the organization. Any foreign or nonresident organization identified in paragraph (1) of this subsection shall designate and maintain a resident agent upon whom may be served any process, notice, or demand required or permitted by law to be served upon such entity by or on behalf of the Commission. Failure of such organization to designate and maintain a resident agent shall render the organization report invalid. (Reference Order Number 20-60,617, effective January 1, 1971.)

(6) Failure by any organization identified in paragraph (1) of this subsection to answer any subpoena, commission to take deposition, or directive to appear at a hearing served upon such organization by or on behalf of the Commission shall render the organization report invalid.

(7) An organization shall refile an organization report annually according to the schedule assigned by the

commission. Prior to the filing date, the commission shall mail notification and information to each organization for update of the organization report file. An organization shall file an amended organization report within 15 days after a change in any information required to be reported in the organization report. Only address changes may be made by letter.

(8) The commission shall meet any requirement under statute or commission rule for an order to be sent or notice to be given by the commission to an organization by mailing the item to the organization's mailing address shown on the most recently filed organization report or the most recently filed letter notification of change of address. Notices sent by regular first-class mail shall be presumed to have been received if, upon arrival of the deadline for any response to the notice, the wrapper containing the notice has not been returned to the commission. Any commission action or proceeding for which notice is required shall go forward on the basis of the notice provided under this subsection, whether or not actual notice has been received. Service of notices and orders sent by certified mail is effective upon:

(A) acceptance of the item by any person at the address;

(B) initial failure to claim or refusal to accept the item by any person at the address prior to its eventual return to the commission by the United States Postal Service; or

(C) return of the item to the commission by the United States Postal Service bearing a notation such as "addressee unknown," "no forwarding address," "forwarding order expired," or any similar notation indicating that the organization's mailing address shown on the most recently filed organization report or address change notification letter is incorrect.

(9) An organization may also designate to the commission in writing a specified address for all commission correspondence relating to a particular district. If designated by an operator, this specified address shall be used in lieu of the organization address for any notices, other than hearing notices, pertaining to that district.

(10) The commission may return, unapproved, to the organization address an organization report which is submitted to the commission not fully completed according to the report's written instructions and not timely corrected. In the event that the commission returns an organization report, all submitted financial assurances shall remain non-refundable. If an organization report approved by the commission is found to contain information that was materially false at the time it was submitted for approval, the commission may suspend or revoke the organization report after notice and opportunity for hearing.

(b) Record requirements. All entities who perform operations which are within the jurisdiction of the commission shall keep books showing accurate records of the drilling, redrilling, or deepening of wells, the volumes of crude oil on hand at the end of each month, the volumes of oil, gas, and geothermal resources produced and disposed of, together with records of such information on leases or property sold or transferred, and other information as required by commission rules and regulations in connection with the performance of such operations, which books shall be kept open for the inspection of the commission or its representatives, and shall report such information as required by the commission to do so.

(c) Time frame. All organizations shall keep copies of records, forms, and documents which are required to be filed with the commission, along with the supporting documents referred to in subsection (b) of this section, for a period of three years, or longer if required by another commission rule, and any such copies may be disposed of at the discretion of such entities after the original records, forms, and documents have been on file with the commission for the required period, except that particular documents shall be retained beyond the required period and until the resolution of pending commission regulatory enforcement proceedings if the documents contain information material to the determination of any issues therein. All records, forms, and documents required to be filed with the commission shall be filed in the same name, exactly as it appears on the organization report.

(d) Issuance of permits to organizations without active organization reports.

(1) Notwithstanding contrary provisions of this section, the commission or its delegate may issue a permit to an organization or individual that does not have an active organization report or does not ordinarily conduct oil and gas activities when the issuance of such a permit is determined to be necessary to implement a compliance schedule, or to remedy circumstances or a violation of a commission rule, order, license, permit, or certificate of compliance relating to safety or the prevention of pollution. For permits issued under this subsection, the commission may impose special conditions or terms not found in like permits issued pursuant to other commission rules. Any organization or individual who requests such a permit shall file an organization report and any other required forms for record-keeping purposes only. The report or form shall contain all information ordinarily required to be submitted to the commission.

(2) This section shall not limit the commission's authority to plug or to replug wells or to clean up pollution or unpermitted discharges of oil and gas waste.

(e) Each organization required to file an organization report under subsection (a) of this section or an affiliate of such an organization that performs operations within the jurisdiction of the Commission that files for federal bankruptcy protection shall provide written notice to the Commission of that action not later than the 30th day after the date the organization or the affiliate files for bankruptcy protection by submitting the notice to the Enforcement Section of the Office of General Counsel. All bankruptcy-related notices sent to the Commission shall be submitted in writing to that section. For the purpose of this section, affiliate means an organization that is effectively controlled by another.

(f) Organization reports shall not be approved unless the organization has complied with the state registration requirements of the Secretary of State and the taxation requirements of the Comptroller of Public Accounts. A tax dispute with the Comptroller of Public Accounts shall not be a basis for disapproving an organization report.

Source Note: The provisions of this §3.1 adopted to be effective January 1, 1976; amended to be effective January 1, 1981, 5 TexReg 4990; amended to be effective February 22, 1986, 11 TexReg 701; amended to be effective December 7, 1987, 12 TexReg 4411; amended to be effective July 22, 1991, 16 TexReg 3767; amended to be effective July 1, 1992, 17 TexReg 4173; amended to be effective May 22, 2000, 25 TexReg 4512; amended to be effective January 11, 2004, 29 TexReg 359

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.103	**Certification for Severance Tax Exemption for Casinghead Gas Previously Vented or Flared**

(a) Purpose. The purpose of this section is to provide a procedure by which an operator may obtain commission certification that the operator markets gas that was previously released into the air for 12 months or more pursuant to §3.32 of this title (relating to Gas Well Gas and Casinghead Gas Shall Be Used for Legal Purposes). Certification under this section is voluntary.

(b) Definitions. The following terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise:

(1) Oil lease--A commission-designated oil lease to which the commission has assigned an identifying number as listed on the monthly oil proration schedule at the time an application is filed under this rule.

(2) Oil well--A wellbore completed in a commission-designated field and assigned to an oil lease as listed on the monthly oil proration schedule at the time an application for certification is filed under this rule.

(c) Eligibility. An operator shall be eligible to receive the tax exemption on marketed casinghead gas for the life of an oil well or oil lease as listed on the oil proration schedule at the time an application for certification is filed under this rule if:

(1) the operator previously released the casinghead gas from an oil well or oil lease into the air for 12 months or more pursuant to §3.32 of this title; and

(2) the operator marketed the gas no earlier than June 1, 1997, in accordance with §3.32 of this title.

(d) Certification.

(1) An operator may apply for commission certification on the appropriate form. The completed form shall be accompanied by information necessary to establish:

(A) prior release into the air of casinghead gas for 12 months or more during a period of 13 consecutive months pursuant to §3.32 of this title; and

(B) such gas has generated taxable proceeds subject to the severance tax as a result of being marketed on or after September 1, 1997.

(2) The director of the commissions's Oil and Gas Division, or the director's delegate, may administratively approve or deny a request for certification.

(3) If the director of the commission's Oil and Gas Division or the director's delegate denies the request, the operator may request a hearing by filing such a request in writing within 15 days after the postmarked date of the notice of the administrative denial.

(4) If the operator fails to appear at the hearing without good cause, the request for certification shall be dismissed.

(5) Filings and correspondence concerning the application for certification shall be addressed to the Railroad Commission, P.O. Box 12967, Austin, Texas 78711-2967, Attention: Permitting/Production Services Section.

(e) Application to the Comptroller. After the commission issues the certification provided for in subsection (d) of this section, the operator may apply to the Comptroller of Public Accounts to receive the tax exemption.

(f) Termination of Authorization to Release Gas. On the date the commission issues the certification provided for in subsection (d) of this section, either by administrative action or by commission order, the volume of casinghead gas authorized to be released into the air as an exception obtained pursuant to §3.32(h) of this title shall be reduced to the volume of casinghead gas not subject to the certification. If all of the volume of casinghead gas authorized to be released under an exception is certified for purposes of the tax exemption, the exception shall no longer apply, and shall automatically terminate as of the date of certification.

Source Note: The provisions of this §3.103 adopted to be effective August 4, 1998, 23 TexReg 7770.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.102	**Tax Reduction for Incremental Production**

(a) Purpose. The purpose of this section is to provide a procedure by which an operator can obtain a 50% severance tax reduction for five years on the incremental oil and casinghead gas production from a qualifying lease.

(b) Definitions. The following terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise:

(1) Oil lease--A commission-designated oil lease to which the commission has assigned an identifying number.

(2) Production--Barrels of oil (including barrels of gas liquids reported as production monthly on the appropriate form) plus casinghead gas, where six thousand cubic feet of gas is the equivalent of one barrel of oil, expressed in barrels of oil equivalent (BOE).

(3) Baseline production--An oil lease's average BOE monthly production during the four highest months of production in the time period from January 1, 1996, through December 31, 1996.

(4) Incremental production--Production from a qualifying lease in excess of baseline production.

(5) Incremental production technique--

(A) any secondary or tertiary production enhancement technique;

(B) any primary production enhancement technique that an operator certifies required an expenditure of at least $5,000 to cause increased production.

(6) Qualifying lease--A lease is a qualifying lease provided that:

(A) the commission has designated the lease as an oil lease and has assigned to it an identifying number;

(B) production from the lease, measured by dividing the sum of lease production during the four-month period used to compute the baseline production by the sum of the number of well-days during the same four-month period, is no more than seven barrels of oil equivalent per day per well, excluding gas flared pursuant to the rules of the commission; and

(C) after the operator performs an incremental production technique, the lease shows incremental production for four of five consecutive months on or after September 1, 1997, and before December 31, 1998.

(7) Incremental ratio--The amount of a qualifying lease's average monthly incremental production during the four-month period used to meet the definition of a qualifying lease divided by its average monthly total production during the same four-month period.

(8) Qualified incremental production--A qualifying lease's total monthly production multiplied by the

incremental ratio.

(9) Well-day--One well producing hydrocarbons for one day.

(c) Qualification for the tax reduction. An operator of a qualifying lease is entitled to a 50% tax reduction on that lease's qualified incremental production for five years provided that:

(1) The operator of a qualifying lease applies to the commission for a determination of an incremental ratio before February 11, 1999;

(2) The commission certifies an incremental ratio;

(3) The operator provides to the state comptroller the certified incremental ratio; and

(4) The operator applies to the state comptroller for the tax relief provided by this section not later than one year after the date the commission certifies the incremental ratio for a qualifying lease.

(d) Request for hearing. If the request for certification of an incremental ratio is denied administratively, or if the operator does not agree with the administrative determination of the amount of the incremental ratio, the applicant may request a hearing. The request for a hearing must be filed within 20 days after the date on which notice of the administrative decision is mailed to the operator. The commission shall provide notice of the hearing to the applicant and to any other affected person named by the applicant. After hearing, the examiner shall recommend final action by the commission.

Source Note: The provisions of this §3.102 adopted to be effective June 23, 1998, 23 TexReg 6437.

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PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.101	**Certification for Severance Tax Exemption or Reduction for Gas Produced From High-Cost Gas Wells**

(a) Purpose. This section specifies the procedure by which an operator can obtain a Railroad Commission of Texas certification that natural gas from a particular gas well qualifies as high-cost natural gas under the Texas Tax Code, Chapter 201, Subchapter B, §201.057(a)(2)(A) and that such gas is exempt from or eligible for a reduction of the severance tax imposed by the Texas Tax Code, Chapter 201.

(b) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Commission--The Railroad Commission of Texas.

(2) Completion--The act of making a well capable of producing gas from a particular commission designated or new field.

(3) Completion date--The date on which a well is first made capable of producing oil or gas from a particular commission-designated or new field, as shown on the completion report filed by the operator with the commission.

(4) Comptroller--The Comptroller of Public Accounts of the State of Texas.

(5) Data-point well--A well that has been tested and/or produced in the proposed tight gas formation; and, from the test results or other data, applicant provides a measured or calculated in situ permeability and/or a measured or calculated pre-stimulation stabilized flow rate against atmospheric pressure.

(6) Director--The director of the Oil and Gas Division or the director's delegate. Any authority given to the director in this section is also retained by the commission. Any action taken by the director pursuant to this section is subject to review by the commission.

(7) High-cost gas--Natural gas which the commission finds to be:

(A) produced from any gas well, if production is from a completion which is located at a depth of more than 15,000 feet;

(B) produced from geopressured brine;

(C) occluded natural gas produced from coal seams;

(D) produced from Devonian shale; or

(E) produced from designated tight formations or produced as a result of production enhancement work.

(8) Operator--The person responsible for the actual physical operation of a gas well.

(9) Spud date--The date of commencement of drilling operations, as shown on commission records.

(c) Applicability.

(1) A severance tax exemption is available for high-cost gas produced from a well that is spudded or completed between May 24, 1989, and September 1, 1996. Eligible high-cost gas shall be exempt from the tax imposed by the Texas Tax Code, Chapter 201, during the period from September 1, 1991, through August 31, 2001.

(2) A severance tax reduction is available for high-cost gas produced from a well that is spudded or completed after August 31, 1996. Eligible high-cost gas shall be entitled to a reduction of the tax imposed

by the Texas Tax Code, Chapter 201, for the first 120 consecutive calendar months beginning on the first day of production or until the cumulative value of the tax reduction equals 50% of the drilling and completion costs incurred for the well, whichever occurs first. The amount of tax reduction is determined pursuant to the Texas Tax Code, §201.057(c). If the application for certification is submitted to the Commission after January 1, 2004, the total allowable credit for taxes paid for reporting periods before the date the application is filed may not exceed the total tax paid on the gas that otherwise qualified for the exemption or tax reduction and that was produced during the 24 consecutive calendar months immediately preceding the month in which the application for certification under this section was filed with the Commission.

(3) The plug back or deepening of an existing wellbore qualifies as a completion under this section. When the plug back or deepening is completed prior to September 1, 1996, the gas produced may qualify for a tax exemption. When the plug back or deepening is completed after August 31, 1996, the gas produced may qualify for a tax reduction. The plug back or deepening qualifies as a completion if:

(A) it is the initial completion in a commission-designated or newly discovered field that has not been previously produced from that wellbore; or

(B) the operator can demonstrate that the strata between the former completion and the new completion contain a minimum of 20 vertical feet of impermeable strata; or

(C) the operator submits the results of bottom hole pressure surveys, gas analyses or other methods or calculations comparing the new completion with previous completions in the wellbore that were in existence prior to May 24, 1989. The application shall include an explanation of the engineering principles, calculations, and reasoning to show that the gas to be produced from the applied-for completion could not have been produced from any completion in existence prior to May 24, 1989.

(4) If the operator determines that a gas well previously certified as producing high-cost gas no longer produces high-cost gas or if the operator takes any action or discovers any information that affects the eligibility of gas for an exemption or tax reduction under Texas Tax Code, §201.057, the operator shall notify the Commission in writing within 30 days after such an event occurs.

(5) If the Commission determines that a gas well previously certified as producing high-cost gas no longer produces high-cost gas or if the commission takes any action or discovers any information that affects the eligibility of gas for an exemption or tax reduction under Texas Tax Code, §201.057, the Commission shall notify within 48 hours, in writing, the comptroller and the operator.

(d) Application procedure.

(1) An application for a state severance tax exemption or tax reduction for a gas well may be made only by the operator of that well. The operator shall file one copy of the required application form, one copy of the required attachments specified in subsection (e)(1)-(6) of this section and any additional information deemed necessary by the Commission to clarify, explain and support the required attachments. Submission of legible copies of required attachments shall comply if the application includes a statement, signed by the operator, that the attachments are true and correct copies of the documents originally filed with the Commission. However, the Commission may require an operator to file certified copies of required attachments or other documents from Commission files if necessary for a certification.

(2) Filings and correspondence on high-cost gas state severance tax applications shall be addressed to the Railroad Commission of Texas, P.O. Box 12967, Austin, Texas 78711-2967, Attention: High-Cost Gas Severance Tax Section. No filings may be made at the district offices.

(e) Application requirements for individual well certifications. To qualify for the severance tax exemption or tax reduction, the operator shall prove that the gas produced is high-cost gas by providing the following information:

(1) Applications for wells producing deep high-cost gas shall include:

(A) the completed applicable commission form; and

(B) copies of all Gas Well Back Pressure Test, Completion or Recompletion Reports and Logs ever filed on the subject well.

(2) Applications for wells producing geopressured brine shall include:

(A) the completed applicable commission form;

(B) copies of all Gas Well Back Pressure Test, Completion or Recompletion Reports and Logs ever filed on the subject well;

(C) a bottom-hole pressure test report and other information establishing the initial reservoir pressure gradient; and

(D) evidence to establish that, before production, the gas from the well was in solution in a brine aquifer with at least 10,000 parts of dissolved solids per million parts of water.

(3) Applications for wells producing coal seam gas shall include:

(A) the completed applicable commission form;

(B) copies of all Gas Well Back Pressure Test, Completion or Recompletion Reports and Logs ever filed on the subject well if the gas is produced through a wellbore, or a detailed description of the production process if the gas is not produced through a wellbore;

(C) a radioactivity, electric or other log which will define the coal seams or, if such logs are not reasonably available, a detailed lithologic description of the gas-producing interval; and

(D) evidence to establish that the natural gas was produced from coal seams.

(4) Applications for wells producing Devonian shale gas shall include:

(A) the completed applicable commission form;

(B) copies of all Gas Well Back Pressure Test, Completion or Recompletion Reports and Logs ever filed on the subject well;

(C) an environmentally corrected, calibrated gamma ray log with values greater than 100 API units over the Devonian age stratigraphic section, or a gamma ray log with superimposed indications of the shale base line and the gamma ray index of 0.7 over this section or, if the gamma ray log is not reasonably available, a driller's log or similar report indicating the general characteristics of the strata penetrated and the corresponding depths at which they are encountered throughout the Devonian age stratigraphic section;

(D) information which calculates the percentage of footage of the producing interval which is not Devonian shale as indicated by the gamma ray log, driller's log, or similar report;

(E) information which demonstrates that the percentage of potentially disqualifying nonshale footage for the stratigraphic section selected is equal to or less than 5.0% of the Devonian stratigraphic age interval; and

(F) reference to a standard stratigraphic chart or text establishing that the producing interval is a shale of Devonian age.

(5) Applications for wells producing designated tight formation gas shall include:

(A) the completed applicable commission form;

(B) copies of all Gas Well Back Pressure Test, Completion or Recompletion Reports and Logs ever filed on the subject well;

(C) specific reference to the commission docket number assigned to the applicable designated tight formation area certification along with a copy of the map with the subject well location shown, which outlines the designated tight formation area approved by the commission.

(6) Applications for wells producing production enhancement gas shall include:

(A) the completed applicable commission form;

(B) copies of all Gas Well Back Pressure Test, Completion or Recompletion Reports and Logs ever filed on the subject well;

(C) a description of the production enhancement work that has been performed on the well, including the dates the work was commenced and completed, or that will be performed on the well;

(D) an itemized statement of costs incurred in performing the production enhancement work, including copies of invoices and bills for such work, or, if the work has not yet been completed, estimates of such costs;

(E) a statement estimating, for a five-year test period beginning from the month in which the application is filed, the increase in gas production resulting from the application of production enhancement work;

(F) calculations showing that the projected increase in revenue does not exceed 200% of the §103 price;

(G) the renegotiated price;

(H) a copy of that portion of the sales contract that authorizes collection of the renegotiated price; and

(I) the properly executed statement under oath made by the purchaser of natural gas which states that there is a reasonable basis for the statements and estimates made by the applicant.

(f) Application requirements for tight formation area certifications.

(1) If justification for an individual well application is based on a tight formation certification and the well is not located within a geographical area that has been previously certified as a designated tight formation area or the well is not completed in a formation interval that has been previously certified as a designated tight formation by the Federal Energy Regulatory Commission under the Natural Gas Policy Act or by the Railroad Commission of Texas, the operator shall first apply for a tight formation area designation.

(2) An applicant requesting a tight formation area designation shall submit a written request to the High-Cost Gas Severance Tax Section, at the address given in subsection (d)(2) of this section, for a

certification that a named formation or a specific portion thereof is a tight formation. The applicant shall supply a list of the names and addresses of all affected persons. For purposes of this subsection, "affected persons" means all operators of all wells listed on the current proration schedule for the applicable field or fields located within the proposed designated area. The applicant shall mail or deliver a copy of the prescribed, completed notice of application form to all affected persons, and if required, shall publish the notice of application in accordance with §1.46 of this title (relating to Notice by Publication in Oil and Gas and Surface Mining and Reclamation Nonrulemaking Proceedings), as found in the Commission's General Rules of Practice and Procedure (16 Texas Administrative Code Chapter 1). Notice of application forms may be obtained by contacting the Railroad Commission of Texas, P.O. Box 12967, Austin, Texas 78711-2967, Attention: High-Cost Severance Tax Section. Before Cont'd...

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PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.100	**Seismic Holes and Core Holes**

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Seismic hole--Any hole drilled for the purpose of securing geophysical information to be used in the exploration or development of oil, gas, geothermal, or other mineral resources.

(2) Core hole--Any hole drilled for the purpose of securing geological information to be used in the exploration or development of oil, gas, geothermal, or other mineral resources, except coal or uranium. For regulations governing coal exploratory wells, see Chapter 12 of this title (relating to Coal Mining Regulations), and for regulations governing uranium exploratory wells, see Chapter 11, Subchapter C of this title (relating to Surface Mining and Reclamation Division, Substantive Rules--Uranium Mining).

(3) Project area--The geographic area in which an exploratory survey involving one or more seismic holes or core holes is carried out.

(4) Protection depth--Depth or depths at which usable quality water must be protected or isolated, as determined by the Texas Commission on Environmental Quality (TCEQ) or its successor agencies.

(5) Operator--The person who contracts for the services of a seismic crew or core hole drilling contractor or, if the seismic survey or core hole testing is not performed on a contract basis, but is performed by an exploration and production company or by a geophysical contractor for speculative purposes, the person who drills the seismic holes or core holes.

(6) Commission--The Railroad Commission of Texas or its authorized representative.

(b) Exemption. Any seismic hole or core hole drilled to a depth of 20 feet or less is not subject to the requirements of this section.

(c) Determination of protection depth. Before drilling any seismic hole or core hole in a project area, an operator shall obtain a letter from the TCEQ stating the protection depth or depths in the project area.

(d) Drilling permits.

(1) Holes that do not penetrate any protection depth. A seismic hole or core hole that does not penetrate any protection depth does not require a drilling permit.

(2) Holes that penetrate any protection depth. A seismic hole or core hole that penetrates any protection depth requires a drilling permit to satisfy the requirements for exploratory wells described in §3.5(g) of this title (relating to Application To Drill, Deepen, Reenter, or Plug Back) (Statewide Rule 5).

(e) Plugging.

(1) Holes that do not penetrate any protection depth. A seismic hole or core hole that does not penetrate any protection depth must be plugged in accordance with subparagraph (A) or (B) of this paragraph. Seismic

holes must be plugged after the hole is loaded with explosives. Core holes must be plugged immediately after completion of coring the hole.

(A) The operator shall adequately plug the hole by filling it from total depth to a depth of no more than 16 feet below the surface with drill cuttings and/or bentonite. Immediately above the drill cuttings and/or bentonite, the operator shall place a bentonite plug no less than 10 feet in length. A plastic cap imprinted with the name of the operator shall be set above the bentonite plug no less than three feet below the surface. The remainder of the hole shall be filled with drill cuttings or native soil. All precautions should be taken to prevent bentonite from bridging over.

(B) Alternative plugging procedures and materials may be utilized when the operator has demonstrated to the commission's satisfaction that the alternatives will protect usable quality water.

(2) Holes that penetrate any protection depth. A seismic hole or core hole that penetrates any protection depth must be plugged in accordance with the requirements of §3.14 of this title (relating to Plugging) (Statewide Rule 14) and a plastic cap imprinted with the name of the operator shall be set in the hole no less than three feet below the surface.

(f) Physical requirements for bentonite plugging materials. Bentonite materials used to plug seismic or core holes shall be derived from naturally occurring, untreated, high swelling sodium bentonite that is composed of at least 85% montmorillonite clay and that meets the International Association of Geophysical Contractors (IAGC) recommended geophysical industry standard dated January 24, 1992, for the physical characteristics of bentonite used in seismic shot hole plugging.

(g) Reporting.

(1) Holes that do not penetrate any protection depth. Within 30 days of plugging the last hole in the project area, the operator shall submit a letter to the commission stating that each seismic hole or core hole in the project area has been plugged in accordance with subsection (e)(1) of this section. The letter must include the plugging date for each hole and the name and address of the operator. A plat of the project area identifying seismic or core hole locations, counties, survey lines, scale, and northerly direction must be attached. A United States Geological Survey map of the project area with hole locations marked will satisfy the plat requirement. In addition, a letter from the TCEQ stating the protection depth or depths must be attached.

(2) Holes that penetrate any protection depth. For any seismic or core hole that penetrates any protection depth, a plugging record shall be filed in accordance with §3.14 of this title (relating to Plugging) (Statewide Rule 14).

Source Note: The provisions of this §3.100 adopted to be effective September 1, 1992, 17 TexReg 5283; amended to be effective August 25, 2003, 28 TexReg 6816

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PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.99	**Cathodic Protection Wells**

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Cathodic protection well--Any well drilled for the purpose of installing one or more anodes to prevent corrosion of a facility associated with the production of oil, gas, or geothermal resources, such as a well casing, storage and separation facility, or pipeline.

(2) Project area--The geographic area in which a related group of cathodic protection wells is drilled.

(3) Protection depth--Depth or depths at which usable quality water must be protected or isolated, as determined by the Texas Commission on Environmental Quality (TCEQ) or its successor agencies.

(4) Commission--The Railroad Commission of Texas or its authorized representative.

(b) Exemption. Any cathodic protection well that is drilled to a depth of 30 feet or less is not subject to the requirements of this section.

(c) Determination of protection depth. Before drilling any cathodic protection well, an operator shall obtain a letter from the TCEQ stating the protection depth or depths.

(d) Drilling permits.

(1) Wells that do not penetrate any protection depth. A cathodic protection well that does not penetrate any protection depth does not require a drilling permit.

(2) Wells that penetrate any protection depth. A cathodic protection well that penetrates any protection depth must be drilled in accordance with the requirements of §3.5(g) of this title (relating to Application To Drill, Deepen, Reenter, or Plug Back) (Statewide Rule 5).

(e) Completion.

(1) Timing. A cathodic protection well must be completed as soon as possible after it is drilled.

(2) Wells that do not penetrate any protection depth. A cathodic protection well that does not penetrate any protection depth must be completed in accordance with subparagraph (A) or (B) of this paragraph.

(A) The operator must place at least a 10-foot cement or bentonite plug at the top of the well. The top of the plug shall be no less than three feet below the surface, and the remainder of the hole between the top of the plug and the surface shall be filled with drill cuttings or native soil.

(B) Alternative completion procedures and materials may be utilized when the operator has demonstrated to the commission's satisfaction that the alternatives will protect usable quality water.

(3) Wells that penetrate any protection depth. A cathodic protection well that penetrates any protection

depth must be completed in accordance with subparagraph (A) or (B) of this paragraph.

(A) The operator must either set and cement casing to the deepest protection depth penetrated or center a 100-foot cement plug across each protection depth penetrated and must place at least a 10-foot cement or bentonite plug at the top of the well. The top of the plug shall be no less than three feet below the surface, and the remainder of the hole between the top of the plug and the surface shall be filled with drill cuttings or native soil.

(B) Alternative completion procedures and materials may be utilized when the operator has demonstrated to the commission's satisfaction that the alternatives will protect usable quality water.

(f) Physical requirements for bentonite plugging materials. Bentonite materials used to plug cathodic protection wells shall be derived from naturally occurring, untreated, high swelling sodium bentonite that is composed of at least 85% montmorillonite clay and that meets the International Association of Geophysical Contractors (IAGC) recommended geophysical industry standard dated January 24, 1992, for the physical characteristics of bentonite used in seismic shot hole plugging.

(g) Reporting. Within 30 days of completion of the last well in a project area, the operator shall submit a letter to the commission stating that each cathodic protection well in the project area has been completed in accordance with subsection (e) of this section. The letter must include the completion date for each well, the name and address of the operator, and the drilling permit and API numbers of the well, if applicable. A plat of the project area identifying cathodic protection well locations, counties, survey lines, scale, and northerly direction must be attached. In addition, a letter from the TCEQ stating the protection depth or depths must be attached.

(h) Abandonment. Upon abandonment of a cathodic protection well, any wires or vent pipe must be cut off at the top of the 10-foot surface plug, and the vent pipe must be securely capped or plugged.

Source Note: The provisions of this §3.99 adopted to be effective July 21, 1992, 17 TexReg 4877; amended to be effective August 25, 2003, 28 TexReg 6816

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PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.98	**Standards for Management of Hazardous Oil and Gas Waste**

(a) Purpose. The purpose of this section is to establish standards for management of hazardous oil and gas waste.

(b) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Activities associated with the exploration, development, and production of oil or gas or geothermal resources--Activities associated with:

(A) the drilling of exploratory wells, oil wells, gas wells, or geothermal resource wells;

(B) the production of oil, gas, or geothermal resources, including:

(i) activities associated with the drilling of injection water source wells that penetrate the base of usable quality water;

(ii) activities associated with the drilling of cathodic protection holes associated with the cathodic protection of wells and pipelines subject to the jurisdiction of the commission to regulate the production of oil, gas, or geothermal resources;

(iii) activities associated with natural gas or natural gas liquids processing plants or reservoir pressure maintenance or repressurizing plants;

(iv) activities associated with any underground natural gas storage facility, provided the terms "natural gas" and "storage facility" shall have the meanings set out in Texas Natural Resources Code, §91.173;

(v) activities associated with any underground hydrocarbon storage facility, provided the terms "hydrocarbons" and "underground hydrocarbon storage facility" shall have the meanings set out in Texas Natural Resources Code, §91.201; and

(vi) activities associated with the storage, handling, reclamation, gathering, transportation, or distribution of oil or gas prior to the refining of such oil or prior to the use of such gas in any manufacturing process or as a residential or industrial fuel;

(C) the operation, abandonment, and proper plugging of wells subject to the jurisdiction of the commission to regulate the exploration, development, and production of oil or gas or geothermal resources; and

(D) the discharge, storage, handling, transportation, reclamation, or disposal of waste or any other substance or material associated with any activity listed in subparagraphs (A) - (C) of this paragraph.

(2) Administrator--The administrator of the United States Environmental Protection Agency, or the administrator's designee.

(3) Authorized facility--Either:

(A) an authorized recycling or reclamation facility; or

(B) an authorized treatment, storage, or disposal facility.

(4) Authorized recycling or reclamation facility--A facility permitted in accordance with the requirements of 40 CFR, Parts 270 and 124 or Part 271, if required, at which hazardous waste that is to be recycled or reclaimed is managed and whose owner or operator is subject to regulation under:

(A) 40 CFR, §261.6(c) or an equivalent state program (concerning facilities that recycle recyclable materials); or

(B) 40 CFR, Part 266, Subparts C (concerning recyclable materials used in a manner constituting disposal), F (concerning recyclable materials used for precious metal recovery), or G (concerning spent lead-acid batteries being reclaimed), or an equivalent state program.

(5) Authorized representative--The person responsible for the overall operation of all or any part of a facility or generation site.

(6) Authorized treatment, storage, or disposal facility--A facility at which hazardous waste is treated, stored, or disposed of that:

(A) has received either:

(i) a permit (or interim status) in accordance with the requirements of 40 CFR, Parts 270 and 124 (EPA permit); or

(ii) a permit (or interim status) from a state authorized in accordance with 40 CFR, Part 271; and

(B) is authorized under applicable state or federal law to treat, store, or dispose of that type of hazardous waste. If a hazardous oil and gas waste is destined to a facility in an authorized state that has not yet obtained authorization from the EPA to regulate that particular hazardous waste, then the designated facility must be a facility allowed by the receiving state to accept such waste and the facility must have a permit issued by the EPA to manage that waste.

(7) Centralized Waste Collection Facility or CWCF--A facility that meets the requirements of subsection (m)(3) of this section.

(8) Certification--A statement of professional opinion based upon knowledge and belief.

(9) CFR--Code of Federal Regulations.

(10) CESQG--A conditionally exempt small quantity generator, as described in subsection (f)(1) of this section (relating to generator classification and accumulation time).

(11) Commission--The Railroad Commission of Texas or its designee.

(12) Container--Any portable device in which material is stored, transported, treated, disposed of, or otherwise handled.

(13) Contaminated media--Soil, debris, residues, waste, surface waters, ground waters, or other materials containing hazardous oil and gas waste as a result of a discharge or clean-up of a discharge.

(14) Department of Transportation or DOT--The United States Department of Transportation.

(15) Designated facility--An authorized facility that has been designated on the manifest by the generator pursuant to the provisions of subsection (o)(1) of this section (relating to general manifest requirements).

(16) Discharge or hazardous waste discharge--The accidental or intentional spilling, leaking, pumping, pouring, emitting, emptying, or dumping of hazardous waste into or on any land or water.

(17) Disposal--The discharge, deposit, injection, dumping, spilling, leaking, or placing of any hazardous waste into or on any land or water so that such waste or any constituent thereof may enter the environment or be emitted into the air or discharged into any waters, including ground waters.

(18) Disposal facility--A facility or part of a facility at which hazardous waste is intentionally placed into or on any land or water, and at which waste will remain after closure.

(19) Elementary neutralization unit--A device consisting of a tank, tank system, container, transport vehicle, or vessel that is used for neutralizing wastes that are hazardous wastes:

(A) only because they exhibit the characteristic of corrosivity under the test referred to in subsection (e)(1)(D)(ii) of this section (relating to characteristically hazardous wastes); or

(B) they are identified in subsection (e)(1)(D)(i) of this section (relating to listed hazardous wastes) only because they exhibit the corrosivity characteristic.

(20) Empty container--A container or an inner liner removed from a container that has held any hazardous waste and that meets the requirements of 40 CFR, §261.7(b).

(21) Environmental Protection Agency or EPA--The United States Environmental Protection Agency.

(22) EPA Acknowledgment of Consent--The cable sent to the EPA from the United States Embassy in a receiving country that acknowledges the written consent of the receiving country to accept the hazardous waste and describes the terms and conditions of the receiving country's consent to the shipment.

(23) EPA hazardous waste number--The number assigned by the EPA to each hazardous waste listed in 40 CFR, Part 261, Subpart D, and to each characteristic identified in 40 CFR, Part 261, Subpart C.

(24) EPA identification number or EPA ID Number--The number assigned by the EPA to each hazardous waste generator, transporter, and treatment, storage, or disposal facility.

(25) EPA Form 8700-12--The EPA form that must be completed and delivered to the commission in order to obtain an EPA ID number.

(26) Executive director of the TCEQ--The executive director of the TCEQ or the executive director's designee.

(27) Facility--All contiguous land, including structures, other appurtenances, and improvements on the land, used for recycling, reclaiming, treating, storing, or disposing of hazardous waste. A facility may consist of several treatment, storage, or disposal operational units (e.g., one or more landfills, surface impoundments, or combinations thereof).

(28) Generate--To produce hazardous oil and gas waste or to engage in any activity (such as importing) that first causes a hazardous oil and gas waste to become subject to regulation under this section.

(29) Generation site--

(A) Excluding sites addressed in subparagraphs (B) (relating to pipelines) and (C) (relating to gas plants) of this paragraph, any of the following operational units that are owned or operated by one person and other sites at which hazardous oil and gas waste is generated or where actions first cause a hazardous oil and gas waste to become subject to regulation, including but not limited to:

(i) all oil and gas wells that produce to one set of storage or treatment vessels, such as a tank battery, the storage or treatment vessels, associated flowlines, and related land surface;

(ii) an injection or disposal site, that is not part of a generation site described in subparagraph (A)(i) of this paragraph, its related injection or disposal wells, associated injection lines, and related land surface;

(iii) an offshore platform; or

(iv) any other site, including all structures, appurtenances, or other improvements associated with that site that are geographically contiguous, but which may be divided by public or private right-of-way, provided the entrance and exit between the properties is at a cross-roads intersection, and access is by crossing as opposed to going along, the right-of-way.

(B) In the case of a pipeline system (other than a field flowline or injection line system), an equipment station (such as a pump station, breakout station, or compressor station) or any other location along a pipeline (such as a drip pot, pigging station, or rupture), together with any and all structures, other appurtenances, and improvements:

(i) that are geographically contiguous with or are physically related to an equipment station or other location described in this paragraph, but excluding any pipeline that connects two or more such stations or locations;

(ii) that are owned or operated by one person; and

(iii) at which hazardous oil and gas waste is produced or where actions first cause a hazardous oil and gas waste to become subject to regulation.

(C) A natural gas treatment or processing plant or a natural gas liquids processing plant.

(30) Generator--Any person, by generation site, whose act or process produces hazardous oil and gas waste or whose act first causes a hazardous oil and gas waste to become subject to regulation under this section, or such person's authorized representative.

(31) Geothermal energy and associated resources Geothermal energy and associated resources as defined in Texas Natural Resources Code, §141.003(4).

(32) Hazardous oil and gas waste--Any oil and gas waste determined to be hazardous under the provisions of subsection (e) of this section (relating to hazardous waste determination).

(33) Hazardous oil and gas waste constituent--A hazardous waste constituent of hazardous oil and gas waste.

(34) Hazardous waste--A hazardous waste, as defined in 40 CFR, §261.3, including a hazardous oil and gas waste.

(35) Hazardous waste constituent--A constituent that caused the administrator to list a hazardous waste in

40 CFR, Part 261, Subpart D, or a constituent listed in table 1 of 40 CFR, §261.24.

(36) International shipment--The transportation of hazardous oil and gas waste into or out of the jurisdiction of the United States.

(37) Land disposal--The placement in or on the land, except as otherwise provided in 40 CFR, Part 268, including placement in a landfill, surface impoundment, waste pile, injection well, land treatment facility, salt dome formation, salt bed formation, or underground mine or cave, or placement in a concrete vault or bunker intended for disposal purposes.

(38) LQG--A large quantity generator, as described in subsection (f)(3) of this section (relating to generator classification and accumulation time).

(39) Management--The systematic control of the collection, source separation, storage, transportation, processing, treatment, recovery, and disposal of hazardous waste.

(40) Manifest--The shipping document required pursuant to the provisions of subsection (o) of this section (relating to manifests).

(41) Manifest document number--The 12-digit identification number assigned to a generator by the EPA, plus a unique five-digit document number assigned to the manifest by the generator, or preprinted on the manifest, for recording and reporting purposes.

(42) Oil and gas waste--Waste generated in connection with activities associated with the exploration, development, and production of oil or gas or geothermal resources, or the solution mining of brine. Until delegation of authority under RCRA to the commission by EPA, the term "oil and gas waste" shall exclude hazardous waste arising out of or incidental to activities associated with natural gas treatment or natural gas liquids processing plants and reservoir pressure maintenance or repressurizing plants.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.97	**Underground Storage of Gas in Salt Formations**

(a) Definitions. The following terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Affected person--A person who, as a result of actions proposed in an application for a storage facility permit or amendment or modification of an existing storage facility permit, has suffered or may suffer actual injury or economic damage other than as a member of the general public.

(2) Cavern--The storage space created in a salt formation by solution mining.

(3) Commission--The Railroad Commission of Texas.

(4) Emergency shutdown valve--A valve that automatically closes to isolate a gas storage well from surface piping in the event of specified conditions that, if uncontrolled, may cause an emergency.

(5) Fresh water--Water having bacteriological, physical, and chemical properties that make it suitable and feasible for beneficial use for any lawful purpose. For purposes of this section, brine associated with the creation, operation, and maintenance of an underground gas storage facility is not considered fresh water.

(6) Gas storage well or storage well--A well used for the injection or withdrawal of natural gas or any other gaseous substance into or out of an underground gas storage facility.

(7) Leak detector--A device capable of detecting by chemical or physical means the presence of hydrocarbon vapor or the escape of vapor through a small opening.

(8) Operator--The person recognized by the commission as being responsible for the physical operation of an underground gas storage facility, or such person's authorized representative.

(9) Owner--The person recognized by the commission as owning all or part of an underground gas storage facility, or such person's authorized representative.

(10) Person--A natural person, corporation, organization, government, governmental subdivision or agency, business trust, estate, trust, partnership, association, or any other legal entity.

(11) Pollution--Alteration of the physical, chemical, or biological quality of, or the contamination of, water that makes it harmful, detrimental, or injurious to humans, animal life, vegetation, or property, or to public health, safety, or welfare, or impairs the usefulness or the public enjoyment of the water for any lawful or reasonable purpose.

(12) Underground gas storage facility or storage facility--A facility used for the storage of natural gas or any other gaseous substance in an underground salt formation, including surface and subsurface rights, appurtenances, and improvements necessary for the operation of the facility.

(b) Permit required.

(1) General. No person may create, operate, or maintain an underground gas storage facility without obtaining a permit from the commission. A permit issued by the commission for such activities before the effective date of this section shall continue in effect until revoked, modified, or suspended by the commission, or until it expires according to its terms. The provisions of this section apply to permits to conduct gas storage operations issued prior to the effective date of this section, except as otherwise specifically provided.

(2) Conflict with other requirements. If a provision of this section conflicts with any provision or term of a commission order, field rule, or permit, the provision of such order, field rule, or permit shall control.

(c) Application.

(1) Information required. An application for a permit to create, operate, or maintain an underground gas storage facility shall be filed with the commission by the owner or operator, or the proposed owner or operator, on the prescribed form. The application shall contain the information necessary to demonstrate compliance with applicable state laws and commission regulations.

(2) Permit amendment. An application for amendment of an existing underground gas storage facility permit shall be filed with the commission:

(A) prior to any planned enlargement of a cavern in excess of the permitted cavern capacity by solution mining;

(B) when required in accordance with paragraph (3) of this subsection;

(C) prior to the drilling of any additional storage wells;

(D) prior to an increase in the maximum operating pressure above the permitted pressure; or

(E) any time that conditions at the storage facility deviate materially from the conditions specified in the permit or permit application.

(3) Increase in capacity. The owner or operator of a storage facility shall notify the commission if information indicates that the capacity of a cavern exceeds the permitted cavern capacity by 20% or more. Such notification shall be made in writing to the commission within 10 days of the date that the owner or operator of the storage facility knows or has reason to know that the cavern capacity exceeds the permitted capacity by 20% or more. The notification shall include a description of the information that indicates that the permitted cavern capacity has been exceeded, and an estimate of the current cavern capacity. Upon receipt of such information, the commission or its designee may take any one or more of the following actions:

(A) require the permittee to comply with a compliance schedule that lists measures to be taken to ensure that conditions at the storage facility do not pose a danger to life or property, and that no waste of gas, uncontrolled escape of gas, or pollution of fresh water occurs;

(B) require the permittee to file an application to amend the underground gas storage facility permit;

(C) modify, cancel, or suspend the permit as provided in subsection (f) of this section; or

(D) take enforcement action.

(d) Standards for underground storage zone.

(1) Impermeable salt formation. An underground gas storage facility may be created, operated, or maintained only in an impermeable salt formation in a manner that will prevent waste of the stored gases, uncontrolled escape of gases, pollution of fresh water, and danger to life or property. This section does not authorize storage of liquid or liquefied hydrocarbons in an underground salt formation. A permit under §3.95 of this title (relating to Underground Storage of Liquid or Liquefied Hydrocarbons in Salt Formations) is required to convert from storage of natural gas to storage of liquid or liquefied hydrocarbons in an underground salt formation.

(2) Fresh water strata. The applicant must submit with the application a letter from the Texas Commission on Environmental Quality or its successor agencies stating the depth to which fresh water strata occur at each storage facility.

(e) Notice and hearing.

(1) Notice requirements. Such notice shall be given no later than the date the application is mailed to or filed with the commission. The applicant shall give notice of an application for a permit to create, operate, or maintain an underground gas storage facility, or to amend an existing storage facility permit, by mailing or delivering a copy of the application form to:

(A) the surface owner of the tract where the storage facility is located or is proposed to be located;

(B) the surface owner of each tract adjoining the tract where the storage facility is located or is proposed to be located;

(C) each oil, gas, or salt leaseholder, other than the applicant, of the tract on which the storage facility is located or is proposed to be located;

(D) each oil, gas, or salt leaseholder of any tract adjoining the tract on which the storage facility is located or is proposed to be located;

(E) the county clerk of the county or counties where the storage facility is located or is proposed to be located; and

(F) if the storage facility is located or is proposed to be located within city limits, the city clerk or other appropriate city official.

(2) Publication of notice. Notice of the application, in a form approved by the commission or its designee, shall be published by the applicant once a week for three consecutive weeks in a newspaper of general circulation in the county where the storage facility is or is proposed to be located. The applicant shall file proof of publication prior to any hearing on the application or administrative approval of the application.

(3) Notice by publication. The applicant shall make diligent efforts to ascertain the name and address of each person identified under paragraph (1)(A) - (D) of this subsection. The exercise of diligent efforts to ascertain names and addresses of such persons shall require an examination of the county records here the facility is located and an investigation of any other information of which the applicant has actual knowledge. If, after diligent efforts, the applicant has been unable to ascertain the name and address of one or more persons required to be notified under paragraph (1)(A) - (D) of this subsection, the notice requirements for those persons are satisfied by the publication of the notice of application as required in paragraph (2) of this subsection. The applicant must submit an affidavit to the commission specifying the efforts that were taken to identify each person whose name and/or address could not be ascertained.

(4) Hearing required for new permits. A permit application for a new underground gas storage facility will

be considered for approval only after notice and hearing. The commission will give notice of the hearing to all affected persons, local governments, and other persons who express, in writing, an interest in the application. After hearing, the examiner shall recommend a final action by the commission.

(5) Hearing on permit amendments.

(A) An application for an amendment to an existing storage facility permit may be approved administratively if the commission receives no protest from a person notified pursuant to paragraph (1) of this subsection or from any other affected person.

(B) If the commission receives a protest from a person notified pursuant to paragraph (1) of this subsection or from any other affected person within 15 days of the date of receipt of the application by the commission, or of the date of the third publication, whichever is later, or if the commission determines that a hearing is in the public interest, then the applicant will be notified that the application cannot be approved administratively. The commission will schedule a hearing on the application upon written request of the applicant. The commission will give notice of the hearing to all affected persons, local governments, and other persons who express, in writing, an interest in the application. After hearing, the examiner shall recommend a final action by the commission.

(C) If the application is administratively denied, a hearing will be scheduled upon written request of the applicant. After hearing, the examiner shall recommend a final action by the commission.

(f) Modification, cancellation, or suspension of a permit.

(1) General. Any permit may be modified, suspended, or canceled after notice and opportunity for hearing if:

(A) a material change in conditions has occurred in the operation, maintenance, or construction of the storage facility, or there are material deviations from the information originally furnished to the commission. A change in conditions at a facility that does not affect the safe operation of the facility or the ability of the facility to operate without causing waste of hydrocarbons or pollution is not considered to be material;

(B) pollution of fresh water is likely as a result of continued operation of the storage facility;

(C) there are material violations of the terms and provisions of the permit or commission regulations;

(D) the applicant has misrepresented any material facts during the permit issuance process; or

(E) injected fluids are escaping or are likely to escape from the storage facility.

(2) Imminent danger. Notwithstanding the provisions of paragraph (1) of this subsection, in the event of an emergency that presents an imminent danger to life or property, or where waste of hydrocarbons, uncontrolled escape of hydrocarbons, or pollution of fresh water is imminent, the commission or its designee may immediately suspend a storage facility permit until a final order is issued pursuant to a hearing, if any, conducted in accordance with the provisions of paragraph (1) of this subsection. All operations at the facility shall cease upon suspension of a permit under this paragraph.

(g) Transfer of permit. A storage facility permit may not be transferred without the prior approval of the commission, or its designee. Until such transfer is approved by the commission or its designee, the proposed transferee may not conduct any activities authorized by the permit. The following procedure shall be followed when requesting approval for transfer of a permit.

(1) Request. Prior to transferring either ownership or operation of a storage facility, the permittee shall file

with the commission a request for transfer of the permit. Such a request may not be filed unless a completed Form P-4, signed by both the permittee and the proposed transferee, has been filed with the commission.

(2) Approval. The commission, or its designee, shall approve the transfer of a storage facility permit, provided:

(A) the proposed transferee is not the subject of any unsatisfied commission enforcement order at the time of the request for permit transfer; and

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.96	**Underground Storage of Gas in Productive or Depleted Reservoirs**

(a) Definitions. The following terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Affected person--A person who, as a result of actions proposed an application for an underground gas storage project permit or an amendment or modification of an existing underground gas storage project permit, has suffered or may suffer actual injury or economic damage other than as a member of the general public.

(2) Commission--The Railroad Commission of Texas.

(3) Fresh water--Water having bacteriological, physical, and chemical properties that make it suitable and feasible for beneficial use for any lawful purpose.

(4) Leak detector--A device capable of detecting by chemical or physical means the presence of hydrocarbon vapor or the escape of vapor through a small opening.

(5) Gas storage or underground gas storage--Storage of natural gas or other gaseous material in a productive or depleted reservoir, exclusive of gas injection for enhanced recovery.

(6) Gas storage project--All surface and subsurface rights, appurtenances, and improvements necessary for conducting underground gas storage operations in a gas storage reservoir.

(7) Gas storage well or storage well--A well used to inject or withdraw natural gas or other gaseous material stored in a productive or depleted reservoir, exclusive of a well used to inject gas for enhanced recovery.

(8) Operator--The person recognized by the commission as being responsible for the physical operation of a gas storage project, or such person's authorized representative.

(9) Person--A natural person, corporation, organization, government, governmental subdivision or agency, business trust, estate, trust, partnership, association, or any other legal entity.

(10) Pollution--Alteration of the physical, chemical, or biological quality of, or the contamination of, water that makes it harmful, detrimental, or injurious to humans, animal life, vegetation, or property, or to public health, safety, or welfare, or impairs the usefulness or the public enjoyment of the water for any lawful or reasonable purpose.

(11) Productive or depleted reservoir--A subsurface sand, stratum, or formation that is productive of, or has previously produced, oil, gas, or geothermal resources.

(b) Permit required.

(1) General. No person may operate a gas storage project without obtaining a permit from the commission.

A permit issued by the commission for operation of a gas storage project before the effective date of this section shall continue in effect until revoked, modified, or suspended by the commission, or until it expires according to its terms. The provisions of this section apply to gas storage projects permitted prior to the effective date of this section, except as otherwise specifically provided.

(2) Conflict with other requirements. If a provision of this section conflicts with any provision or term of a commission order, field rule, or permit, the provision of such order, field rule, or permit shall control.

(c) Application. An application to operate a gas storage project shall be filed with the commission by the owner or operator or proposed owner or operator. The application shall include the following:

(1) compliance with safety requirements--information demonstrating compliance with the provisions of subsection (i) of this section;

(2) request for reservoir designation--a request for designation of a productive or depleted reservoir as a gas storage reservoir, supported by the following:

(A) information demonstrating that the reservoir is suitable for gas storage; and

(B) information demonstrating the amount of recoverable native gas remaining in the reservoir;

(3) compliance with standards for injection wells--information demonstrating compliance with the provisions of subsections (j), (k), and (l) of this section for each gas injection well. The requirements of this paragraph do not apply to wells used for gas withdrawal only;

(4) water protection letter--a letter from the Texas Commission on Environmental Quality or its successor agencies stating the depth to which fresh water strata occur in the project area;

(5) public interest--a request that the commission issue an order containing the findings described in the Texas Natural Resources Code, §91.174(a), if such an order is desired by the applicant;

(6) fees--the fees required under §3.78 of this title (relating to Fees and Financial Security Requirements) for each gas storage well in the storage project that will be used for injection.

(d) Permit amendment. An application for amendment of an existing gas storage project permit shall be filed with the commission as specified in paragraphs (1)-(4) of this subsection.

(1) Expansion of reservoir. An application for permit amendment shall be filed prior to expanding the areal extent of the gas storage reservoir.

(2) Increase in pressure. An application for permit amendment shall be filed prior to increasing the gas storage reservoir pressure above the maximum permitted pressure.

(3) Adding storage wells. An application for permit amendment shall be filed prior to adding additional gas storage wells to the project.

(4) Material deviation. An application for permit amendment shall be filed at any time that conditions at the storage project deviate materially from the conditions specified in the permit or permit application.

(e) Standards for storage reservoir. A gas storage project shall be operated only in a productive or depleted reservoir in a manner that will prevent waste of oil, gas, or geothermal resources, uncontrolled escape of gases, pollution of fresh water, and danger to life or property.

(f) Notice and hearing.

(1) Notice requirements. By no later than the date the application is mailed to or filed with the commission, the applicant shall give notice of an application for a permit to operate a gas storage project, or to amend an existing storage project permit, by mailing or delivering a copy of the application to:

(A) each mineral interest owner, other than the applicant, of the proposed gas storage reservoir;

(B) each leaseholder of minerals lying above or below the proposed gas storage reservoir;

(C) each leaseholder of minerals offsetting the proposed gas storage reservoir;

(D) each owner or leaseholder of any portion of the surface overlying the proposed gas storage reservoir;

(E) the clerk of the county or counties where the proposed gas storage reservoir is located; and

(F) the city clerk or other appropriate city official where the proposed gas storage reservoir is located within city limits.

(2) Publication of notice. Notice of the application for an original or amended gas storage project permit, in a form approved by the commission or its designee, shall be published by the applicant once a week for three consecutive weeks in a newspaper of general circulation in the county where the gas storage project is located. The applicant shall file proof of publication of the notice prior to any hearing on the application or administrative approval.

(3) Notice by publication. The applicant shall make diligent efforts to ascertain the name and address of each person identified under paragraph (1)(A)-(D) of this subsection. The exercise of diligent efforts to ascertain the names and addresses of such persons shall require an examination of county records where the facility is located and an investigation of any other information of which the applicant has actual knowledge. If, after diligent efforts, the applicant has been unable to ascertain the name and address of one or more persons required to be notified under paragraph (1)(A)-(D) of this subsection, the notice requirements for those persons are satisfied by the publication of the notice of application as required in paragraph (2) of this subsection. The applicant must submit an affidavit to the commission specifying the efforts that were taken to identify each person whose name and/or address could not be ascertained.

(4) Hearing required for new permits. An application for a new gas storage project permit will be considered for approval only after notice and hearing. The commission will give notice of the hearing to all affected persons, local governments, and other persons who express, in writing, an interest in the application. After hearing, the examiner shall recommend a final action by the commission.

(5) Hearing on permit amendments.

(A) If the commission receives a protest regarding an application for amendment of a gas storage project permit from a person notified pursuant to paragraph (1) of this subsection or from any other affected person within 15 days of the date of receipt of the application by the commission, or of the date of the third publication, whichever is later, or if the commission or its designee determines that a hearing is in the public interest, then the applicant will be notified that the application for amendment cannot be administratively approved. The commission will schedule a hearing on the application upon request of the applicant. The commission will give notice of the hearing to all affected persons, local governments, and other persons who express, in writing, an interest in the application. After hearing, the examiner shall recommend a final action by the commission.

(B) If the commission receives no protest regarding an application for amendment of a gas storage project permit from a person notified pursuant to paragraph (1) of this subsection or from any other affected person, the application may be approved administratively.

(C) If the application for amendment of a gas storage project permit is administratively denied, a hearing will be scheduled upon written request of the applicant. After hearing, the examiner shall recommend a final action by the commission.

(g) Modification, cancellation, or suspension of a permit.

(1) General. A permit may be modified, suspended, or canceled after notice and opportunity for hearing under any of the following circumstances:

(A) a material change in conditions has occurred in the operation of the gas storage project, or there are material deviations from the information originally furnished to the commission. A change in conditions at a facility that does not affect the safe operation of the facility or the ability of the facility to operate without causing waste of hydrocarbons or pollution is not considered to be material;

(B) fresh water is likely to be polluted as a result of the continued operation of the gas storage project;

(C) there are material violations of the terms and provisions of the permit or of applicable commission orders or regulations;

(D) the applicant has misrepresented material facts during the permit issuance process; or

(E) injected fluids are escaping or are likely to escape from the storage project.

(2) Imminent danger. Notwithstanding the provisions of paragraph (1) of this subsection, in the event of an emergency that presents an imminent danger to life or property, or where waste of hydrocarbons, uncontrolled escape of hydrocarbons, or pollution of fresh water is imminent, the commission or its designee may immediately suspend a permit for underground gas storage until a final order is issued pursuant to a hearing, if any, conducted in accordance with the provisions of paragraph (1) of this subsection. All underground gas storage operations shall cease upon suspension of a permit under this paragraph.

(h) Transfer of permit. A gas storage project permit may be transferred from one operator to another operator if both of the following requirements are met.

(1) Notice. Written notice of intended permit transfer is submitted to the commission at least 15 days prior to the date the transfer takes place.

(2) No objection. The commission or its designee does not notify the present permit holder of an objection to the transfer prior to the transfer date stated in the notification in paragraph (1) of this subsection.

(i) Safety requirements for gas storage projects.

(1) Leak detectors.

(A) Within two years of the effective date of this section, leak detectors shall be installed and in operation at each gas storage well that is located 100 yards or less from a residence, commercial establishment, church, school, or small, well-defined outside area, and at each structurally enclosed compressor site. For purposes of this section, the term "small, well-defined outside area" means an area such as a playground, recreation area, outdoor theater, or other place of public assembly that is occupied by 20 or more persons on at least five days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive.

(B) Each leak detector required under this paragraph shall be tested twice each calendar year at intervals not to exceed 7-1/2 months and, when defective, repaired or replaced within 10 days.

(2) Warning systems. Within two years of the effective date of this section, all leak detectors required in paragraph (1) of this subsection shall be integrated with warning systems that are audible and visible in the control room and at any remote control center. The circuitry shall be designed so that failure of a detector or pressure monitor to function will activate the warning.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.95	**Underground Storage of Liquid or Liquefied Hydrocarbons in Salt Formations**

(a) Definitions. The following terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Affected person--A person who, as a result of actions proposed in an application for a storage facility permit or for amendment or modification of an existing storage facility permit, has suffered or may suffer actual injury or economic damage other than as a member of the general public.

(2) Brine string--The uncemented tubing through which highly saline water flows into or out of a hydrocarbon storage well during hydrocarbon withdrawal or injection operations.

(3) Cavern--The storage space created in a salt formation by solution mining.

(4) Commission--The Railroad Commission of Texas.

(5) Emergency shutdown valve--A valve that automatically closes to isolate a hydrocarbon storage well from surface piping in the event of specified conditions that, if uncontrolled, may cause an emergency.

(6) Fire detector--A device capable of detecting the presence of a flame or the heat from a fire.

(7) Fresh water--Water having bacteriological, physical, and chemical properties that make it suitable and feasible for beneficial use for any lawful purpose. For purposes of this section, brine associated with the creation, operation, and maintenance of an underground hydrocarbon storage facility is not considered fresh water.

(8) Hydrocarbon storage well or storage well--A well used for the injection or withdrawal of liquid or liquefied hydrocarbons into or out of an underground hydrocarbon storage facility.

(9) Leak detector--A device capable of detecting by chemical or physical means the presence of hydrocarbon vapor or the escape of vapor through a small opening.

(10) Liquid or liquefied hydrocarbons--Crude oil and products, derivatives, or by-products of oil or gas that are:

(A) liquid under standard conditions of temperature and pressure;

(B) liquefied under the temperatures and pressures at which they are stored; or

(C) stored under conditions that necessitate the use of displacement fluids to withdraw them from storage.

(11) Operator--The person recognized by the commission as being responsible for the physical operation of an underground hydrocarbon storage facility, or such person's authorized representative.

(12) Owner--The person recognized by the commission as owning all or part of a storage facility, or such

person's authorized representative.

(13) Person--A natural person, corporation, organization, government, governmental subdivision or agency, business trust, estate, trust, partnership, association, or any other legal entity.

(14) Pollution--Alteration of the physical, chemical, or biological quality of, or the contamination of, water that makes it harmful, detrimental, or injurious to humans, animal life, vegetation, or property, or to public health, safety, or welfare, or impairs the usefulness or the public enjoyment of the water for any lawful or reasonable purpose.

(15) Process or transfer area--Any area at an underground hydrocarbon storage facility where hydrocarbons are physically altered by equipment, including dehydrators, compressors, and pumps, or where hydrocarbons are transferred to or from trucks, rail cars, or pipelines.

(16) Underground hydrocarbon storage facility or storage facility--A facility used for the storage of liquid or liquefied hydrocarbons in an underground salt formation, including surface and subsurface rights, appurtenances, and improvements necessary for the operation of the facility.

(b) Permit required.

(1) General. No person may create, operate, or maintain an underground hydrocarbon storage facility without obtaining a permit from the commission. A permit issued by the commission for such activities before the effective date of this section shall continue in effect until revoked, modified, or suspended by the commission, or until it expires by its terms. The provisions of this section apply to permits for underground hydrocarbon storage facility operations issued prior to the effective date of this section, except as specifically provided in this section.

(2) Conflict with other requirements. If a provision of this section conflicts with any provision or term of a commission order, field rule, or permit, the provision of such order, field rule, or permit shall control.

(c) Application.

(1) Information required. An application for a permit to create, operate, or maintain an underground hydrocarbon storage facility shall be filed with the commission by the owner or operator, or proposed owner or operator, on the prescribed form. The application shall contain the information necessary to demonstrate compliance with the applicable state laws and commission regulations.

(2) Permit amendment. An application for amendment of an existing underground hydrocarbon storage facility permit shall be filed with the commission:

(A) prior to any planned enlargement of a cavern in excess of the permitted cavern capacity by solution mining;

(B) when required in accordance with paragraph (3) of this subsection;

(C) prior to the drilling of any additional hydrocarbon storage wells;

(D) prior to any increase in the volume of liquid or liquefied hydrocarbons stored in the cavern in excess of the permitted storage volume; or

(E) any time that conditions at the storage facility deviate materially from conditions specified in the permit or the permit application.

(3) Increase in capacity. The owner or operator of a storage facility shall notify the commission if information indicates that the capacity of a cavern exceeds the permitted cavern capacity by 20% or more. Such notification shall be made in writing to the commission within 10 days of the date that the owner or operator knows or has reason to know that the cavern capacity exceeds the permitted capacity by 20% or more. The notification shall include a description of the information that indicates that the permitted cavern capacity has been exceeded, and an estimate of the current cavern capacity. Upon receipt of such information, the commission or its designee may take any one or more of the following actions:

(A) require the permittee to comply with a compliance schedule that lists measures to be taken to ensure that conditions at the storage facility do not pose a danger to life or property, and that no waste of hydrocarbons, uncontrolled escape of hydrocarbons, or pollution of fresh water occurs;

(B) require the permittee to file an application to amend the underground hydrocarbon storage facility permit;

(C) modify, cancel, or suspend the permit as provided in subsection (f) of this section; or

(D) take enforcement action.

(4) Related activities. An application for a permit to dispose of saltwater or other oil and gas waste arising out of or incidental to the creation, operation, or maintenance of an underground hydrocarbon storage facility shall be filed in accordance with applicable commission requirements.

(d) Standards for underground storage zone.

(1) Impermeable salt formation. An underground hydrocarbon storage facility may be created, operated, or maintained only in an impermeable salt formation in a manner that will prevent waste of the stored hydrocarbons, uncontrolled escape of hydrocarbons, pollution of fresh water, and danger to life or property. Natural gas storage operations are not authorized under the provisions of this section. A permit under §3.97 of this title (relating to Underground Storage of Gas in Salt Formations) is required to convert from storage of liquid or liquefied hydrocarbons to storage of natural gas in an underground salt formation.

(2) Fresh water strata. The applicant must submit with the application a letter from the Texas Commission on Environmental Quality or its successor agencies stating the depth to which fresh water strata occur at each storage facility.

(e) Notice and hearing.

(1) Notice requirements. Such notice shall be given no later than the date the application is mailed to or filed with the commission. The applicant shall give notice of an application for a permit to create, operate, or maintain an underground hydrocarbon storage facility, or to amend an existing storage facility permit, by mailing or delivering a copy of the application form to:

(A) the surface owner of the tract where the storage facility is located or is proposed to be located;

(B) the surface owner of each tract adjoining the tract where the storage facility is located or is proposed to be located;

(C) each oil, gas, or salt leaseholder, other than the applicant, of the tract on which the storage facility is located or is proposed to be located;

(D) each oil, gas, or salt leaseholder of any tract adjoining the tract on which the storage facility is located or is proposed to be located;

(E) the county clerk of the county where the storage facility is located or is proposed to be located; and

(F) if the storage facility is located or proposed to be located within city limits, the city clerk or other appropriate city official.

(2) Publication of notice. Notice of the application, in a form approved by the commission or its designee, shall be published by the applicant once a week for three consecutive weeks in a newspaper of general circulation in the county or counties where the facility is or is proposed to be located. The applicant shall file proof of publication prior to any hearing on the application or administrative approval of the application.

(3) Notice by publication. The applicant shall make diligent efforts to ascertain the name and address of each person identified under paragraph (1)(A) - (D) of this subsection. The exercise of diligent efforts to ascertain the names and addresses of such persons shall require an examination of the county records where the facility is located and an investigation of any other information of which the applicant has actual knowledge. If, after diligent efforts, the applicant has been unable to ascertain the name and address of one or more persons required to be notified under paragraph (1)(A) - (D) of this subsection, the notice requirements for those persons are satisfied by the publication of the notice of application as required in paragraph (2) of this subsection. The applicant must submit an affidavit to the commission specifying the efforts that were taken to identify each person whose name and/or address could not be ascertained.

(4) Hearing required for new permits. A permit application for a new underground hydrocarbon storage facility will be considered for approval only after notice and hearing. The commission will give notice of the hearing to all affected persons, local governments, and other persons who express, in writing, an interest in the application. After hearing, the examiner shall recommend a final action by the commission.

(5) Hearing on permit amendments.

(A) An application for an amendment to an existing storage facility permit may be approved administratively if the commission receives no protest from a person notified pursuant to the provisions of paragraph (1) of this subsection, or from any other affected person.

(B) If the commission receives a protest from a person notified pursuant to paragraph (1) of this subsection or from any other affected person within 15 days of the date of receipt of the application by the commission, or of the date of the third publication, whichever is later, or if the commission determines that a hearing is in the public interest, then the applicant will be notified that the application cannot be approved administratively. The commission will schedule a hearing on the application upon written request of the applicant. The commission will give notice of the hearing to all affected persons, local governments, and other persons who express, in writing, an interest in the application. After hearing, the examiner shall recommend a final action by the commission.

(C) If the application is administratively denied, a hearing will be scheduled upon written request of the applicant. After hearing, the examiner shall recommend a final action by the commission.

(f) Modification, cancellation, or suspension of a permit.

(1) General. Any permit may be modified, suspended, or canceled after notice and opportunity for hearing if:

(A) a material change in conditions has occurred in the operation, maintenance, or construction of the storage facility, or there are material deviations from the information originally furnished to the commission. A change in conditions at a facility that does not affect the safe operation of the facility or the ability of the facility to operate without causing waste of hydrocarbons or pollution is not considered to be material;

(B) fresh water is likely to be polluted as a result of continued operation of the facility;

(C) there are material violations of the terms and provisions of the permit or commission regulations;

(D) the applicant has misrepresented any material facts during the permit issuance process; or

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.93	**Water Quality Certification Definitions**

(a) The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) 401 certification--A certification issued by the commission, under the authority of the Federal Clean Water Act, §401, that a federal permit that may result in a discharge to waters of the United States is consistent with applicable state and federal water quality laws and regulations.

(2) Commission--The Railroad Commission of Texas or its designee.

(3) Department of the Army permits--Individual or general permits or letters of permission issued by the U.S. Army Corps of Engineers under the authority of the Federal Clean Water Act, §404, or the Rivers and Harbors Act of 1899, §9 and §10, United States Code, Title 33, §402 and §403.

(4) District engineer--The U.S. Army Corps of Engineers representative responsible for administering and enforcing federal laws and regulations, including processing and issuance of permits, under the jurisdiction of the U.S. Army Corps of Engineers.

(5) Federal Clean Water Act--United States Code, Title 33, Chapter 26.

(6) NPDES permit--A permit issued by the regional administrator under the authority of the Federal Clean Water Act, §402, Title 33, United States Code, §1342. NPDES permits can either be individual or general permits.

(7) Permitting agency--Any agency of the federal government to which application is made for any permit to conduct an activity that may result in any discharge into waters of the United States.

(8) Person--A natural person, corporation, organization, government or governmental subdivision or agency, business trust, estate, trust, partnership, association, or any other legal entity.

(9) Pollutant--Any constituent that contaminates or alters the physical, thermal, chemical, or biological quality of water so as to be harmful, detrimental, or injurious to humans, animal life, vegetation, or property or to the public health, safety, or welfare, or that impairs the usefulness or the public enjoyment of the water for any lawful purpose.

(10) Regional administrator--The administrator of the United States Environmental Protection Agency, Region 6.

(11) Water quality standards--Texas Surface Water Quality Standards, Title 30, Texas Administrative Code, Chapter 307.

(12) Waters of the United States--Interstate waters, the territorial seas, and waters that would or could affect interstate commerce, including tributaries of such waters and adjacent wetlands, as defined in Title 33, Code of Federal Regulations, Part 328.

(b) Certification Required. No person may conduct any activity subject to the jurisdiction of the commission pursuant to a Department of the Army permit or an NPDES permit if the activity may result in a discharge into waters of the United States within the boundaries of the State of Texas, unless the commission has first issued a certification or waiver of certification under this section.

(c) Request for Certification. The regional administrator, district engineer, or the permit applicant may submit a request for certification to the commission.

(1) Request by Applicant. If the permit applicant requests certification, the applicant shall submit to the commission:

(A) a copy of the completed permit application and any amendments thereto;

(B) a list on a map or on a separate sheet attached to a map of the names and addresses of owners of tracts of land adjacent to the site where the proposed activity would occur and, where the activity may result in a discharge to watercourse other than the Gulf of Mexico or a bay, the owners of each waterfront tract between the potential discharge point and 1/2 mile downstream of the potential discharge point, except for those waterfront tracts within the corporate limits of an incorporated city, town, or village;

(C) a request for certification; and

(D) for Department of the Army permits in the coastal zone, as described in 31 TAC §503.1 (Coastal Management Program Boundary), a description of the acreage proposed to be filled, if any.

(2) Request by EPA or the Corps. Except as provided in subsection (d)(1) of this section, a request for certification submitted by the regional administrator or the district engineer shall contain the information specified in this paragraph:

(A) a copy of the public notice;

(B) a request for certification;

(C) for NPDES permits, a copy of the draft permit, if available; and

(D) for Department of the Army permits in the coastal zone, as described in 31 TAC §503.1 (Coastal Management Program Boundary), a description of the acreage proposed to be filled, if any.

(3) Request for Additional Information. Where the commission believes more information is required to accomplish review of a request for certification, the commission shall notify the applicant or the permitting agency and request such information. In response to such a notification from the commission, the applicant or the permitting agency shall submit such materials as the commission finds necessary for review of the request for certification. Except as otherwise provided, such information shall be provided within ten days of issuance of a request for additional information by the commission.

(d) Notice of Request for Certification.

(1) Joint Notice. Notice of a request for certification shall be made using a joint mailed notice issued by the U.S. Army Corps of Engineers or the U.S. Environmental Protection Agency after agreements with those agencies have been reached regarding the content of the notice and the persons entitled to notice in Texas. When a joint notice is issued by either the U.S. Army Corps of Engineers or the U.S. Environmental Protection Agency, the requirements of subsection (c) (2) of this section do not apply.

(2) Notice by Applicant. If a joint notice is not used as provided in paragraph (1) of this subsection, the

applicant must mail notice of the request for certification on or before the date the request for certification is filed with the commission. Such notice shall include the information required in paragraph (3) of this subsection. The applicant shall provide notice by first class mail to:

(A) the owners of land adjacent to the tract upon which the activity is proposed to take place, and where the activity may result in a discharge to a watercourse other than the Gulf of Mexico or a bay, the surface owners of each waterfront tract between the potential discharge point and 1/2 mile downstream of the potential discharge point, excluding owners of those waterfront tracts within the corporate limits of an incorporated city, town, or village;

(B) the mayor and health authorities of any city or town in which the proposed activity will be located or that is within 1/2 mile downstream of the potential discharge;

(C) the county judge and health authorities of any county in which the proposed activity will be located or that is within 1/2 mile downstream of the potential discharge;

(D) the Texas Commission on Environmental Quality (TCEQ) or its successor agencies;

(E) the Texas Parks and Wildlife Department;

(F) the U.S. Environmental Protection Agency, Region 6;

(G) the U.S. Fish and Wildlife Service; and

(H) for a proposed activity within the coastal management program boundary as defined under Title 31, Texas Administrative Code §503.1 (Coastal Management Program Boundary), the Secretary of the Coastal Coordination Council.

(3) Contents of Notice. Any notice provided as required in paragraph (2) of this subsection shall contain:

(A) the applicant's name and mailing address, together with the name and mailing address of the party conducting the activity, if different from the applicant;

(B) a brief written description of the activity;

(C) a statement that the applicant is seeking certification from the commission under the Federal Clean Water Act, §401;

(D) a statement that any comments concerning the request for certification may be submitted in writing to the assistant Director of Environmental Services, Railroad Commission, 1701 North Congress Avenue, P.O. Box 12967, Austin, Texas 78711-2967, on or before the deadline for submission of written public comments, which, absent special circumstances, shall be at least 30 days after the date notice is mailed; and

(E) a statement that a copy of the permit application is available for review in the office of the federal permitting agency.

(4) Emergency Actions. When the division engineer for the U.S. Army Corps of Engineers authorizes emergency procedures and it is in the public interest to provide a certification in less than 30 days, the commission may waive the notice and hearing requirements under this section and issue a final determination. For emergency actions within the coastal zone, as described in 31 TAC §503.1 (Coastal Management Program Boundary), the commission may only issue a final determination if the emergency action is consistent with the provisions of 31 TAC §501.14(j)(7) (Policies for Specific Activities and Coastal Natural Resource Areas).

(e) Public Comments.

(1) Written Comments. The commission shall consider all comments related to the water quality impacts of the proposed activity that are submitted to the commission in writing prior to the deadline for submission of comments.

(2) Public Meetings. The commission shall hold a meeting to receive public comment on a request for certification if the commission finds that such a meeting is in the public interest. If the commission holds a meeting to receive public comment on a request for certification, the commission shall notify the applicant by first class mail not less than ten days before the date set for the public meeting that a meeting to receive public comment will be held on the request for certification. The commission will also provide notice by first-class mail or by personal service to all of the persons identified under subsection (d)(2) of this section and the federal permitting agency at least ten days prior to the public meeting. The notice of public meeting shall identify the federal permit application; the date, time, place, and nature of the public meeting; the legal authority and jurisdiction under which the public meeting is to be held; the applicant's proposed action; the requirements for submitting written comments; the method for obtaining additional information; and such other information as the commission deems necessary. The notice to the federal permitting agency shall also estimate the additional time necessary to consider the request for certification and shall state that the commission is not waiving certification.

(f) Commission Review of Requests for Certification. After expiration of the time for receipt of public comments, the commission shall determine whether the proposed activity for which a request for certification has been received will result in any discharge into waters of the United States within the boundaries of the State of Texas, and if so, whether the proposed activity will comply with all applicable water quality requirements. Applicable water quality requirements include, but are not limited to, state water quality standards, and any other applicable water quality requirements. For an activity within the boundary of the Texas Coastal Management Program (CMP), applicable state water quality requirements include the enforceable goals and policies of the CMP, Title 31, Texas Administrative Code, Chapter 501.

(g) Final Action.

(1) Issuance of Final Determination. A final determination on a request for certification of an NPDES or Department of the Army permit shall be issued by the commission within 15 days from the close of the public comment period, unless the regional administrator or the district engineer, in consultation with the commission, finds that unusual circumstances require a longer time. If the commission does not act upon the request for certification within 15 days from the close of the public comment period or within a longer time granted by the regional administrator or the district engineer, the commission will be deemed to have waived certification. Notwithstanding any contrary provisions of this paragraph, in unusual circumstances the commission may elect to delay acting upon a request for certification of an NPDES permit until after a review of the draft permit.

(2) Notification of Final Determination. The commission shall notify the applicant, the regional administrator or district engineer, and any person so requesting of its final determination. Such final determination shall waive, grant, grant conditionally or deny certification. The notification of a final determination shall be in writing and shall include:

(A) the name and address of the applicant;

(B) a statement of conditions that are necessary to ensure compliance with the applicable water quality requirements;

(C) when the state certifies a draft permit instead of a permit application, any condition required to ensure compliance with applicable water quality requirements shall be identified, citing the federal or state law references upon which that condition is based. Failure by the commission to provide such a citation waives its right to certify with respect to that condition;

(D) for NPDES permits, a statement of the extent to which each condition of the draft permit can be made less stringent without the concurrence of the commission; and

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.91	**Cleanup of Soil Contaminated by a Crude Oil Spill**

(a) Terms. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Free oil--The crude oil that has not been absorbed by the soil and is accessible for removal.

(2) Sensitive areas--These areas are defined by the presence of factors, whether one or more, that make an area vulnerable to pollution from crude oil spills. Factors that are characteristic of sensitive areas include the presence of shallow groundwater or pathways for communication with deeper groundwater; proximity to surface water, including lakes, rivers, streams, dry or flowing creeks, irrigation canals, stock tanks, and wetlands; proximity to natural wildlife refuges or parks; or proximity to commercial or residential areas.

(3) Hydrocarbon condensate--The light hydrocarbon liquids produced in association with natural gas.

(b) Scope. These cleanup standards and procedures apply to the cleanup of soil in non-sensitive areas contaminated by crude oil spills from activities associated with the exploration, development, and production, including transportation, of oil or gas or geothermal resources as defined in §3.8(a)(30) of this title (relating to Water Protection). For the purposes of this section, crude oil does not include hydrocarbon condensate. These standards and procedures do not apply to hydrocarbon condensate spills, crude oil spills in sensitive areas, or crude oil spills that occurred prior to the effective date of this section. Cleanup requirements for hydrocarbon condensate spills and crude oil spills in sensitive areas will be determined on a case-by-case basis. Cleanup requirements for crude oil contamination that occurred wholly or partially prior to the effective date of this section will also be determined on a case-by-case basis. Where cleanup requirements are to be determined on a case-by-case basis, the operator must consult with the appropriate district office on proper cleanup standards and methods, reporting requirements, or other special procedures.

(c) Requirements for cleanup.

(1) Removal of free oil. To minimize the depth of oil penetration, all free oil must be removed immediately for reclamation or disposal.

(2) Delineation. Once all free oil has been removed, the area of contamination must be immediately delineated, both vertically and horizontally. For purposes of this paragraph, the area of contamination means the affected area with more than 1.0% by weight total petroleum hydrocarbons.

(3) Excavation. At a minimum, all soil containing over 1.0% by weight total petroleum hydrocarbons must be brought to the surface for disposal or remediation.

(4) Prevention of stormwater contamination. To prevent stormwater contamination, soil excavated from the spill site containing over 5.0% by weight total petroleum hydrocarbons must immediately be:

(A) mixed in place to 5.0% by weight or less total petroleum hydrocarbons; or

(B) removed to an approved disposal site; or

(C) removed to a secure interim storage location for future remediation or disposal. The secure interim storage location may be on site or off site. The storage location must be designed to prevent pollution from contaminated stormwater runoff. Placing oily soil on plastic and covering it with plastic is one acceptable means to prevent stormwater contamination; however, other methods may be used if adequate to prevent pollution from stormwater runoff.

(d) Remediation of soil.

(1) Final cleanup level. A final cleanup level of 1.0% by weight total petroleum hydrocarbons must be

achieved as soon as technically feasible, but not later than one year after the spill incident. The operator may select any technically sound method that achieves the final result.

(2) Requirements for bioremediation. If on-site bioremediation or enhanced bioremediation is chosen as the remediation method, the soil to be bioremediated must be mixed with ambient or other soil to achieve a uniform mixture that is no more than 18 inches in depth and that contains no more than 5.0% by weight total petroleum hydrocarbons.

(e) Reporting requirements.

(1) Crude oil spills over five barrels. For each spill exceeding five barrels of crude oil, the responsible operator must comply with the notification and reporting requirements of §3.20 of this title (relating to Notification of Fire Breaks, Leaks, or Blow-outs) and submit a report on a Form H-8 to the appropriate district office. The following information must be included:

(A) area (square feet), maximum depth (feet), and volume (cubic yards) of soil contaminated with greater than 1.0% by weight total petroleum hydrocarbons;

(B) a signed statement that all soil containing over 1.0% by weight total petroleum hydrocarbons was brought to the surface for remediation or disposal;

(C) a signed statement that all soil containing over 5.0% by weight total petroleum hydrocarbons has been mixed in place to 5.0% by weight or less total petroleum hydrocarbons or has been removed to an approved disposal site or to a secure interim storage location;

(D) a detailed description of the disposal or remediation method used or planned to be used for cleanup of the site;

(E) the estimated date of completion of site cleanup.

(2) Crude oil spills over 25 barrels. For each spill exceeding 25 barrels of crude oil, in addition to the report required in paragraph (1) of this subsection, the operator must submit to the appropriate district office a final report upon completion of the cleanup of the site. Analyses of samples representative of the spill site must be submitted to verify that the final cleanup concentration has been achieved.

(3) Crude oil spills of five barrels or less. Spills into the soil of five barrels or less of crude oil must be remediated to these standards, but are not required to be reported to the commission. All spills of crude oil into water must be reported to the commission.

(f) Alternatives. Alternatives to the standards and procedures of this section may be approved by the commission for good cause, such as new technology, if the operator has demonstrated to the commission's satisfaction that the alternatives provide equal or greater protection of the environment. A proposed alternative must be submitted in writing and approved by the commission.

Source Note: The provisions of this §3.91 adopted to be effective November 1, 1993, 18 TexReg 6835.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.86	**Horizontal Drainhole Wells**

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Correlative interval--The depth interval designated by the field rules, by new field designation, or, where a correlative interval has not been designated by the commission, by other evidence submitted by the operator showing the producing interval for the field in which the horizontal drainhole is completed.

(2) Horizontal drainhole--That portion of the wellbore drilled in the correlative interval, between the penetration point and the terminus.

(3) Horizontal drainhole displacement--The calculated horizontal displacement of the horizontal drainhole from the penetration point to the terminus.

(4) Horizontal drainhole well--Any well that is developed with one or more horizontal drainholes having a horizontal drainhole displacement of at least 100 feet.

(5) Penetration point--The point where the drainhole penetrates the top of the correlative interval.

(6) Terminus--The farthest point required to be surveyed along the horizontal drainhole from the penetration point and within the correlative interval.

(b) Drainhole spacing.

(1) No point on a horizontal drainhole shall be drilled nearer than 1,200 feet (horizontal displacement), or other between-well spacing requirement under applicable rules for the field, to any point along any other horizontal drainhole in another well, or to any other well completed or drilling in the same field on the same lease, pooled unit, or unitized tract.

(2) No point on a horizontal drainhole shall be drilled nearer than 467 feet, or other lease-line spacing requirement under applicable rules for the field, from any property line, lease line, or subdivision line.

(3) All wells developed with horizontal drainholes shall otherwise comply with Statewide Rule 37, §3.37 of this title (relating to Statewide Spacing Rule), or other applicable spacing rules.

(c) Well densities. All wells developed with horizontal drainholes shall comply with Statewide Rule 38, §3.38 of this title (relating to Well Densities) or other applicable density rules.

(d) Proration and drilling units.

(1) Acreage may be assigned to each horizontal drainhole well for the purpose of allocating allowable oil or gas production up to the amount specified by applicable rules for a proration unit for a vertical well plus the additional acreage assignment as provided in this paragraph.

Attached Graphic

(2) Assignment of acreage to proration and drilling units for horizontal drainhole wells must be done in accordance with Statewide Rule 40, §3.40 of this title (relating to Assignment of Acreage to Pooled Development and Proration Units).

(3) All proration and drilling units shall consist of continuous and contiguous acreage and proration units shall consist of acreage that can be reasonably considered to be productive of oil or gas.

(4) All points on the horizontal drainhole must be within the proration and drilling unit.

(5) The maximum daily allowable for a horizontal drainhole well shall be determined by multiplying the applicable allowable for a vertical well in the field with a proration unit containing the maximum acreage authorized by the applicable rules for the field, exclusive of tolerance acreage, by a fraction:

(A) the numerator of which is the acreage assigned to the horizontal drainhole well for proration purposes; and

(B) the denominator of which is the maximum acreage authorized by the applicable field rules for proration purposes, exclusive of tolerance acreage. The daily oil allowable shall be adjusted in accordance with Statewide Rule 49(a), §3.49(a) of this title (relating to Gas-Oil Ratio), when applicable.

(6) The maximum diagonal for each proration unit containing a horizontal drainhole well shall be the horizontal drainhole displacement of the longest horizontal drainhole for the well plus:

(A) 2,100 feet for fields that are regulated under statewide rules; or

(B) the maximum diagonal allowed for fields where the special field rules specify a maximum diagonal.

(e) Multiple drainholes allowed.

(1) A single well may be developed with more than one horizontal drainhole originating from a single vertical wellbore.

(2) A horizontal drainhole well developed with more than one horizontal drainhole shall be treated as a single well.

(3) The horizontal drainhole displacement used for calculating additional acreage assignment for a well completed with multiple horizontal drainholes shall be the horizontal drainhole displacement of the longest horizontal drainhole plus the projection of any other horizontal drainhole on a line that extends in a 180 degree direction from the longest horizontal drainhole.

(f) Drilling applications and required reports.

(1) Application. Any intent to develop a new or existing well with horizontal drainholes must be indicated on the application to drill. An application for a permit to drill a horizontal drainhole shall include the fees required by Statewide Rule 78, §3.78 of this title (relating to Fees and Financial Security Requirements), and shall be certified by a person acquainted with the facts, stating that all information in the application is true and complete to the best of that person's knowledge.

(2) Drilling unit plat. The application to drill a horizontal drainhole shall be accompanied by a plat.

(A) In addition to the plat requirements provided for in §3.5 of this title (relating to Application to Drill, Deepen, Reenter, or Plug Back) (Statewide Rule 5), the plat shall include:

(i) the lease, pooled unit, or unitized tract, showing the acreage assigned to the drilling unit for the proposed well and the acreage assigned to the drilling units for all current applied for, permitted, or completed oil, gas, or oil and gas wells on the lease, pooled unit, or unitized tract;

(ii) the surface location of the proposed horizontal drainhole well, and the proposed path, penetration points, and terminus locations of all drainholes;

(iii) two perpendicular lines from the nearest point on the lease line, pooled unit line, or any unleased interest in a tract of the pooled unit, depicting the distance(s) to:

(I) the penetration point(s); and

(II) the terminus location(s);

(iv) perpendicular lines providing the distance in feet from the two nearest non-parallel survey lines to the terminus location(s);

(v) a line providing the distance in feet from the closest point along the horizontal course(s) of the drainhole(s) to the nearest point on the lease line, pooled unit line, or unitized tract line. If there is an unleased interest in a tract of the pooled unit that is nearer than the pooled unit line, the nearest point on that unleased tract boundary shall be used; and

(vi) lines from the nearest oil, gas, or oil and gas well, applied for, permitted or completed in the same lease or pooled unit and in the same field and reservoir depicting the distance to:

(I) the penetration point(s);

(II) the closest point along the horizontal course(s) of the drainhole(s); and

(III) the terminus location(s).

(B) An amended drilling permit application and plat shall be filed after completion of the horizontal drainhole well if the commission determines that the drainhole as drilled is not reasonable with respect to the drainhole represented on the plat filed with the drilling permit application.

(3) Directional survey. A directional survey from the surface to the farthest point drilled on the horizontal drainhole shall be required for all horizontal drainholes. The directional survey and accompanying reports shall be conducted and filed in accordance with Statewide Rules 11 and 12, §3.11 and §3.12 of this title (relating to Inclination and Directional Surveys Required and Directional Survey Company Report). No allowable shall be assigned to any horizontal drainhole well until a directional survey and survey plat has been filed with and accepted by the commission.

(4) Proration unit plat. The required proration unit plat must depict the lease, pooled unit, or unitized tract, showing the acreage assigned to the proration unit for the horizontal drainhole well, the acreage assigned to the proration units for all wells on the lease, pooled unit, or unitized tact, and the path, penetration point, and terminus of all drainholes. No allowable shall be assigned to any horizontal drainhole well until the proration unit plat has been filed with and accepted by the commission.

(g) Exceptions and procedure for obtaining exceptions.

(1) The commission may grant exceptions to this section in order to prevent waste, prevent confiscation, or to protect correlative rights.

(2) If a permit to drill a horizontal drainhole requires an exception to this section, the notice and opportunity for hearing procedures for obtaining exceptions to the density provisions prescribed in Statewide Rule 38, §3.38 of this title (relating to Well Densities), shall be followed as set forth in Statewide Rule 38(h), §3.38(h) of this title (relating to Well Densities).

(3) For notice purposes, the commission presumes that for each adjacent tract and each tract nearer to any point along the proposed or existing horizontal drainhole than the prescribed minimum lease-line spacing distance, affected persons include:

(A) the designated operator;

(B) all lessees of record for tracts that have no designated operator; and

(C) all owners of record of unleased mineral interests.

Source Note: The provisions of this §3.86 adopted to be effective June 1, 1990, 15 TexReg 2635; amended to be effective July 10, 2000, 25 TexReg 6487; amended to be effective June 11, 2001, 26 TexReg 4088; amended to be effective September 1, 2004, 29 TexReg 8271

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.85	**Manifest To Accompany Each Transport of Liquid Hydrocarbons by Vehicle**

(a) The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Cargo manifest--One or more documents that together contain the information required by subsection (c) of this section. That part of a manifest which contains information unique to the particular transport being described (such as date and time of removal) must be part of a book, tablet, or series, wherein the documents are sequentially numbered.

(2) Commission--The Railroad Commission of Texas.

(3) Facility--Any place used to store, process, refine, reclaim, dispose of, or treat liquid hydrocarbons.

(4) Lease--A well producing oil, gas, or oil and gas, and any group of contiguous wells producing oil, gas, or oil and gas of any number operated as a producing unit.

(5) Liquid hydrocarbons--Unrefined oil or condensate, and refined oil or condensate to be blended with unrefined liquid hydrocarbons.

(6) Oil tanker vehicle--A motor vehicle licensed for highway use on a public highway or used on a public highway:

(A) that is equipped with, carrying, pulling, or otherwise transporting an assembly, compartment, tank, or other container that is used for transporting, hauling, or delivering liquids; and

(B) that is being used to transport liquid hydrocarbons on a public highway.

(7) Public highway--A way or place of whatever nature open to the use of the public as a matter of right for the purpose of vehicular travel, even if the way or place is temporarily closed for the purpose of construction, maintenance, or repair.

(8) Transporter--Each gatherer, storer, or other handler of liquid hydrocarbons who moves or transports those liquid hydrocarbons by truck or other motor vehicle, provided however, that the provisions of this rule do not apply to:

(A) common carriers as defined in the Natural Resources Code, Chapter 111; or

(B) the movement of salt water, brine, sludge, drilling mud, or other liquid or semiliquid material if the commission has authorized the entity to move such material and such material contains less than 7.0% liquid hydrocarbon, by volume, or if not authorized by the commission, the movement is not for hire and the material moved does not contain more than 7.0% liquid hydrocarbons by volume.

(b) A cargo manifest must be carried in each oil tanker vehicle transporting liquid hydrocarbons on a public highway in this state and must be presented on request for inspection as provided by subsection (f) of this section.

(c) For each load of liquid hydrocarbons loaded onto and transported by an oil tanker vehicle, the cargo manifest must include:

(1) an identification of the lease or facility from which the liquid hydrocarbons were removed, which must include:

(A) the lease or facility name; and

(B) the name of the operator of the lease or facility;

(2) the total quantity of liquid hydrocarbons removed from the lease or facility and loaded onto the oil tanker vehicle; provided that for purposes of indicating quantity on the copy of the manifest left with the lease operator, top and bottom gauges will suffice. On the other copies, an estimate in barrels must be included;

(3) the date and hour when the liquid hydrocarbons were removed from the lease or facility and loaded onto the oil tanker vehicle;

(4) the identity of the transporter which must include;

(A) the company or individual transporter's name and address;

(B) the oil tanker vehicle driver's name; and

(C) a unique number for the oil tanker vehicle that for a truck tractor and semitrailer type oil tanker vehicle must include unique vehicle numbers for both truck tractor and semitrailer; and

(5) the intended point of destination for the liquid hydrocarbons, including the name of the receiving facility.

(d) Copy of manifest to be left at the lease.

(1) A copy of the cargo manifest must be left at the lease or facility from which the liquid hydrocarbons were removed or delivered to the lease or facility operator, his agent, or his representative.

(2) The requirements of this section may be met by leaving a separate document at the lease or facility from which the liquid hydrocarbons were removed or by delivering to the lease or facility operator a separate document that includes information required under subsection (c)(1)-(3) and (4)(A) and (B) this section.

(3) If more than one load of liquid hydrocarbons is removed from a single tank or other container of liquid hydrocarbons within a period of 24 consecutive hours, subsection (c)(2) and (3) of this section may be met for purposes of this section by a separate document that includes:

(A) the total quantity of liquid hydrocarbons removed;

(B) the date and hour the first load was removed; and

(C) the date and hour the last load was removed.

(4) If the operator of a facility requires that a transporter leave at the facility or deliver to the operator a

document other than the transporter's cargo manifest, a transporter may meet the requirements of this section by leaving those specified documents at an agreed location or delivering the document to the operator.

(e) After the delivery of all liquid hydrocarbons in an oil tanker vehicle is completed, the cargo manifest must be maintained in the records of the transporter for a period of not less than two years from the date the liquid hydrocarbons are removed from the oil tanker vehicle.

(f) Upon request from a commission agent or other law enforcement official the transporter must produce the cargo manifest for inspection immediately, whether it is on an oil tanker vehicle or in the records of the transporter. Copies of cargo manifests must be filed with the commission, upon request from the commission.

(g) Companies or individuals who do not have organization reports (Form P-5) on file with the Railroad Commission, as required by §3.1 of this title (relating to Organization Report; Retention of Records; Notice Requirement (commonly referred to as Statewide Rule 1)), may not issue cargo manifests.

(h) Every truck or other vehicle covered by this section shall bear on both sides thereof the name of the company or individual responsible for such transportation, the number of the vehicle, and the number of the certificate or permit authorizing the service. In the case of vehicles not for hire, this number shall be the company's organizational report (P-5) number. The identifying signs shall be printed in letters not less than two inches in height, in sharp color contrast to the background, and shall be plainly legible for a distance of at least 50 feet.

Source Note: The provisions of this §3.85 adopted to be effective August 25, 2003, 28 TexReg 6816

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.84	**Gas Shortage Emergency Response**

(a) The purpose of this section is to provide a means for a producer or purchaser to increase production and takes from wells in a field in response to an increase in demand caused by unforeseen events. This section outlines the commission's mechanisms for both determining that a gas shortage emergency exists, and responding to a gas shortage emergency.

(b) The commission may, after notice and hearing, determine that a gas shortage emergency exists or has existed. The commission may also determine the duration of the emergency at such hearing. The commission shall issue notice when it has determined that a gas shortage emergency exists, or has existed, and when it determines the gas shortage emergency has ended or will end. In determining whether a gas shortage emergency exists or has existed, the commission shall consider any relevant information, including, but not limited to, the following:

(1) notification from gas storage facilities that they are attaining maximum gas withdrawal rates;

(2) notification from a gas utility, distributor, transporter, producer or purchaser that gas shortages have occurred or are anticipated; and

(3) weather data.

(c) Upon the commission's finding that a gas shortage emergency exists, or has existed, producers or purchasers shall be authorized to meet the increased demand for the duration of the gas shortage emergency as determined by the commission regardless of a well's assigned allowable or allowable status.

(d) If inequities occur as a result of production authorized by subsection (c) of this section, an adjustment shall be made at the hearing in which production reported for the month of the gas shortage emergency is considered in setting future allowables. Such adjustment shall include the assignment of additional allowable to adequately protect correlative rights. The commission may determine the maximum amount of the supplemental allowable by multiplying the number of days of the gas shortage emergency period by the difference between the well's capability (as defined in §3.31 of this title (relating to Gas Reservoirs and Gas Well Allowable)) and the assigned allowable.

Source Note: The provisions of this §3.84 adopted to be effective September 13, 1994, 19 TexReg 6853; amended to be effective November 24, 2004, 29 TexReg 10728

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.83	**Tax Exemption for Two-Year Inactive Wells and Three-Year Inactive Wells**

(a) Purpose. The purpose of this section is to provide a procedure by which an operator can obtain commission certification of a wellbore as a two-year inactive well or three-year inactive well in order to qualify for the tax exemptions provided for in the Tax Code, §§201.053, 202.052, and 202.056.

(b) Definitions.

(1) Two-year inactive well--A well that has not produced any hydrocarbons in more than one calendar month in the two years prior to the date of certification by the Commission under this section.

(2) Three-year inactive well--A well that has not produced any hydrocarbons in more than one calendar month in the three years prior to the date of certification by the commission under this section.

(3) Eligible well--Wells eligible under this section include those that:

(A) were previous producing or injection wells that have not been plugged or abandoned; or

(B) have been plugged and abandoned; or

(C) are active injection wells.

(4) Well--A wellbore with single or multiple completions.

(c) Certification. The commission or its delegate may certify a well as a two-year inactive well or a three-year inactive well. If the commission or its delegate declines to certify a well administratively, the operator affected by this action may request a hearing.

(d) Revocation of Certification. Certification of a two-year inactive well or a three-year inactive well may be revoked by the commission for cause which includes, but is not limited to, receipt of information by the commission that a certified well produced hydrocarbons in more than one calendar month in the applicable two or three years prior to certification, or if production from other wells is credited to the two-year inactive well or the three-year inactive well, or if a certified well is reported to the commission to be capable of production but is not capable of production. The Comptroller of Public Accounts will be notified of any revocation.

(e) Certified Wells.

(1) Three-year inactive wells. The commission may not certify a three-year inactive well under this section after February 29, 1996. Prior to applying to the Comptroller of Public Accounts for the tax incentives listed in subsection (a) of this section, the operator of a three-year inactive certified well shall file with the commission a test report showing productive capability for the well. Production is presumed to begin on this well test date. The certification remains with the well in the event of a change of operator or ownership.

(2) Two-year inactive wells. The commission may not designate a two-year inactive well under this section

after February 28, 2010. An application for two-year inactive well certification shall be made during the period of September 1, 1997, through August 31, 2009, to qualify for the tax exemption. Certification will be issued upon the filing of a test report showing the well's capability and an approval of application for certification. Production is presumed to begin on the well test date as reported on the appropriate report. The certification shall remain with the well in the event of a change of operator or ownership.

Source Note: The provisions of this §3.83 adopted to be effective November 23, 1993, 18 TexReg 8195; amended to be effective January 10, 1996, 20 TexReg 11119; amended to be effective July 21, 1998, 23 TexReg 7363; amended to be effective September 10, 2001, 26 TexReg 6869

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.81	**Brine Mining Injection Wells**

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Affected person--A person who, as a result of the activity sought to be permitted, has suffered or may suffer actual injury or economic damage other than as a member of the general public.

(2) Brine mining facility or facility--The brine mining injection well, and the pits, tanks, fresh water wells, pumps, and other structures and equipment that are or will be used in conjunction with the brine mining injection well.

(3) Brine mining injection well--A well used to inject fluid for the purpose of extracting brine by the solution of a subsurface salt formation. The term "brine mining injection well" does not include a well used to inject fluid for the purpose of leaching a cavern for the underground storage of hydrocarbons or the disposal of waste, or a well used to inject fluid for the purpose of extracting sulphur by the thermofluid mining process.

(4) Commission--The Railroad Commission of Texas.

(5) Director--The director of the Oil and Gas Division or a staff delegate designated in writing by the director of the Oil and Gas Division or the commission.

(6) Existing brine mining injection well--A brine mining injection well in which injection operations began prior to the effective date of this section.

(7) Fresh water--Water having bacteriological, physical, and chemical properties that make it suitable and feasible for beneficial use for any lawful purpose.

(8) New brine mining injection well--A brine mining injection well in which injection operations begin on or after the effective date of this section.

(9) Permit--A written authorization issued by the commission under this section for the operation of a brine mining injection well.

(10) Person--A natural person, corporation, organization, government or governmental subdivision or agency, business trust, estate, trust partnership, association, or any other legal entity.

(11) Pollution--The alteration of the physical, chemical, or biological quality of, or the contamination of, water that makes it harmful, detrimental, or injurious to humans, animal life, vegetation or property or to public health, safety, or welfare, or impairs the usefulness or the public enjoyment of the water for any lawful purpose.

(b) Prohibitions.

(1) Unauthorized injection. No person may operate a brine mining injection well without obtaining a

permit from the commission under this section. No person may begin constructing a new brine mining injection well until the commission has issued a permit to operate the well under this section and a permit to drill, deepen, plug back, or reenter the well under §3.5 of this title (relating to Application to Drill, Deepen, Reenter, or Plug Back) (Statewide Rule 5).

(2) Fluid migration. No person may operate a brine mining injection well in a manner that allow fluids to escape from the permitted injection zone. If fluids are migrating from the permitted injection zone, the operator shall immediately cease injection operations.

(3) Falsifying documents and tampering with gauges. No person may knowingly make any false statement, representation, or certification in any application, report, record, or other document submitted or required to be maintained under this section or under any permit issued pursuant to this section, or falsify, tamper with, or knowingly render inaccurate any monitoring device or method required to be maintained under this section or under any permit issued pursuant to this section.

(c) Standards for permit issuance. A permit may be issued only if the commission determines that the operation of the brine mining injection well will not result in the pollution of fresh water. All permits issued under this section will contain the conditions required by subsections (f) and (g) of this section, and all other conditions reasonably necessary to prevent the pollution of fresh water.

(d) Permit application.

(1) Duty to apply. Any person who operates or proposes to operate a brine mining injection well shall file a permit application with the commission in Austin within the time provided in paragraph (2) of this subsection. The applicant shall mail or deliver a copy of the application to the appropriate district office on the same day the application is mailed or delivered to the commission in Austin. A permit application will be considered filed with the commission on the date it is received by the commission in Austin.

(2) Time to apply.

(A) Any person who proposes to operate a new brine mining injection well shall file a permit application at least 180 days before the date on which injection is to begin, unless a later date has been authorized by the director.

(B) Any person who is operating an existing brine injection well shall file a permit application within 90 days of the effective date of this section.

(C) Any person who has obtained a permit under this section and who wishes to continue to operate the brine mining injection well after the permit expires shall file an application for new permit at least 180 days before the existing permit expires, unless a later date has been authorized by the director.

(3) Who applies. When a brine mining facility is owned by one person but is operated by another person, it is the operator's duty to file an application for a permit.

(4) Application requirements for all applicants. All applicants shall submit the following information, using application forms supplied by the commission:

(A) name, mailing address, and location of the brine mining facility for which the application is submitted;

(B) the operator's name, mailing address, telephone number, and status as federal, state, private, public, or other entity, and a statement indicating whether the operator is the owner of the facility;

(C) the proposed uses for the brine mined at the facility;

(D) a listing of all permits or construction approvals for the facility received or applied for under federal or state environmental programs;

(E) a topographic map, or other map if the topographic map is unavailable, extending one mile beyond the property boundaries of the facility, depicting the facility and those springs, other surface water bodies, drinking water wells, and other wells listed in public records or otherwise known to the applicant within 1/4 mile of the facility property boundary;

(F) a plat showing the oil and gas operators of the tract on which the facility is located and the tracts adjacent to the tract on which the facility is located. On the plat or on a separate sheet attached to the plat, the applicant shall list the names and addresses of the oil and gas operators;

(G) a plat showing the surface ownership of the tract on which the facility is located and the tracts adjacent to the tract on which the facility is located. On the plat or on a separate sheet attached to the plat, the applicant shall list the names and addresses of the surface owners, as determined from the current county tax rolls or other reliable sources, and shall identify the source of the list. If the director determines that, after diligent efforts, the applicant has been unable to ascertain the name and address of one or more surface owners, the director may waive the requirements of this subparagraph with respect to those surface owners;

(H) a map with surveys marked showing the type, location, and depth of all wells of public record within a 1/4 mile radius of the brine mining injection well that penetrate the salt formation. The applicant shall attach the following information to the map:

(i) a tabulation of the wells showing the dates the wells were drilled and the present status of the wells; and

(ii) plugging records for plugged and abandoned wells and completion records for other wells;

(I) a letter from the Texas Commission on Environmental Quality stating the depth to which fresh water strata should be protected;

(J) a complete electric log of the brine mining injection well or a nearby well. On the log, the applicant shall identify the geologic formations between the land surface and the top of the salt formation and the depths at which they occur;

(K) a drawing of the surface and subsurface construction details of the brine mining injection well;

(L) the proposed maximum daily injection rate and maximum injection pressure;

(M) the proposed injection procedure;

(N) the proposed mechanical integrity testing procedure;

(O) the source of mining water to be used at the facility. If the source is groundwater, the following information must be included:

(i) the groundwater formation name;

(ii) an depth of the groundwater formation; and

(iii) an analysis of the groundwater;

(P) the direction of the hydraulic gradient in the area; and

(Q) the proposed groundwater monitoring plan, or an alternate plan for assuring that fluids are not escaping from the permitted injection zone.

(5) Additional information. The applicant shall submit any other information required on the application form supplied by the commission. In addition to the information reported on the application form, the applicant shall submit, at the director's request, any other information the commission may reasonably require to assess the brine mining injection well and to determine whether to issue a permit.

(e) Signatories to applications and reports.

(1) Applications. All applications shall be signed as follows:

(A) for a corporation, by a responsible corporate officer. A responsible corporate officer means a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy-making or decision-making functions for the corporation; or

(B) for a partnership or sole proprietorship, by a general partner or the proprietor, respectively.

(2) Reports. All reports required by permits and other information requested by the commission shall be signed by a person described in paragraph (1) of this subsection or by a duly authorized representative of that person. A person is a duly authorized representative only if:

(A) the authorization is made in writing by a person described in paragraph (1) of this subsection;

(B) the authorization specifies an individual or position having responsibility for the overall operation of the regulated facility; and

(C) the authorization is submitted to the commission before or together with any report of information signed by the authorized representative.

(3) Certification. Any person signing a document under paragraph (1) or (2) of this subsection shall make the following certification: "I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gathered and evaluated the information submitted. Based on my inquiry of the person or persons who manage the system, or who are directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information."

(f) Conditions applicable to all permits. The conditions specified in this subsection apply to all permits.

(1) Duty to comply. The operator shall comply with all conditions of the permit. Any permit noncompliance is grounds for enforcement action, for permit termination, revocation and reissuance, or modification, or for denial of a permit renewal application.

(2) Duty to reapply. If the operator wishes to continue a permitted activity after the expiration date of the permit, the operator shall apply for and obtain a new permit.

(3) Need to halt or reduce activity not a defense. It is not a defense for an operator in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit.

(4) Duty to mitigate. The operator shall take all reasonable steps to minimize and correct any adverse effect on the environment resulting from noncompliance with the permit.

(5) Proper operation and maintenance. The operator shall at all times properly operate and maintain all facilities and systems of treatment and control, and related appurtenances, that are installed or used by the operator to achieve compliance with the conditions of the permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up and auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of the permit.

(6) Permit actions. The permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the operator for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance does not stay any permit condition.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.80	**Commission Oil and Gas Forms, Applications, and Filing Requirements**

(a) Forms. Forms required to be filed at the Commission shall be those prescribed by the Commission as listed in Table 1 of this subsection. A complete set of all Commission forms listed on Table 1 required to be filed at the Commission shall be kept by the Commission secretary and posted on the Commission's web site. Notice of any new or amended forms shall be issued by the Commission. For any required or discretionary filing, an organization may either file the prescribed form on paper or use any electronic filing process in accordance with subsections (e) or (f) of this section, as applicable. The Commission may at its discretion accept an earlier version of a prescribed form, provided that it contains all required information and meets the requirements of subsection (e)(3) of this section.

Attached Graphic

(b) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Commission--The Railroad Commission of Texas.

(2) Electronic filing process--An electronic transmission to the Commission in a prescribed form and/or format authorized by the Commission and completed in accordance with Commission instructions.

(3) Form--A printed or typed paper document or electronic submission, including any necessary instructions, with blank spaces for insertion of required or requested specific information.

(4) Organization--Any person, firm, partnership, joint stock association, corporation, or other organization, domestic or foreign, operating wholly or partially within this state, acting as principal or agent for another, for the purpose of performing operations within the jurisdiction of the Commission.

(5) Position of ownership or control--A person holds a position of ownership or control in an organization if the person is:

(A) an officer or director of the organization;

(B) a general partner of the organization;

(C) the owner of an organization which is a sole proprietorship;

(D) the owner of more than a 25 percent ownership interest in the organization; or

(E) the designated trustee of the organization.

(6) Violation--Non-compliance with a statute, Commission rule, order, license, permit, or certificate relating to safety or the prevention or control of pollution.

(c) Organization eligibility. The Commission may not accept an organization report or an application for a permit, or approve a certificate of compliance if:

(1) the organization that submitted the report, application, or certificate violated a statute or Commission rule, order, license, certificate, or permit that relates to safety or the prevention or control of pollution; or

(2) any person who holds a position of ownership or control in the organization has, within the seven years preceding the date on which the report, application, or certificate is filed, held a position of ownership or control in another organization, and during that period of ownership or control the other organization violated a statute or Commission rule, order, license, permit, or certificate that relates to safety or the prevention or control of pollution.

(d) Violations. An organization has committed a violation if there is either a Commission order against an organization finding that the organization has committed a violation and all appeals have been exhausted or an agreed order entered into by the Commission and an organization relating to an alleged violation, and:

(1) the conditions that constituted the violation or alleged violation have not been corrected;

(2) all administrative, civil and criminal penalties, if any, relating to the violation or agreed settlement relating to an alleged violation have not been paid; or

(3) all reimbursements of costs and expenses, if any, assessed by the Commission relating to the violation or to the alleged violation have not been collected.

(e) Authorization and standards for electronic filing.

(1) An organization may file electronically any form listed on Table 1 for which the Commission has provided an electronic version, provided that the organization pays all required filing fees and complies with all requirements, including but not limited to security procedures, for electronic filing.

(2) The Commission deems an organization that files electronically or on whose behalf is filed electronically any form, as of the time of filing, to have knowledge of and to be responsible for the information filed on the form, pursuant to the statutory requirements, restrictions, and standards found in and pertaining to:

(A) Texas Natural Resources Code, Title 3 (oil and gas well drilling, production, and plugging);

(B) Texas Natural Resources Code, Title 5 (geothermal resources);

(C) Texas Natural Resources Code, Title 11 (hazardous liquids storage);

(D) Texas Utilities Code, Chapter 121, Subchapter I (sour gas pipeline facilities);

(E) Texas Water Code, §26.131 (discharge permits);

(F) Texas Water Code, Chapter 27 (class II injection and disposal wells and class III brine mining wells);

(G) Texas Water Code, Chapter 29 (oil and gas waste haulers);

(H) Texas Health and Safety Code, §401.415 (oil and gas naturally occurring radioactive material (NORM) waste); and

(I) Texas Administrative Code, Title 16, Chapter 3 (Oil and Gas Division) and Chapter 4 (Environmental Protection).

(3) All forms that an organization submits or that are submitted on behalf of an organization shall be transmitted in the manner prescribed by the Commission that is compatible with its software, equipment, and facilities.

(4) The Commission may provide notice electronically to an organization of, and may provide an organization the ability to confirm electronically, the Commission's receipt of a form submitted electronically by or on behalf of that organization.

(5) The Commission deems that the signature of an organization's authorized representative appears on each form submitted electronically by or on behalf of the organization, as if this signature actually appears, as of the time the form is submitted electronically to the Commission.

(6) The Commission holds each organization responsible, under the penalties prescribed in Texas Natural Resources Code, §91.143, for all forms, information, or data that an organization files or that are filed on its behalf. The Commission charges each organization with the obligation to review and correct, if necessary, all forms or data that an organization files or that are filed on its behalf.

(f) Other electronic transmissions. The Commission may at its discretion accept other documents or data electronically transmitted.

Source Note: The provisions of this §3.80 adopted to be effective June 11, 2001, 26 TexReg 4088; amended to be effective April 12, 2004, 29 TexReg 3612; amended to be effective July 12, 2004, 29 TexReg 6633; amended to be effective October 11, 2004, 29 TexReg 9533

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.79	**Definitions**

The following words and terms, when used in this chapter, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Adjacent estuarine zones--This term embraces the area inland from the coast line of Texas and is comprised of the bays, inlets, and estuaries along the gulf coast.

(2) By-product--Any element found in a geothermal formation which when brought to the surface is not used in geothermal heat or pressure inducing energy generation.

(3) Casinghead gas--Any gas or vapor, or both, indigenous to an oil stratum and produced from such stratum with oil.

(4) Commission--The Railroad Commission of Texas.

(5) Common reservoir--Any oil, gas, or geothermal resources field or part thereof which comprises and includes any area which is underlaid, or which from geological or other scientific data or experiments or from drilling operations or other evidence appears to be underlaid by a common pool or accumulation of oil, gas, or geothermal resources.

(6) Cubic foot of gas or standard cubic foot of gas--The volume of gas contained in one cubic foot of space at a standard pressure base and at a standard temperature base. The standard pressure base shall be 14.65 pounds per square inch absolute, and the standard temperature base shall be 60 degrees Fahrenheit. Whenever the conditions of pressure and temperature differ from the standard in this definition, conversion of the volume from these conditions to the standard conditions shall be made in accordance with the ideal gas laws, corrected for deviation.

(7) District office--The commission-designated office for the geographic area in which the property or act subject to regulation is located or arises.

(8) Dry gas--Any natural gas produced from a stratum that does not produce crude petroleum oil.

(9) Exploratory well--Any well drilled for the purpose of securing geological or geophysical information to be used in the exploration or development of oil, gas, geothermal, or other mineral resources, except coal and uranium, and includes what is commonly referred to in the industry as "slim hole tests," "core hole tests," or "seismic holes." For regulations governing coal exploratory wells, see Chapter 12 of this title (relating to Coal Mining Regulations), and for regulations governing uranium exploratory wells, see Chapter 11, Subchapter C of this title (relating to Surface Mining and Reclamation Division, Substantive Rules--Uranium Mining).

(10) Gas lift--Gas lift by the use of gas not in solution with oil produced.

(11) Gas well--Any well:

(A) which produces natural gas not associated or blended with crude petroleum oil at the time of production;

(B) which produces more than 100,000 cubic feet of natural gas to each barrel of crude petroleum oil from the same producing horizon; or

(C) which produces natural gas from a formation or producing horizon productive of gas only encountered in a wellbore through which crude petroleum oil also is produced through the inside of another string of casing or tubing. A well which produces hydrocarbon liquids, a part of which is formed by a condensation from a gas phase and a part of which is crude petroleum oil, shall be classified as a gas well unless there is produced one barrel or more of crude petroleum oil per 100,000 cubic feet of natural gas; and that the term "crude petroleum oil" shall not be construed to mean any liquid hydrocarbon mixture or portion thereof which is not in the liquid phase in the reservoir, removed from the reservoir in such liquid phase, and obtained at the surface as such.

(12) Gatherer--Includes any pipeline, truck, motor vehicle, boat, barge, or person authorized to gather or accept oil, gas, or geothermal resources from lease production or lease storage.

(13) Geothermal energy and associated resources--

(A) All products of geothermal processes, embracing indigenous steam, hot water and hot brines, and geopressured water;

(B) Steam and other gases, hot water and hot brines resulting from water, gas, or other fluids artificially introduced into geothermal formations;

(C) Heat or other associated energy found in geothermal formations;

(D) Any by-product derived from them.

(14) Geothermal resource well--A well drilled within the established limits of a designated geothermal field.

(A) A geopressured geothermal well must be completed within a geopressured aquifer.

(B) A geopressured aquifer is a water-bearing zone with a pressure gradient in excess of 0.5 pounds per square inch per foot and a temperature gradient in excess of 1.6 degrees Fahrenheit per 100 feet of depth.

(15) Marginal well--Any oil well which is incapable of producing its maximum capacity of oil except by pumping, gas lift, or other means of artificial lift, and which well so equipped is capable, under normal unrestricted operating conditions, of producing such daily quantities of oil as herein set out, as would be damaged, or result in a loss of production ultimately recoverable, or cause the premature abandonment of same, if its maximum daily production were artificially curtailed. The following described wells shall be deemed "marginal wells" in this state.

(A) Any oil well incapable of producing its maximum daily capacity of oil except by pumping, gas lift, or other means of artificial lift, within this state and having a maximum daily capacity for production of 10 barrels or less, averaged over the preceding 10 consecutive days of stabilized production, producing from a depth of 2,000 feet or less.

(B) Any oil well incapable of producing its maximum daily capacity of oil except by pumping, gas lift, or other means of artificial lift, within this state and having a maximum daily capacity for production of 20 barrels or less, averaged over the preceding 10 consecutive days of stabilized production, producing from a horizon deeper than 2,000 feet and less in depth than 4,000 feet.

(C) Any oil well incapable of producing its maximum daily capacity of oil except by pumping, gas lift, or other means of artificial lift, within this state and having a maximum daily capacity for production of 25 barrels or less, averaged over the preceding 10 consecutive days of stabilized production, producing from a horizon deeper than 4,000 feet and less in depth than 6,000 feet.

(D) Any oil well incapable of producing its maximum daily capacity of oil except by pumping, gas lift, or other means of artificial lift, within this state and having a maximum daily capacity for production of 30 barrels or less, averaged over the preceding 10 consecutive days of stabilized production, producing from a horizon deeper than 6,000 feet and less in depth than 8,000 feet.

(E) Any oil well incapable of producing its maximum daily capacity of oil except by pumping, gas lift, or other means of artificial lift, within this state and having a maximum daily capacity for production of 35 barrels or less, averaged over the preceding 10 consecutive days of stabilized production, producing from a horizon deeper than 8,000 feet. (Reference Order Number 20-59,200, effective May 1, 1969.)

(16) Natural gas or gas--These terms shall have the same meaning, as used in the rules, regulations, or forms of the commission.

(17) Natural gasoline--Gasoline manufactured from casinghead gas or from any natural gas.

(18) Oil well--Any well which produces one barrel or more crude petroleum oil to each 100,000 cubic feet of natural gas.

(19) Operator--A person, acting for himself or as an agent for others and designated to the commission as the one who has the primary responsibility for complying with its rules and regulations in any and all acts subject to the jurisdiction of the commission.

(20) Person--Any natural person, corporation, association, partnership, receiver, trustee, guardian, executor, administrator, and a fiduciary or representative of any kind.

(21) Product--Includes refined crude oil, crude tops, topped crude, processed crude petroleum, residue from crude petroleum, cracking stock, uncracked fuel oil, fuel oil, treated crude oil, residuum, casinghead gasoline, natural gas gasoline, gas oil, naphtha, distillate, gasoline, kerosene, benzine, wash oil, waste oil, blended gasoline, lubricating oil, blends or mixtures of petroleum, and/or any and all liquid products or by-products derived from crude petroleum oil or gas, whether hereinabove enumerated or not.

(22) Sour gas--Any natural gas containing more than 1 1/2 grains of hydrogen sulphide per 100 cubic feet or more than 30 grains of total sulphur per 100 cubic feet, or gas which in its natural state is found by the commission to be unfit for use in generating light or fuel for domestic purposes.

(23) Sweet gas--All natural gas except sour gas and casinghead gas.

(24) Texas offshore--This term embraces the area in the Gulf of Mexico seaward of the coast line of Texas comprised of:

(A) the three league area confirmed to the State of Texas by the Submerged Land Act (43 United States Code §§1301-1315); and

(B) the area seaward of such three league area owned by the United States.

(25) Transportation or to transport--The movement of any crude petroleum oil or products of crude

petroleum oil or the products of either from any receptacle in which any such crude petroleum or products of crude petroleum oil or the products of either has been stored to any other receptacle by any means or method whatsoever, including the movement by any pipeline, railway, truck, motor vehicle, barge, boat, or railway tank car. It is the purpose of this definition to include the movement or transportation of crude petroleum oil and products of crude petroleum oil and the products of either by any means whatsoever from any receptacle containing the same to any other receptacle anywhere within or from the State of Texas, regardless of whether or not possession or control or ownership change.

(26) Transporter or transporting agency--Includes any common carrier by pipeline, railway, truck, motor vehicle, boat, or barge, and/or any person transporting oil or a product by pipeline, railway, truck, motor vehicle, boat, or barge.

Source Note: The provisions of this §3.79 adopted to be effective August 25, 2003, 28 TexReg 6816

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.78	**Fees and Financial Security Requirements**

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise:

(1) Violation--Noncompliance with a Commission rule, order, license, permit, or certificate relating to safety or the prevention or control of pollution.

(2) Outstanding violation--A violation for which:

(A) either:

(i) a Commission order finding a violation has been entered and all appeals have been exhausted; or

(ii) an agreed order between the Commission and the organization relating to a violation has been entered; and

(B) one or more of the following conditions still exist:

(i) the conditions that constituted the violation have not been corrected;

(ii) all administrative, civil, and criminal penalties, if any, relating to the violation of such Commission rules, orders, licenses, permits, or certificates have not been paid; or

(iii) all reimbursements of any costs and expenses assessed by the Commission relating to the violation of such Commission rules, orders, licenses, permits, or certificates have not been paid.

(3) Commercial facility--A facility whose owner or operator receives compensation from others for the storage, reclamation, treatment, or disposal of oil field fluids or oil and gas wastes that are wholly or partially trucked or hauled to the facility and whose primary business purpose is to provide these services for compensation if:

(A) the facility is permitted under §3.8 of this title (relating to Water Protection);

(B) the facility is permitted under §3.57 of this title (relating to Reclaiming Tank Bottoms, Other Hydrocarbon Wastes, and Other Waste Materials);

(C) the facility is permitted under §3.9 of this title (relating to Disposal Wells) and a collecting pit permitted under §3.8 is located at the facility; or

(D) the facility is permitted under §3.46 of this title (relating to Fluid Injection into Productive Reservoirs) and a collecting pit permitted under §3.8 is located at the facility.

(4) Financial security--An individual performance bond, blanket performance bond, letter of credit, or cash deposit filed with the Commission.

(5) Bay well--Any well under the jurisdiction of the Commission for which the surface location is either:

(A) located in or on a lake, river, stream, canal, estuary, bayou, or other inland navigable waters of the state and which requires plugging by means other than conventional land-based methods, including, but not limited to, use of a barge, use of a boat, dredging, or building a causeway or other access road to bring in the necessary equipment to plug the well; or,

(B) located on state lands seaward of the mean high tide line of the Gulf of Mexico in water of a depth at mean high tide of not more than 100 feet that is sheltered from the direct action of the open seas of the Gulf of Mexico.

(6) Land well--Any well subject to Commission jurisdiction for which the surface location is not in or on inland or coastal waters.

(7) Offshore well--Any well subject to Commission jurisdiction for which the surface location is on state lands in or on the Gulf of Mexico, that is not a bay well.

(8) Officers and owners--Any persons owning or controlling an organization including officers, directors, general partners, sole proprietors, owners of more than 25% ownership interest, any trustee of an organization, and any person determined by a final judgment or final administrative order to have exercised control over the organization.

(9) Letter of credit--An irrevocable letter of credit issued:

(A) on a Commission-approved form;

(B) by and drawn on a third party bank authorized under state or federal law to do business in Texas; and

(C) renewed and continued in effect until the conditions of the letter of credit have been met or its release is approved by the Commission or its authorized delegate.

(10) Bond--A surety instrument issued:

(A) on a Commission-approved form;

(B) by and drawn on a third party corporate surety authorized under state law to issue surety bonds in Texas; and

(C) renewed and continued in effect until the conditions of the bond have been met or its release is approved by the Commission or its authorized delegate.

(11) Director--The director of the Commission's Oil and Gas Division or the director's delegate.

(b) Filing fees. The following filing fees are required to be paid to the Railroad Commission.

(1) With each application or materially amended application for a permit to drill, deepen, plug back, or reenter a well, the applicant shall submit to the Commission a nonrefundable fee of:

(A) $200 if the proposed total depth of the well is 2,000 feet or less;

(B) $225 if the proposed total depth of the well is greater than 2,000 feet but less than or equal to 4,000 feet;

(C) $250 if the proposed total depth of the well is greater than 4,000 feet but less than or equal to 9,000 feet; or

(D) $300 if the proposed total depth of the well is greater than 9,000 feet.

(2) An application for a permit to drill, deepen, plug back, or reenter a well will be considered materially amended if the amendment is made for a purpose other than:

(A) to add omitted required information;

(B) to correct typographical errors; or

(C) to correct clerical errors.

(3) An applicant shall submit an additional nonrefundable fee of $150 when requesting that the Commission expedite the application for a permit to drill, deepen, plug back, or reenter a well.

(4) With each individual application for an exception to any rule or rules in this chapter, the applicant shall submit to the Commission a nonrefundable fee of $150, except as provided in paragraph (5) of this subsection.

(5) With each application for an exception to any rule or rules in this chapter that includes an exception to §3.37 of this title (relating to Statewide Spacing Rule) (Statewide Rule 37) or §3.38 of this title (relating to Well Densities) (Statewide Rule 38), the applicant shall submit a nonrefundable fee of $200.

(6) With each application for an oil and gas waste disposal well permit, the applicant shall submit to the Commission a nonrefundable fee of $100 per well.

(7) With each application for a fluid injection well permit, the applicant shall submit to the Commission a nonrefundable fee of $200 per well. Fluid injection well means any well used to inject fluid or gas into the ground in connection with the exploration or production of oil or gas other than an oil and gas waste disposal well.

(8) With each application for a permit to discharge to surface water other than a permit for a discharge that meets national pollutant discharge elimination system (NPDES) requirements for agricultural or wildlife use, the applicant shall submit to the Commission a nonrefundable fee of $300.

(9) If a certificate of compliance for an oil lease or gas well has been canceled for violation of one or more Commission rules, the operator shall submit to the Commission a nonrefundable fee of $300 for each severance or seal order issued for the well or lease before the Commission may reissue the certificate pursuant to §3.58 of this title (relating to Oil, Gas, or Geothermal Resource Producer's Reports) (Statewide Rule 58).

(10) With each application for issuance, renewal, or material amendment of an oil and gas waste hauler's permit, the applicant shall submit to the Commission a nonrefundable fee of $100.

(11) With each Natural Gas Policy Act (15 United States Code §§3301-3432) application, the applicant shall submit to the Commission a nonrefundable fee of $150.

(12) Hazardous waste generation fee. A person who generates hazardous oil and gas waste, as that term is defined in §3.98 of this title (relating to Standards for Management of Hazardous Oil and Gas Waste), shall pay to the Commission the fees specified in §3.98(z).

(13) A check or money order for any of the aforementioned fees shall be made payable to the Railroad Commission of Texas. If the check accompanying an application is not honored upon presentment, the permit issued on the basis of that application, the allowable assigned, the exception to a statewide rule granted on the basis of the application, the certificate of compliance reissued, or the Natural Gas Policy Act category determination made on the basis of the application may be suspended or revoked.

(14) If an operator submits a check that is not honored on presentment, the operator shall, for a period of 24 months after the check was presented, submit any payments in the form of a credit card, cashier's check, or cash.

(c) Organization Report Fee. An organization report required by Texas Natural Resources Code, §91.142, shall be accompanied by a fee as follows:

(1) for an operator of:

(A) not more than 25 wells, $300;

(B) more than 25 but not more than 100 wells, $500; or

(C) more than 100 wells, $1,000;

(2) for an operator of one or more natural gas pipelines, $225;

(3) for an operator of one or more of the following service activities: pollution cleanup contractor; directional surveying; approved cementer for plugging wells; or physically moving or storing crude or condensate, $300;

(4) for an operator of one or more liquids pipelines, $625;

(5) for an operator of all other service activities or facilities, $500;

(6) for an operator with multiple activities, a total fee equal to the sum of the separate fees applicable to each category of service activity, facility, pipeline, or number of wells operated shall be submitted, provided that the total fee for an operator of wells shall not exceed $1,125; and

(7) for an entity not currently performing operations under the jurisdiction of the Commission, $300.

(d) Financial security.

(1) Except for those operators exempted under subsection (g)(7) of this section, any person, including any firm, partnership, joint stock association, corporation, or other organization, required by Texas Natural Resources Code, §91.142, to file an organization report with the Commission must also file financial security in one of the following forms:

(A) an individual performance bond;

(B) a blanket performance bond; or

(C) a letter of credit or cash deposit in the same amount as required for an individual performance bond or blanket performance bond.

(2) An unbonded operator that has a current and active organization report and filed a nonrefundable annual fee as its financial security prior to September 1, 2004, may continue to perform operations subject to

the Commission's jurisdiction with such financial security until the first date after September 1, 2004, for annual renewal of the operator's organization report, at which time the operator shall file financial security as required by subsection (g) of this section.

(e) Forms for financial security. Operators shall submit bonds and letters of credit on forms prescribed by the Commission.

(f) Filing deadlines for financial security. Operators shall submit required financial security at the time of filing an initial organization report or upon yearly renewal, or as otherwise required under this section.

(g) Amount of financial security. An operator required to file financial security under subsection (d) of this section shall file financial security described in this subsection.

(1) Types and amounts of financial security required.

(A) A person operating one or more wells may file an individual performance bond, letter of credit, or cash deposit in an amount equal to the sum of $2.00 for each foot of total well depth for each well operated.

(B) A person operating one or more wells may file a blanket bond, letter of credit, or cash deposit to cover all wells for which a bond, letter of credit, or cash deposit is required in an amount equal to the sum of the base amount determined by the total number of wells operated. A person performing multiple operations shall be required to file only one blanket bond, letter of credit, or cash deposit unless the person is operating a commercial facility, in which case the person also shall comply with the financial security requirements of subsection (l) of this section. The financial security amount shall be at least the base amount determined by the total number of wells operated or $25,000, whichever is greater. The base amount is determined as follows:

(i) The base amount for a person operating 10 or fewer wells or performs other operations shall be $25,000.

(ii) The base amount for a person operating more than 10 but fewer than 100 wells shall be $50,000.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.76	**Commission Approval of Plats for Mineral Development**

(a) The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Minerals--Oil and/or gas.

(2) Operations site--A surface area of two or more acres that an owner of a possessory mineral interest may use to explore for and produce minerals, which is located in whole or in part within a qualified subdivision, and designated on the subdivision plat.

(3) Possessory mineral interest--A mineral interest that includes the right to use the land surface for exploration and production of minerals.

(4) Qualified subdivision--A tract of land not more than 640 acres:

(A) that is located in a county having a population in excess of 400,000, or in a county having a population in excess of 140,000 that borders a county having a population in excess of 400,000 or located on a barrier island;

(B) that has been subdivided in a manner authorized by law by the surface owners for residential, commercial, or industrial use; and

(C) that contains an operations site for each separate 80 acres within the 640-acre tract and provisions for road and pipeline easements to allow use of the operations sites.

(5) Barrier island--An island bordering on the Gulf of Mexico and entirely surrounded by water.

(b) As provided in subsections (e) and (f) of this section, the surface owners of a parcel of land may restrict use of the surface by the possessory mineral owners if the tract is a qualified subdivision and if a plat of the subdivision has been approved by the Railroad Commission after notice and hearing and filed with the clerk of the county in which the qualified subdivision is to be located.

(c) An application for a hearing under this section must be made in writing and mailed or delivered to the director of the Oil and Gas Division. The application must include:

(1) a jurisdictional statement setting out the facts stated in subsection (a)(4)(A) and (B) of this section;

(2) a statement that the applicant has authority to represent and represents all surface owners of land contained in the proposed qualified subdivision;

(3) the names and addresses of all owners of possessory mineral interests and all mineral lessors of land contained in the proposed qualified subdivision;

(4) a plat of the proposed subdivision showing each proposed 80-acre tract with its operations site, road easements, and pipeline easements and a legible copy thereof no larger than 8 1/2 inches by 11 inches;

(5) a concise description of mineral development in the area, including the number of oil and/or gas wells within 2.5 miles of the boundary of the proposed qualified subdivision and the depths at which each well is completed;

(6) a list of all the Railroad Commission designated oil and/or gas fields, if any, which underlie the proposed qualified subdivision; including the spacing and density requirements. If no Railroad Commission designated fields underlie the qualified subdivision, the application should so state.

(d) The Railroad Commission shall, on proper notice to the applicant and owners of possessory mineral interests and mineral lessors of land contained in the proposed qualified subdivision, hold a hearing on the application to determine the adequacy of the number and location of operations sites and road and pipeline easements. At the hearing on the application, evidence may be presented by the applicant and the owners of possessory mineral interests and mineral lessors. The applicant must carry the burden of proof. After considering the evidence, the commission may approve, reject, or amend the application to ensure that the mineral resources of the subdivision may be fully and effectively developed.

(e) An owner of a possessory mineral interest within a Railroad Commission approved qualified subdivision may use only the surface contained in designated operations sites for exploration, development, and production of minerals and only the designated easements as necessary to adequately use the operations sites.

(f) The owner of the possessory mineral interest may drill wells or extend well bores from an operations site or from a site outside of the qualified subdivision to bottomhole locations vertically beneath the surface of parts of the qualified subdivision other than the operation sites. Such drilling is subject to other applicable commission rules and regulations, and is permissible only to the extent that the operations do not unreasonably interfere with the use of the surface of the qualified subdivision outside the operations site.

(g) Subsections (e) and (f) of this section cease to apply to a subdivision if, by the third anniversary of the date on which the order of the commission becomes final:

(1) the surface owner has not commenced actual construction of roads or utilities within the qualified subdivision; and

(2) a lot within the qualified subdivision has not been sold to a third party.

(h) All or any portion of a qualified subdivision may be amended, replatted, or abandoned by the surface owner. An amendment or replat, however, may not alter, diminish, or impair the usefulness of an operations site or appurtenant road or pipeline easement unless the amendment or replat is approved by the commission. Railroad Commission approval of a replat or amendment may be administratively granted by the director of the Oil and Gas Division, or his delegate, upon submission of items required in subsection (c) of this section and after notice and opportunity for hearing has been afforded to all possessory mineral interest owners and mineral lessors of land contained within the original and/or replatted or amended qualified subdivision.

Source Note: The provisions of this §3.76 adopted to be effective July 10, 2000, 25 TexReg 6487

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.73	**Pipeline Connection; Cancellation of Certificate of Compliance; Severance**

(a) No pipeline shall be connected with any oil, gas, or geothermal resources well until the operator of the well provides the pipeline operator with a certificate from the Commission that the rules in this title have been complied with. This section shall not prevent a temporary connection with any well in order to take care of production and prevent waste until the operator has a reasonable time, not to exceed 30 days from the date of such connection, within which to obtain such certificate. For purposes of this section, the term "Commission" means the Railroad Commission of Texas, the Director of the Oil and Gas Division, or the Director's delegate.

(b) No pipeline operator shall physically disconnect its facilities from or cease providing pipeline services to any well or lease without first obtaining:

(1) written consent of the well or lease operator for the proposed disconnect or termination; or

(2) written permission from the Commission. This section does not apply to temporary suspensions of service authorized under other rules in this title or attributable to maintenance, safety, or product quality issues.

(c) If the pipeline operator is unable to obtain the written consent of the well or lease operator to physically disconnect from or cease providing service to the well or lease, or the well or lease operator objects to the proposed physical disconnect or termination of service, and the pipeline operator still desires to physically disconnect from or cease providing service to the well or lease, the pipeline operator shall file an application with the Commission requesting permission to physically disconnect its facilities from or cease providing service to the well or lease. An affected well or lease operator may object to physical disconnection or cessation of service and file a complaint with the Commission under this subsection.

(1) The pipeline operator shall file its application with the Commission at least 30 days prior to the date on which the pipeline operator desires to make the physical disconnection or cease providing service. On the same date as the pipeline operator files its application with the Commission, the pipeline operator shall send a copy of the application to the operator of the well or lease affected by the application by certified mail, return receipt requested. The application shall identify the well operator and pipeline operator, identify each lease or well involved, and provide sufficient information to allow the Commission to make a determination pursuant to subsection (c)(4).

(2) If the operator of the well or lease does not file with the Commission a written objection to the application within 28 days following the filing of the application, the Commission shall administratively approve or deny the application and shall notify the pipeline operator and the well or lease operator of the decision by certified mail, return receipt requested. Following such notification, either party shall have 21 days to file a written request for hearing. If neither party files a timely request for hearing, the administrative approval or denial shall be deemed final.

(3) If either party files a timely request for hearing, the Commission shall refer the application to the Office of General Counsel docket services to be set for hearing within 60 days following the date of referral.

(4) In determining whether or not to approve a request to physically disconnect from or cease providing service to a well or lease, the Commission may consider relevant factors, including but not limited to:

(A) operational integrity of the pipeline facilities;

(B) operational integrity of the equipment on the well or lease;

(C) cost of continued operation of the physical connection or service;

(D) risk to public safety, human health and the environment;

(E) availability of alternative transportation;

(F) protection of correlative rights; and

(G) prevention of waste.

(d) The Commission may shut in and seal any well, and cancel any certificate of compliance if it appears that the operator of a well has violated or is violating, in connection with the operation of the well, any statutes, rules in this title, permits, or orders of the Commission. Upon receipt of information that indicates operations are being conducted in violation of statutes, rules in this title, or a Commission permit or order, the Commission shall send a notice letter to the operator directing the operator to correct the violation. The letter shall state the facts or conduct alleged to warrant the shut-in and sealing of the well, and cancellation of the certificate of compliance. The letter shall give the operator an opportunity to show compliance with the statutes, rules in this title, or Commission permits or orders. The letter shall be sent by registered or certified mail, and shall indicate the time within which compliance shall be demonstrated or achieved. The time period allowed for the operator to achieve compliance shall not be less than 10 days from the date the notice letter is sent.

(e) Within the time period set out in the notice letter, the operator shall either demonstrate compliance or correct the violation, and notify the Commission of its action.

(f) If the violation is not corrected within the time period set out in the notice letter, the Commission may shut in and seal the well, and cancel the certificate of compliance.

(g) If a certificate of compliance has been cancelled, the Commission may not issue a new certificate of compliance until the owner or operator of the property covered by the certificate of compliance submits to the Commission a reissuance fee as required by §3.78 of this title (relating to Fees and Financial Security Requirements) (Statewide Rule 78); and

(1) the property covered by the certificate is brought into compliance with the statutes, rules in this title, and Commission permits and orders; or

(2) the Commission determines that there are just and equitable grounds for reissuing the certificate.

(h) Pursuant to Texas Natural Resources Code, §85.165, upon notice from the Commission to any operator of a pipeline or other carrier connected to any oil, gas, or geothermal resource well that the certificate of compliance applicable to the well has been cancelled by the Commission, the operator of the pipeline or other carrier shall disconnect from or suspend service to the well and shall not transport any oil or gas produced from that well until a new certificate of compliance has been issued by the Commission. Pursuant to Texas Natural Resources Code, §85.3855, failure to comply with this subsection may subject a person to a penalty of up to $10,000 per violation.

(i) Pursuant to Texas Natural Resources Code, §85.166, upon notice from the Commission that a certificate of compliance as to any oil, gas, or geothermal resource well has been cancelled as provided in this section, the operator of such well shall not produce oil, gas, or geothermal resources from that well until a new certificate of compliance with respect to the well has been issued by the Commission as provided in this section. Pursuant to Texas Natural Resources Code, §85.3855, failure to comply with this subsection may subject a person to a penalty of up to $10,000 per violation.

(j) The provisions of this section shall be cumulative of other Commission actions and procedures relating to violations of state statutes or Commission permits, rules, and orders, including the authority of the Commission to immediately shut in a well or lease, or to direct the operator to shut in a well or lease, when an emergency exists due to pollution or an imminent threat of harm to people or property.

Source Note: The provisions of this §3.73 adopted to be effective October 28, 2003, 28 TexReg 9241; amended to be effective September 1, 2004, 29 TexReg 8271

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RULE §3.72	**Obtaining Pipeline Connections**

(a) A common carrier pipeline transporting crude oil in Texas, upon application for connection and offer of crude oil by a producer or persons owning unconnected lease batteries, shall connect such lease batteries in the following instances:

(1) when such request is made for connection of lease batteries in the general area served by a common carrier, which is an affiliate or subsidiary of a common purchaser, as defined in the Texas Natural Resources Code, §111.081; and

(2) within individual fields, when any common carrier possesses the only pipeline serving such field or common reservoir and request is made for connection of an unconnected lease battery in the field, provided, that for just cause a common carrier pipeline may apply for an exception. If proper application has been made for such connection and the common carrier pipeline refuses to connect the unconnected lease battery, a complaint for failure to connect may be filed with the commission by the person seeking the connection. The complaining person may allege discrimination or noncompliance with the provisions of this subsection or the appropriate section(s) of the Texas Natural Resources Code.

(b) Whether the matter comes to the commission either as an application for exception by the pipeline or on a complaint for failure to connect, at least 10 days' notice shall be given to all interested parties, after which the hearing shall be held. At the hearing, the commission may require and consider, among other factors, evidence relating to ability of the pipeline carrier to transport the quality of oil, the market or lack of market for the proffered oil, and the period required to return the capital investment for the connection. It is not its intention to limit, nor does the commission herein limit, the consideration by it of any facts with respect to a claim of violation of, or of any facts that may constitute a cause of action for violation of, any of the provisions of Texas Natural Resources Code, §§11.001-11.136, whether enumerated in this section or not.

Source Note: The provisions of this §3.72 adopted to be effective August 25, 2003, 28 TexReg 6816

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RULE §3.71	**Pipeline Tariffs**

Every person owning, operating, or managing any pipeline, or any part of any pipeline, for the gathering, receiving, loading, transporting, storing, or delivering of crude petroleum as a common carrier shall be subject to and governed by the following provisions. Common carriers specified in this section shall be referred to as "pipelines," and the owners or shippers of crude petroleum by pipelines shall be referred to as "shippers."

(1) All marketable oil to be received for transportation. By the term "marketable oil" is meant any crude petroleum adapted for refining or fuel purposes, properly settled and containing not more than 2.0% of basic sediment, water, or other impurities above a point six inches below the pipeline connection with the tank. Pipelines shall receive for transportation all such "marketable oil" tendered; but no pipeline shall be required to receive for shipment from any one person an amount exceeding 3,000 barrels of petroleum in any one day; and, if the oil tendered for transportation differs materially in character from that usually produced in the field and being transported therefrom by the pipeline, then it shall be transported under such terms as the shipper and the owner of the pipeline may agree or the commission may require.

(2) Basic sediment, how determined--temperature. In determining the amount of sediment, water, or other impurities, a pipeline is authorized to make a test of the oil offered for transportation from an average sample from each such tank, by the use of centrifugal machine, or by the use of any other appliance agreed upon by the pipeline and the shipper. The same method of ascertaining the amount of the sediment, water, or other impurities shall be used in the delivery as in the receipt of oil. A pipeline shall not be required to receive for transportation, nor shall consignee be required to accept as a delivery, any oil of a higher temperature than 90 degrees Fahrenheit, except that during the summer oil shall be received at any atmospheric temperature, and may be delivered at like temperature. Consignee shall have the same right to test the oil upon delivery at destination that the pipeline has to test before receiving from the shipper.

(3) "Barrel" defined. For the purpose of these sections, a "barrel" of crude petroleum is declared to be 42 gallons of 231 cubic inches per gallon at 60 degrees Fahrenheit.

(4) Oil involved in litigation, etc.--indemnity against loss. When any oil offered for transportation is involved in litigation, or the ownership is in dispute, or when the oil appears to be encumbered by lien or charge of any kind, the pipeline may require of shippers an indemnity bond to protect it against all loss.

(5) Storage. Each pipeline shall provide, without additional charge, sufficient storage, such as is incident and necessary to the transportation of oil, including storage at destination or so near thereto as to be available for prompt delivery to destination point, for five days from the date of order of delivery at destination.

(6) Identity of oil, maintenance of oil. A pipeline may deliver to consignee either the identical oil received for transportation, subject to such consequences of mixing with other oil as are incident to the usual pipeline transportation, or it may make delivery from its common stock at destination; provided, if this last be done, the delivery shall be of substantially like kind and market value.

(7) Minimum quantity to be received. A pipeline shall not be required to receive less than one tank car-load of oil when oil is offered for loading into tank cars at destination of the pipeline. When oil is offered for transportation for other than tank car delivery, a pipeline shall not be required to receive less than 500 barrels.

(8) Gathering charges. Tariffs to be filed by a pipeline shall specify separately the charges for gathering of the oil, for transportation, and for delivery.

(9) Measuring, testing, and deductions (reference Special Order Number 20-63,098 effective June 18, 1973).

(A) Except as provided in subparagraph (B) of this paragraph, all crude oil tendered to a pipeline shall be gauged and tested by a representative of the pipeline prior to its receipt by the pipeline. The shipper may be present or represented at the gauging or testing. Quantities shall be computed from correctly compiled tank tables showing 100% of the full capacity of the tanks.

(B) As an alternative to the method of measurement provided in subparagraph (A) of this paragraph, crude oil and condensate may be measured and tested, before transfer of custody to the initial transporter, by:

(i) lease automatic custody transfer (LACT) equipment, provided such equipment is installed and operated in accordance with the latest revision of American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 6.1, or;

(ii) any device or method, approved by the commission or its delegate, which yields accurate measurements of crude oil or condensate.

(C) Adjustments to the quantities determined by the methods described in subparagraphs (A) or (B) of this paragraph shall be made for temperature from the nearest whole number degree to the basis of 60 degrees Fahrenheit and to the nearest 5/10 API degree gravity in accordance with the volume correction Tables 5A and 6A contained in API Standard 2540, American Society for Testing Materials 01250, Institute of Petroleum 200, first edition, August 1980. A pipeline may deduct the basic sediment, water, and other impurities as shown by the centrifugal or other test agreed upon by the shipper and pipeline; and 1.0% for evaporation and loss during transportation. The net balance shall be the quantity deliverable by the pipeline. In allowing the deductions, it is not the intention of the commission to affect any tax or royalty obligations imposed by the laws of Texas on any producer or shipper of crude oil.

(D) A transfer of custody of crude between transporters is subject to measurement as agreed upon by the transporters.

(10) Delivery and demurrage. Each pipeline shall transport oil with reasonable diligence, considering the quality of the oil, the distance of transportation, and other material elements, but at any time after receipt of a consignment of oil, upon 24 hours' notice to the consignee, may offer oil for delivery from its common stock at the point of destination, conformable to paragraph (6) of this section, at a rate not exceeding 10,000 barrels per day of 24 hours. Computation of time of storage (as provided for in paragraph (5) of this section) shall begin at the expiration of such notice. At the expiration of the time allowed in paragraph (5) of this section for storage at destination, a pipeline may assess a demurrage charge on oil offered for delivery and remaining undelivered, at a rate for the first 10 days of $.001 per barrel; and thereafter at a rate of $.0075 per barrel, for each day of 24 hours or fractional part thereof.

(11) Unpaid charges, lien for and sale to cover. A pipeline shall have a lien on all oil to cover charges for transportation, including demurrage, and it may withhold delivery of oil until the charges are paid. If the

charges shall remain unpaid for more than five days after notice of readiness to deliver, the pipeline may sell the oil at public auction at the general office of the pipeline on any day not a legal holiday. The date for the sale shall be not less than 48 hours after publication of notice in a daily newspaper of general circulation published in the city where the general office of the pipeline is located. The notice shall give the time and place of the sale, and the quantity of the oil to be sold. From the proceeds of the sale, the pipeline may deduct all charges lawfully accruing, including demurrage, and all expenses of the sale. The net balance shall be paid to the person lawfully entitled thereto.

(12) Notice of claim. Notice of claims for loss, damage, or delay in connection with the shipment of oil must be made in writing to the pipeline within 91 days after the damage, loss, or delay occurred. If the claim is for failure to make delivery, the claim must be made within 91 days after a reasonable time for delivery has elapsed.

(13) Telephone-telegraph line--shipper to use. If a pipeline maintains a private telegraph or telephone line, a shipper may use it without extra charge, for messages incident to shipments. However, a pipeline shall not be held liable for failure to deliver any messages away from its office or for delay in transmission or for interruption of service.

(14) Contracts of transportation. When a consignment of oil is accepted, the pipeline shall give the shipper a run ticket, and shall give the shipper a statement that shows the amount of oil received for transportation, the points of origin and destination, corrections made for temperature, deductions made for impurities, and the rate for such transportation.

(15) Shipper's tanks, etc.--inspection. When a shipment of oil has been offered for transportation the pipeline shall have the right to go upon the premises where the oil is produced or stored, and have access to any and all tanks or storage receptacles for the purpose of making any examination, inspection, or test authorized by this section.

(16) Offers in excess of facilities. If oil is offered to any pipeline for transportation in excess of the amount that can be immediately transported, the transportation furnished by the pipeline shall be apportioned among all shippers in proportion to the amounts offered by each; but no offer for transportation shall be considered beyond the amount which the person requesting the shipment then has ready for shipment by the pipeline. The pipeline shall be considered as a shipper of oil produced or purchased by itself and held for shipment through its line, and its oil shall be entitled to participate in such apportionate.

(17) Interchange of tonnage. Pipelines shall provide the necessary connections and facilities for the exchange of tonnage at every locality reached by two or more pipelines, when the commission finds that a necessity exists for connection, and under such regulations as said commission may determine in each case.

(18) Receipt and delivery--necessary facilities for. Each pipeline shall install and maintain facilities for the receipt and delivery of marketable crude petroleum of shippers at any point on its line if the commission finds that a necessity exists therefor, and under regulations by the commission.

(19) Reports of loss from fires, lightning, and leakage.

(A) Each pipeline shall immediately notify the commission district office, electronically or by telephone, of each fire that occurs at any oil tank owned or controlled by the pipeline, or of any tank struck by lightning. Each pipeline shall in like manner report each break or leak in any of its tanks or pipelines from which more than five barrels escape. Each pipeline shall file the required information with the commission in accordance with the appropriate commission form within 30 days from the date of the spill or leak.

(B) No risk of fire, storm, flood, or act of God, and no risk resulting from riots, insurrection, rebellion, war, or act of the public enemy, or from quarantine or authority of law or any order, requisition or necessity of the government of the United States in time of war, shall be borne by a pipeline, nor shall any liability accrue to it from any damage thereby occasioned. If loss of any crude oil from any such causes occurs after the oil has been received for transportation, and before it has been delivered to the consignee, the shipper shall bear a loss in such proportion as the amount of his shipment is to all of the oil held in transportation by the pipeline at the time of such loss, and the shipper shall be entitled to have delivered only such portion of his shipment as may remain after a deduction of his due proportion of such loss, but in such event the shipper shall be required to pay charges only on the quantity of oil delivered. This section shall not apply if the loss occurs because of negligence of the pipeline.

(C) Common carrier pipelines shall mail (return receipt requested) or hand deliver to landowners (persons who have legal title to the property in question) and residents (persons whose mailing address is the property in question) of land upon which a spill or leak has occurred, all spill or leak reports required by the commission for that particular spill or leak within 30 days of filing the required reports with the commission. Registration with the commission by landowners and residents for the purpose of receiving spill or leak reports shall be required every five years, with renewal registration starting January 1, 1999. If a landowner or resident is not registered with the commission, the common carrier is not required to furnish such reports to the resident or landowner.

(20) Printing and posting. Each pipeline shall have paragraphs (1)-(19) of this section printed on its tariff sheets, and shall post the printed sections in a prominent place in its various offices for the inspection of the shipping public. Each pipeline shall post and publish only such rules and regulations as may be adopted by the commission as general rules or such special rules as may be adopted for any particular field.

(21) Immediately upon the publication of its tariffs, and each subsequent amendment thereof, each pipeline is requested to file one copy with the commission.

(22) Records.

(A) Each person operating crude oil gathering, transportation, or storage facilities in the state must maintain daily records of the quantities of all crude oil moved from each oil field in the state, and such records shall also show separately for each field to whom delivery is made, and the quantities so delivered.

(B) The information contained in the records thus required to be kept must be reported to the commission by the gatherers, transporters, and handlers at such times and in such manner as may be required by the commission.

Source Note: The provisions of this §3.71 adopted to be effective August 25, 2003, 28 TexReg 6816

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RULE §3.70	**Pipeline Permits Required**

(a) No pipeline or gathering system, whether a common carrier or not, shall be used to transport oil, gas, or geothermal resources from any tract of land within this state without a permit from the commission. Application for the permit shall be made upon the required form, and the permit will be granted if the commission is satisfied from such application and the evidence in support thereof, and its own investigation, that the proposed line is, or will be, so laid, equipped, and managed, as to reduce to a minimum the possibility of waste, and will be operated in accordance with the conservation laws and conservation rules and regulations of the commission.

(b) The permit, if granted, shall be revocable at any time after hearing held after 10 days' notice, if the commission finds that the line is so unsafe, or so improperly equipped, or so managed, as likely to result in waste. If the commission finds the line is in such condition as to cause waste, five days' written notice shall be given to the operating company to correct the condition before notice of hearing for revocation of the permit is given. A permit may also be revoked after 10 days' notice and hearing, if the commission finds that the operator of the line, in its operation thereof, is willfully violating or contributing to the violation of the laws of Texas regulating the production, transportation, processing, refining, treating, and/or marketing of crude oil or geothermal resources, or any of the laws of the state to conserve the oil, gas, or geothermal resources, or any rule or regulation of the commission enacted under such laws.

Source Note: The provisions of this §3.70 adopted to be effective August 25, 2003, 28 TexReg 6816

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RULE §3.63	**Carbon Black Plant Permits Required**

(a) Each operator of a carbon black plant shall make application for a permit to operate the plant, using the appropriate form.

(b) No person shall operate a plant for the burning of natural gas in the manufacture of carbon black without a permit authorizing the operation of the plant.

(c) Each 12 months the commission, on application, may grant a permit to each of the operators of carbon black plants for a period of 12 months.

Source Note: The provisions of this §3.63 adopted to be effective January 1, 1976.

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RULE §3.62	**Cycling Plant Control and Reports**

(a) The operator of each cycling plant shall use tanks for measuring the crude oil, condensate, or other liquid hydrocarbons taken into or extracted by the cycling plant.

(b) The operator of each cycling plant shall meter the following separately:

(1) all gas taken into the plant from statutory gas wells;

(2) all casinghead gas taken into the cycling plant;

(3) all gas used for plant fuel;

(4) all gas taken by pipe lines or for domestic or commercial uses;

(5) all gas, including flash vapors, vented directly or indirectly to the air.

(c) Gas used for lifting water by jetting, or used in turbines and subsequently vented to the air or burned in a flare, shall be accurately metered and reported by the operator as vented on the appropriate form.

(d) No cycling plant shall be permitted to vent any gas taken into the plant from statutory gas wells; however, the venting of a volume of flash vapors not to exceed 2.0% of the volume of gas taken into said plant shall be considered to be compliance.

(e) No gas shall be used for plant operation that is not burned in boilers, heaters, or internal combustion engines in a reasonably efficient manner, and no raw gas or residue gas shall be used for plant fuel if any flash vapors are being vented or flared.

(f) No cycling plant shall be operated without a certificate of compliance. The appropriate form submitted to the commission and approved by it shall be in effect for a period of 12 months, but may be renewed for one or more periods of 12 months. The certificate of compliance shall be revoked if an inspection reveals noncompliance.

Source Note: The provisions of this §3.62 adopted to be effective January 1, 1976.

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RULE §3.61	**Refinery and Gasoline Plants**

(a) The operator of each refinery in the state shall use tanks for measuring the crude oil and products taken into the refinery and the finished products of the refinery.

(b) No refinery or gasoline plant shall be operated without a certificate of compliance on a form supplied by the commission and approved by it, which shall be in effect for a period of 12 months, but may be renewed for one or more additional 12-month period. The operator must equip the plant with tanks and proper metering facilities.

(c) Measuring facilities for the accurate measurement of the volume of each type of gas taken into a natural gasoline plant shall be installed and used by the operator of the gasoline plant. Meters must be provided and used for measuring separately the dry sweet natural gas, the dry sour natural gas, casinghead gas, and refinery vapors taken into each plant. Accurate meters must be installed and used in each gasoline plant in which is processed dry gas (as distinguished from casinghead gas) so that all disposals of residue gas from such natural gasoline plant are accurately accounted for. Adequate devices should likewise be installed and used in each gasoline plant at which casinghead gas exclusively, or casinghead gas and refinery vapors only are processed, for the purpose of making approximate estimates of the volume of residue gas produced from such plant; such devices may consist either of meters, pilot tubes, pressure recording gauges, or manometers, through which measurements may be made from which reasonably accurate estimates of volume can be made.

(d) Measuring natural gasoline.

(1) Adequate tanks or meters of standard or approved types must be provided for measuring accurately all finished products of natural gasoline plants.

(2) The operator of each natural gasoline plant shall meter separately the volume of dry sweet natural gas, dry sour natural gas, casinghead gas, and refinery vapors that are taken into each natural gasoline plant.

(3) The operator of each natural gasoline plant in which dry natural gas (as distinguished from casinghead gas) is processed shall use metering facilities so that all disposition of residue gas from such natural gasoline plants are accurately accounted for. The operator of each natural gasoline plant in which casinghead gas exclusively, or casinghead gas and refinery vapors only, are processed shall install and use measuring devices, consisting either of meters, pitot tubes, pressure recording gauges, or manometers, with which measurements may be made of the residue gas disposition from the plant.

(4) The operator of each natural gasoline plant shall provide and use tanks or meters of standard or approved type for measuring each finished product of the plant.

Source Note: The provisions of this §3.61 adopted to be effective January 1, 1976.

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RULE §3.60	**Refinery Reports**

On or before the 15th day of each calendar month, the operator of each refinery, processing plant, blending plant or treating plant, and/or other plant situated within the state that processes or manufactures a product, except those gas processing plants for which another form is required by §3.54(a) of this title (relating to Gas Reports Required), shall file with the commission a report covering the operations of the refinery or plant during the preceding month. The report must contain the data and information required to be reported on the form.

Source Note: The provisions of this §3.60 adopted to be effective January 1, 1976.

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RULE §3.59	**Oil and Gas Transporter's Reports**

(a) General. The commission may, from time to time, require oil and gas pipeline companies to make reports to the commission showing wells connected with their lines during any month, the amount of production taken therefrom, names of parties from whom oil and gas are purchased, and the amount of oil or gas purchased therefrom.

(b) Daily report. The commission may, in case of overproduction or for any other reason which it deems urgent, require oil and gas pipe line companies to furnish daily reports of the amount of oil or gas purchased or taken from different wells or parties.

(c) Weekly stock report. Rescinded by Order Number 20-57,970, effective 11-16-67.

(d) Monthly transportation and storage report.

(1) Each gatherer, transporter, storer, and/or handler of crude oil or products, or both, shall file with the commission on or before the last day of each calendar month a report showing the required information concerning the transportation operations of such gatherer, transporter, or storer for the next preceding month. Such form is incorporated in and made a part of this section.

(2) The original of the report, covering all of the operations of the gatherer, transporter, storer, and/or handler of crude oil or products, or both, shall be filed in the Austin office of the commission. One copy of the report shall be filed in each district office in which the gatherer, transporter, storer, and/or handler of crude oil or products, or both, operates, but may include only the information pertaining to the operations in that district in which it is filed.

(3) The written instructions appearing on said form are incorporated in and made a part of this section, and all of the data and information on the form shall be reported and arranged on the form as required by the form.

(4) No gatherer, transporter, storer, and/or handler of crude oil shall remove crude oil from any property unless such property is identified by a sign posted in compliance with §3.3(3) of this title (relating to Identification of Properties, Wells, and Tanks).

(5) The provisions of this section shall not apply to the operator of any refinery, processing plant, blending plant, or treating plant to which §3.60 of this title (relating to Refinery Reports) applies if the operator has filed the required form.

(e) Annual report.

(1) Each common carrier pipeline shall make and file with the commission, at its Austin office, an annual report for each calendar year. The report must show the names of the officers, directors, and stockholders, and the residence of each; the amount of capital stock and bonded indebtedness outstanding; the results of financial operations; the sources of revenue; and the expenditures, assets and liabilities, and statistical data of oil transported; and such other information as may be deemed pertinent by the commission concerning

the carrier's transactions in the performance of services under its charter provisions relative to the transportation of crude petroleum in the State of Texas.

(2) The annual report must be made to the commission on the form prescribed and furnished by the commission; and must be returned complete, under oath, within 30 days after the receipt of the forms from the commission.

(3) For all purposes applicable under these rules and regulations the "Classification of Investment for Pipe Lines, Pipe Line Operating Revenues, and Pipe Line Operating Expenses" prescribed by the Interstate Commerce Commission and effective on January 1, 1915, is adopted and made a part of these rules for the use of all common carrier pipelines subject to the provisions of that act of the legislature, being Chapter 30 of the Regular Session of the 35th Legislature, State of Texas.

Source Note: The provisions of this §3.59 adopted to be effective January 1, 1976.

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RULE §3.58	**Oil, Gas, or Geothermal Resource Operator's Reports**

(a) Certificate of Compliance and transportation authority.

(1) Each operator who seeks to operate wells related to crude oil, natural gas, or geothermal resources shall file with the commission's Austin office a commission form P-4 (certificate of compliance and transportation authority) for each property on which the wells are located certifying that the operator has complied with the conservation laws and the oil, gas, and geothermal resources conservation orders, rules, and regulations of the commission in respect to the property. The Commission form P-4 establishes the operator of an oil lease, gas well, or other well; certifies responsibility for regulatory compliance, including plugging wells in accordance with §3.14 of this title (relating to plugging); and identifies gatherers, purchasers, and purchasers' commission-assigned system codes authorized for each well or lease. Operators shall file form P-4 for new oil leases, gas wells, or other wells; recompletions; reclassifications of wells from oil to gas or gas to oil; consolidation, unitization or subdivision of oil leases; or change of gatherer, gas purchaser, gas purchaser system code, operator, field name or lease name. When an operator files a form P-4, the oil and gas division shall review the form for completeness and accuracy. Except as otherwise authorized by the Commission, a transporter (whether the operator or someone else) shall not transport the oil, gas, or geothermal resources from such property until the Commission has approved the certificate of compliance and transportation authority. No certificate of compliance designating or changing the designation of an operator will be approved that is signed, either as transferor or transferee, by a non-employee agent of the organization unless the organization has filed with the commission, on its organization report, the name of the non-employee agent it has authorized to sign such certificates of compliance on its behalf.

(2) An approved certificate of compliance and transportation authority shall bind the operator until another operator files a subsequent certificate and the Commission has approved the subsequent certificate and transferred the property on commission records to the subsequent operator.

(3) The appropriate district office or the Austin office may grant temporary authority for an operator to use a transporter not authorized for a particular property in order to take care of production and prevent waste. The operator shall secure such temporary authority in writing from the appropriate district office or the Austin office before the oil or condensate is moved. In an emergency situation the operator may secure such temporary authority verbally but shall notify the district office in writing within 10 days after the oil or condensate is moved. An emergency situation exists when oil or condensate must be moved off a lease because it poses an imminent threat to the public health and safety, or when the threat of waste is imminent. The operator shall also furnish copies of such authorization or notification to the regular transporter and to the temporary transporter.

(4) If an applicant wishes to assume operator status for a property, but is unable to obtain the signature of the previous operator on the certificate of compliance and transportation authority, the applicant shall file with the oil and gas division in Austin a completed form P-4 signed by a designated officer or agent of the applicant, along with an explanatory letter and legal documentation of the applicant's right to operate the property. Prior to approval of such an application, the office of the general counsel will notify the last known operator of record, if such operator's address is available, affording such operator an opportunity to protest.

(b) Monthly producer's report (oil, natural gas and geothermal resources). For each calendar month, each operator who is a producer of crude oil, natural gas or geothermal resources shall file with the commission a report for each of the operator's producing properties. Operators shall file such reports on commission form P-1 (producer's monthly report of oil wells), commission form P-2 (producer's monthly report of gas wells), or commission form GT-2 (producer's monthly report of geothermal wells). These commission forms report monthly production and disposition of oil and casinghead gas (form P-1), gas well gas and condensate (form P-2) and geothermal resources (form GT-2). On or before the last day of the month subsequent to the period of the report, the operator shall file an original and one copy of each such form, the original to be filed in the

Austin office, and one copy with the transporter taking the oil, gas or geothermal resources from the property.

(c) Recovered load oil.

(1) The operator of each lease from which load oil is recovered shall file the original and one copy of commission form P-3 (authority to transport recovered load or frac oil) with the district office, and another copy with the transporter prior to running the load oil. Form P-3 requires a producer to report the quantity of recovered load or frac oil to be transported from a particular lease and to identify the transporter. The form P-3 (authority to transport recovered load or frac oil) filed by the operator shall be the authority for the transporter to run the quantity of recovered load or frac oil stated in the form.

(2) The provisions of this subsection apply only to oil that has been obtained from a source other than the lease on which it is used. "Recovered load oil or frac oil," as that term is used herein, is any oil or liquid hydrocarbons used in any operation in an oil or gas well, and which has been recovered as a merchantable product.

(d) Subdivision and consolidation of oil leases.

(1) An operator seeking to subdivide or consolidate existing oil leases shall file and obtain approval of a commission form P-4 (certificate of compliance and transportation authority) and a commission form P-6 (request for permission to subdivide or consolidate oil lease(s)). Form P-6 identifies the leases to be subdivided or consolidated as well as the resulting leases. Two plats shall be filed with form P-6, one showing the boundaries of the lease(s) before and one showing the boundaries of the lease(s) after the subdivision or consolidation.

(2) An operator seeking to subdivide an existing oil lease that it operates or to assume operatorship of fewer than all of the wells on an oil lease shall file and obtain approval of a commission form P-4 (certificate of compliance and transportation authority) and a commission form P-6 (request for permission to subdivide or consolidate oil lease(s)). A request to subdivide an oil lease may be approved administratively if the commission staff determines that approval of the request will not cause waste, harm correlative rights, or result in the circumvention of commission rules.

(3) An operator seeking to consolidate two or more existing oil leases that it operates shall file and obtain approval of a commission form P-4 (certificate of compliance and transportation authority) and a commission form P-6 (request for permission to subdivide or consolidate oil lease(s)). A request to consolidate two or more oil leases may be approved administratively if the commission staff determines that approval of the request will not cause waste, harm correlative rights, or result in the circumvention of commission rules and:

(A) the mineral and royalty ownership of the leases proposed for consolidation is identical in all respects;

(B) the operator has obtained a surface commingling exception permit pursuant to §3.26 of this title (relating to separating devices, tanks, and surface commingling of oil) that authorizes commingling of production from all of the leases proposed for consolidation ; or

(C) the operator has filed and obtained approval of a valid commission form P-12 (certificate of pooling authority) authorizing pooling of all of the leases proposed for consolidation.

Source Note: The provisions of this §3.58 adopted to be effective January 1, 1976; amended to be effective February 23, 1979, 4 TexReg 436; amended to be effective May 9, 1988, 13 TexReg 2026; amended to be effective May 22, 2000, 25 TexReg 4512; amended to be effective May 12, 2002, 27 TexReg 3756

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PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.57	**Reclaiming Tank Bottoms, Other Hydrocarbon Wastes, and Other Waste Materials**

(a) Applicability. This section is applicable to reclamation of tank bottoms and other hydrocarbon wastes generated through activities associated with the exploration, development, and production (including transportation) of crude oil and other waste materials containing oil, as those activities are defined in §3.8(a)(30) of this title (relating to Water Protection). The provisions of this section shall not apply where tank bottoms or other hydrocarbon-bearing materials are recycled or processed on-site by the owner/custodian and are returned to a tank or vessel at the same lease or facility. This section is not applicable to the practice of recycling or reusing drilling mud, except as to those hydrocarbons recovered from such mud recycling and sent to a permitted reclamation plant.

(b) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Tank bottoms--A mixture of crude oil or lease condensate, water, and other substances that is concentrated at the bottom of producing lease tanks and pipeline storage tanks (commonly referred to as basic sediment and water or BS&W).

(2) Other hydrocarbon wastes--Oily waste materials, other than tank bottoms, which have been generated in connection with activities associated with the exploration, development, and production of oil or gas or geothermal resources, as those activities are defined in §3.8(a)(30) of this title (relating to Water Protection). The term "other hydrocarbon wastes" includes, but is not limited to, pit hydrocarbons, skim oil, spillage, and leakage of crude oil or condensate from producing lease or pipeline storage tanks, and crude oil or condensate associated with pipeline ruptures and other spills.

(3) Authorized person--A tank bottoms cleaner or transporter that is under contract for disposition of untreated tank bottoms or other hydrocarbon wastes to a person who has obtained a permit to operate a reclamation plant.

(4) Affected person--A person who has suffered or will suffer actual injury or economic damage other than as a member of the general public and includes surface owners of property on which a reclamation plant is located and surface owners of adjoining properties.

(5) Director--The director of the Oil and Gas Division or a staff delegate designated in writing by the director of the Oil and Gas Division or the commission.

(c) Permitting process.

(1) Removal of tank bottoms or other hydrocarbon wastes from any producing lease tank, pipeline storage tank, or other production facility, for reclaiming by any person, is prohibited unless such person has either obtained a permit to operate a reclamation plant, or is an authorized person. Applicants for a reclamation plant operating permit shall file the appropriate form with the commission in Austin.

(2) The applicant shall give notice by mailing or delivering a copy of the application to the county clerk of

the county where the reclamation plant is to be located, and to the city clerk or other appropriate city official of any city where the reclamation plant is located within the corporate limits of the city, on or before the date the application is mailed to or filed with the commission.

(3) In order to give notice to other local governments and interested or affected persons, notice of the application shall be published once by the applicant in a newspaper of general circulation for the county where the reclamation plant is to be located, in a form approved by the commission. Publication shall occur on or before the date the application is mailed to or filed with the commission. The applicant shall file with the commission in Austin proof of publication prior to the hearing or administrative approval.

(4) If a protest from an affected person or local government is made to the commission within 15 days of receipt of the application or of publication, or if the commission determines that a hearing is in the public interest, then a hearing will be held on the application after the commission provides notice of hearing to all affected persons, local governments, or other persons who express an interest in writing in the application.

(5) If no protest from an affected person or local government is received by the commission within the allotted time, the director may administratively approve the application. If the director denies administrative approval, the applicant shall have a right to a hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(6) Applicants must demonstrate they are familiar with commission rules and have the proper facilities to comply with the rules.

(7) Except as provided in subparagraphs (A) and (B) of this paragraph, a permit to operate a reclamation plant shall remain in effect until canceled at the request of the operator. Existing permits subject to annual renewal may be renewed so as to remain in effect until canceled. Such renewal shall be subject to the requirements of paragraph (10) of this subsection. A reclamation plant permit may be canceled by the commission after notice and opportunity for hearing, if:

(A) the permitted facility has been inactive for 12 months; or

(B) there has been a violation, or a violation is threatened, of any provision of the permit, the conservation laws of the state, or rules or orders of the commission.

(8) If the operator objects to the cancellation, the operator must file, within 15 days of the date shown on the notice, a written objection and request for a hearing to determine whether the permit should be canceled. If such written request is timely filed, the cancellation will be suspended until a final order is issued pursuant to the hearing. If such request is not received within the required time period, the permit will be canceled. In the event of an emergency which presents an imminent pollution, waste, or public safety threat, the commission may suspend the permit until an order is issued pursuant to the hearing.

(9) A permit to operate a reclamation plant is not transferable. A new permit must be obtained by the new operator.

(10) Reclamation plants permitted under this section shall file financial security as required under §3.78(l) of this title (relating to Fees and Financial Security Requirements).

(d) Operation of a reclamation plant.

(1) The following provisions apply to any removal of tank bottoms or other hydrocarbon wastes from any oil producing lease tank, pipeline storage tank, or other production facility.

(A) Notwithstanding the provisions of §3.85(a)(8) of this title (relating to Manifest To Accompany Each Transport of Liquid Hydrocarbons by Vehicle), an operator of a reclamation plant or an authorized person shall execute a manifest in accordance with §3.85 of this title (relating to Manifest To Accompany Each Transport of Liquid Hydrocarbons by Vehicle), upon each removal of tank bottoms or other hydrocarbon wastes from any oil producing lease tank, pipeline storage tank, or other production facility. In addition to the information required pursuant to §3.85 of this title (relating to Manifest To Accompany Each Transport of Liquid Hydrocarbons by Vehicle), the operator of the reclamation plant or other authorized person shall also include on the manifest:

(i) the commission identification number of the lease or facility from which the material is removed; and

(ii) the gross and net volume of the material as determined by the required shakeout test.

(B) The operator of the reclamation plant or other authorized person shall fill out the manifest before leaving the lease or facility from which the liquid hydrocarbons are removed, and shall retain a copy on file for two years.

(C) The operator of the reclamation plant or other authorized person shall leave a copy of the manifest in the vehicle transporting the material.

(2) The operator of a reclamation plant or other authorized person shall conduct a shakeout (centrifuge) test on all tank bottoms or other hydrocarbon wastes upon removal from any producing lease tank, pipeline storage tank, or other production facility, to determine the crude oil content and lease condensate thereof.

(3) The shakeout test shall be conducted in accordance with the most current American Petroleum Institute or American Society for Testing Materials method.

(e) Reporting of reclaimed crude oil or lease condensate on commission required report.

(1) For wastes taken to a reclamation plant the following provisions shall apply.

(A) The net crude oil content or lease condensate from a producing lease's tank bottom as indicated by the shakeout test shall be used to calculate the amount of oil to be reported as a disposition on the monthly production report. The net amount of crude oil or lease condensate from tank bottoms taken from a pipeline facility shall be reported as a delivery on the monthly transporter report.

(B) For other hydrocarbon wastes, the net crude oil content or lease condensate of the wastes removed from a tank, treater, firewall, pit, or other container at an active facility, including a pipeline facility, shall also be reported as a disposition or delivery from the facility.

(2) The net crude oil content or lease condensate of any tank bottoms or other hydrocarbon wastes removed from an active facility, including a pipeline facility, and disposed of on-site or delivered to a site other than a reclamation plant shall also be reported as a delivery or disposition from the facility. All such disposal shall be in accordance with §§3.8, 3.9, and 3.46 of this title (relating to Water Protection; Disposal Wells; and Fluid Injection into Productive Reservoirs). Operators may be required to obtain a minor permit for such disposal using procedures set out in §3.8(d) and (g) of this title (relating to Water Protection). Prior to approval of the minor permit, the commission may require an analysis of the disposable material to be performed.

(f) General provisions applicable to materials taken to a reclamation plant.

(1) The removal of tank bottoms or other hydrocarbon wastes from any facility for which monthly reports

are not filed with the commission must be authorized in writing by the commission prior to such removal. A written request for such authorization must be sent to the commission office in Austin, and must detail the location, description, estimated volume, and specific origin of the material to be removed, as well as the name of the reclaimer and intended destination of the material. If the authorization is denied, the applicant may request a hearing.

(2) The receipt of any tank bottoms or other hydrocarbon wastes from outside the State of Texas must be authorized in writing by the commission prior to such receipt. However, written approval is not required if another entity will indicate, in the appropriate monthly report, a corresponding delivery of the same material. If the request is denied, the applicant may request a hearing.

(3) The receipt of any waste materials other than tank bottoms or other hydrocarbon wastes must be authorized in writing by the commission prior to such receipt. The commission may require the reclamation plant operator to submit an analysis of such waste materials prior to a determination of whether to authorize such receipt. If the request is denied, the applicant may request a hearing.

(4) The operator of a reclamation plant shall file a report on the appropriate commission form for each reclamation plant facility by the 15th day of each calendar month, covering the facility's activities for the previous month. The operator of a reclamation plant shall file a copy of the monthly report in the district office of any district in which the operator made receipts or deliveries for the month covered by the report.

(5) All wastes generated by reclaiming operations shall be disposed of in accordance with §§3.8, 3.9, and 3.46 of this title (relating to Water Protection; Disposal Wells; and Fluid Injection into Productive Reservoirs). No person conducting activities subject to regulation by the commission may cause or allow pollution of surface or subsurface water in the state.

(g) Commission review of administrative actions. Administrative actions performed by the director or commission staff pursuant to this rule are subject to review by the commissioners.

(h) Policy. The provisions of this rule shall be administered so as to prevent waste and protect correlative rights.

Source Note: The provisions of this §3.57 adopted to be effective April 11, 1990, 15 TexReg 1693; amended to be effective June 1, 1998, 23 TexReg 5656; amended to be effective July 10, 2000, 25 TexReg 6487; amended to be effective September 1, 2004, 29 TexReg 8271

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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.56	**Scrubber Oil and Skim Hydrocarbons**

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings unless the context clearly indicates otherwise:

(1) Identifiable liquid hydrocarbons--Volume of scrubber oil/skim hydrocarbons that is received at a gas plant/produced water disposal facility where the origin of such liquid hydrocarbons can be clearly identified.

(2) Producing property--A location from which hydrocarbons are being produced that has been assigned a lease identification number by the Commission and which is used in reporting production.

(3) Scrubber oil--Liquid hydrocarbons which accumulate in lines that are transporting casinghead gas and which are captured at the inlet to a gas processing plant.

(4) Skim hydrocarbons--Oil and condensate which accumulate during produced water disposal operations.

(5) Tolerance--The amount of skim hydrocarbons that may be recovered before the produced water disposal system operator must allocate to the producing property.

(6) Unidentifiable liquid hydrocarbons--Scrubber oil/skim hydrocarbons received at a gas plant/produced water disposal facility where the origin of such liquid hydrocarbons cannot be identified.

(b) Disposition of scrubber oil, skim hydrocarbons, and identifiable liquid hydrocarbon volumes.

(1) Scrubber oil. Any scrubber oil that has not been returned to a producing property by the end of a monthly report period shall be reported by the operator of the gas plant on the monthly plant report, Form R-3 (Monthly Report for Gas Processing Plants). The unidentifiable liquid hydrocarbons recovered and reported on Form R-3 may be disposed of at the point of accumulation. The accepted Form R-3 shall be the authority for the movement of the hydrocarbons to beneficial disposition.

(2) Skim hydrocarbons.

(A) All unidentifiable liquid hydrocarbons recovered by a single operator or multiple operator produced water disposal system shall be reported on the Form P-18 (Skim Oil/Condensate Report) for each reporting period.

(B) The unidentifiable liquid hydrocarbons recovered and reported on Form P-18 may be disposed of at the point of accumulation. The accepted Form P-18 shall be the authority for the movement of the hydrocarbons to beneficial disposition.

(C) Unidentifiable liquid hydrocarbons recovered by a single operator produced water disposal system shall be allocated to each producing property in the proportion that the volume of water received from the producing property bears to the total volume of water received by the system during a reporting period.

(D) Unidentifiable liquid hydrocarbons recovered by a multiple operator produced water disposal system in excess of a tolerance ratio of one barrel of liquid hydrocarbons for each 2,000 barrels of produced water received shall be allocated to each producing property in the proportion that the volume of water received from the producing property bears to the total volume of water received by the system during a reporting period. The produced water disposal system operator shall notify the operator of each producing property of any allocations to that property by furnishing a copy of the allocations as shown on Form P-18 (Skim Oil/Condensate Report).

(E) The operator of each producing property shall report the volume of liquid hydrocarbons allocated to the producing property as production from the property on either Form P-1 (Producer's Monthly Report of Oil Wells) or Form P-2 (Producer's Monthly Report of Gas Wells). The volume allocated back shall be shown as skim oil or skim condensate on the appropriate form.

(3) Identifiable liquid hydrocarbon volumes.

(A) Identifiable liquid hydrocarbon volumes returned to the producing property during the reporting period in which the volume is received at the gas plant/produced water disposal facility shall not be reported to the Commission by the gas plant/facility operator. The gas plant/produced water disposal facility operator shall notify the appropriate Commission district office by telephone prior to the return of such volumes. The movement of these volumes back to the producing property shall comply with §3.85 of this title (relating to Manifest to Accompany Each Transport of Liquid Hydrocarbons by Vehicle), commonly referred to as Statewide Rule 85.

(B) Identifiable volumes not returned to the producing property shall be reported to the Commission and to the operator of the producing property on Form R-3 or Form P-18 as prescribed in paragraph (1) or (2) of this subsection. Volumes shall be specifically credited to the appropriate producing property. The operator of the producing property shall report the disposition of such identifiable volumes as either skim hydrocarbons or scrubber oil on the appropriate production report.

Source Note: The provisions of this §3.56 adopted to be effective January 10, 2000, 25 TexReg 80; amended to be effective November 24, 2004, 29 TexReg 10728

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RULE §3.55	**Reports on Gas Wells Commingling Liquid Hydrocarbons before Metering**

(a) When the full well stream from a gas well is moved to a plant or central separation facilities, and the liquid hydrocarbons produced by two or more wells are commingled without being measured or metered from each gas well, the operator of each well so producing shall periodically file with the commission, as provided for in this section, a report showing the following information for each well:

(1) the specific gravity of the gas at 60 degrees Fahrenheit, after the removal of the liquid hydrocarbons;

(2) the API gravity corrected to 60 degrees Fahrenheit of the liquid hydrocarbons removed;

(3) the number of stock tank barrels of liquid hydrocarbons (corrected to 60 degrees Fahrenheit) recovered per 1,000 standard cubic feet of gas.

(b) Tests.

(1) The tests necessary for this report shall be made by one or more of the following methods:

(A) conventional mechanical separation;

(B) low temperature separation;

(C) split stream method;

(D) in accordance with AGA-NGAA Testing Code 101-43.

(2) The tests shall be made semiannually, or quarterly if contracts for royalty payments require quarterly tests. Semiannual tests must be made during the first and third or second and fourth quarters of the year. If a contract for royalty payments requires quarterly tests, the tests shall be made during each quarter. Both semiannual and quarterly tests may be made during any month of the quarter if the same (first, second, or third) month of each quarter is used thereafter for any well.

(c) The results of each test shall be submitted in duplicate on the appropriate commission form to the proper commission district office not later than the 15th day of each month following the month in which the test is made. The tests shall be required when the conditions set out in the first paragraph of this section exist, regardless of whether or not the conditions are an exception to §3.26 of this title (relating to Separating Devices, Tanks, and Surface Commingling of Oil) (Statewide Rule 26). The tests shall not be required, however, in any reservoir in which 100% of the operating and royalty ownership has been unitized.

(d) This section does not purport to alter any procedure for periodic tests of gas wells that has previously been approved by the commission. If test periods agreed upon by the interested parties have not been approved by the commission, and if the periods agreed upon differ from the test periods provided for in this section, alternative testing periods may be approved by the commission upon application.

Source Note: The provisions of this §3.55 adopted to be effective January 1, 1976; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective November 24, 2004, 29 TexReg 10728

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RULE §3.54	**Gas Reports Required**

(a) Gas processing plant report. As soon after the first day of each calendar month as practicable, and never later than the 25th day of each calendar month, the operator of each plant manufacturing or extracting liquid hydrocarbons, including gasoline, butane, propane, condensate, kerosene, or other derivatives from natural gas, or refinery or storage vapors, shall file, in duplicate, in the Austin office, a report concerning the operation of the plant during the immediately preceding month, which must contain the data and information required on the form.

(b) Pressure maintenance and repressuring plant report.

(1) As soon after the first day of each month as practicable, but never later than the 15th day of each calendar month, the operator of each plant that returns natural gas to oil or gas producing reservoirs, or both, for the purpose of maintaining pressure or repressuring an oil or gas reservoir, but is not reporting such gas on any other commission approved form, shall file in duplicate in the district office a report concerning the operation of the plant during the immediately preceding month, which must contain the data and information required on the form.

(2) Pressure maintenance.

(A) The operator of each pressure-maintenance or repressuring plant shall file the report although no liquid hydrocarbons are recovered.

(B) The term "pressure-maintenance plant" or "repressuring plant" as used herein means any equipment or device, mechanical or otherwise, used for the purpose of returning any natural gas, residue gas from a gas processing plant, including plant and storage vapors, to an underground oil reservoir if the plant is operated as a separate unit. If pressure maintenance or repressuring operations are conducted as an integral part of a gas processing plant extracting, manufacturing, or recovering liquid hydrocarbons from natural gas or vapors, or both, the operations shall be reported by the operator of the processing plant.

(c) Producer's report of condensate and/or crude oil produced from gas wells. As soon as practicable after the first day, and never later than the last day of the calendar month, subsequent to the period of the report, the operator of each gas well from which liquids are recovered on the lease shall file the required form.

(d) Carbon black plant report. As soon as practicable after the first day and never later than the 15th day of each calendar month, each operator of a carbon black plant shall file a report. The report shall cover the operation of the plant for the immediately preceding month and shall be filed in duplicate in the district office.

(e) Monthly gas production report. As soon after the first day of each month as practicable, and never later than the last day of the calendar month, subsequent to the period of the report, every operator producing natural gas from wells classified as either gas wells or oil wells by the commission, except those expressly exempted by the commission shall file a report on the required form.

Source Note: The provisions of this §3.54 adopted to be effective January 1, 1976; amended to be effective February 23, 1979, 4 TexReg 436; amended to be effective May 7, 1991, 16 TexReg 2297.

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TITLE 16	ECONOMIC REGULATION
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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.53	**Annual Well Tests and Well Status Reports Required**

(a) Oil wells.

(1) Unless otherwise provided for in this section, each operator of producing oil wells shall annually test each producing oil well for a 24-hour period during the test period specified on the well status report form and shall record all oil, gas and water volumes resulting from the test on the form.

(2) For any oil well capable of producing no more than five barrels of oil per 24-hour period, the operator of such well may report the required oil, gas and water volumes based on an allocation of that well's production on a prorated daily basis, rather than an actual well test. This option of using production allocation instead of actual well tests does not apply to surface-commingled wells, swabbed wells, the East Texas Field or the following Panhandle fields: Panhandle Carson County Field (Field Number 68845-001); Panhandle Collingsworth County Field (Field Number 68859-001); Panhandle Gray County Field (Field Number 68873-001); Panhandle Hutchison County Field (Field Number 68887-001); Panhandle Moore County field (Field Number 68901-001); Panhandle Potter County Field (Field Number 68915-001); and Panhandle Wheeler County Field (Field Number 68929-001).

(3) Each operator of a well or wells listed in the oil proration schedule shall file with the commission an oil well status report form in accordance with instructions on the form. All wells on a lease, and injection and disposal wells, must be reported.

(4) Changes in oil well status filed between regularly scheduled oil well status surveys shall be submitted on oil well status report forms in accordance with instructions thereon.

(b) Gas wells. Each operator of a gas well producing liquid hydrocarbons shall file with the commission gas well status reports in accordance with instructions thereon.

Source Note: The provisions of this §3.53 adopted to be effective January 1, 1976; amended to be effective November 21, 1980, 5 TexReg 4419; amended to be effective February 13, 1997, 22 TexReg 1313; amended to be effective January 10, 2000, 25 TexReg 79

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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.52	**Oil Well Allowable Production**

(a) The daily allowable production of any lease or property shall not include production based upon the daily potential production of the field or area in which such well is located unless such well is actually on production, and such lease or property shall share in the total allowable production of the field or area, only to the extent of such well's actual ability to produce from day to day regardless of the rated potential production thereof according to the commission schedules.

(b) Production of a well in any one day shall not exceed 110% of the top well allowable as fixed by applicable rules and orders. Production and runs from a lease during the monthly allowable period shall not exceed 105% of the monthly allowable for the well or wells on the lease. However, the volume of oil that is produced and removed from the producing property as tolerance production shall be treated as overproduction and overruns shall be made up during the next succeeding month.

(c) All oil allowable volumes shall be measured in a manner consistent with §3.71 of this title (relating to Pipeline Tariffs) (Statewide Rule 71).

(d) A newly completed well coming into production during a proration period will be gauged either by a commission agent, or pipeline gauger if a commission agent is not available, if an offset lease owner witnesses the gauge taken by the pipeline gauger. The allowable production of such newly completed well shall be in addition to the existing total allowable production of the field as previously ascertained. The well whose allowable is thus fixed shall take its ratable share of production at the next succeeding schedule date according to rule.

(e) All oil produced from any well governed by any proration order of the commission shall be charged against the allowable daily production of such well regardless of the disposition which is made of the oil so produced.

(f) The operator of any lease or unitized area in the State of Texas may be permitted to produce the total allowable for any such lease or unitized area subject to the following provisions:

(1) The operator must submit an application to produce that total allowable on a lease or unit production basis to the commission with a plat showing the subject lease or unit as well as the adjacent properties thereto. Such plat shall identify properly all properties and wells. The applicant shall give written notice to all operators in the field when application is made for permission to produce on a lease basis in a field. If no protest is received by the commission within 15 days of the date of mailing, the application may be granted by administrative action. If protest is received, notice will be given and the matter set for hearing.

(2) The total daily allowable of the lease or unit shall be initially established as an allowable equal to the sum of the current allowables for all wells on the lease or unit. The allowable credited to any new or existing well may be increased to the top well allowable permitted by subsequently filing a new potential test on that well. The maximum total daily allowable of the lease or unit will be equal to the sum of the scheduled top allowables assignable to each well for its proration unit.

(3) The total daily allowable of the lease or unit may be produced in any quantity from any well or

combination of wells with the exception that wells nearer than a regular location from a lease or unit line shall not be permitted to produce more than their normal allowables and wells at a distance of a regular location from a lease or unit line shall not be produced at a rate of more that two times the top allowable for such well unless waivers of objection to rates in excess of this limit have been obtained from the operators of wells offsetting the well.

(4) Annual well test or allocation:

(A) An annual well test, or an allocation pursuant to §3.53(a)(2) of this title (relating to Annual Well Tests and Well Status Reports Required) shall be made and reported on the oil well status report form on each lease or unit property to which a lease production basis has been granted showing an individual well test or allocation on each oil well on the property made during the prescribed test period determined by the commission. Annual well tests may be witnessed by offset operators. An offset operator that desires to witness an annual well test shall give the testing operator written notice of its desire to witness the next scheduled annual well test of a specific well. A testing operator that has received prior written notice that an offset operator desires to witness an annual well test shall give that offset operator at least 24 hours advance notice of the date of the next annual well test for that well. The Commission will use the test or allocation data in the preparation of the oil proration schedule. The total schedule daily lease allowable shall be the sum of the individual well allowables as determined under applicable rules and the lease production basis shall be designated on the oil proration schedule by an appropriate symbol. All wells on the lease for which an allowable is requested shall have their production volumes reported pursuant to §3.53(a).

(B) Any producing well with a gas-oil ratio in excess of that permitted by the applicable rules shall have its daily allowable calculated by dividing the producing gas-oil ratio into the daily gas limit of the well.

(5) The Commission shall continue to require special tests in cases of commingled production where individual lease apportionment is determined by this method. Other special tests may be required as the Commission deems necessary.

(6) In the event that the monthly gas production of the lease or unit exceeds the permissible monthly lease gas limit, the volume of gas in excess of the lease gas limit shall be considered overproduction and must be made up by underproduction of the lease gas limit. Whenever the overproduced amount equals the next month's lease gas limit the overproduced amount shall immediately be reduced to zero by shutting in the lease or by other means acceptable to the Commission.

(7) The East Texas Field is excluded from the provisions of this section.

Source Note: The provisions of this §3.52 adopted to be effective January 1, 1976; amended to be effective May 1, 1991, 16 TexReg 2095; amended to be effective February 18, 1994, 19 TexReg 783; amended to be effective February 13, 1997, 22 TexReg 1313; amended to be effective January 10, 2000, 25 TexReg 79; amended to be effective November 24, 2004, 29 TexReg 10728

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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.51	**Oil Potential Test Forms Required**

(a) A potential test form with all information requested thereon filled in shall be filed in the district office not later than 10 days after the test is completed. If the operator fails to file a potential test in an acceptable form within the 10-day period, then the effective date of the allowable resulting from the test shall not extend back more than 10 days prior to the date that the test form, properly completed, is filed in the district office. The 10-day provision shall govern regardless of whether the potential test is taken during the month in which it is received in the district office or any prior month.

(b) The initial potential test form for any new completion or recompletion must be accompanied by the well record.

Source Note: The provisions of this §3.51 adopted to be effective January 1, 1976.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.50	**Enhanced Oil Recovery Projects--Approval and Certification for Tax Incentive**

(a) Purpose. The purpose of this section is to provide a procedure by which an operator can obtain Railroad Commission approval and certification of enhanced oil recovery (EOR) projects pursuant to the Tax Code, Title 2, Chapter 202, Subchapter B, §202.052 and §202.054.

(b) Applicability.

(1) This section applies to:

(A) new EOR projects and the change from secondary EOR projects to tertiary projects which qualify as new EOR projects, and which begin active operation on or after September 1, 1989; and

(B) expansions of existing EOR projects.

(2) An EOR project may not qualify as an expansion if the project has qualified as a new EOR project under this section.

(c) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Active operation--The start and continuation of a fluid injection program for a secondary or tertiary recovery project to enhance the displacement process in the reservoir. Applying for permits and moving equipment into the field alone are not considered active operations.

(2) Commission--The Railroad Commission of Texas.

(3) Commission representative--A commission employee authorized to act for the commission. Any authority given to a commission representative is also retained by the commission. Any action taken by the commission representative is subject to review by the commission.

(4) Comptroller--The Comptroller of Public Accounts.

(5) Enhanced oil recovery project (EOR)--The use of any process for the displacement of oil from the reservoir other than primary recovery and includes the use of an immiscible, miscible, chemical, thermal, or biological process. This term does not include pressure maintenance or water disposal projects.

(6) Existing enhanced recovery project--An EOR project that has begun active operation but was not approved by the Commission as a new EOR project.

(7) Expanded enhanced recovery project or expansion--The addition of injection and producing wells, the change of injection pattern, or other commission approved operating changes to an existing enhanced oil recovery project that will result in the recovery of oil that would not otherwise be recovered.

(8) Fluid injection--Injection through an injection well of a fluid (liquid or gaseous) into a producing

formation as part of an EOR project.

(9) Incremental production--The volume of oil produced by an expanded enhanced recovery project in excess of the production decline rate established under conditions before expansion of an existing enhanced recovery project.

(10) Oil recovery from an enhanced recovery project--The oil produced from the designated area the commission certifies to be affected by the project.

(11) Operator--The person recognized by the commission as being responsible for the actual physical operation of an EOR project and the wells associated with the EOR project.

(12) Positive production response--Occurs when the rate of oil production from wells within the designated area affected by an EOR project is greater than the rate that would have occurred without the project.

(13) Pressure maintenance--The injection of fluid into the reservoir for the purpose of maintaining the reservoir pressure at or near the bubble point or other critical pressure wherein fluid injection volumes are not sufficient to refill existing reservoir voidage in the approved project area and displace oil that would not be displaced by primary recovery operations.

(14) Primary recovery--The displacement of oil from the reservoir into the wellbore(s) by means of the natural pressure of the oil reservoir, including artificial lift.

(15) Production decline rate--The projected future oil production from a project area as extrapolated by a method approved by the commission.

(16) Recovered oil tax rate--The tax rate provided by the Tax Code, §202.052(b).

(17) Secondary recovery project--An enhanced recovery project that is not a tertiary recovery project.

(18) Termination--Occurs when the approved fluid injection program associated with an EOR project stops or is discontinued.

(19) Tertiary recovery project--An EOR project using a tertiary recovery method (as defined in the federal June 1979 energy regulations referred to in the Internal Revenue Code of 1986, §4993, or approved by the United States secretary of the treasury for purposes of administering the Internal Revenue Code of 1986, §4993, without regard to whether that section remains in effect) including those listed as follows:

(A) Alkaline (or caustic) flooding--An augmented waterflooding technique in which the water is made chemically basic as a result of the addition of alkali metals.

(B) Carbon dioxide augmented waterflooding--Injection of carbonated water, or water and carbon dioxide, to increase waterflood efficiency.

(C) Cyclic steam injection--The alternating injection of steam and production of oil with condensed steam from the same well or wells.

(D) Immiscible carbon dioxide displacement--Injection of carbon dioxide into an oil reservoir to effect oil displacement under conditions in which miscibility with reservoir oil is not obtained.

(E) In situ combustion--Combustion of oil in the reservoir, sustained by continuous air injection, to displace unburned oil toward producing wells.

(F) Microemulsion, or micellar/emulsion, flooding--An augmented waterflooding technique in which a surfactant system is injected in order to enhance oil displacement toward producing wells. A surfactant system normally includes a surfactant, hydrocarbon, cosurfactant, an electrolyte and water, and polymers for mobility control.

(G) Miscible fluid displacement--An oil displacement process in which gas or alcohol is injected into an oil reservoir, at pressure levels such that the injected gas or alcohol and reservoir oil are miscible. The process may include the concurrent, alternating, or subsequent injection of water. The injected gas may be natural gas, enriched natural gas, a liquefied petroleum gas slug driven by natural gas, carbon dioxide, nitrogen, or flue gas. Gas cycling, i.e., gas injection into gas condensate reservoirs, is not a miscible fluid displacement technique nor a tertiary enhanced recovery technique within the meaning of this section.

(H) Polymer augmented waterflooding--Augmented waterflooding in which organic polymers are injected with the water to improve a real and vertical sweep efficiency.

(I) Steam drive injection--The continuous injection of steam into one set of wells (injection wells) or other injection source to effect oil displacement toward and production from a second set of wells (production wells).

(20) Water disposal project--The injection of produced water into the reservoir for the purpose of disposing of the produced water wherein the water injection volumes are not sufficient to refill existing reservoir voidage in the approved project area and displace oil that would not be displaced by primary recovery operations.

(d) Application requirements. To qualify for the recovered oil tax rate the operator shall:

(1) submit an application for approval on the appropriate form. All applications must be filed at the Commission's Austin office. The form shall be executed and certified by a person having knowledge of the facts entered on the form. If an application is already on file under the Natural Resources Code, Chapter 101, Subchapter B, or for approval as a tertiary recovery project for purposes of the Internal Revenue Code of 1986, §4993, the operator may file a new EOR project and area designation application if the active operation of the project does not begin before the application under this section is approved by the Commission;

(2) submit all necessary forms to the Oil and Gas Division and provide the Commission with any relevant information required to administer this section such as: area plats showing the proposed project area and all injection and producing wells within the area, production and injection history, planned enhanced oil recovery procedures, and any other pertinent data;

(3) obtain a unitization agreement if required for purposes of carrying out the project under the Natural Resources Code, Chapter 101, Subchapter B. The Commission may not approve the project unless the unitization is approved; and

(4) submit an application on the appropriate form and obtain the necessary permits to conduct fluid injection operations pursuant to §3.46 of this title (relating to Fluid Injection into Productive Reservoirs) (Statewide Rule 46), if such permits have not already been obtained.

(e) Concurrent applications. The operator may file concurrently:

(1) an application for approval of a new or expanded EOR project under this section, together with;

(2) an application for approval of a unitization agreement for purposes of carrying out the enhanced oil

recovery project under the Natural Resources Code, §§101.001 et seq.; or

(3) an application for approval for certification of the project as a tertiary recovery project.

(f) Opportunity for hearing. A commission representative may administratively approve the application. If the commission representative denies administrative approval, the applicant shall have the right to a hearing upon request. After hearing, the examiner shall recommend final action by the commission.

(g) Approval and certification.

(1) Project approval. In order to be eligible for the recovered oil tax rate as provided in the Tax Code, §202.052(b), the operator shall apply for and be granted Commission approval of a new EOR project or an expansion of an existing EOR project, prior to commencing active operation of the new project or expanded project. For a project to be approved the operator shall:

(A) prove that it qualifies as an EOR project;

(B) designate the area to be affected by the project and obtain Commission approval of the designation; and

(C) if production from the wells within the project area is reported with production from wells not in the project area, designate the method to account for and report production from the project area.

(2) Positive production response certificate.

(A) The operator of an EOR project that meets the requirements of this section shall demonstrate to the Commission a positive oil production response before the operator can receive Commission certification of such a positive production response. The certification date may be any date desired by the operator, subject to Commission approval, following the date on which a positive oil production response first occurred. The operator shall apply for a positive production response certificate within three years of project approval for secondary projects, and within five years of project approval for tertiary projects, to qualify for the recovered oil tax rate. The oil produced from the designated area of a new EOR project or incremental oil produced from the designated area of an expanded EOR project after the date of certification of a positive production response is eligible for the recovered oil tax rate. The operator shall apply to the comptroller pursuant to the Tax Code, §202.052 and §202.054, to qualify for the recovered oil tax rate.

(B) The application for positive response certification shall include:

(i) production and injection graphs with supporting tabular data illustrating a positive production response and volumes of water or other substances that have been injected on the designated area since the initiation of the new or the expanded EOR project;

(ii) a plat of the affected area showing all injection and producing wells, with completion dates; and

(iii) any other data requested by the Oil and Gas Division.

(C) The application for the positive production response certificate shall be processed administratively. If the Commission representative denies administrative approval, the applicant shall have the right to a hearing upon request. After hearing, the examiner shall recommend final action by the Commission.

(h) Annual reporting.

(1) The operator shall file an annual report on the appropriate form with the Oil and Gas Division each year

the project remains eligible for the reduced severance tax rate. This form shall be filed within 30 days of the first anniversary of the date that the Commission acted on the EOR positive production response certification application and annually thereafter.

(2) The report shall contain the following:

(A) Commission certification date of positive production response;

(B) monthly volume of injected fluid(s);

(C) number of well(s) used for injection;

(D) monthly production of oil, gas, and water;

(E) number of active producing wells; and

(F) any other relevant information requested by the Oil and Gas Division.

(i) Reduced or enlarged areas. The operator may apply for reduced or enlarged project area certification if the application for reduction or enlargement is received prior to the filing of an application for positive production response certification of the original enhanced oil recovery project.

(j) Termination and penalty. Upon approval by the Commission and the comptroller, the recovered oil tax rate shall continue for a maximum of 10 years, unless the project is sooner terminated. If the project is terminated prior to the 10-year period, the operator shall notify the Commission and the comptroller in writing within 30 days after the last day of active operations. Failure to so notify may result in civil penalties, interest, and the tax due. If the Commission determines a project has been terminated or there is action that affects the tax rate, it shall notify the comptroller immediately in writing.

Source Note: The provisions of this §3.50 adopted to be effective February 20, 1990, 15 TexReg 652; amended to be effective March 18, 1992, 17 TexReg 1615; amended to be effective November 17, 1993, 18 TexReg 7922; amended to be effective April 6, 1998, 23 TexReg 3435; amended to be effective October 12, 2003, 28 TexReg 8585

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.49	**Gas-Oil Ratio**

(a) Any oil well producing with a gas-oil ratio in excess of 2,000 cubic feet of gas per barrel of oil produced shall be allowed to produce daily only that volume of gas obtained by multiplying its maximum daily oil allowable, as determined by the allocation formula applicable to the well, by 2,000. The gas volume thus obtained shall be known as the daily gas limit of the well. The daily oil allowable of the well shall then be determined by dividing its daily gas limit, obtained as provided in this section, by its producing gas-oil ratio in cubic feet per barrel of oil produced.

(b) Any gas well producing from the same reservoir in which oil wells are completed and producing shall be allowed to produce daily only that amount of gas which is the volumetric equivalent in reservoir displacement of the gas and oil produced from the oil well in the reservoir that withdraws the maximum amount of gas in the production of its daily oil allowable.

(1) The following formula shall be used in the determination of the allowable of a gas well producing with a gas-oil ratio of 100,000 or more.

Attached Graphic

(2) The following formula shall be used in the determination of the allowable of a gas well producing with a gas-oil ratio of less than 100,000 under the provisions of the rule stated.

Attached Graphic

(3) The allowable for an associated gas well as determined by this subsection shall be limited to the lesser of:

(A) the gas well allowable as calculated by paragraph (1) or (2) of this subsection;

(B) the well's capability as determined by §3.31(e) of this title (relating to Gas Reservoirs and Gas Well Allowable) (Statewide Rule 31); or

(C) the highest monthly production during those months averaged to a daily amount for wells that reported production during any of the three most recently reported production months.

(c) The necessary reservoir data shall be obtained from the file of the most recent MER hearing or shall be estimated by the commission unless more recent information is submitted by the operators.

(d) If the gas produced from an oil reservoir is returned to the same reservoir from which it was produced, only the volume of gas not returned to the reservoir shall be considered in applying the rule stated.

(e) Associated gas wells.

(1) Subsection (b) of this section will not be applicable to associated gas wells in reservoirs for which unlimited net gas-oil ratio authority has been granted for oil wells, where such net gas is defined as total gas produced less gas diverted to legal uses; however, this subsection does not apply to reservoirs where net gas

is defined as total gas produced less gas returned to the reservoir from which it was produced, or where special field rules have been adopted for associated gas wells, or where a total gas volume limitation is placed upon the oil well producing under a net ratio, except that each associated gas well in such a reservoir shall be entitled to an additional gas voidage not to exceed the limitation placed upon the net ratio authority granted and the facts are shown on the current oil proration schedule for the field.

(2) Allowables for associated gas wells producing from reservoirs that are subject to an unlimited net gas-oil ratio authority will be dropped from the associated gas well schedule, effective that date such an unlimited net gas-oil ratio is authorized for any oil well in such reservoir.

(f) All gas-oil ratios determined by test or allocation shall be reported on the oil well status report form in accordance with instructions thereon and the provisions of §3.53(a) of this title (relating to Annual Well Tests and Well Status Reports Required).

(g) Allowables.

(1) No well shall have its allowable curtailed below the allowable fixed by the applicable field rules and the general statewide market demand order, unless such well is incapable of producing this allowable on a calendar day basis.

(2) Any well that has a gas-oil ratio in excess of the prescribed ratio for the field in which it is located will have its schedule daily allowable penalized due to such ratio.

Source Note: The provisions of this §3.49 adopted to be effective January 1, 1976; amended to be effective July 1, 1992, 17 TexReg 3236; amended to be effective February 13, 1997, 22 TexReg 1313; amended to be effective November 24, 2004, 29 TexReg 10728

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TITLE 16	ECONOMIC REGULATION
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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.48	**Capacity Oil Allowables for Secondary or Tertiary Recovery Projects**

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Capacity oil allowable--The allowable assigned from time to time by the director of the Oil and Gas Division or the director's delegate to an oil lease or unit engaged in a secondary or tertiary recovery program, that is consistent with the ability of the lease or unit to produce and that will prevent the occurrence of overproduced status for the lease or unit. Capacity oil allowables encompass and supercede what the Railroad Commission formerly designated as waterflood allowables.

(2) Offsetting operators and unleased mineral interest owners affected by the application--All offsetting operators and unleased mineral interest owners to the lease or unit except for those offsetting operators and unleased mineral owners the director of the Oil and Gas Division or the director's delegate determines to be unaffected by the application.

(b) Application. The director of the Oil and Gas Division or the director's delegate may grant a capacity oil allowable for a lease or unit, to the operator of a secondary or tertiary recovery project, when evidence of production increase in response to the secondary or tertiary recovery project is noted. The operator's application for a capacity oil allowable shall consist of:

(1) a written request that shall contain a statement indicating that all offsetting operators and unleased mineral interest owners affected by the application have been sent a copy of the complete application, and a list of such offsetting operators and unleased mineral interest owners indicating the date that notification was sent;

(2) evidence of the operator's participation in the subject secondary or tertiary recovery project;

(3) a plat indicating all producing wells and injection wells on the lease or unit and all offsetting operators and unleased mineral interest owners to the lease or unit;

(4) if available, signed waivers of objection from all offsetting operators and unleased mineral interest owners affected by the application; and

(5) a production graph illustrating both increased production and volumes of water or other substances used in the secondary or tertiary recovery project that have been injected on the lease or unit since initiation of the secondary or tertiary recovery project.

(c) Notice and hearing. If the operator does not submit signed waivers of objection from all offsetting operators and unleased mineral interest owners affected by the application, there shall be a minimum of 21 days notice of the application for a capacity oil allowable; provided that, if the operator requests a hearing to consider the application, such hearing shall be held only after at least 10 days notice. If the director of the Oil and Gas Division or the director's delegate declines to approve the initial application, or if a protest is received by the Oil and Gas Division within the prescribed notice period, the operator may request a hearing to show that the capacity oil allowable is necessary either to prevent waste or to protect correlative rights. Any hearing held pursuant to this section shall be held only after at least 10 days notice. If the operator submits signed waivers of objection from all offsetting operators and unleased mineral interest owners affected by the application, or if no protest is received by the Oil and Gas Division within the 21-day notice period, or if no protestant appears at a hearing to consider an application for a capacity oil allowable, the capacity oil allowable may be granted administratively by the director of the Oil and Gas Division or the director's delegate if the application establishes that the capacity oil allowable is necessary to ensure maximum recovery from the secondary or tertiary recovery project.

(d) Temporary basis. A capacity oil allowable may be granted on a temporary basis by the director of the Oil and Gas Division or the director's delegate upon receipt of a complete application indicating that an immediate allowable increase is necessary to ensure maximum recovery from the secondary or tertiary recovery project. If a hearing is held to consider the application, any capacity oil allowable previously granted on a temporary basis under this section will remain in effect until a signed order of the Railroad Commission is issued in the matter. If the commission order denies the application, or if an applicant fails to request a hearing to consider a protested application, additional production resulting from the capacity oil allowable granted on a temporary basis will be treated as overproduction.

Source Note: The provisions of this §3.48 adopted to be effective March 28, 1988, 13 TexReg 1257.

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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.47	**Allowable Transfers for Saltwater Injection Wells**

An allowable transfer will not be authorized for a well converted from oil production to saltwater disposal; however, an operator may make application to use the well for dual-purpose waterflood and saltwater disposal if injection is into an oil productive zone, and it is shown that the water injection will not injure the reservoir but will probably be of benefit to the reservoir as a secondary recovery program even though the beneficial effect of the water injection cannot be readily determined.

Source Note: The provisions of this §3.47 adopted to be effective January 1, 1976.

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TITLE 16	ECONOMIC REGULATION
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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.46	**Fluid Injection into Productive Reservoirs**

(a) Permit required. Any person who engages in fluid injection operations in reservoirs productive of oil, gas, or geothermal resources must obtain a permit from the commission. Permits may be issued when the injection will not endanger oil, gas, or geothermal resources or cause the pollution of freshwater strata unproductive of oil, gas, or geothermal resources. Permits from the commission issued before the effective date of this section shall continue in effect until revoked, modified, or suspended by the commission.

(b) Filing of application.

(1) Application. An application to conduct fluid injection operations in a reservoir productive of oil, gas, or geothermal resources shall be filed in Austin on the form prescribed by the commission accompanied by the prescribed fee. On the same date, one copy shall be filed with the appropriate district office. The form shall be executed by a party having knowledge of the facts entered on the form. The applicant shall file the freshwater injection data form if fresh water is to be injected.

(2) Commercial disposal well. An applicant for a permit to dispose of oil and gas waste in a commercial disposal well shall clearly indicate on the application and in the notice of application that the application is for a commercial disposal well permit. For the purposes of this rule, "commercial disposal well" means a well whose owner or operator receives compensation from others for the disposal of oil field fluids or oil and gas wastes that are wholly or partially trucked or hauled to the well, and the primary business purpose for the well is to provide these services for compensation.

(c) Notice and opportunity for hearing.

(1) The applicant shall give notice by mailing or delivering a copy of the application to affected persons who include the owner of record of the surface tract on which the well is located; each commission-designated operator of any well located within one half mile of the proposed injection well; the county clerk of the county in which the well is located; and the city clerk or other appropriate city official of any city where the well is located within the corporate limits of the city, on or before the date the application is mailed to or filed with the commission. For the purposes of this section, the term "of record" means recorded in the real property or probate records of the county in which the property is located.

(2) In addition to the requirements of subsection (c)(1), a commercial disposal well permit applicant shall give notice to owners of record of each surface tract that adjoins the proposed injection tract by mailing or delivering a copy of the application to each such surface owner.

(3) If, in connection with a particular application, the commission or its delegate determines that another class of persons should receive notice of the application, the commission or its delegate may require the applicant to mail or deliver a copy of the application to members of that class. Such classes of persons could include adjacent surface owners or underground water conservation districts.

(4) In order to give notice to other local governments, interested, or affected persons, notice of the application shall be published once by the applicant in a newspaper of general circulation for the county where the well will be located in a form approved by the commission or its delegate. The applicant shall file

with the commission in Austin proof of publication prior to the hearing or administrative approval.

(5) Protested applications:

(A) If a protest from an affected person or local government is made to the commission within 15 days of receipt of the application or of publication, whichever is later, or if the commission or its delegate determines that a hearing is in the public interest, then a hearing will be held on the application after the commission provides notice of hearing to all affected persons, local governments, or other persons, who express an interest, in writing, in the application.

(B) For purposes of this section, "affected person" means a person who has suffered or will suffer actual injury or economic damage other than as a member of the general public or as a competitor, and includes surface owners of property on which the well is located and commission-designated operators of wells located within one-half mile of the proposed disposal well.

(6) If no protest from an affected person is received by the commission, the commission's delegate may administratively approve the application. If the commission's delegate denies administrative approval, the applicant shall have a right to a hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(d) Subsequent commission action.

(1) An injection well permit may be modified, suspended, or terminated by the commission for just cause after notice and opportunity for hearing, if:

(A) a material change of conditions occurs in the operation or completion of the injection well, or there are material changes in the information originally furnished;

(B) fresh water is likely to be polluted as a result of continued operation of the well;

(C) there are substantial violations of the terms and provisions of the permit or of commission rules;

(D) the applicant has misrepresented any material facts during the permit issuance process;

(E) injected fluids are escaping from the permitted injection zone; or

(F) waste of oil, gas, or geothermal resources is occurring or is likely to occur as a result of the permitted operations.

(2) An injection well permit may be transferred from one operator to another operator provided that the commission's delegate does not notify the present permit holder of an objection to the transfer prior to the date the lease is transferred on commission records.

(3) Voluntary permit suspension.

(A) An operator may apply to temporarily suspend its injection authority by filing a written request for permit suspension with the commission in Austin, and attaching to the written request the results of an MIT test performed during the previous three-month period in accordance with the provisions of subsection (j)(4) of this section. The provisions of this paragraph shall not apply to any well that is permitted as a commercial injection well.

(B) The commission or its delegate may grant the permit suspension upon determining that the results of the MIT test submitted under subparagraph (A) of this paragraph indicate that the well meets the performance standards of subsection (j)(4) of this section.

(C) During the period of permit suspension, the operator shall not use the well for injection or disposal purposes.

(D) During the period of permit suspension, the operator shall comply with all applicable well testing requirements of §3.14 of this title (relating to plugging, and commonly referred to as Statewide Rule 14) but need not perform the MIT test that would otherwise be required under the provisions of subsection (j)(4) of this section or the permit. Further, during the period of permit suspension, the provisions of subsection (i)(1) - (3) of this section shall not apply.

(E) The operator may reinstate injection authority under a suspended permit by filing a written notification with the commission in Austin. The written notification shall be accompanied by an MIT test performed during the three-month period prior to the date notice of reinstatement is filed. The MIT test shall have been performed in accordance with the provisions and standards of subsection (j)(4) of this section.

(e) Area of Review.

(1) Except as otherwise provided in this subsection, the applicant shall review the data of public record for wells that penetrate the proposed disposal zone within a 1/4 mile radius of the proposed disposal well to determine if all abandoned wells have been plugged in a manner that will prevent the movement of fluids from the disposal zone into freshwater strata. The applicant shall identify in the application any wells which appear from such review of public records to be unplugged or improperly plugged and any other unplugged or improperly plugged wells of which the applicant has actual knowledge.

(2) The commission or its delegate may grant a variance from the area-of-review requirements of paragraph (1) of this subsection upon proof that the variance will not result in a material increase in the risk of fluid movement into freshwater strata or to the surface. Such a variance may be granted for an area defined both vertically and laterally (such as a field) or for an individual well. An application for an areal variance need not be filed in conjunction with an individual permit application or application for permit amendment. Factors that may be considered by the commission or its delegate in granting a variance include:

(A) the area affected by pressure increases resulting from injection operations;

(B) the presence of local geological conditions that preclude movement of fluid that could endanger freshwater strata or the surface; or

(C) other compelling evidence that the variance will not result in a material increase in the risk of fluid movement into freshwater strata or to the surface.

(3) Persons applying for a variance from the area-of-review requirements of paragraph (1) of this subsection on the basis of factors set out in paragraph (2)(B) or (C) of this subsection for an individual well shall provide notice of the application to those persons given notice under the provisions of subsection (c)(1) of this section. The provisions of subsection (c) of this section shall apply in the case of an application for a variance from the area-of-review requirements for an individual well.

(4) Notice of an application for an areal variance from the area-of-review requirements under paragraph (1) of this subsection shall be given on or before the date the application is filed with the commission:

(A) by publication once in a newspaper having general circulation in each county, or portion thereof, where the variance would apply. Such notice shall be in a form approved by the commission or its delegate prior to publication and must be at least three inches by five inches in size. The notice shall state that protests to the application may be filed with the commission during the 15-day period following the date of publication. The notice shall appear in a section of the newspaper containing state or local news items;

(B) by mailing or delivering a copy of the application, along with a statement that any protest to the application should be filed with the commission within 15 days of the date the application is filed with the commission, to the following:

(i) the manager of each underground water conservation district in which the variance would apply, if any;

(ii) the city clerk or other appropriate official of each incorporated city in which the variance would apply, if any;

(iii) the county clerk of each county in which the variance would apply; and

(iv) any other person or persons that the commission or its delegate determines should receive notice of the application.

(5) If a protest to an application for an areal variance is made to the commission by an affected person, local government, underground water conservation district, or other state agency within 15 days of receipt of the application or of publication, whichever is later, or if the commission's delegate determines that a hearing on the application is in the public interest, then a hearing will be held on the application after the commission provides notice of the hearing to all local governments, underground water conservation districts, state agencies, or other persons, who express an interest, in writing, in the application. If no protest from an affected person is received by the commission, the commission's delegate may administratively approve the application. If the application is denied administratively, the person(s) filing the application shall have a right to hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(6) An areal variance granted under the provisions of this subsection may be modified, terminated, or suspended by the commission after notice and opportunity for hearing is provided to each person shown on commission records to operate an oil or gas lease in the area in which the proposed modification, termination, or suspension would apply. If a hearing on a proposal to modify, terminate, or suspend an areal variance is held, any applications filed subsequent to the date notice of hearing is given must include the area-of-review information required under paragraph (1) of this subsection pending issuance of a final order.

(f) Casing. Injection wells shall be cased and the casing cemented in compliance with §3.13 of this title (relating to Casing, Cementing, Drilling, and Completion Requirements) in such a manner that the injected fluids will not endanger oil, gas, or geothermal resources and will not endanger freshwater formations not productive of oil, gas, or geothermal resources.

(g) Special equipment.

(1) Tubing and packer. Wells drilled or converted for injection shall be equipped with tubing set on a mechanical packer. Packers shall be set no higher than 200 feet below the known top of cement behind the long string casing but in no case higher than 150 feet below the base of usable quality water. For purposes of this section, the term "tubing" refers to a string of pipe through which injection may occur and which is neither wholly nor partially cemented in place. A string of pipe that is wholly or partially cemented in place is considered casing for purposes of this section.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.45	**Oil Allowables**

(a) Oil allowable yardsticks.

(1) 1947 allowable yardstick. The following schedule allowable shall be assigned all wells according to depth of the reservoir and proration unit size authorized by the commission upon expiration of the discovery allowable, if discovery of the field occurred prior to January 1, 1965, provided that paragraph (3) of this subsection does not apply.

Attached Graphic

(2) 1965 allowable yardstick. The following schedule allowable shall be assigned all wells according to depth of the reservoir and proration unit size authorized by the commission upon expiration of the discovery allowable, if discovery of the field occurred on or after January 1, 1965.

Attached Graphic

(3) Exception. Wells in fields discovered prior to January 1, 1965, whose discovery allowables either have expired or will expire subsequent to July 1, 1964, upon expiration of the discovery allowable, may be assigned allowable pursuant to the 1965 yardstick, if such allowables exceed those which would be assigned pursuant to the 1947 yardstick, or if the proration unit size authorized by the commission is not provided for in the 1947 yardstick. It is provided that any adjustment made in allowable assignment pursuant to this paragraph shall not be made prior to the effective date of this order. Retroactive adjustment shall not be allowed.

(4) Texas offshore allowable yardstick.

Attached Graphic

(b) Assignment of allowables for wells under statewide rules.

(1) All wells completed in fields operating under statewide rules which were assigned the 20-acre yardstick allowable prior to the adoption of the new spacing rule on October 1, 1962, will be continued at the same allowable rate unless, after notice and hearing, special rules or other special orders are adopted that would provide for a higher producing rate. Any new well completed in such a reservoir will be given the same allowable rate as is assigned the other wells even though it has been drilled as a regular location under the new statewide spacing rule and density rule.

(2) All wells completed in fields operating under statewide rules that are presently on discovery status or have had discovery status terminated subsequent to the adoption of the new state spacing rule on October 1, 1962, will be given the 40-acre yardstick allowable, until such time as a change is ordered by the commission.

(c) Production of marginal wells.

(1) To artificially curtail the production of any "marginal well" below the marginal limit prior to its ultimate plugging and abandonment is hereby declared to be waste, and no rule or order of the Railroad Commission of Texas, or other constituted legal authority shall be entered requiring restriction of the production of any "marginal well" as defined in this chapter.

(2) Application of paragraph (1) of this subsection shall be confined to unrestricted operating conditions which accord with established operating rules of the commission, and shall be subject to all operating conditions designed to prevent waste imposed by the commission, which conditions apply to all wells alike. (Reference Order Number 20-54,115, effective January 1, 1965.)

Source Note: The provisions of this §3.45 adopted to be effective January 1, 1976; amended to be effective March 10, 1986, 11 TexReg 901

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.43	**Application for Temporary Field Rules**

(a) The commission will accept applications for temporary field rule hearings for oil, gas, or geothermal resource fields after the first well has been completed.

(b) When requesting such hearings, the applicant must furnish the commission a list of the names and addresses of all operators holding leases on land touching the tract on which the discovery well is located. The applicant must list the names and addresses of the owners of the abutting unleased land.

(c) Temporary field rules will apply until permanent field rules are adopted.

Source Note: The provisions of this §3.43 adopted to be effective January 1, 1976.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.42	**Oil Discovery Allowable**

(a) The commission shall determine the discovery allowable rate for oil wells proven to be completed in a new and separate reservoir from the following discovery allowable schedule.

Attached Graphic

(b) Duration and exemption from market demand limitation.

(1) Onshore. Each oil well completed in an oil reservoir determined by the commission to be a new onshore oil field onshore may receive, as a maximum daily, its discovery allowable, exempt from market demand limitation, for a period of 24 months (36 months for depth intervals deeper than 10,000 feet) from the date of assignment of the oil allowable to such discovery well or until the 11th oil well has been completed therein, whichever occurs first.

(2) Offshore. Each oil well completed in an oil reservoir determined by the commission to be a new offshore oil field may receive, as a maximum daily allowable, its discovery oil allowable, exempt from market demand limitation, for a period of 24 months (36 months for depth intervals deeper than 10,000 feet) from the date of assignment of the oil allowable to such discovery well or until the sixth oil well has been completed therein, whichever occurs first.

(c) The director or the director's delegate shall review the production performance of discovery wells to evaluate whether waste is occurring due to the discovery allowable. If the director or the director's delegate believes waste is or may be occurring, the director or the director's delegate may request any additional relevant information from the operator and may set the matter for hearing to allow the commission to determine if the discovery allowable should be lowered to prevent waste.

Source Note: The provisions of this §3.42 adopted to be effective January 1, 1976; amended to be effective August 6, 1980, 5 TexReg 2930; amended to be effective November 28, 1989, 14 TexReg 6006; amended to be effective January 4, 1999, 24 TexReg 131

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.41	**Application for New Oil or Gas Field Designation and/or Allowable**

(a) The commission shall assign a new field designation and/or discovery allowable after an operator furnishes to the commission's Austin office proper evidence, other than horizontal distance, proving that a well is a new discovery. An operator shall include the following in the application:

(1) a legible area map, drawn to scale, preferably on white paper, which shows the following:

(A) all oil, gas, and abandoned wells within at least a 2 1/2-mile radius of the well claimed to be a discovery well;

(B) the producing intervals of all pertinent oil and gas wells identified in subparagraph (A) of this paragraph;

(C) all commission-recognized fields within a 2 1/2-mile radius of the well claimed to be a discovery well, that are presently active or were active in the past, identified by commission-assigned field names, names of the producing formations, and approximate average depth of the producing interval;

(D) the total depth of all wells identified in subparagraph (A) of this paragraph that penetrated the subject zone;

(E) scale, legend, and name of person who prepared the map;

(2) a complete legible electric log of the well. However, an operator is not required to file a complete electric log if the operator has filed all other required data, a portion of the log showing the top and bottom of the proposed reservoir interval, log headings, and applicable scales, and satisfactorily proves discovery as a new reservoir. Any electric log filed shall be considered public information pursuant to §3.16 of this title (relating to Log and Completion or Plugging Report) (Statewide Rule 16).

(3) a bottom-hole pressure for oil wells, submitted on the appropriate form. This bottom-hole pressure may be determined by a pressure build-up test, drill stem test, or wire- line formation tester. Calculations based on fluid level surveys or calculations made on flowing wells using shut-in wellhead pressures may be used if no test data is available.

(4) a subsurface structure map and/or cross section(s), if separation is based on structural differences, including faulting and pinch-outs. The structure map shall show the contour of the top of the producing formation and the line(s) of cross section. The cross section(s) shall be prepared from comparable electric logs (not tracings) with the wells, producing formation, and hydrocarbon reservoir identified. The engineer or geologist who prepared the map and cross section shall sign them.

(5) reservoir pressure measurements or calculations, if separation is based on pressure differentials.

(6) core data, drillstem test data, cross sections of nearby wells, and/or production data estimating the fluid level, if separation is based on differences in fluid levels. The operator shall obtain the fluid level data

within 10 days of the potential test date.

(b) The staff may require additional data deemed necessary to make a determination. Deviation from the requirements of subsection (a) of this section may be allowed at the staff's discretion.

(c) The director, oil and gas, may administratively grant an application if all required data is submitted with the form prescribed, and the evidence proves that the new reservoir is effectively separated from any other reservoir previously shown to be productive.

(d) If the director of the Oil and Gas Division, or the director's delegate, declines administratively to grant an application, the operator may request a hearing. If the commission receives the hearing request within 10 days of the date of the notice of administrative denial of the application, the commission shall schedule a hearing. After hearing, the examiner shall recommend final commission action.

Source Note: The provisions of this §3.41 adopted to effective January 1, 1976; amended to be effective July 24, 1980, 5 TexReg 2859; amended to be effective February 28, 1986, 11 TexReg 545; amended to be effective January 4, 1999, 24 TexReg 131

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.40	**Assignment of Acreage to Pooled Development and Proration Units**

(a) An operator may pool acreage, in accordance with appropriate contractual authority and applicable field rules, for the purpose of creating a drilling unit or proration unit by filing an original certified plat delineating the pooled unit and a Certificate of Pooling Authority, Form P-12 (revised 5/2001), according to the following requirements:

(1) Each tract in the certified plat shall be identified with an outline and a tract identifier that corresponds to the tract identifier listed on the Form P-12.

(2) The operator shall provide information on the Certificate of Pooling Authority, Form P-12, accurately and according to the instructions on the form.

(A) The operator shall separately list each tract committed to the pooled unit by authority granted to the operator.

(B) For each tract listed on Form P-12, the operator shall state the number of acres contained within the tract. The operator shall indicate by checking the appropriate box on Form P-12 if, within an individual tract, there exists a non-pooled and/or unleased interest.

(C) The operator shall state on Form P-12 the total number of acres in the pooled unit. The total number of acres in the pooled unit shall equal the sum of all acres in each individual tract listed.

(D) If a pooled unit contains more tracts than can be listed on a single Form P-12, the operator shall file as many additional Forms P-12 as necessary to list each pooled tract individually. The additional Forms P-12 shall be numbered in sequence.

(E) The operator shall provide the requested identification and contact information on the Form P-12.

(F) The operator shall certify the information on the Form P-12 by signing and dating the form.

(3) Failure to timely file the required information on the certified plat or the Form P-12 may result in the dismissal of the W-1 application. "Timely" means within three months of the Commission notifying the operator of the need for additional information on the certified plat and/or the Form P-12.

(4) The operator shall file the original certified plat and Form P-12 at the Commission's Austin office. The operator shall file a copy of the certified plat and Form P-12 with the appropriate Commission district office or offices. If the operator files electronically through the Commission's Electronic Compliance and Approval Process (ECAP) system, the operator is not required to file additional paper copies in the appropriate Commission district office, because all Commission offices will have electronic access to the Form P-12 and certified plat.

(5) The operator shall file the Form P-12 and certified plat:

(A) with the drilling permit application when two or more tracts are joined to form a pooled unit for Commission purposes to obtain a drilling permit;

(B) with completion paperwork when the pooled unit's acreage is being used or assigned for allowable purposes;

(C) to designate a pooled unit formed after completion paperwork has been filed when the pooled unit's acreage is being used or assigned for allowable purposes; or

(D) to designate a change in a pooled unit previously recognized by the Commission. The operator shall file any changes to a pooled unit in accordance with the requirements of §3.38(d)(3) of this title, relating to Well Densities.

(b) If a tract to be pooled has an outstanding interest for which pooling authority does not exist, the tract may be assigned to a unit where authority exists in the remaining undivided interest, provided, that total gross acreage in the tract is included for allocation purposes, and the certificate filed with the commission shows that a certain undivided interest is outstanding in the tract. The commission will not allow an operator to assign only his undivided interest out of a basic tract, where a nonpooled interest exists.

(c) The nonpooled undivided interest holder retains his development rights in his basic tract, and should such rights be exercised, authority to develop the basic tract be approved by the commission, and a well completed as a producer thereon, then the entire interest in the basic tract must be allocated to said well, and any interest insofar as it is pooled with another tract must be assigned to the well on the basic tract for allocation purposes. Splitting of undivided interest in a basic tract between two or more wells on two or more tracts is not acceptable.

(d) Acreage assigned to a well for drilling and development, or for allocation of allowable, shall not be assigned to any other well or wells projected to or completed in the same reservoir; such duplicate assignment of acreage is not acceptable, provided, however, that this limitation shall not prevent the reformation of development or proration units so long as no duplicate assignment of acreage occurs, and further, that such reformation does not violate other conservation regulations.

Source Note: The provisions of this §3.40 adopted to be effective January 1, 1976; amended to be effective January 9, 2002, 27 TexReg 150

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.39	**Proration and Drilling Units: Contiguity of Acreage and Exception Thereto**

(a) Proration and drilling units established for individual wells drilled or to be drilled shall consist of acreage which is contiguous.

(b) An exception to the contiguous acreage provision may be granted at the operator's request if acreage that is to be included in the proration or drilling unit is separated by a long, narrow right-of-way tract.

Source Note: The provisions of this §3.39 adopted to be effective January 1, 1976.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.38	**Well Densities**

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Commission designee--Director of the Oil and Gas Division or any Commission employee designated in writing by the director or the Commission.

(2) Drilling unit--The acreage assigned to a well for drilling purposes.

(3) Proration unit--The acreage assigned to a well for the purpose of assigning allowables and allocating allowable production to the well.

(4) Substandard acreage--Less acreage than the smallest amount established for standard or optional drilling units.

(5) Surplus acreage--Substandard acreage within a lease, pooled unit, or unitized tract that remains unassigned after the assignment of acreage to each applied for, permitted, or completed well in a field, in an amount equaling or exceeding the amount established for standard or optional drilling units. Surplus acreage is distinguished from the term "tolerance acreage,"in that tolerance acreage is defined in context with proration regulation, while surplus acreage is defined by this rule only in context with well density regulation.

(6) Tolerance acreage--Acreage within a lease, pooled unit, or unitized tract that may be assigned to a well for proration purposes pursuant to special field rules in addition to the amount established for a prescribed or optional proration unit.

(b) Density requirements.

(1) General prohibition. No well shall be drilled on substandard acreage except as hereinafter provided.

(2) Standard units.

(A) The standard drilling unit for all oil, gas, and geothermal resource fields wherein only spacing rules, either special, country regular, or statewide, are applicable is hereby prescribed to be the following.

Attached Graphic

(B) The spacing rules listed in subparagraph (A) of this paragraph are not exclusive. If any spacing rule not listed in subparagraph (A) of this subsection is brought to the attention of the commission, it will be given an appropriate acreage assignment.

(c) Development to final density. An application to drill a well for oil, gas, or geothermal resource on a drilling unit composed of surplus acreage, commonly referred to as the "tolerance well," may be granted as regular when the operator seeking such permit certifies to the commission in a prescribed form the necessary data to show that such permit is needed to develop a lease, pooled unit, or unitized tract to final density, and only in the following circumstances:

(1) when the amount of surplus acreage equals or exceeds the maximum amount provided for tolerance acreage by special or county regular rules for the field, provided that this paragraph does not apply for a lease, pooled unit, or unitized tract that is completely developed with optional units and the special or county regular rules for the field do not have a tolerance provisions expressly made applicable to optional proration units;

(2) if the special or county regular rules for the field do not have a tolerance provision expressly made applicable to optional proration units, when the amount of surplus acreage equals or exceeds one-half of the smallest amount established for an optional drilling unit; or

(3) if the applicable rules for the field do not have a tolerance provision for the standard drilling or proration unit, when the amount of surplus acreage equals or exceeds one-half the amount prescribed for the standard unit.

(d) Applications involving the voluntary subdivision rule.

(1) Density exception not required. An exception to the minimum density provision is not required for the first well in a field on a lease, pooled unit, or unitized tract composed of substandard acreage, when the leases, or the drillsite tract of a pooled unit or unitized tract:

(A) took its present size and shape prior to the date of attachment of the voluntary subdivision rule (§3.37(g) of this title (relating to Statewide Spacing Rule)); or

(B) took its present size and shape after the date of attachment of the voluntary subdivision rule (§3.37(g) of this title (relating to Statewide Spacing Rule)) and was not composed of substandard acreage in the field according to the density rules in effect at the time it took its present size and shape.

(2) Density exception required. An exception to the density provision is required, and may be granted only to prevent waste, for a well on a lease, pooled unit, or unitized tract that is composed of substandard acreage and that:

(A) took its present size and shape after the date of attachment of the voluntary subdivision rule (§3.37(g) of this title (relating to the Statewide Spacing Rule)); and

(B) was composed of substandard acreage in the field according to the density rules in effect at the time it took its present size and shape.

(3) Unit dissolution.

(A) If two or more separate tracts are joined to form a unit for oil or gas development, the unit is accepted by the Commission, and the unit has produced hydrocarbons in the preceding twenty (20) years, the unit may not thereafter be dissolved into the separate tracts with the rules of the commission applicable to each separate tract if the dissolution results in any tract composed of substandard acreage for the field from which the unit produced, unless the Commission approves such dissolution.

(B) The Commission shall grant approval only after application, notice, and an opportunity for hearing. The applicant seeking the unit dissolution shall provide a list of the names and addresses of all current lessees and unleased mineral interest owners of each tract within the joined or unitized tract at the time the application is filed. The Commission shall give notice of the application to all current lessees and unleased mineral interest owners of each tract within the joined or unitized tract. Additionally, if one or more wells on the unitized tract has produced from the field within the 12-month period prior to the application, the applicant shall include on the list all affected persons described in subsection (h)(1)(A) of this section, and the Commission shall give notice of the application to these affected persons.

(C) A Commission designee may grant administrative approval if the Commission designee determines that granting the application will not result in the circumvention of the density restrictions of this section or other Commission rules, and if either:

(i) written waivers are filed by all affected persons; or

(ii) no protest is filed within the time set forth in the notice of application.

(e) Application involving unitized areas with entity for density orders. An exception to the minimum density provision is not required for a well in a unitized area for which the commission has granted an entity for density order, if the sum of all applied for, permitted, or completed producing wells in the field within the unitized area, multiplied by the applicable density provision, does not exceed the total number of acres in the unitized area. The operator must indicate the docket number of the entity for density order on the application form.

(f) Exceptions to density provisions authorized. The Commission, or Commission designee, in order to prevent waste or, except as provided in subsection (d)(2) of this section, to prevent the confiscation of property, may grant exceptions to the density provisions set forth in this section. Such an exception may be granted only after notice and an opportunity for hearing.

(g) Filing requirements.

(1) Application. An application for permit to drill shall include the fees required in §3.78 of this title (relating to Fees and Financial Security Requirements) and shall be certified by a person acquainted with the facts, stating that all information in the application is true and complete to the best of that person's knowledge.

(2) Plat. When filing an application for an exception to the density requirements of this section, in addition to the plat requirements in §3.5 of this title (relating to Application to Drill, Deepen, Reenter, or Plug Back) (Statewide Rule 5), the applicant shall attach to each copy of the application a plat that:

(A) depicts the lease, pooled unit, or unitized tract, showing thereon the acreage assigned to the drilling unit for the proposed well and the acreage assigned to all current applied for, permitted, or completed oil, gas, or oil and gas wells in the same field or reservoir which are located within the lease, pooled unit, or unitized tract;

(B) on large leases, pooled units, or unitized tracts, if the established density is not exceeded as shown on the face of the application, outlines the acreage assigned to the well for which the permit is sought and the immediately adjacent wells on the lease, pooled unit, or unitized tract;

(C) on leases, pooled units, or unitized tracts from which production is secured from more than one field, outlines the acreage assigned to the wells in each field that is the subject of the current application;

(D) corresponds to the listing required under subsection (g)(1)(A) of this section.

(E) is certified by a person acquainted with the facts pertinent to the application that the plat is accurately drawn to scale and correctly reflects all pertinent and required data.

(3) Substandard acreage. An application for a permit to drill on a lease, pooled unit, or unitized tract

composed of substandard acreage must include a certification in a prescribed form indicating the date the lease, or the drillsite tract of a pooled unit or unitized tract, took its present size and shape.

(4) Surplus acreage. An application for permit to drill on surplus acreage pursuant to subsection (c) of this section must include a certification in a prescribed form indicating the date the lease, pooled unit, or unitized tract took its present size and shape.

(5) Certifications. Certifications required under paragraphs (3) and (4) of this subsection shall be filed on Form W-1A, Substandard Acreage Certification.

(A) The operator shall file the Form W-1A with the drilling permit application and shall indicate the purpose of filing. The operator shall accurately complete all information required on the form in accordance with instructions on the form.

(B) The operator shall list the field or fields for which the substandard acreage certification applies in the designated area on the form. If there are more than three fields for which the certification applies, the operator shall attach additional Forms W-1A and shall number the additional pages in sequence.

(C) The operator shall file the original Form W-1A with the Commission's Austin office and a copy with the appropriate district office, unless the operator files electronically through the Commission's Electronic Compliance and Approval Process (ECAP) system.

(D) The operator or the operator's agent shall certify the information provided on the Form W-1A is true, complete, and correct by signing and dating the form, and listing the requested identification and contact information.

(E) Failure to timely file the required information on the appropriate form may result in the dismissal of the application.

(h) Procedure for obtaining exceptions to the density provisions.

(1) Filing requirements. If a permit to drill requires an exception to the applicable density provision, the operator must file, in addition to the items required by subsection (g) of this section:

(A) a list of the names and addresses of all affected persons. For the purpose of giving notice of application, the Commission presumes that affected persons include the operators and unleased mineral interest owners of all adjacent offset tracts, and the operators and unleased mineral interest owners of all tracts nearer to the proposed well than the prescribed minimum lease-line spacing distance. The Commission designee may determine that such a person is not affected only upon written request and a showing by the applicant that:

(i) competent, convincing geological or engineering data indicate that drainage of hydrocarbons from the particular tracts subject to the request will not occur due to production from the proposed well; and

(ii) notice to the particular operators and unleased mineral interest owners would be unduly burdensome or expensive;

(B) engineering and/or geological data, including a written explanation of each exhibit, showing that the drilling of a well on substandard acreage is necessary to prevent waste or to prevent the confiscation of property;

(C) additional data requested by the Commission designee.

(2) Notice of application. Upon receipt of a complete application, the Commission will give notice of the application by mail to all affected persons for whom signed waivers have not been submitted.

(3) Approval without hearing. If the Commission designee determines, based on the data submitted, that a permit requiring an exception to the applicable density provision is justified according to subsection (f) of this section, then the Commission designee may issue the exception permit administratively if:

(A) signed waivers from all affected persons were submitted with the application; or

(B) notice of application was given in accordance with paragraph (2) of this subsection and no protest was filed within 21 days of the notice; or

(C) no person appeared to protest the application at a hearing scheduled pursuant to paragraph (4)(A) of this subsection.

(4) Hearing on the application.

(A) If a written protest is filed within 21 days after the notice of application is given in accordance with paragraph (2) of this subsection, the application will be set for hearing.

(B) If the application is not protested and the Commission designee determines that a permit requiring an exception to the applicable density provision is not justified according to subsection (f) of this section, the operator may request a hearing to consider the application.

(i) Duration. A permit is issued as an exception to the applicable density provision shall expire two years from the effective date of the permit; unless drilling operations are commenced in good faith within the two year period.

Source Note: The provisions of this §3.38 adopted to be effective November 1, 1989, 14 TexReg 5255; amended to be effective April 21, 1997, 22 TexReg 3404; amended to be effective July 10, 2000, 25 TexReg 6487; amended to be effective June 11, 2001, 26 TexReg 4088; amended to be effective February 13, 2002, 27 TexReg 906; amended to be effective September 1, 2004, 29 TexReg 8271

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.37	**Statewide Spacing Rule**

(a) Distance requirements.

(1) No well for oil, gas, or geothermal resource shall hereafter be drilled nearer than 1,200 feet to any well completed in or drilling to the same horizon on the same tract or farm, and no well shall be drilled nearer than 467 feet to any property line, lease line, or subdivision line; provided the commission, in order to prevent waste or to prevent the confiscation of property, may grant exceptions to permit drilling within shorter distances than prescribed in this paragraph when the commission shall determine that such exceptions are necessary either to prevent waste or to prevent the confiscation of property.

(2) When an exception to this section is desired, application shall be made by filing the proper fee as provided in §3.78 of this title (relating to Fees and Financial Security Requirements) and the appropriate form according to the instructions on the form, accompanied by a plat as described in subsection (c) of this section. A person acquainted with the facts pertinent to the application shall certify that all facts stated in it are true and within the knowledge of that person.

(A) When an exception to only the minimum lease-line spacing requirement is desired, the applicant shall file a list of the mailing addresses of all affected persons, who, for tracts closer to the well than the greater of one-half of the prescribed minimum between-well spacing distance or the minimum lease-line spacing distance, include:

(i) the designated operator;

(ii) all lessees of record for tracts that have no designated operator; and

(iii) all owners of record of unleased mineral interests.

(B) When an exception to the minimum between-well spacing requirement of this section is desired, the applicant is required to file the mailing addresses of those persons identified in subparagraph (A)(i)-(iii) of this paragraph for each adjacent tract and each tract nearer to the well than the greater of one-half the prescribed minimum between-well spacing distance or the minimum lease-line spacing.

(3) An exception may be granted pursuant to subsection (h)(2) of this section, or after a public hearing held after at least 10 days notice to all persons described in paragraph (2) of this subsection. At any such hearing, the burden shall be on the applicant to establish that an exception to this section is necessary either to prevent waste or to prevent the confiscation of property. For purposes of giving notice of an application for an exception, the commission will presume that every person described in paragraph (2) of this subsection will be affected by the application, unless the Oil and Gas Division director or the director's delegate determines they are unaffected. Such determination will be made only upon written request and a showing by the applicant that:

(A) competent, conclusive geological or engineering data indicate that no drainage of hydrocarbons from the particular tract(s) subject to the request will occur due to production from the applicant's proposed well; and

(B) notice to the particular operator(s), lessee(s) of record, or owner(s) of record of unleased mineral interest would be unduly burdensome or expensive.

(b) The distances mentioned in subsection (a) of this section are minimum distances to provide standard development on a pattern of one well to each 40 acres in areas where proration units have not been established.

(c) In filing an application for an exception to the distance requirements of this section, in addition to the plat requirements in §3.5 of this title (relating to Application to Drill, Deepen, Reenter, or Plug Back) (Statewide Rule 5), the applicant shall attach to each copy of the form a plat that:

(1) shows to scale the property on which the exception is sought; all other applied for, permitted, and completed oil, gas, or oil and gas wells in the same field and reservoir on said property; and all adjoining surrounding properties and completed wells in the same field and reservoir within the prescribed minimum between-well spacing distance of the applicant's well;

(2) shows the entire lease, pooled unit, or unitized tract indicating the names and offsetting properties of all affected offset operators;

(3) corresponds to the listing required under subsection (a)(2) of this section;

(4) is certified by a person acquainted with the facts pertinent to the application that the plat is accurately drawn to scale and correctly reflects all pertinent and required data.

(d) In the interest of protecting life and for the purpose of preventing waste and preventing the confiscation of property, the commission reserves the right in particular oil, gas, and geothermal resource fields to enter special orders increasing or decreasing the minimum distances provided by this section.

(e) No well drilled in violation of this section without special permit obtained, issued, or granted in the manner prescribed in said section, and no well drilled under such special permit or on the commission's own order which does not conform in all respects to the terms of such permit shall be permitted to produce either oil, gas, or geothermal resources and any such well so drilled in violation of said section or on the commission's own order shall be plugged.

(f) No operator shall commence the drilling of a well, either on a regular location or on a Rule 37 exception location, until first having been notified by the commission that the regular location has been approved, or that the Rule 37 exception location has been approved. Failure of an operator to comply with this subsection will cause such well to be closed in and the holding up of the allowable of such well.

(g) Subdivision of property.

(1) In applying Rule 37 (Statewide Spacing Rule) of statewide application and in applying every special rule with relation to spacing in every field in this state, no subdivision of property made subsequent to the adoption of the original spacing rule will be considered in determining whether or not any property is being confiscated within the terms of such spacing rule, and no subdivision of property will be regarded in applying such spacing rule or in determining the matter of confiscation if such subdivision took place subsequent to the promulgation and adoption of the original spacing rule.

(2) Any subdivision of property creating a tract of such size and shape that it is necessary to obtain an exception to the spacing rule before a well can be drilled thereon is a voluntary subdivision and not entitled to a permit to prevent confiscation of property if it were either:

(A) segregated from a larger tract in contemplation of oil, gas, or geothermal resource development; or

(B) segregated by fee title conveyance from a larger tract after the spacing rule became effective and the voluntary subdivision rule attached.

(3) The date of attachment of the voluntary subdivision rule is the date of discovery of oil, gas, or geothermal resource production in a certain continuous reservoir, regardless of the subsequent lateral extensions of such reservoir, provided that such rule does not attach in the case of a segregation of a small

tract by fee title conveyance which is not located in an oil, gas, or geothermal resource field having a discovery date prior to the date of such segregation.

(4) The date of attachment of the voluntary subdivision rule for multiple reservoir fields located in the same structural feature and separated vertically but not laterally (i.e., the multiple reservoirs overlap geographically at least in part), shall be the same date as that assigned to the earliest discovery well for such multiple reservoir structure.

(5) If a newly discovered reservoir is located outside the then productive limits of any previously discovered reservoirs and is classified by the commission as a newly discovered field, then the date of discovery of such newly found reservoir remains the date of attachment for the voluntary subdivision rule, even though subsequent development may result in the extension of such newly discovered reservoir until it overlies or underlies older reservoirs with prior discovery dates.

(6) The date of attachment of the voluntary subdivision rule for a reservoir that has been developed through expansion of separately recognized fields into a recognized single reservoir and is merged by commission order is the earliest discovery date of production from such merged reservoir, and that date will be used subsequent to the date of merger of the fields into a single field.

(7) The date of attachment of the voluntary subdivision rule for a reservoir under any special circumstance which the commission deems sufficient to provide for an exception may be established other than as prescribed in this section, so that innocent parties may have their rights protected.

(h) Exceptions to Rule 37.

(1) An order granting exception to Rule 37 wherein protest is had shall carry as its last paragraph the following language: It is further ordered by the commission that this order shall not be final until 20 days after it is actually mailed to the parties by the commission; provided that if a motion for rehearing of the application is filed by any party at interest within such 20-day period, this order shall not become final until such motion is overruled, or if such motion is granted, this order shall be subject to further action by the commission. Permits issued pursuant to paragraph (2) of this subsection shall be issued without the 20-day waiting period.

(2) The director of the Oil and Gas Division or a delegate of the director may issue an exception permit for drilling, deepening, or additional completion, recompletion, or reentry in an existing well bore if:

(A) a notice of at least 10 days has been given, and no protest has been made to the application; or

(B) written waivers of objection are received from all persons to whom notice would be given pursuant to subsection (a)(2) of this section.

(3) Applications filed for drilling, deepening, or additional completion, recompletion, or reentry will be processed and permit issued in accordance with this regulation, subject to the commission's discretion to set any application for hearing. If the director or a delegate of the director declines to grant an application, the operator may request a hearing.

(i) Rule 37 permits.

(1) Unless otherwise specified in a permit or in a final order granting an exception to this section, permits issued by the commission for completions requiring an exception to this section shall expire two years from the effective date of the permit unless drilling operations are commenced in good faith within the two-year permit period. The permit period will not be extended.

(2) So long as a Rule 37 exception is in litigation, the two-year permit period will not commence. On final adjudication and decree from the last court of appeal the two-year permit period will commence, beginning on the date of final decree.

(j) Once an application for a spacing exception has been denied, no new application shall be entertained except on changed conditions. Changed conditions in the commission's administration of its Spacing Rule 37 and amendments thereto applicable to the various special fields and reservoirs of Texas and in passing upon applications for permits under said rule and amendments shall include, among other things, the following.

(1) Any material changes in the physical conditions of the producing reservoir under the tract under consideration or under the area surrounding said tract which would materially affect the recovery of oil, gas, or geothermal resource from the given tract.

(2) Any material changes in the distribution or allocation of allowable production in the area surrounding the tract under consideration which would materially affect or tend to affect the recovery of oil, gas, or geothermal resource from the given tract.

(3) Any additional permits granted by the commission for wells drilled in the area surrounding or on offset tracts to the tract under consideration which would materially affect or tend to affect the recovery of oil, gas, or geothermal resource from the given tract.

(4) Any additional facts or evidence thereof materially affecting or tending to affect the recovery of oil, gas, or geothermal resource from the applicant's tract, or the property rights of applicant, which were not known of and considered by the commission at any previous hearing or application thereon.

(k) Exceptions to Statewide Rule 37 apply to the total depth for which the permit is granted or if special field rules are applicable, an exception to the spacing rule shall be granted only for the reservoir or reservoirs or applicable depth to which the well is projected. Subsequent recompletion of the well to reservoirs other than that covered by the permit issued would be granted only after the filing and processing of a new application.

(l) Salt dome oil or gas fields.

(1) The provisions of this section shall not apply to certain approved salt dome oil or gas fields. An application for classification as a salt dome oil or gas field shall include the following:

(A) geological evidence proving that an oil or gas field is a piercement-type salt dome, that faulting has caused the producing formation to be at a 45 angle or greater, and that each well is likely to be completed in a separate reservoir;

(B) establishment, by plat or otherwise, of the probable productive limits of the salt dome area;

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.36	**Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas**

(a) Applicability. Each operator who conducts operations as described in paragraph (1) of this subsection shall be subject to this section and shall provide safeguards to protect the general public from the harmful effects of hydrogen sulfide. This section applies to both intentional and accidental releases of hydrogen sulfide.

(1) Operations including drilling, working over, producing, injecting, gathering, processing, transporting, and storage of hydrocarbon fluids that are part of, or directly related to, field production, transportation, and handling of hydrocarbon fluids that contain gas in the system which has hydrogen sulfide as a constituent of the gas, to the extent as specified in subsection (c) of this section, general provisions.

(2) This section shall not apply to:

(A) operations involving processing oil, gas, or hydrocarbon fluids which are either an industrial modification or products from industrial modification, such as refining, petrochemical plants, or chemical plants;

(B) operations involving gathering, storing, and transporting stabilized liquid hydrocarbons;

(C) operations where the concentration of hydrogen sulfide in the system is less than 100 ppm.

(b) Definitions.

(1) Industrial modification--This term is used to identify those operations related to refining, petrochemical plants, and chemical plants. The term does not include field processing such as that performed by gasoline plants and their associated gathering systems.

(2) Stabilized liquid hydrocarbon--The product of a production operation in which the entrained gaseous hydrocarbons have been removed to the degree that said liquid may be stored at atmospheric conditions.

(3) Radius of exposure--That radius constructed with the point of escape as its starting point and its length calculated as provided for in subsection (c)(2) of this section.

(4) Area of exposure--The area within a circle constructed with the point of escape as its center and the radius of exposure as its radius.

(5) Public area--A dwelling, place of business, church, school, hospital, school bus stop, government building, a public road, all or any portion of a park, city, town, village, or other similar area that can expect to be populated.

(6) Public road--Any federal, state, county, or municipal street or road owned or maintained for public access or use.

(7) Sulfide stress cracking--The cracking phenomenon which is the result of corrosive action of hydrogen

sulfide on susceptible metals under stress.

(8) Facility modification--Any change in the operation such as an increase in throughput, in excess of the designed capacity, or any change that would increase the radius of exposure.

(9) Public infringement--This shall mean that a public area and/or a public road, or both, has been established within an area of exposure to the degree that such infringement would change the applicable provisions of this rule to those operations responsible for creating the area of exposure.

(10) Potentially hazardous volume of hydrogen sulfide--A volume of hydrogen sulfide gas of such concentration that:

(A) the 100 ppm radius of exposure is in excess of 50 feet and includes any part of a "public area" except a public road; or

(B) the 500 ppm radius of exposure is greater than 50 feet and includes any part of a public road; or

(C) the 100 ppm radius of exposure is greater than 3,000 feet.

(11) Contingency plan--A written document that shall provide an organized plan of action for alerting and protecting the public within an area of exposure prior to an intentional release, or following the accidental release of a potentially hazardous volume of hydrogen sulfide.

(12) Reaction-type contingency plan--A preplanned, written procedure for alerting and protecting the public, within an area of exposure, where it is impossible or impractical to brief in advance all of the public that might possibly be within the area of exposure at the moment of an accidental release of a potentially hazardous volume of hydrogen sulfide.

(13) Definition of referenced organizations and publications.

(A) ANSI--American National Standard Institute, 1430 Broadway, New York, New York 10018, Table I, Standard 253.1-1967.

(B) API--American Petroleum Institute, 300 Corrigan Tower Building, Dallas, Texas 75201, Publication API RP-49, Publication API RP-14E, Sections 1.7(c), 2.1(c) 4.7.

(C) ASTM--American Society for Testing and Materials, 1916 Race Street, Philadelphia, Pennsylvania 19103, Standard D-2385-66.

(D) GPA--Gas Processors Association, 1812 First Place, Tulsa, Oklahoma 74120, Plant Operation Test Manual C-1, GPA Publication 2265-68.

(E) NACE--National Association of Corrosion Engineers, P.O. Box 1499, Houston, Texas 77001, Standard MR-01-75.

(F) DOT--Department of Transportation, Office of Pipeline Safety, 400 Seventh Street, S.W., Washington, D.C. 20590, Title 49, Code of Federal Regulations, Parts 192 and 195.

(G) OSHA--Occupational Safety and Health Administration, United States Department of Labor, 200 Constitution Avenue, NW, Washington D.C. 20270, Title 29, Code of Federal Regulations, Part 1910.145(c)(4)(i).

(H) RRC--Railroad Commission of Texas, Gas Utilities Division, P.O. Drawer 12967, Capitol Station, Austin, Texas 78711, Gas Utilities Dockets 446 and 183.

(c) General provisions.

(1) Each operator shall determine the hydrogen sulfide concentration in the gaseous mixture in the operation or system.

(A) Tests shall be made in accordance with standards as set by ASTM Standard D-2385-66, or GPA Plant Operation Test Manual C-1, GPA Publication 2265-68, or other methods approved by the commission.

(B) Test of vapor accumulation in storage tanks may be made with industry accepted colormetric tubes.

(2) For all operations subject to this section, the radius of exposure shall be determined, except in the cases of storage tanks, by the following Pasquill-Gifford equations, or by other methods that have been approved by the commission.

(A) For determining the location of the 100 ppm radius of exposure: x = [(1.589) (mole fraction H_2 S)(Q)] to the power of (.6258).

(B) For determining the location of the 500 ppm radius of exposure: x = [(0.4546) (mole fraction H_2 S)(Q)] to the power of (.6258). Where x = radius of exposure in feet; Q = maximum volume determined to be available for escape in cubic feet per day; H_2S = mole fraction of hydrogen sulfide in the gaseous mixture available for escape.

(3) The volume used as the escape rate in determining the radius of exposure shall be that specified in subparagraph (A) - (E) of this paragraph, as applicable.

(A) The maximum daily volume rate of gas containing hydrogen sulfide handled by that system element for which the radius of exposure is calculated.

(B) For existing gas wells, the current adjusted open-flow rate, or the operator's estimate of the well's capacity to flow against zero back-pressure at the wellhead shall be used.

(C) For new wells drilled in developed areas, the escape rate shall be determined by using the current adjusted open-flow rate of offset wells, or the field average current adjusted open-flow rate, whichever is larger.

(D) The escape rate used in determining the radius of exposure shall be corrected to standard conditions of 14.65 pounds per square inch (psia) and 60 degrees Fahrenheit.

(E) For intentional releases from pipelines and pressurized vessels, the operator's estimate of the volume and release rate based on the gas contained in the system elements to be de-pressured.

(4) For the drilling of a well in an area where insufficient data exists to calculate a radius of exposure, but where hydrogen sulfide may be expected, then a 100 ppm radius of exposure equal to 3,000 feet shall be assumed. A lesser-assumed radius may be considered upon written request setting out the justification for same.

(5) Storage tank provision: storage tanks which are utilized as a part of a production operation, and which are operated at or near atmospheric pressure, and where the vapor accumulation has a hydrogen sulfide concentration in excess of 500 ppm, shall be subject to the following.

(A) No determination of a radius of exposure shall be made for storage tanks as herein described.

(B) A warning sign shall be posted on or within 50 feet of the facility to alert the general public of the potential danger.

(C) Fencing as a security measure is required when storage tanks are located inside the limits of a townsite or city, or where conditions cause the storage tanks to be exposed to the public.

(D) The warning and marker provision, paragraph (6)(A)(i), (ii), and (iv) of this subsection.

(E) The certificate of compliance provision, subsection (d)(1) of this section.

(6) All operators whose operations are subject to this section, and where the 100 ppm radius of exposure is in excess of 50 feet, shall be subject to the following.

(A) Warning and marker provision.

(i) For above-ground and fixed surface facilities, the operator shall post, where permitted by law, clearly visible warning signs on access roads or public streets, or roads which provide direct access to facilities located within the area of exposure.

(ii) In populated areas such as cases of townsites and cities where the use of signs is not considered to be acceptable, then an alternative warning plan may be approved upon written request to the commission.

(iii) For buried lines subject to this section, the operator shall comply with the following.

(I) A marker sign shall be installed at public road crossings.

(II) Marker signs shall be installed along the line, when it is located within a public area or along a public road, at intervals frequent enough in the judgment of the operator so as to provide warning to avoid the accidental rupturing of line by excavation.

(III) The marker sign shall contain sufficient information to establish the ownership and existence of the line and shall indicate by the use of the words "Poison Gas" that a potential danger exists. Markers installed in compliance with the regulations of the federal Department of Transportation shall satisfy the requirements of this provision. Marker signs installed prior to the effective date of this section shall be acceptable provided they indicate the existence of a potential hazard.

(iv) In satisfying the sign requirement of clause (i) of this subparagraph, the following will be acceptable.

(I) Sign of sufficient size to be readable at a reasonable distance from the facility.

(II) New signs constructed to satisfy this section shall use the language of "Caution" and "Poison Gas" with a black and yellow color contrast. Colors shall satisfy Table I of American National Standard Institute Standard 253.1-1967. Signs installed to satisfy this section are to be compatible with the regulations of the federal Occupational Safety and Health Administration.

(III) Existing signs installed prior to the effective date of this section will be acceptable if they indicate the existence of a potential hazard.

(B) Security provision.

(i) Unattended fixed surface facilities shall be protected from public access when located within 1/4 mile of a dwelling, place of business, hospital, school, church, government building, school bus stop, public park, town, city, village, or similarly populated area. This protection shall be provided by fencing and locking, or removal of pressure gauges and plugging of valve opening, or other similar means. For the purpose of this provision, surface pipeline shall not be considered as a fixed surface facility.

(ii) For well sites, fencing as a security measure is required when a well is located inside the limits of a townsite or city, or where conditions cause the well to be exposed to the public.

(iii) The fencing provision will be considered satisfied where the fencing structure is a deterrent to public access.

(C) Materials and equipment provision.

(i) For new construction or modification of facilities (including materials and equipment to be used in drilling and workover operations) completed or contemplated subsequent to the effective date of this section, the metal components shall be those metals which have been selected and manufactured so as to be resistant to hydrogen sulfide stress cracking under the operating conditions for which their use is intended, provided that they satisfy the requirements described in the latest editions of NACE Standard MR-01-75 and API RP-14E, sections 1.7(c), 2.1(c), 4.7. The handling and installation of materials and equipment used in hydrogen sulfide service are to be performed in such a manner so as not to induce susceptibility to sulfide stress cracking. Other materials which are nonsusceptible to sulfide stress cracking, such as fiberglass and plastics, may be used in hydrogen sulfide service provided such materials have been manufactured and inspected in a manner which will satisfy the latest published, applicable industry standard, specifications, or recommended practices.

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TITLE 16 ECONOMIC REGULATION

PART 1 RAILROAD COMMISSION OF TEXAS

CHAPTER 3 OIL AND GAS DIVISION

RULE §3.35 **Procedures for Identification and Control of Wellbores in Which Certain Logging Tools Have Been Abandoned**

(a) Abandonment of radioactive source.

(1) Immediate notice of the loss of a radioactive source shall be filed by the operator with the commission designating the location, by county, survey name and abstract number, lease name and well number, distances from survey boundaries and Lambert Coordinates.

(2) Procedures for recovery of the lost radioactive source will be furnished to the commission and such radioactive source shall not be declared abandoned until all reasonable effort has been expended to retrieve the tool.

(3) The operator shall erect, under supervision of the commission, a standardized permanent surface marker as a visual warning to any person who may reenter the hole for any reason, showing that it contains a radioactive source. This marker shall contain the following information: well name, commission number, surface location, name of the operator, name of the lease, the source or material abandoned in the well, the total depth of the well, the depth at which the source is abandoned, the plug back depth, the date of the abandonment of the source, the activity of the source, and a warning not to drill below the plug back depth.

(b) Abandonment procedures.

(1) Wells in which radioactive sources are abandoned shall be mechanically equipped so as to prevent either accidental or intentional mechanical disintegration of the radioactive source.

(A) Sources abandoned in the bottom of the well shall be covered with a substantial standard color dyed (red iron oxide) cement plug on top of which a whipstock or other approved deflection device shall be set. The dye is to alert the reentry operator prior to encountering the source.

(B) Upon abandoning the well in which a logging source has been cemented in place behind a casing string above total depth, a standard color dyed cement plug shall be placed opposite the abandoned source and a whipstock or other approved deflection device placed on top of the plug.

(C) In the event the operator finds that after expending a reasonable effort, because of hole conditions, it is not possible to abandon the source as prescribed in subparagraphs (A) and (B) of this paragraph, he shall seek commission approval to an alternate abandonment procedure.

(D) When a logging source must be abandoned in a producing zone, a standard color dyed cement plug shall be set and a whipstock or other approved deflection device placed above to direct the sidetrack at least 15 feet away from the source.

(2) Upon permanent abandonment of any well in which a radioactive source is left in the hole, and after removal of the wellhead, a permanent plaque shall be attached to the top of the casing left in the hole in such a manner that reentry cannot be accomplished without disturbing the plaque. This plaque shall serve as a visual warning to any person reentering the hole that a radioactive source has been abandoned in place in the

well. The plaque shall contain the trefoil radiation symbol with a radioactive warning and shall be constructed of a long-lasting material such as monel, stainless steel, or brass, in accordance with specifications established by the commission. The plugging report filed with the commission shall identify the well as an abandoned radioactive source well, and shall show compliance with the procedures required by this section.

(3) The commission will maintain a current listing of all abandoned radioactive source wells, and each district office will keep such a list for radioactive source wells in that district.

Source Note: The provisions of this §3.35 adopted to be effective January 1, 1976.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.34	**Gas To Be Produced and Purchased Ratably**

(a) Definitions. The following words and terms, when used in this section and in §3.31 of this title (relating to Gas Reservoirs and Gas Well Allowable) (Statewide Rule 31) shall have the following meanings, unless the context clearly indicates otherwise.

(1) Affiliate--A person or entity that owns, is owned by, or is under common ownership with another person or entity to the extent of 50% or more or that otherwise controls or is controlled by another person or entity. Affiliates of a common entity are also affiliates of each other. A person or entity that purchases gas solely for purposes other than resale shall not be considered an affiliate, and an interstate pipeline, as defined in the Natural Gas Policy Act of 1978, §2(15) (15 United States Code §3301 et seq.), shall not be considered an affiliate of an intrastate pipeline.

(2) Commission designee--A Railroad Commission employee authorized to act for the commission. Any authority given to a commission designee is also retained by the commission. Any action taken by the commission designee is subject to review by the commission.

(3) Downstream purchaser--One that purchases natural gas for resale and is not a first purchaser.

(4) First purchaser or initial purchaser--The first purchaser of natural gas produced from a well. A first purchaser and any affiliate of the purchaser that transports any natural gas it purchases from a well by use of the same pipeline system used by the first purchaser of which it is an affiliate shall be treated as a single first purchaser for purposes of ratability requirements; provided, however, that an affiliate that is purchasing and accepting deliveries pursuant to a special marketing program that is in compliance with this section, shall be treated as a separate first purchaser; and, provided further that the designation of such affiliate as a separate first purchaser is reviewable by the commission and may be disallowed upon a showing that the designation was for purposes of circumventing this section. Any affiliate may file forms in its own name.

(5) Pipeline system--A network of physically connected pipelines that are operated as a single unit under normal conditions.

(A) A first purchaser's pipeline system is that portion of a physical segment of a pipeline that the first purchaser owns.

(B) If a first purchaser does not own the pipeline it uses to transport its gas, the first purchaser's pipeline system shall include all the wells from which it purchases that are on the pipeline system of the transport pipeline.

(C) A first purchaser may not segregate its purchases from any one field into two or more pipeline systems by transporting on another pipeline gas that it purchases as a first purchaser if the first purchaser is also purchasing as a first purchaser from the same field and transporting on a pipeline that it owns.

(D) A first purchaser may not segregate its purchases from any one field into two or more pipeline systems by executing gas exchange agreements.

(E) Any of a first purchaser's pipeline systems which serve a common customer or common customers in a common geographic location shall be operated in a manner to avoid unjust or unreasonable discrimination in takes as between those systems.

(F) A first purchaser shall not segregate its physically connected pipelines that are capable of being operated as a single unit under normal conditions into two or more pipeline systems or designate a gathering system as a separate system for purposes of circumventing this section.

(6) Prorated gas field--A reservoir or field in which an allocation formula is in effect.

(b) General provisions. This section is promulgated to promote and maintain ratable production of natural gas and to require production in compliance with priority categories established by the commission for the purposes of preventing waste, including production in excess of market demand, protecting correlative rights, preventing discrimination, and conserving the natural resources of this state. An operator shall not produce in excess of its ratable share of the market demand as determined by this section and §3.28 and §3.31 of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported, and Gas Reservoirs and Gas Well Allowable) (Statewide Rules 28 and 31). An operator shall produce ratably as set out in subsection (e) of this section and shall produce in compliance with subsection (i) of this section which establishes priority categories of natural gas. Because production is dictated by pipeline capacity and market demand, pipelines are an integral part of production regulation. The requirements imposed on pipelines by this section and §3.28 and §3.31 of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported, and Gas Reservoirs and Gas Well Allowable) (Statewide Rules 28 and 31) are enforced to assist in the regulation of production and provide the only method by which such production regulation can be enforced and market demand met as required by statutory law. A first purchaser shall not discriminate between different wells from which it purchases in the same field, nor shall it discriminate unjustly or unreasonably between separate fields. The provisions of this section requiring ratable production and purchasing of gas apply to purchase and production from wells from which a first purchaser is purchasing on its pipeline system.

(c) Designation of pipeline system. A first purchaser shall, on or before a date designated by the commission or a commission designee, designate its pipeline system(s) and shall identify its affiliates that use the same pipeline system, including an affiliate operating a special marketing program that is in compliance with subsection (k) of this section. A pipeline system designation must identify the physical segment of pipeline that constitutes the pipeline system and identify by Railroad Commission of Texas lease and/or identification number and field the wells on that pipeline system from which the first purchaser is purchasing. A change in pipeline system designation is not required to add or delete well connections. The designation of a pipeline system cannot be changed by a first purchaser without prior approval by the commission or a commission designee. Approval of a change in pipeline system designation cannot be given without prior notice of the requested designation given by the first purchaser to affected operators of wells on the system(s) for which a change in designation is sought. A hearing to determine the proper designation of a first purchaser's pipeline system may be called by the commission, or may be requested by a first purchaser or by an operator filing a complaint. The burden of proof in the hearing shall be on the first purchaser.

(d) Operators who use produced gas. Any person who purchases natural gas at the wellhead, at a common point within a field or fields or at the outlet of a processing or treating plant must determine if it is the initial purchaser.

(e) Production guidelines. An operator shall produce without discrimination between its wells in the same field on the same first purchaser's pipeline system and without unjust or unreasonable discrimination between its wells in separate fields on the same first purchaser's pipeline system. An operator shall apportion a first purchaser's delivery requests ratably to its wells in each field on the same first purchaser's pipeline system without discrimination in the same manner as provided in this section and §3.28 and §3.31 of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported, and Gas Reservoirs and Gas Well Allowable) (Statewide Rules 28 and 31) and shall not produce in excess of its ratable share of the market demand as its share is determined by those rules. An operator shall produce in compliance with the priority categories of gas production established by the commission in subsection (i) of this section.

(f) Purchases from different fields.

(1) In making purchases and accepting deliveries between fields, a first purchaser of natural gas that purchases and accepts delivery of gas from more than one field on its same pipeline system must accept from each field a consistent percentage of the portion of the aggregate deliverability as determined by the deliverability tests and total gas limits that it is entitled to purchase from all wells from which it purchases on its pipeline system, unless the purchaser can demonstrate a just and reasonable basis for discriminating between fields.

(2) Natural gas purchases from a well by a first purchaser that uses another first purchaser's pipeline system to transport its gas and sells the gas purchased on that pipeline system solely to the first purchaser that owns the transport pipeline must be treated as first purchases of gas by the first purchaser that owns the transport pipeline.

(g) Purchases within a field.

(1) In making purchases and accepting deliveries within fields, a first purchaser of natural gas that purchases and accepts delivery of gas from different gas wells in the same priority category (see subsection (i) of this section) in the same field on its same pipeline system shall purchase and accept from the wells from which it purchases in the field a consistent percentage of the portion that it is entitled to purchase of the maximum allowable that a well is entitled to under the field's allocation formula. If purchases and deliveries from different wells in the same field become nonratable, the first purchaser shall consider commission-assigned underproduction and overproduction to establish an appropriate pattern of purchases or acceptance of deliveries to restore ratability.

(2) Natural gas purchases from a well by a first purchaser that uses another first purchaser's pipeline system to transport its gas and sells the gas purchased on that pipeline system solely to the first purchaser that owns the transport pipeline must be treated as first purchases of gas by the first purchaser that owns the transport pipeline.

(3) Purchases and deliveries of casinghead gas shall be based on the well's gas limit as specified in §3.49 of this title (relating to Gas-Oil Ratio) (Statewide Rule 49) as provided in subsection (h) of this section. Overproduction and underproduction of gas is administered by the provisions of §3.31 of this title (relating to Gas Reservoirs and Gas Well Allowable) (Statewide Rule 31). A first purchaser shall not reduce purchases from a limited well as described in §3.31(g)(5) until all prorated gas wells from which it purchases in the field connected to its same pipeline system are ratably reduced to the assigned allowable of the limited well. Below that point, purchases from all prorated wells and limited wells should be reduced ratably by purchasing and accepting delivery of the same percentage of the portion that it is entitled to purchase of the maximum allowable established for the well by the field's allocation formula. If purchases and deliveries from different wells in the same field become nonratable, the first purchaser shall consider commission-assigned underproduction and overproduction in establishing an appropriate pattern of purchases or acceptances of deliveries to restore ratability. When purchases of gas described in subsection (i)(2) or (5) of this section are to be reduced, they shall be reduced ratably within each priority category.

(h) Casinghead gas reductions. When purchases and deliveries of casinghead gas described in subsection (i)(1) or (3) of this section are to be reduced, each well's share of the reduction shall be calculated by multiplying the total reduction by the fractional share that each well's gas limit bears to the arithmetic sum of the aggregate gas limits of all wells in the field from which the first purchaser has been purchasing on its same pipeline system. In calculating its reduction of a well, a first purchaser shall use that portion of the gas limits that it is entitled to purchase. A well operating under net gas/oil ratio authority shall produce no more gas than its gas limit as it would be reduced by the previously mentioned procedure absent the net gas/oil ratio authority.

(i) Priority categories. First purchasers of gas shall satisfy their pipeline system demand for gas by purchasing and accepting delivery of gas from the following priority categories in ascending numerical order. Lower priority category gas is gas from a higher numerical category. A first purchaser shall not within its pipeline system curtail gas from a priority category if the purchaser is purchasing and accepting delivery of lower priority category gas as a first purchaser on its same pipeline system. A first purchaser's purchases and acceptance of delivery of first, second, or third priority category gas under an obligation to purchase and accept delivery from the tailgate of a plant processing gas to extract liquids, or from a gathering system that purchases from wells and is required by contract or by its physical connections to sell its gas entirely to the purchaser, whether or not these purchases are made as a first purchaser, shall not be curtailed if the first purchaser is purchasing and accepting delivery of lower priority category gas as a first purchaser on its same pipeline system. If curtailed, the curtailment must be ratable with like priority category gas which the first purchaser is purchasing and accepting delivery of from wells on its same pipeline system.

(1) First priority shall be given to casinghead gas produced from certified tertiary recovery projects approved by the commission and secondary recovery projects involving water injection, gas injection, or pressure maintenance approved by the commission to prevent waste.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.33	**Geothermal Resource Production Test Forms Required**

(a) A production test form, with all information requested thereon filled in, shall be filed in the district office not later than 10 days after the test is completed. Production operations shall not be commenced before the test form is filed and the commission grants authority to initiate operations.

(b) The initial production test form for any new completion or recompletion must be accompanied by the well record.

Source Note: The provisions of this §3.33 adopted to be effective January 1, 1976.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.32	**Gas Well Gas and Casinghead Gas Shall Be Utilized for Legal Purposes**

(a) The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Fugitive emissions--Releases of gas from lease production, gathering, compression, or gas plant equipment components, including emissions from valve stems, pressure relief valves, flanges and connections, gas-operated valves, compressor and pump seals, pumping well stuffing boxes, casing-to-casing bradenheads subject to the provisions of §3.17 of this title (relating to Pressure on Bradenhead), pits, and sumps, that cannot reasonably be captured and sold or routed to a vent or flare.

(2) Gathering system--Facilities employed to collect, compress, and transport gas to another gas gathering system, a gas plant, compression facility, or transmission line.

(3) Lease production facilities--Production, separation, treating, compression, flowlines, storage, and other production handling equipment employed on a lease in the production of gas, condensate, and oil.

(4) Low pressure separator gas--Gas separated or liberated from a gas-liquid stream in a low pressure separation facility. Low pressure separation facilities include but are not limited to separators, treaters, free water knockouts, and other associated equipment.

(5) Tank vapors--Gas which evolves from oil, condensate, or water when placed in a gunbarrel or storage tank.

(b) Activities authorized by this section may be subject to rules and regulations promulgated by the United States Environmental Protection Agency under the federal Clean Air Act or the Texas Commission on Environmental Quality under the Texas Clean Air Act.

(c) General Provisions. All gas from any oil well, gas well, gas gathering system, gas plant or other gas handling equipment shall be utilized for purposes and uses authorized by law, except as provided in this section. This section does not apply to gas transmission or gas distribution facilities or operations.

(d) Exempt Gas Releases.

(1) Releases of gas that are not readily measured by devices routinely used in the operation of oil wells, gas wells, gas gathering systems, or gas plants, such as meters, are not required by the commission to be reported or charged against lease allowable production and are not subject to the remaining requirements of this section. Releases of gas exempt from the requirements of this section under this paragraph include, but are not limited to, the following:

(A) tank vapors from crude oil storage tanks, gas well condensate storage tanks, or salt water storage tanks, including makeup gas for gas blanket maintenance;

(B) fugitive emissions of gas;

(C) amine treater, glycol dehydrator flash tank and/or reboiler emissions;

(D) blowdown gas from flow lines, gathering lines, meter runs, pressurized vessels, compressors, or other gas handling equipment for construction, maintenance or repair;

(E) gas purged from compressor cylinders or other gas handling equipment for startup;

(F) gas released at a wellsite during drilling operations and prior to the completion date of the well, including gas produced during air or gas drilling operations or gas which must be separated from drilling fluids using a mud-gas separator, or mud-degasser; or

(G) gas released at a wellsite during initial completion, recompletion in another field, or workover operations in the same field, including but not limited to perforating, stimulating, deepening, cleanout, well maintenance or repair operations.

(2) Notwithstanding the foregoing, the commission or the commission's delegate may require the flaring of releases of gas not readily measured by devices routinely used in the operation of oil wells, gas wells, gas gathering systems, or gas plants, such as meters, if the commission or the commission's delegate determines that flaring is required for safety reasons.

(e) Gas Releases to be Burned in a Flare.

(1) Except as otherwise provided in subsections (d), (f)(1)(B) and (C), (g)(2), or an exception granted under subsection (h) of this section, all gas releases of greater than 24 hours duration authorized under the provisions of this section shall be burned in a flare if the gas can be burned safely. All gas releases of 24 hours' duration or less authorized under the provisions of this section may be vented to the air if flaring is not required for safety reasons or by other regulation and the gas can be safely vented.

(2) Gas releases authorized under this section must be managed in accordance with the provisions of §3.36 of this title (relating to Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas) when applicable.

(3) An exception to the requirements of this subsection may be granted under subsection (h) by the commission or the commission's delegate to allow the venting of gas to the air for releases of greater than 24 hours' duration if the operator presents information that shows the gas cannot be both safely and continuously burned in a flare, and the gas can be safely vented.

(4) Notwithstanding the provisions of paragraph (1) of this subsection or an exception granted under subsection (h), the commission or the commission's delegate may require that the gas be flared if flaring is required for safety reasons.

(f) Gas Releases in Oil and Gas Production Operations.

(1) The following releases of gas resulting from routine oil and gas production operations are necessary in the efficient drilling and operation of oil and gas wells and are hereby authorized subject to the requirements of subsection (e) of this section. The released gas shall be measured or estimated in accordance with §3.27 of this title (relating to Gas To Be Measured and Surface Commingling of Gas) and reported and charged against lease allowable production.

(A) Gas may be released for a period not to exceed ten producing days after initial completion, recompletion in another field, or workover operations in the same field, including but not limited to perforating, stimulating, deepening, cleanout, well maintenance or repair operations.

(B) Gas from a well that must be unloaded or cleaned-up to atmospheric pressure may be vented to the air for periods not to exceed 24 hours in one continuous event or a total of 72 hours in one calendar month.

(C) In the event of a full or partial shutdown by a gas gathering system, compression facility, or gas plant, gas from a lease production facility served by that gas gathering system, compression facility or gas plant may be released for a period not to exceed 24 hours. The operator shall notify the appropriate commission district office by telephone or facsimile as soon as reasonably possible after the release of gas begins. An operator may continue the release by flaring or by venting of the gas, if flaring is not required for safety reasons or by other regulation, beyond the initial 24-hour period, pending commission approval or denial of a request for an administrative exception under subsection (h) of this section. The operator shall file the request with the commission by the end of the next full business day following the first 24 hours of the release unless the deadline is extended by the commission or the commission's delegate.

(D) Hydrocarbon gas contained in the waste stream from a membrane unit or molecular sieve used to remove carbon dioxide, hydrogen sulfide, or other contaminants from a gas stream may be released, provided that at least 85% of the hydrocarbon gas in the inlet gas stream is recovered and directed to a legal use.

(E) Low pressure separator gas, not to exceed 15 mcfd of hydrocarbon gas per gas well or 50 mcfd of hydrocarbon gas per commission-designated oil lease or commingling point for commingled operations, may be released.

(2) The commission or the commission's delegate may administratively grant or renew an exception to the requirements or limitations of this subsection subject to the requirements of subsection (h) to allow additional releases of gas if the operator of a well or production facility presents information to show the necessity for the release. The volume of gas that is released must be measured or estimated in accordance with §3.27 of this title (relating to Gas To Be Measured and Surface Commingling of Gas) and reported on the appropriate commission form and shall be charged to the operator's allowable production. Necessity for the release includes, but is not limited to, the following situations:

(A) Cleaning a well of solids or fluids or both for more than ten producing days following initial completion, recompletion in another field, or workover operations in the same field, including but not limited to perforating, stimulating, deepening, cleanout, or well maintenance or repair operations;

(B) Unloading excess formation fluid buildup in a wellbore for periods in excess of 24 hours in one continuous event or 72 hours total in one calendar month;

(C) Volumes of low pressure gas that can be measured with devices routinely used in oil and gas exploration, development, and production operations and that are not directed by an operator to a gas gathering system, gas pipeline, or other marketing facility, or other purposes and uses authorized by law due to mechanical, physical, or economic impracticability;

(D) For casinghead gas only, the unavailability of a gas pipeline or other marketing facility, or other purposes and uses authorized by law; or

(E) Avoiding curtailment of gas production which will result in a reduction of ultimate recovery from a gas well or oil reservoir.

(g) Gas releases from gas gathering system, gas plant or gas handling operations.

(1) The operator of a gas gathering system, gas plant, gas compressor facility or other gas handling equipment not directly associated with lease production of gas, shall not intentionally allow gas to be released for a period of more than 24 hours after the start of an upset condition. The operator shall notify the appropriate commission district office by telephone or facsimile as soon as reasonably possible after the release of gas begins. The volume of gas that is released must be measured or estimated in accordance with §3.27 of this title (relating to Gas To Be Measured and Surface Commingling of Gas) and reported on the appropriate commission form. The provisions of this subsection do not apply to accidental releases which are subject to or reported pursuant to any other commission rule.

(2) The commission or the commission's delegate may administratively grant or renew an exception to the requirements or limitations of this subsection and allow additional releases of gas for a period greater than 24 hours if the operator presents information that shows the necessity for the release. An operator may

continue the release by flaring or by venting of the gas, if flaring is not required for safety reasons or by other regulation, beyond the initial 24-hour period pending commission consideration of a request for an administrative exception under subsection (h) of this section. The request for exception is to be filed with the commission by the end of the next full business day following the first 24 hours of the release unless the deadline is extended by the commission or the commission's delegate. The following are examples of situations that may qualify for an exception under this paragraph:

(A) gas gathering system or gas plant construction, repairs or maintenance;

(B) gas plant turnaround; or

(C) emergency situations.

(h) Exceptions. The commission or the commission's delegate may administratively grant an exception authorized by this section provided that the requirements of this subsection are met.

(1) The request for an exception shall be accompanied by the fee required by §3.78(b)(5) of this title (relating to Fees and Financial Security Requirements).

(2) An administrative exception shall not exceed a period of 180 days.

(3) The 180-day limitation shall not apply for volumes of gas less than or equal to 50 mcf of hydrocarbon gas per day for each gas well, commission-designated oil lease, or commingled vent or flare point.

(4) Requests for exceptions for more than 180 days and for volumes greater than 50 mcf of hydrocarbon gas per day shall be granted only in a final order signed by the commission.

(5) A request for an exception to cover an operating emergency, system upset, or other unplanned condition may be submitted by facsimile transmission or other means, provided that an original signed request is accompanied by the fee required by subsection (h)(1) of this section and is received by the commission within three working days of the facsimile transmission request.

(6) Exceptions shall be issued to the operator of a gas well or commission-designated oil lease or commingling point for commingled operations and to the operator of a processing plant or other facility subject to this section.

(7) Exceptions are not transferable upon a change of operatorship. Operators shall have 90 days from the date of commission approval of a transfer of operatorship to review existing exceptions to this section and, if continuation of the exception is needed, to make application for a new exception. The existing exception and existing authority shall remain in effect during the 90-day review period. If an operator files an application and fee for a new exception before the 90-day review period expires and the 90-day review period expires before the commission acts on the application, the operator is authorized to continue to operate under the existing authority pending final commission action on the application.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.31	**Gas Reservoirs and Gas Well Allowable**

(a) General.

(1) Allowables of gas wells not currently assigned an allowable will not be made effective:

(A) prior to the well's completion or reclassification date; or

(B) more than 15 days prior to the date all reports or information necessary to the assignment of an allowable are received in the appropriate commission office.

(2) If a report or item of information necessary to the assignment of an allowable is not filed on time, there shall be a one-day allowable reduction for each day the report or information is late.

(b) Changes in gas well allowables.

(1) Changes in allowable of gas wells currently assigned an allowable will be effective on the date of the test or date of the change affecting the well's allowable (when the operator submits special tests or information), provided this is not more than 15 days prior to the date the special test or information is received in the appropriate district office.

(2) With respect to a multicompleted well, the allowable of the second and succeeding zones will be made effective no earlier than the date the last report or item necessary for the assignment of an allowable is received in the appropriate commission office.

(3) When a well is recompleted as a gas well in a different field, any overproduction that has occurred in the old field must be made up before an allowable will be assigned in the new field.

(c) Requirements for gas wells in a field for which an allocation formula has been adopted.

(1) If acreage is a factor in the allocation formula, a certified plat showing the acreage assigned to the well for proration purposes shall be submitted. The plat must be accompanied by a statement that all of the acreage claimed can reasonably be considered productive of gas and that the distance limitations of the field rules have not been exceeded. If all of the acreage claimed is not contained in a single lease, a certificate of pooling authority must be submitted, on the appropriate commission form. If the distance limitations of the field rules are shown to have been exceeded, the plat must show the number of acres within and beyond the distance limitations. An operator may request an exception to the distance limitations which may be administratively approved by the commission or a commission designee if all the acreage can be considered productive. If approval of the request is declined or protest is received, the request may be set for hearing. If all of the acreage cannot be considered productive, the plat must also show the productive limit of the acreage. If a plat shows acreage in the unit in excess of the maximum number of acres permitted by the field rules, it will not be accepted.

(2) If bottom-hole or reservoir pressure is a factor in the allocation formula, it shall be submitted on the appropriate commission form and shall be measured at, or corrected to, the proper datum plane.

(3) If any other information, data or parameter is a factor in the allocation formula, it must be submitted on the appropriate commission form.

(d) Determining prorated reservoir allowable and lawful market demand.

(1) On or before the 25th day of each month, the commission will determine the lawful market demand for gas to be produced from each reservoir during the upcoming allowable month. The monthly reservoir allowable shall be equal to the lawful market demand for that reservoir. The lawful reservoir market demand for prorated reservoirs shall be equal to the adjusted reservoir market demand forecast adjusted by a forecast

correction adjustment, and a commission adjustment (i.e., lawful reservoir market demand = adjusted reservoir market demand forecast + forecast correction adjustment + commission adjustment).

(A) Allowable month--The month during which allowables determined pursuant to this section will be effective.

(B) Adjusted reservoir market demand forecast--The sum of all operator reservoir market demand forecasts for a reservoir after any necessary downward adjustments have been made to individual operator reservoir market demand forecasts and optional operator forecasts so that no such forecast will exceed the total capability of the operator's wells for the reservoir during the allowable month.

(C) Operator reservoir market demand forecast--The sum of the operator's well forecasts for a reservoir determined by the commission pursuant to this subsection.

(i) The commission will determine a forecast for each well that will be active during the allowable month that:

(I) for prorated and limited wells is equal to the well's production during the same allowable month in the prior year; and

(II) for special or administrative special allowable wells is equal to the well's production during the most recently reported production month.

(ii) If the well had no reported production during the same allowable month in the prior year or if a special or administrative special allowable well had no reported production in the most recently reported production month, the forecast shall be equal to:

(I) the well's highest reported monthly production during any of the three most recently reported production months; or, if no production has been reported for those months;

(II) the well's capability.

(iii) Alternatively, the operator reservoir market demand forecast may be determined by an optional operator forecast.

(D) Optional operator forecast--The commission designated operator may file an optional market demand forecast for all of the operator's wells in the reservoir that is equal to the anticipated market demand for the production from the operator's wells in the field during the allowable month. The optional operator forecast for the operator's wells in the reservoir can be no greater than the total capability of the operator's wells or less than zero. An optional operator forecast must be filed by the 10th day of the month preceding the allowable month.

(E) Forecast correction adjustment--

(i) The February 1994 forecast correction adjustment shall be the reservoir market demand for November 1993 for all wells in a reservoir that are not administrative special allowable wells for February 1994, subtracted from the production reported for November 1993 for those wells;

(ii) The March 1994 forecast correction adjustment shall be the reservoir market demand for December 1993 for all wells in a reservoir that are not administrative special allowable wells for March 1994, subtracted from the production reported for December 1993 for those wells;

(iii) The April 1994 forecast correction adjustment shall be the reservoir market demand for January

1994 for all wells in a reservoir that are not administrative special allowable wells for April 1994, subtracted from the production reported for January 1994 for those wells;

(iv) For May 1994 and subsequent months, the forecast correction adjustment shall be equal to the total reservoir production from the most recent reported month, minus (total adjusted reservoir market demand forecast for the production month + supplemental change adjustment for that month + commission adjustment for that month), minus (production from all special and administrative special allowable wells minus allowable assigned to those special wells for that month).

(F) Supplemental change adjustment--Any adjustment to the reservoir allowable that is necessary to account for an automatic allowable revision in a prior month, a change of well or well test status during a prior month, the provisions of a final order modifying field or well production status, or any other ministerial change.

(G) Commission adjustment--Any other adjustments to the adjusted reservoir market demand forecast that the commission determines are necessary.

(2) The commission may reject or modify any optional operator forecast if it determines that the forecast is inaccurate or being used to manipulate the allocation of gas rather than to determine the reasonable market demand.

(e) Well capability.

(1) No gas well shall be given an initial allowable in excess of its capability.

(A) Except as provided in subparagraphs (B) and (C) of this paragraph, a well's capability is defined as the lesser of:

(i) the well's latest deliverability test on file with the commission; or

(ii) the well's highest monthly production during any of the three most recently reported production months.

(B) If a well is a special or an administrative special allowable well, its capability is defined as the lesser of:

(i) the well's latest deliverability test on file with the commission; or

(ii) the well's most recently reported monthly production.

(C) If a well is new to a reservoir and has been active for less than six months, its capability shall be defined as the well's latest deliverability test on file with the commission.

(2) An operator may submit a substitute capability determination for any well in a prorated field that represents the maximum monthly production capability of the well under normal operating conditions for a specific six-month period.

(A) The determination may be made on the basis of a well test or other acceptable information by a registered professional engineer who certifies that the determination was made by the engineer or under the supervision of the engineer, and that the capability has been determined in accordance with generally accepted engineering practices. Alternatively, the substitute capability determination may be made by an independent tester on the basis of a well test conducted in accordance with §3.28(c) of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported) (Statewide Rule 28). The request for a substitute capability must be submitted on the appropriate form.

(B) The commission or a commission designee may reject any substitute capability determination for good cause.

(C) The capability determined pursuant to this paragraph shall be used as the well's capability for a period of six months from the effective date of the determination unless:

(i) the operator files a written request that the substitute capability determination be cancelled. If such a request is submitted, the substitute capability may be cancelled by the commission or commission designee; or

(ii) an affected person files a protest alleging, with specificity, the inaccuracy or invalidity of the determination. If a protest is filed, the commission may set the matter for hearing. A protested substitute capability determination shall be effective on the intended effective date, unless the commission orders otherwise. If the commission determines that the protested substitute capability was incorrect, appropriate allowable or status adjustments will be made for the affected well.

(f) Fields operating under statewide rules. A statewide prorated field is any gas field in which no special field rules have been adopted and in which at least one well in the field has a current reported deliverability test of greater than 250 Mcf a day. Daily allowable production of gas from individual wells in a statewide prorated field shall be determined by allocating the allowable production among the individual wells in the proportion that each well's deliverability (based on the latest deliverability test of record) bears to the summation of the most recent reported deliverability tests of all wells producing from the same field. Allocated allowables shall be subject to the well capability provisions of this section.

(g) Definitions of prorated and nonprorated wells and fields.

(1) A prorated well is a well for which an allowable is determined by an allocation formula.

(2) A nonprorated well is a well for which an allowable is not determined by an allocation formula.

(3) A prorated field is a field that has two or more wells one of which is a prorated well.

(4) A nonprorated field is any field that is not a prorated field.

(5) Statewide Exempt Fields:

(A) A statewide exempt field is any gas field in which no special field rules have been adopted and in which no well in the field has a current reported deliverability test of greater than 250 Mcf per day. Wells in statewide exempt fields shall be assigned allowables equal to their capacity to produce but in no event greater than 250 Mcf per day.

(B) In fields where special field rules exist and no well has a current deliverability test of greater than 250 Mcf per day, an operator may request statewide exempt field status. The request may be granted administratively by the commission or commission designee if the applicant provides the commission with a declaration, signed by all operators, subject to the false filing penalties provided for in the Texas Natural Resources Code, §91.143, stating all operators in the field agree to exempt status. If declarations are not provided from all operators in the field or if the commission or commission designee declines to grant any request administratively, the applicant may request a hearing. If a notice of intent to appear in protest of the application has not been filed by five days before the date of the hearing, then there shall be a presumption that each well's first purchaser has a market for 100% of the well's deliverability as determined by the most recent deliverability tests on file with the Commission and that granting exempt status to the field will not harm correlative rights or cause waste and exempt status will be granted. Wells in exempt fields with special rules shall be assigned allowables equal to their capability to produce but in no event greater than 250 Mcf per day. If 250 Mcf per day is exceeded by any well, the field will be changed to the existing special field rule allocation. Reinstatement of allocation formula may be initiated by the commission designee, or by one of the operators in the field.

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PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.30	**Memorandum of Understanding between the Railroad Commission of Texas (RRC) and the Texas Commission on Environmental Quality (TCEQ)**

(a) Need for agreement.

(1) Section 10 of House Bill 1407, 67th Legislature, 1981, which appeared as a footnote to the Texas Solid Waste Disposal Act, Texas Civil Statutes, Article 4477-7, provides as follows: On or before January 1, 1982, the Texas Department of Water Resources, the Texas Department of Health, and the Railroad Commission of Texas shall execute a memorandum of understanding that specifies in detail these agencies' interpretation of the division of jurisdiction among the agencies over waste materials that result from or are related to activities associated with the exploration for and the development, production, and refining of oil or gas. The agencies shall amend the memorandum of understanding at any time that the agencies find it to be necessary.

(2) The original Memorandum of Understanding (MOU) between the agencies became effective January 1, 1982. The MOU was revised effective December 1, 1987, to reflect legislative clarification of the Railroad Commission's jurisdiction over oil and gas wastes and the Texas Water Commission's (successor to the Texas Department of Water Resources) jurisdiction over industrial and hazardous wastes.

(3) The agencies have determined that the revised MOU that became effective on December 1, 1987, should again be revised to further clarify jurisdictional boundaries and to reflect legislative changes in agency responsibility and the combination of the Texas Water Commission, the Texas Air Control Board, and portions of the Texas Department of Health to form the Texas Natural Resource Conservation Commission.

(b) General agency jurisdictions.

(1) Texas Commission on Environmental Quality (TCEQ) (the successor agency to the Texas Natural Resource Conservation Commission (TNRCC)). References in this section to TCEQ shall mean TCEQ or any successor agencies.

(A) The TCEQ has jurisdiction over solid waste under Chapter 361 of the Texas Health and Safety Code, §§361.001-361.754. The TCEQ's jurisdiction encompasses both hazardous and nonhazardous, industrial and municipal, solid wastes.

(B) Under Texas Health and Safety Code, §361.003(34), solid waste under the jurisdiction of the TCEQ is defined to include "garbage, rubbish, refuse, sludge from a waste treatment plant, water supply treatment plant, or air pollution control facility, and other discarded material, including solid, liquid, semisolid, or contained gaseous material resulting from industrial, municipal, commercial, mining, and agricultural operations and from community and institutional activities."

(C) Solid waste is further defined in Texas Health and Safety Code, §361.003(34), to exclude "material which results from activities associated with the exploration, development, or production of oil or gas or geothermal resources and other substance or material regulated by the Railroad Commission of Texas pursuant to Section 91.101, Natural Resources Code...."

(D) In addition, Texas Health and Safety Code, §361.003(34), defines the term solid waste to include the following until the United States Environmental Protection Agency (EPA) delegates its authority under the Resource Conservation and Recovery Act, 42 United States Code (U.S.C.) §6901, et seq., (RCRA) to the RRC: "waste, substance or material that results from activities associated with gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance plants, or repressurizing plants and is a hazardous waste as defined by the administrator of the EPA...."

(E) After delegation of RCRA authority to the Railroad Commission of Texas (RRC), the definition of solid waste (which defines TCEQ's jurisdiction) will not include hazardous wastes generated at natural gas or natural gas liquids processing plants, or reservoir pressure maintenance or repressurizing plants. The term natural gas or natural gas liquids processing plant refers to a plant the primary function of which is the extraction of natural gas liquids from field gas or fractionation of natural gas liquids. The term does not include a separately located natural gas treating plant for which the primary function is the removal of carbon dioxide, hydrogen sulfide, or other impurities from the natural gas stream. A separator, dehydration unit, heater treater, sweetening unit, compressor, or similar equipment is considered a part of a natural gas or natural gas liquids processing plant only if it is located at a plant the primary function of which is the extraction of natural gas liquids from field gas or fractionation of natural gas liquids. Further, a pressure maintenance or repressurizing plant is a plant for processing natural gas for reinjection (for reservoir pressure maintenance or repressurization) in a natural gas recycling project. A compressor station along a natural gas pipeline system or a pump station along a crude oil pipeline system is not a pressure maintenance or repressurizing plant.

(2) Railroad Commission of Texas (RRC).

(A) Generally, under Texas Natural Resources Code, Title 3, and Texas Water Code, Chapter 26, wastes (both hazardous and nonhazardous) resulting from activities associated with the exploration, development, or production of oil or gas or geothermal resources, including transportation of crude oil or natural gas by pipeline, and other activities regulated by the RRC are under the jurisdiction of the RRC. These wastes are termed "oil and gas wastes." In compliance with Texas Health and Safety Code, §361.025 (concerning exempt activities), a list of activities that generate wastes that are subject to the jurisdiction of the RRC is found at §3.8(a)(30) of this title (relating to Water Protection) and at 30 Texas Administrative Code §335.1 (concerning definitions), which contains a definition of "activities associated with the exploration, development, and production of oil or gas or geothermal resources." This MOU provides further guidance regarding the agencies' interpretation of these rules and statutes.

(B) Notwithstanding subparagraph (A) of this paragraph, hazardous wastes generated at natural gas or natural gas liquids processing plants or reservoir pressure maintenance or repressurizing plants are subject to the jurisdiction of the TCEQ until the RRC is authorized by EPA to administer RCRA. When the RRC is authorized by EPA to administer RCRA, jurisdiction over such hazardous wastes will transfer from the TCEQ to the RRC.

(c) Definition of hazardous waste.

(1) Under the Texas Health and Safety Code, §361.003(12), a "hazardous waste" subject to the jurisdiction of the TCEQ is defined as "solid waste identified or listed as a hazardous waste by the administrator of the United States Environmental Protection Agency under the federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, as amended (42 U.S.C. §6901, et seq.)." Similarly, under Texas Natural Resources Code, §91.601(1), "oil and gas hazardous waste" subject to the jurisdiction of the RRC is defined as an "oil and gas waste that is a hazardous waste as defined by the administrator of the United States Environmental Protection Agency under the federal Solid Waste Disposal Act, as amended

by the Resource Conservation and Recovery Act of 1976 (42 U.S.C. §6901, et seq.)."

(2) Federal regulations adopted under authority of the federal Solid Waste Disposal Act, as amended by RCRA, exempt from regulation as hazardous waste certain oil and gas wastes. Under 40 Code of Federal Regulations (CFR) §261.4(b)(5), "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy" are described as wastes that are exempt from federal hazardous waste regulations.

(3) A partial list of wastes associated with oil, gas, and geothermal exploration, development, and production that are considered exempt from hazardous waste regulation under RCRA can be found in EPA's "Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes," 53 FedReg 25,446 (July 6, 1988). A further explanation of the exemption can be found in the "Clarification of the Regulatory Determination for Wastes from the Exploration, Development and Production of Crude Oil, Natural Gas and Geothermal Energy, " 58 FedReg 15,284 (March 22, 1993). The exemption codified at 40 CFR §261.4(b)(5) and discussed in the Regulatory Determination has been, and may continue to be, clarified in subsequent guidance issued by the EPA.

(d) Jurisdiction over specific disposal activities.

(1) Discharges under Texas Water Code, Chapter 26. Under the Texas Water Code, Chapter 26, the TCEQ has jurisdiction over discharges of waste into or adjacent to water in the state, other than discharges regulated by the RRC. The RRC regulates discharges of waste from activities associated with the exploration, development, or production of oil, gas, or geothermal resources, including transportation of crude oil and natural gas by pipeline, and from solution brine mining activities (except solution mining activities conducted for the purpose of creating caverns in naturally-occurring salt formations for the storage of wastes regulated by the TCEQ) under Texas Natural Resources Code, Title 3, and Texas Water Code, Chapter 26. Discharges of waste regulated by the RRC into water in the state shall not cause a violation of the water quality standards. While water quality standards are established by the TCEQ, the RRC has the responsibility for enforcing any violations of such standards. Texas Water Code, Chapter 26, does not require that discharges regulated by the RRC comply with regulations of the TCEQ that are not water quality standards. Because of the complexity of 30 Texas Administrative Code §307.6 (concerning toxic materials), the staffs of the TCEQ and the RRC will consult from time to time regarding application and interpretation of the Texas Surface Water Quality Standards.

(2) Disposal wells under Texas Water Code, Chapter 27. Jurisdiction over wastes disposed by injection is divided between the RRC and the TCEQ as set forth in Texas Water Code, Chapter 27 (the Injection Well Act). The RRC has jurisdiction under Texas Water Code, Chapter 27, over injection wells used to dispose of oil and gas waste. Texas Water Code, Chapter 27, defines "oil and gas waste" to mean "waste arising out of or incidental to drilling for or producing of oil, gas, or geothermal resources, waste arising out of or incidental to the underground storage of hydrocarbons other than storage in artificial tanks or containers, or waste arising out of or incidental to the operation of gasoline plants, natural gas processing plants, or pressure maintenance or repressurizing plants. The term includes but is not limited to salt water, brine, sludge, drilling mud, and other liquid or semi-liquid waste material." The term "waste arising out of or incidental to drilling for or producing of oil, gas, or geothermal resources" includes waste associated with transportation of crude oil or natural gas by pipeline pursuant to Texas Natural Resources Code, §91.101. The TCEQ has jurisdiction over injection wells used to dispose of other types of waste.

(3) Disposal of naturally occurring radioactive material (NORM). (The term "disposal" does not include receipt, possession, use, processing, transfer, transport, storage, or commercial distribution of radioactive materials, including NORM. These activities are under the jurisdiction of the Texas Department of Health per Texas Health and Safety Code, §401.011(a).)

(A) Under Texas Health and Safety Code, §401.415, the RRC has jurisdiction over the disposal of NORM that constitutes, is contained in, or has contaminated oil and gas waste. This waste material is called "oil and gas NORM waste." Oil and gas NORM waste may be generated in connection with the exploration, development, or production of oil or gas. Oil and gas NORM waste may also be generated in connection with geothermal resource exploration, development, or production activities or solution brine mining activities.

(B) Under Texas Health and Safety Code, §401.412, the TCEQ has jurisdiction over the disposal of NORM which is not oil and gas NORM waste.

(e) Jurisdiction over waste from specific oil and gas activities.

(1) Drilling, operation, and plugging of wells associated with the exploration, development, or production of oil, gas, or geothermal resources. Wells associated with the exploration, development, or production of oil, gas, or geothermal resources include exploratory wells, cathodic protection holes, core holes, oil wells, gas wells, geothermal resource wells, fluid injection wells used for secondary or enhanced recovery of oil or gas, oil and gas waste disposal wells, and injection water source wells. Several types of waste materials can be generated during the drilling, operation, and plugging of these wells. These waste materials include drilling fluids (including water-based and oil-based fluids), cuttings, produced water, produced sand, waste hydrocarbons (including used oil), fracturing fluids, spent acid, workover fluids, treating chemicals (including scale inhibitors, emulsion breakers, paraffin inhibitors, and surfactants), waste cement, filters (including used oil filters), domestic sewage (including waterborne human waste and waste from activities such as bathing and food preparation), and trash (including inert waste, barrels, dope cans, oily rags, mud sacks, and garbage). Generally, these wastes, whether disposed of by discharge, landfill, land farm, evaporation, or injection, are subject to the jurisdiction of the RRC.

(2) Field treatment of produced fluids. Oil, gas, and water produced from oil, gas, or geothermal resource wells may be treated in the field in facilities such as separators, skimmers, heater treaters, dehydrators, and sweetening units. Waste materials that result from the field treatment of oil and gas include waste hydrocarbons (including used oil), produced water, hydrogen sulfide scavengers, dehydration wastes, treating and cleaning chemicals, filters (including used oil filters), asbestos insulation, domestic Cont'd...

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.28	**Potential and Deliverability of Gas Wells To Be Ascertained and Reported**

(a) The information necessary to determine the absolute daily open flow potential of each producing associated or nonassociated gas well shall be ascertained, and a report shall be filed as required on the appropriate Commission form in the appropriate Commission office within 30 days of completion of the well. The test shall be performed in accordance with the commission's publication, Back Pressure Test for Natural Gas Wells, State of Texas, or other test procedure approved in advance by the Commission and shall be reported on the Commission's prescribed form. An operator, at his option, may determine absolute open flow potential from a stabilized one-point test. For a one-point test, the well shall be flowed on a single choke setting until a stabilized flow is achieved, but not less than 72 hours. The shut-in and flowing bottom hole pressures shall be calculated in the manner prescribed for a four-point test. The Commission may authorize a one-point test of shorter duration for a well which is not connected to a sales line, but a test which is in compliance with this section must be conducted and reported after the well is connected before an allowable will be assigned to the well. Back-dating of allowables will be performed in accordance with §3.31 of this title (relating to Gas Reservoirs and Gas Well Allowable).

(b) After conducting the test required by subsection (a) of this section each operator of a gas well shall conduct an initial deliverability test not later than ten days after the start of production for one or more legal purposes and shall report such initial deliverability test on the prescribed form. If a 72-hour one-point back pressure test on a well connected to a sales line was conducted as provided in subsection (a) of this section, the same test may be used to determine initial deliverability, provided the test was conducted in accordance with subsection (c) of this section. After the initial deliverability test has been conducted, the following schedule for well testing applies. Nonassociated gas wells shall be tested semiannually. Associated 49(b) gas wells shall be tested annually. Wells with current reported deliverability of 100 Mcf a day or less are not required to test as long as deliverability and production remain at or below 100 Mcf a day but are required to file Form G-10 according to the instructions on the form. Wells with a deliverability greater than 100 Mcf a day and less than or equal to 250 Mcf a day in fields without special field rules are not required to be tested as long as deliverability and production remain equal to or less than 250 Mcf a day. Wells operating under special field rules which conflict with this subsection shall test in accordance with the special field rules. Notwithstanding the above provisions on frequency of testing, gas wells commingling liquid hydrocarbons before metering must comply with the testing provisions applicable to such wells. All deliverability tests shall be conducted in accordance with subsection (c) of this section and the instructions printed on the Form G-10. The results of each test shall be attested to by the operator or his appointed agent. The first purchaser or its representative upon request to the operator shall have the right to witness such tests. Gas meter charts, printouts, or other documents showing the actual measurement of the gas produced or other data required to be recorded during any deliverability test conducted under this subsection shall be preserved as required by §3.1 of this title (relating to Organization Report; Retention of Records; Notice Requirements) (Statewide Rule 1). In the event that the first purchaser and the operator cannot agree upon the validity of the test results, then either party may request a retest of the well. The first purchaser upon request to the operator shall have the right to witness the retest. If either party requests a representative from the Commission to witness a retest of the well, the results of a Commission-witnessed test shall be conclusive for the purposes of this section until the next regularly scheduled test of the well. In the event a retest is witnessed by the Commission, the retest shall be signed by the representative of the Commission. In the event that downhole remedial work or other substantial production enhancement work is performed, or if a pumping unit, compressor, or other equipment is installed to increase deliverability of a well subject to the Commission-witnessed testing procedure described in this subsection, a new test may be requested and shall be performed according to the procedure outlined in this subsection.

(c) Unless applicable special field rules provide otherwise or the director of the oil and gas division or the director's delegate authorizes an alternate procedure due to a well's producing characteristics, deliverability tests shall be performed as follows. Deliverability tests shall be scheduled by the producer within the testing period designated by the Railroad Commission, and only the recorded data specified by the Form G-10 is required to be reported. All deliverability tests shall be performed by producing the subject well at stabilized rates for a minimum time period of 72 hours. A deliverability test shall be conducted under normal and usual operating conditions using the normal and usual operating equipment in place on the well being tested, and the well shall be produced against the normal and usual line pressure prevailing in the line into which the well produces. The average daily producing rate for each 24-hour period, the wellhead pressure before the commencement of the 72-hour test, and the flowing wellhead pressure at the beginning of each 24-hour period shall be recorded. In addition, a 24-hour shut-in wellhead pressure shall be determined either within the six-month period prior to the commencement of the 72-hour deliverability test or immediately after the completion of the deliverability test. The shut-in wellhead pressure that was determined and the date on which the 24-hour test was commenced shall be recorded on Form G-10. Exceptions and extensions to the timing requirements for deliverability tests and shut-in wellhead pressure tests may be granted by the Commission for good cause. The flow rate during each day of the first 48 hours of the test must be as close as possible to the flow rate during the final 24 hours of the test, but must equal at least 75% of such flow rate. The deliverability of the well during the last 24 hours of the flow test shall be used for allowable and allocation purposes. If pipeline conditions exist such that a producer believes a representative deliverability test cannot be performed, the producer with pipeline notification may request in writing that the commission use either of the following as a representative deliverability:

(1) the deliverability test performed during the previous testing period; or

(2) the maximum daily production from any of the 12 months prior to the due date of the test as determined by dividing the highest monthly production by the number of days in that month.

(d) If the deliverability of a well changes after a test is reported to the Commission, the deliverability of record for a well will be decreased upon receipt of a written request from the operator to reduce the deliverability of record to a specified amount. If the deliverability of a well increases, a retest must be conducted in the manner specified in this section and must be reported on Form G-10 before the deliverability of record will be increased.

(e) First purchasers with packages of gas dedicated entirely to a downstream purchaser shall coordinate testing with and provide test results to that downstream purchaser if requested by the downstream purchaser. In these cases, the downstream purchaser upon request to the operator shall have the right to witness all deliverability tests and retests.

(f) Tests of wells connected to a pipeline shall be made in a manner that no gas is flared, vented, or otherwise wastefully used.

Source Note: The provisions of this §3.28 adopted to be effective September 1, 1986, 11 TexReg 3680; amended to be effective October 12, 1998, 23 TexReg 10397; amended to be effective February 28, 2000, 25 TexReg 1592; amended to be effective November 24, 2004, 29 TexReg 10728

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.27	**Gas To Be Measured and Surface Commingling of Gas**

(a) All natural gas, except casinghead gas, produced from wells shall be measured, with each completion being measured separately, before the gas leaves the lease, and the producer shall report the volume produced from each completion to the commission. Exceptions to this provision may be granted by the commission upon written application.

(b) All casinghead gas sold, processed for its gasoline content, used in a field other than that in which it is produced, or used in cycling or repressuring operations, shall be measured before the gas leaves the lease, and the producer shall report the volume produced to the commission. Exceptions to this provision may be granted by the commission upon written application.

(c) All casinghead gas produced in this state which is not covered by the provisions of subsection (b) of this section, shall be measured before the gas leaves the lease, is used as fuel, or is released into the air, based on its use or on periodic tests, and reported to the commission by the producer. The volume of casinghead gas produced by wells exempt from gas/oil ratio surveys must be estimated, based on general knowledge of the characteristics of the wells. Exceptions to this provision may be granted by the commission upon written application.

(d) Releases and production of gas at a volume or daily flow rate, commonly referred to as "too small to measure" (TSTM), which, due to minute quantity, cannot be accurately determined or for which a determination of gas volume is not reasonably practical using routine oil and gas industry methods, practices, and techniques are exempt from compliance with this rule and are not required to be reported to the commission or charged against lease allowable production.

(e) In order to prevent waste, to promote conservation or to protect correlative rights, the commission may approve surface commingling of gas or oil and gas described in subsections (a), (b) or (c) of this section and produced from two or more tracts of land producing from the same commission-designated reservoir or from one or more tracts of land producing from different commission-designated reservoirs in accordance with §3.26(b) of this title (relating to Separating Devices, Tanks, and Surface Commingling of Oil).

(f) In reporting gas well production, the full-well stream gas shall be reported and charged against each gas well for allowable purposes. All gas produced, including all gas used on the lease or released into the air, must be reported regardless of its disposition.

(g) If gas is produced from a lease or other property covered by the coastal or inland waters of the state, the gas produced may, at the option of the operator, be measured on a shore or at a point removed from the lease or other property from which it was produced.

(h) All natural hydrocarbon gas produced and utilized from wells completed in geothermal resource reservoirs shall be measured and allocated to each individual lease based on semiannual tests conducted on full well stream lease production.

(i) For purposes of this rule, "measured" shall mean a determination of gas volume in accordance with this rule and other rules of the commission, including accurate estimates of unmetered gas volumes released into the air or used as fuel.

(j) No meter or meter run used for measuring gas as required by this rule shall be equipped with a manifold which will allow gas flow to be diverted or bypassed around the metering element in any manner unless it is of the type listed in paragraphs (1) or (2) of this subsection:

(1) double chambered orifice meter fittings with proper meter manifolding to allow equalized pressure across the meter during servicing;

(2) double chambered or single chambered orifice meter fittings equipped with proper meter manifolding or other types of metering devices accompanied by one of the following types of meter inspection manifolds:

(A) a manifold with block valves on each end of the meter run and a single block valve in the manifold complete with provisions to seal and a continuously maintained seal record;

(B) an inspection manifold having block valves at each end of the meter run and two block valves in the manifold with a bleeder between the two and with one valve equipped with provisions to seal and continuously maintained seal records;

(C) a manifold equipped with block valves at each end of the meter run and one or more block valves in the manifold, when accompanied by a documented waiver from the owner or owners of at least 60% of the royalty interest and the owner or owners of at least 60% of the working interest of the lease from which the gas is produced.

(k) Whenever sealing procedures are used to provide security in the meter inspection manifold systems, the seal records shall be maintained for at least three years at an appropriate office and made available for Railroad Commission inspection during normal working hours. At any time a seal is broken or replaced, a notation will be made on the orifice meter chart along with graphic representation of estimated gas flow during the time the meter is out of service.

(l) All meter requirements apply to all meters which are used to measure lease production, including sales meters if sales meter volumes are allocated back to individual leases.

(m) The commission may grant an exception to measurement requirements under subsections (a), (b) and (c) of this section if the requirements of this subsection are met. An exception granted under this subsection will be revoked if the most recent well test or production reported to the commission reflects a production rate of more than 20 MCF of gas per day or if any of the other requirements for an exception under this subsection are no longer satisfied. An applicant seeking an exception under this subsection must file an application establishing:

(1) the most recent production test reported to the commission demonstrates that the gas well or oil lease for which an exception is sought produces at a rate of no more than 20 MCF of gas per day;

(2) an annual test of the production of the gas well or oil lease provides an accurate estimate of the daily rate of gas flow;

(3) the flow rate established in paragraph (2) of this subsection multiplied by the recorded duration determined by any device or means that accurately records the duration of production each month yields an accurate estimate of monthly production; and

(4) the operator of the pipeline connected to the gas well or oil lease concurs in writing with the

application.

(n) Failure to comply with the provisions of this rule will result in severance of the producing well, lease, facility, or gas pipeline or in other appropriate enforcement proceeding.

Source Note: The provisions of this §3.27 adopted to be effective January 1, 1976; amended to be effective April 12, 1983, 8 TexReg 1019; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective June 23, 1997, 22 TexReg 5747.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.26	**Separating Devices, Tanks, and Surface Commingling of Oil**

(a) Where oil and gas are found in the same stratum and it is impossible to separate one from the other, or when a well has been classified as a gas well and such gas well is not connected to a cycling plant and such well is being produced on a lease and the gas is utilized under Texas Natural Resources Code §§86.181 - 86.185, the operator shall install a separating device of approved type and sufficient capacity to separate the oil and liquid hydrocarbons from the gas.

(1) The separating device shall be kept in place as long as a necessity for it exists, and, after being installed, such device shall not be removed nor the use thereof discontinued without the consent of the commission.

(2) All oil and any other liquid hydrocarbons as and when produced shall be adequately measured according to the pipeline rules and regulations of the commission before the same leaves the lease from which they are produced, except for gas wells where the full well stream is moved to a plant or central separation facility in accordance with §3.55 of this title (relating to Reports on Gas Wells Commingling Liquid Hydrocarbons before Metering) (Statewide Rule 55) and the full well stream is measured, with each completion being separately measured, before the gas leaves the lease.

(3) Sufficient tankage and separator capacity shall be provided by the producer to adequately take daily gauges of all oil and any other liquid hydrocarbons unless LACT equipment, installed and operated in accordance with the latest revision of American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 6.1 or another method approved by the commission or its delegate, is being used to effect custody transfer.

(b) In order to prevent waste, to promote conservation or to protect correlative rights, the commission may approve surface commingling of oil, gas, or oil and gas production from two or more tracts of land producing from the same commission-designated reservoir or from one or more tracts of land producing from different commission-designated reservoirs as follows:

(1) Administrative approval. Upon written application, the commission may grant approval for surface commingling administratively when any one of the following conditions is met:

(A) The tracts or commission-designated reservoirs have identical working interest and royalty interest ownership in identical percentages and therefore there is no commingling of separate interests;

(B) Production from each tract and each commission-designated reservoir is separately measured and therefore there is no commingling of separate interests; or

(C) When the tracts or commission-designated reservoirs do not have identical working interest and royalty interest ownership in identical percentages and the commission has not received a protest to an application within 21 days of notice of the application being mailed by the applicant to all working and royalty interest owners or, if publication is required, within 21 days of the date of last publication and the applicant provides:

(i) a method of allocating production to ensure the protection of correlative rights, in accordance with paragraph (3) of this subsection; and

(ii) an affidavit or other evidence that all working interest and royalty interest owners have been notified of the application by certified mail or have provided applicant with waivers of notice requirements; or

(iii) in the event the applicant is unable, after due diligence, to provide notice by certified mail to all working interest and royalty interest owners, a publisher's affidavit or other evidence that the commission's notice of application has been published once a week for four consecutive weeks in a newspaper of general circulation in the county or counties in which the tracts that are the subject of the application are located.

(2) Request for hearing. When the tracts or commission-designated reservoirs do not have identical working interest and royalty interest ownership in identical percentages and a person entitled to notice of the application has filed a protest to the application with the commission, the applicant may request a hearing on the application. The commission shall give notice of the hearing to all working interest and royalty interest owners. The commission may permit the commingling if the applicant demonstrates that the proposed commingling will protect the rights of all interest owners in accordance with paragraph (3) of this subsection and will prevent waste, promote conservation or protect correlative rights.

(3) Reasonable allocation required. The applicant must demonstrate to the Commission or its designee that the proposed commingling of hydrocarbons will not harm the correlative rights of the working or royalty interest owners of any of the wells to be commingled. The method of allocation of production to individual interests must accurately attribute to each interest its fair share of aggregated production.

(A) In the absence of contrary information, such as indications of material fluctuations in the monthly production volume of a well proposed for commingling, the Commission will presume that allocation based on the daily production rate for each well as determined and reported to the Commission by semi-annual well tests will accurately attribute to each interest its fair share of production without harm to correlative rights. As used in this section, "daily production rate" for a well means the 24 hour production rate determined by the most recent well test conducted and reported to the commission in accordance with §§3.28, 3.52, 3.53, and 3.55 of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported, Oil Well Allowable Production, Annual Well Tests and Well Status Reports Required, and Reports on Gas Wells Commingling Liquid Hydrocarbons before Metering).

(B) Operators may test commingled wells annually after approval by the Commission or the commission's delegate of the operator's written request demonstrating that annual testing will not harm the correlative rights of the working or royalty interest owners of the commingled wells. Allocation of commingled production shall not be based on well tests conducted less frequently than annually.

(C) Nothing in this section prohibits allocations based on more frequent well tests than the semi-annual well test set out in subparagraph (A) of this paragraph. Additional tests used for allocation do not have to be filed with the commission but must be available for inspection at the request of the commission, working interest owners or royalty interest owners.

(D) Allocations may be based on a method other than periodic well tests if the Commission or its designee determines that the alternative allocation method will insure a reasonable allocation of production as required by this paragraph.

(4) Additional notice required. In addition to giving notice to the persons entitled to notice under paragraph (1)(C) of this subsection, an applicant for a surface commingling exception must give notice of the application to the operator of each tract adjacent to one or more of the tracts proposed for commingling that has one or more wells producing from the same commission-designated reservoir as any well proposed for

commingling if:

(A) any one of the wells proposed for commingling produces from a commission-designated reservoir for which special field rules have been adopted; or

(B) any one of the wells proposed for commingling produces from multiple commission-designated reservoirs, unless:

(i) an exception to §3.10 of this title (relating to Restriction of Production of Oil and Gas from Different Strata) has previously been obtained for production from the well; or

(ii) the applicant continues to separately measure production from each different commission-designated reservoir produced from the same wellbore.

(c) If oil or any other liquid hydrocarbon is produced from a lease or other property covered by the coastal or inland waters of the state, the liquid produced may, at the option of the operator, be measured on a shre or at a point removed from the lease or other property on which it is produced.

(d) Oil gravity tests and reports (Reference Order Number 20-55, 647, effective 4-1-66, and Reference Order Number 20-58, 528, effective 5-10-68.) If oil or any other liquid hydrocarbon is produced from a lease or other property covered by the coastal or inland waters of the state, the liquid produced may, at the option of the operator, be measured on a shore or at a point removed from the lease or other property on which it is produced.

(1) Where individual lease oil production, or authorized commingled oil production, separator, treating, and/or storage vessels, other than conventional emulsoin breaking treaters, are connected to a gas gathering system so that heat or vacuum may be applied prior to oil measurement for commission-required production reports, the operator may, at his option, apply heat or vacuum to the oil only to the extent the average gravity of the stock tank oil will not be reduced below a limiting gravity for each lease as established by an average oil gravity test conducted under the following conditions (Reference Order Number 20-55, 647, effective 4-1-66):

(A) the separator or separator system, which shall include any type vessel that is used to separate hydrocarbons, shall be operated at not less than atmospheric pressure;

(B) no heat shall be applied;

(C) the test interval shall be for a minimum of 24 hours, and the average oil gravity after weathering for not more than 24 hours shall then become the limiting gravity factor for applying heat or vacuum to unmeasured oil on the tested lease.

(2) Initial gravity tests shall be made by the operator when such separator, treating, and/or storage vessels are first used pursuant to this section. Subsequent tests shall be made at the request of either the commission or any interested party; and such subsequent tests shall be witnessed by the requesting party. Any interested party may witness the tests.

(3) Each operator shall enter on the face of his required production report the gravity of the oil delivered to market from the lease reported, and it is provided that should a volume of oil delivered to market from such lease separation facilities not meet the gravity requirement established by the described test, adjustment shall be made by charging the allowable of the lease on the relationship of the volume and the gravity of the particular crude.

(4) Where a conventional heater treater is required and is used only to break oil from an emulsion prior to oil measurement, this section will not be applicable; provided, however, that by this limitation on the section, it is not intended that excessive heat may be used in conventional heater treater, and in circumstances where such heater treater is connected to a gas gathering system and it is found by commission investigation made on its own volition or on complaint of any interested party that excessive heat is used, either the provisions of this section or special restrictive regulation may be made applicable.

Source Note: The provisions of this §3.26 adopted January 1, 1976; amended to be effective February 23, 1979, 4 TexReg 436; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective February 18, 1994, 19 TexReg 783; amended to be effective June 23, 1997, 22 TexReg 5747; amended to be effective May 1, 2000, 25 TexReg 3741; amended to be effective November 24, 2004, 29 TexReg 10728

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PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.25	**Use of Common Storage**

(a) In all fields or areas in which the commission has approved the use of common storage where oil is produced from two or more separate reservoirs or zones and separate proration schedules are published by the commission for each reservoir or zone, the operator of said lease shall not be required to file a separate Producer's Certificate of Compliance and Authorization to Transport Oil or Gas From Lease Form for each reservoir or zone, but may file one form to authorize the transportation of oil or gas from all reservoirs or zones producing into common storage.

(b) A gatherer transporting oil from such common storage shall not be required to file a separate transporter's report for each separate reservoir or zone or each separate lease but shall file such report on a combined basis for the total amount of commingled oil in common storage.

(c) The operator of a lease or leases for which the commission has authorized the use of common storage of oil produced from two or more reservoirs or zones and from two or more leases shall file a Monthly Producer's Report for each separate reservoir or zone and/or for each separate lease and, in addition thereto, said operator shall file a report showing the data included on the individual reports on a combined basis for the total amount of commingled oil in common storage.

Source Note: The provisions of this §3.25 adopted to be effective January 1, 1976.

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RULE §3.24	**Check Valves Required**

(a) Where two or more wells are being produced through a common line, a common separator, or a common manifold, the flow lines leading from each well to such common line, common separator, or common manifold shall be equipped with a check valve or other means of shut-off which shall at all times be kept in good working order. The check valve or other means of shut-off shall be placed in each flow line above the surface of the ground and shall be located in the flow line as close to the wellhead connection as is practicable. Where a manifold system is employed in which each well produced through the manifold system has its own individual flow line leading from the wellhead to the manifold, then it shall be permissible for the check valve or other means of shut-off to be placed in the flow line near a point where the flow line enters the manifold system. The check valve or other means of shut-off must be above ground, and must be in the flow line serving the well and must be located between the wellhead and the point where the flow line connects with any other flow line, common separator, or common manifold. Each check valve or other means of shut-off shall be placed in the flow line serving the well so that it will permit the passage of fluids from the well and will act as a check to prevent any fluid from entering the well through the flow line from any outside source.

(b) Operator shall do all things necessary to keep the check valve or other means of shut-off in good working order, and operators, when requested by an agent of the commission, will test the check valve or other means of shut-off for leakage.

Source Note: The provisions of this §3.24 adopted to be effective January 1, 1976.

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RULE §3.23	**Vacuum Pumps**

The installation of a vacuum pump or other device for the purpose of putting vacuum on any gas or oil-bearing formation, or the application of any vacuum to any gas or oil-bearing formation is prohibited, except as follows.

(1) If casinghead gas is utilized in a casinghead-gas plant, vacuum may be used, but no more than is sufficient to gather the gas and deliver it at the plant. In no event shall more than two points of vacuum (two inches of mercury) be used at the casinghead.

(2) In a field which is depleted or practically depleted vacuum may be used, but no vacuum pump shall be installed or used without a permit from the commission obtained upon application after notice to adjacent lease owners and operators and a public hearing on such application.

Source Note: The provisions of this §3.23 adopted to be effective January 1, 1976.

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RULE §3.22	**Protection of Birds**

(a) If an operator who maintains a tank or pit does not take protective measures necessary to prevent harm to birds, the operator may incur liability under federal and state wildlife protection laws. Federal statutes, such as the Migratory Bird Treaty Act, provide substantial penalties for the death of certain species of birds due to contact with oil in a tank or pit. These penalties may include imprisonment. State statutes also protect certain species of birds. The Railroad Commission of Texas (commission) is cooperating with federal and state wildlife authorities in their efforts to protect birds.

(b) An operator must screen, net, cover, or otherwise render harmless to birds the following categories of open-top tanks and pits associated with the exploration, development, and production of oil and gas, including transportation of oil and gas by pipeline:

(1) open-top storage tanks that are eight feet or greater in diameter and contain a continuous or frequent surface film or accumulation of oil; however, temporary, portable storage tanks that are used to hold fluids during drilling operations, workovers, or well tests are exempt;

(2) skimming pits as defined in §3.8 of this title (relating to Water Protection) (Statewide Rule 8); and

(3) collecting pits as defined in §3.8 of this title (relating to Water Protection) that are used as skimming pits.

(c) If the commission finds a surface film or accumulation of oil in any other pit regulated under §3.8 of this title (relating to Water Protection), the commission will instruct the operator to remove the oil. If the operator fails to remove the oil from the pit in accordance with the commission's instructions or if the commission finds a surface film or accumulation of oil in the pit again within a 12-month period, the commission will require the operator to screen, net, cover, or otherwise render the pit harmless to birds. Before complying with this requirement, the operator will have a right to a hearing upon request. In addition to the enforcement actions specified by this subsection, the commission may take any other appropriate enforcement actions within its authority.

Source Note: The provisions of this §3.22 adopted to be effective September 1, 1991, 16 TexReg 2523; amended to be effective November 1, 1991, 16 TexReg 4737.

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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.21	**Fire Prevention and Swabbing**

(a) No hydrocarbon flow tank, unless entirely buried, shall hereafter be placed nearer than 150 feet from any derrick, rig, building, power plant, or boiler of any description. The director of the Oil and Gas Division or his delegate may administratively grant exceptions to this requirement. If the director of the Oil and Gas Division declines to administratively grant, continue, or extend an exception, the operator shall move the hydrocarbon flow tank to the required distance or request a hearing on the matter. After hearing, the examiner shall recommend final action to the commission.

(b) No field working hydrocarbon tank having a capacity of 10,000 barrels or more shall be built nearer than 200 feet (measured from shell to shell) to any other like tank.

(c) No person engaged in the production, transportation, storage, handling, refining, reclaiming, processing, treating, or marketing of crude petroleum oil or the products or by-products thereof shall store, either permanently or temporarily, crude petroleum oil or the products and by-products thereof in open pits or earthen storage.

(d) All oil tanks where there is a gas hazard shall be gas tight and provided with proper gas vents.

(e) No forge or open light shall be placed inside the derrick of a well showing oil or gas.

(f) Boilers must be equipped with steam lines for fighting fire and must not be set nearer than 150 feet to any producing well.

(g) All wells shall be cleaned into a pit not less than 40 feet from the derrick floor and 150 feet from any fire hazard.

(h) No boiler or electric lighting generator shall be placed or remain nearer than 150 feet to any producing well or oil tank.

(i) Any rubbish or debris that might constitute a fire hazard shall be removed to a distance of at least 150 feet from the vicinity of any well, tank, or pump station. All waste shall be burned or disposed of in such manner as to avoid creating a fire hazard.

(j) Dikes or fire walls shall not be required except such fire walls must be erected and kept around all permanent oil tanks, or battery of tanks, that are within the corporate limits of any city, town, or village; or where such tanks are closer than 500 feet to any highway or inhabited dwelling or closer than 1,000 feet to any school or church; or where such tanks are so located as to be deemed by the commission to be an objectionable hazard.

(k) Swabbing, bailing, or air jetting of wells is prohibited as a production method for wells unless the Commission has, after notice and hearing, granted an exception to this subsection. The Commission shall give notice of the hearing at least 10 days prior to the date of the hearing.

(1) An operator seeking an exception to allow swabbing, bailing, or air jetting of a well shall:

(A) provide the Commission with the names and mailing addresses of the mineral interest owners of record and surface owners of record of the lease on which a well for which an exception is sought is located;

(B) present evidence at the hearing establishing:

(i) the method of production proposed;

(ii) that any production is properly accounted for pursuant to §3.26 of this title (relating to Separating Devices, Tanks, and Surface Commingling of Oil);

(iii) that the proposed exception is necessary to prevent waste or protect correlative rights;

(iv) that wellhead control is sufficient to prevent releases from the well;

(v) that no pollution of usable quality water or safety hazard will result from either the proposed production method or the condition of the well; and

(vi) that the operator possesses a continuing good faith claim to the right to operate the well.

(2) In addition to the information set out in paragraph (1) of this subsection, factors that the Commission may consider in ruling on a request for an exception include:

(A) whether the well has passed a mechanical integrity test within the preceding 12 months;

(B) the estimated monthly and cumulative production from the well if the requested exception is granted;

(C) whether production will be into an on-lease tank battery or a mobile tank;

(D) the adequacy of the financial assurance provided by the operator to assure that the well will be timely and properly plugged;

(E) whether production volume, fine sands in the reservoir, or other factors render pumping of the well impracticable;

(F) whether the reservoir from which the well produces contains hydrogen sulfide; and

(G) the operator's history of compliance with Commission rules.

(3) This section does not prohibit swabbing as a non-recurring method to start initial production, to test or clean out a well, or to restore a well to flowing or pumping status.

Source Note: The provisions of this §3.21 adopted to be effective January 1, 1976, amended to be effective October 3, 1980, 5 TexReg 3794; amended to be effective October 2, 2002, 27 TexReg 9149

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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.20	**Notification of Fire Breaks, Leaks, or Blow-outs**

(a) General requirements.

(1) Operators shall give immediate notice of a fire, leak, spill, or break to the appropriate commission district office by telephone or telegraph. Such notice shall be followed by a letter giving the full description of the event, and it shall include the volume of crude oil, gas, geothermal resources, other well liquids, or associated products lost.

(2) All operators of any oil wells, gas wells, geothermal wells, pipelines receiving tanks, storage tanks, or receiving and storage receptacles into which crude oil, gas, or geothermal resources are produced, received, stored, or through which oil, gas, or geothermal resources are piped or transported, shall immediately notify the commission by letter, giving full details concerning all fires which occur at oil wells, gas wells, geothermal wells, tanks, or receptacles owned, operated, or controlled by them or on their property, and all such persons shall immediately report all tanks or receptacles struck by lightning and any other fire which destroys crude oil, natural gas, or geothermal resources, or any of them, and shall immediately report by letter any breaks or leaks in or from tanks or other receptacles and pipelines from which oil, gas, or geothermal resources are escaping or have escaped. In all such reports of fires, breaks, leaks, or escapes, or other accidents of this nature, the location of the well, tank, receptacle, or line break shall be given by county, survey, and property, so that the exact location thereof can be readily located on the ground. Such report shall likewise specify what steps have been taken or are in progress to remedy the situation reported and shall detail the quantity (estimated, if no accurate measurement can be obtained, in which case the report shall show that the same is an estimate) of oil, gas, or geothermal resources, lost, destroyed, or permitted to escape. In case any tank or receptacle is permitted to run over, the escape thus occurring shall be reported as in the case of a leak. (Reference Order Number 20-60,399, effective 9-24-70.)

(b) The report hereby required as to oil losses shall be necessary only in case such oil loss exceeds five barrels in the aggregate.

(c) Any operation with respect to the pickup of pipeline break oil shall be done subject to the following provisions. The provisions hereafter set out shall not apply to the picking up and the returning of pipeline break oil to the pipeline from which it escaped either at the place of the pipeline break, or at the nearest pipeline station to the break where facilities are available to return such oil to the pipeline; provided, that such operations are conducted by the pipeline operator at the time of the pipeline break and its repair; provided, further, that such authority as is herein granted for the picking up of pipeline break oil shall not relieve the operator of such pipeline of notifying the commission of such pipeline break, and the furnishing to the commission of the information required by the provisions set out in subsection (a) of this section for reporting such pipeline breaks.

(1) Any person desiring to pick up, reclaim, or salvage pipeline break oil, other than as provided in this subsection, shall obtain in writing a permit before commencing operations. All applications for permits to pick up, reclaim, or salvage such oil shall be made in writing under oath to the district office.

(2) Applications to pick up, reclaim, or salvage pipeline break oil shall state the location of such oil, the location of the break in the pipeline causing the leakage of such oil, the name of the pipeline, the owner

thereof, and the date of the break.

(3) Pipeline break oil that is not returned to the pipeline from which it escaped shall be offered to the applicant to reclaim by the operator of such pipeline but shall be charged to such pipeline stock account.

Source Note: The provisions of this §3.20 adopted to be effective January 1, 1976.

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RULE §3.19	**Density of Mud-Fluid**

In cable tool drilling, no operator shall drill into a known oil, gas, or geothermal resource producing formation with water from a higher formation in the hole, or with a sufficient head of water introduced into the hole to prevent gas blowing to the surface. The well shall either be allowed to blow until it has been drilled-in or it shall be drilled under a head of fluid whose weight shall average not less than 9 1/2 pounds per gallon; but in no case shall gas be allowed to blow for a longer period than three days after completion of the well. Mud-laden fluid used for protecting oil, gas, or geothermal resource bearing sands in upper formations while oil, gas, or geothermal resource is being produced from deeper formations shall have an average weight of not less than 91 pounds per gallon.

Source Note: The provisions of this §3.19 adopted to be effective January 1, 1976.

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RULE §3.18	**Mud Circulation Required**

When coming out of the hole with the drill pipe, drilling fluid shall be circulated until equalized, and a fill-up line shall be turned into the casing to insure a full load of fluid on the bottom of the hole at all times.

Source Note: The provisions of this §3.18 adopted to be effective January 1, 1976.

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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.17	**Pressure on Bradenhead**

(a) All wells shall be equipped with a Bradenhead. Whenever pressure develops between any two strings of casing, the district office shall be notified immediately. No cement may be pumped between any two strings or pipe at the top of the hole, except after permission has been granted by the district office.

(b) Any well showing pressure on the Bradenhead, or leaking gas, oil, or geothermal resource between the surface and the production or oil string shall be tested in the following manner. The well shall be killed and pump pressure applied through the tubing head. Should the pressure gauge on the Bradenhead reflect the applied pressure, the casing shall be condemned and a new production or oil string shall be run and cemented. This method shall be used when the origin of the pressure cannot be determined otherwise.

Source Note: The provisions of this §3.17 adopted to be effective January 1, 1976.

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RULE §3.16	**Log and Completion or Plugging Report**

(a) The owner or operator of an oil, gas, or geothermal resource well, within 30 days after the completion of such well or the plugging of such well, if the well is a dry hole, shall file with the commission the appropriate completion or plugging report, and if a basic electric log is run on the well, a legible, unaltered final copy of such a log shall be attached. A basic electric log means a lithology, porosity, or resistivity log run over the entire wellbore or in the alternative, if no such log is run over the entire wellbore, the log which is the most complete of such logs run. Amended completion reports must be filed for any change in perforations, or openhole or casing records within 30 days after recompleting the well. In addition, if the well is deepened, a copy of a basic electric log run after September 1, 1985, should be submitted if such log is run over a deeper interval than the interval covered by a basic electric log already on file with the commission for that wellbore.

(b) Each log filed with the commission shall be considered public information and shall be available to the public during normal business hours. If the owner or operator of such well described in subsection (a) of this section desires log(s) to be confidential, the owner or operator must submit a written request for a delayed filing of the log(s). When filing such a request, the owner or operator must retain the log(s) and may delay filing such log(s) for one year beginning from the date the completion or plugging report is required to be filed with the commission. The owner or operator of such well may request an additional filing delay of two years, provided the written request is filed prior to the expiration date of the initial confidentiality period. If a well is drilled on land submerged in state water, the owner or operator may request an additional filing delay of two years so that a possible total filing delay of five years may be obtained. A request for the additional two year filing delay period must be in writing and be received prior to the expiration of the first two year filing delay. Logs must be filed with the commission within 30 days after the expiration of the final confidentiality period.

(c) If the logs are not filed in accordance with the provisions of this section, the commission may refuse to assign an allowable to a well or may set the allowable for such well at zero. If the well is a dry hole and the logs are not filed in accordance with the provisions of this section, the commission may initiate penalty action pursuant to the Texas Natural Resources Code, Title 3.

Source Note: The provisions of this §3.16 adopted to be effective January 1, 1976; amended to be effective February 20, 1986, 11 TexReg 545.

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RULE §3.15	**Surface Casing To Be Left in Place**

Unless alternative methods are approved pursuant to §3.13 of this title (relating to Casing, Cementing, Drilling, and Completion of Requirements), fresh water sands are to be protected with surface casing which has been cemented, and such casing shall not be removed from the well at abandonment. This applies to wells drilled by cable tool and rotary rigs alike.

Source Note: The provisions of this §3.15 adopted to be effective January 1, 1976; amended to be effective March 10, 1986, 11 TexReg 901.

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RULE §3.14	**Plugging**

(a) Definitions and application to plug.

(1) The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise:

(A) Active operation--Regular and continuing activities related to the production of oil and gas for which the operator has all necessary permits. In the case of a well that has been inactive for 12 consecutive months or longer and that is not permitted as a disposal or injection well, the well remains inactive for purposes of this section, regardless of any minimal activity, until the well has reported production of at least 10 barrels of oil for oil wells or 100 mcf of gas for gas wells each month for at least three consecutive months.

(B) Approved cementer--A cementing company, service company, or operator approved by the Commission to mix and pump cement for the purpose of plugging a well in accordance with the provisions of this section. The term shall also apply to a cementing company, service company, or operator authorized by the Commission to use an alternate material other than cement to plug a well.

(C) Delinquent inactive well--An unplugged well that has had no reported production, disposal, injection, or other permitted activity for a period of greater than 12 months and for which, after notice and opportunity for hearing, the Commission has not extended the plugging deadline.

(D) Funnel viscosity--Viscosity as measured by the Marsh funnel, based on the number of seconds required for 1,000 cubic centimeters of fluid to flow through the funnel.

(E) Good faith claim--A factually supported claim based on a recognized legal theory to a continuing possessory right in a mineral estate, such as evidence of a currently valid oil and gas lease or a recorded deed conveying a fee interest in the mineral estate.

(F) Groundwater conservation district--Any district or authority created under §52, Article III, or §59, Article XVI, Texas Constitution, that has the authority to regulate the spacing of water wells, the production from water wells, or both.

(G) Operator designation form--A certificate of compliance and transportation authority or an application to drill, deepen, recomplete, plug back, or reenter which has been completed, signed and filed with the Commission.

(H) Productive horizon--Any stratum known to contain oil, gas, or geothermal resources in producible quantities in the vicinity of an unplugged well.

(I) Related piping--The surface piping and subsurface piping that is less than three feet beneath the ground surface between pieces of equipment located at any collection or treatment facility. Such piping would include piping between and among headers, manifolds, separators, storage tanks, gun barrels, heater treaters, dehydrators, and any other equipment located at a collection or treatment facility. The term is not intended to refer to lines, such as flowlines, gathering lines, and injection lines that lead up to and away from any such collection or treatment facility.

(J) Reported production--Production of oil or gas, excluding production attributable to well tests, accurately reported to the Commission on a monthly producer's report.

(K) To serve notice on the surface owner or resident--To hand deliver a written notice identifying the well or wells to be plugged and the projected date the well or wells will be plugged to the surface owner, or resident if the owner is absent, at least three days prior to the day of plugging or to mail the notice by first class mail, postage pre-paid, to the last known address of the surface owner or resident at least seven days prior to the day of plugging.

(L) Unbonded operator--An operator that has a current and active organization report on file with the Commission that filed a nonrefundable annual fee as financial security prior to September 1, 2004, and is not required by §3.78 of this title (relating to Fees and Financial Security Requirements) to file an individual performance bond, blanket performance bond, letter of credit, or cash deposit as its financial security until the first date for annual renewal of the operator's organization report after September 1, 2004.

(M) Usable quality water strata--All strata determined by the Texas Commission on Environmental Quality or its successor agencies to contain usable quality water.

(N) Written notice--Notice actually received by the intended recipient in tangible or retrievable form, including notice set out on paper and hand-delivered, facsimile transmissions, and electronic mail transmissions.

(2) The operator shall give the Commission notice of its intention to plug any well or wells drilled for oil, gas, or geothermal resources or for any other purpose over which the Commission has jurisdiction, except those specifically addressed in §3.100(e)(1) of this title (relating to Seismic Holes and Core Holes) (Statewide Rule 100), prior to plugging. The operator shall deliver or transmit the written notice to the district office on the appropriate form.

(3) The operator shall cause the notice of its intention to plug to be delivered to the district office at least five days prior to the beginning of plugging operations. The notice shall set out the proposed plugging procedure as well as the complete casing record. The operator shall not commence the work of plugging the well or wells until the proposed procedure has been approved by the district director or the director's delegate. The operator shall not initiate approved plugging operations before the date set out in the notification for the beginning of plugging operations unless authorized by the district director or the director's delegate. The operator shall notify the district office at least four hours before commencing plugging operations and proceed with the work as approved. The district director or the director's delegate may grant exceptions to the requirements of this paragraph concerning the timing of notices when a workover or drilling rig is already at work on location, and ready to commence plugging operations. Operations shall not be suspended prior to plugging the well unless the hole is cased and casing is cemented in place in compliance with Commission rules. The Commission's approval of a notice of intent to plug and abandon a well shall not relieve an operator of the requirement to comply with subsection (b)(2) of this section, nor does such approval constitute an extension of time to comply with subsection (b)(2) of this section.

(4) The surface owner and the operator may file an application to condition an abandoned well located on the surface owner's tract for usable quality water production operations. The application shall be made on the form prescribed by the Commission, the Application of Landowner to Condition an Abandoned Well for Fresh Water Production.

(A) Standard for Commission Approval. Before the Commission will consider approval of an application:

(i) the surface owner shall assume responsibility for plugging the well and obligate himself, his heirs, successors, and assignees to complete the plugging operations;

(ii) the operator responsible for plugging the well shall place all cement plugs required by this rule up to the base of the usable quality water strata; and

(iii) the surface owner shall submit:

(I) a signed statement attesting to the fact that:

(-a-) there is no groundwater conservation district for the area in which the well is located; or

(-b-) there is a groundwater conservation district for the area where the well is located, but the groundwater conservation district does not require that the well be permitted or registered; or

(-c-) the surface owner has registered the well with the groundwater conservation district for the area where the well is located; or

(II) a copy of the permit from the groundwater conservation district for the area where the well is located.

(B) The duty of the operator to properly plug ends only when:

(i) the operator has properly plugged the well in accordance with Commission requirements up to the base of the usable quality water stratum;

(ii) the surface owner has registered the well with, or has obtained a permit for the well from, the groundwater conservation district, if applicable; and

(iii) the Commission has approved the application of surface owner to condition an abandoned well for fresh water production.

(5) The operator of a well shall serve notice on the surface owner of the well site tract, or the resident if the owner is absent, before the scheduled date for beginning the plugging operations. A representative of the surface owner may be present to witness the plugging of the well. Plugging shall not be delayed because of the lack of actual notice to the surface owner or resident if the operator has served notice as required by this paragraph. The district director or the director's delegate may grant exceptions to the requirements of this paragraph concerning the timing of notices when a workover or drilling rig is already at work on location and ready to commence plugging operations.

(b) Commencement of plugging operations, extensions, and testing.

(1) The operator shall complete and file in the district office a duly verified plugging record, in duplicate, on the appropriate form within 30 days after plugging operations are completed. A cementing report made by the party cementing the well shall be attached to, or made a part of, the plugging report. If the well the operator is plugging is a dry hole, an electric log status report shall be filed with the plugging record.

(2) Plugging operations on each dry or inactive well shall be commenced within a period of one year after drilling or operations cease and shall proceed with due diligence until completed. Plugging operations on delinquent inactive wells shall be commenced immediately unless the well is restored to active operation. For good cause, a reasonable extension of time in which to start the plugging operations may be granted pursuant to the following procedures.

(A) Plugging of inactive wells operated by unbonded operators. During the interim period between September 1, 2004, and the first date for annual renewal of an unbonded operator's organization report after September 1, 2004, the Commission or its delegate may administratively grant an extension of up to one year of the deadline for plugging an inactive well that is operated by an unbonded operator if the following criteria are met:

(i) The well and associated facilities are in compliance with all other laws and Commission rules;

(ii) The operator's organization report is current and active;

(iii) The operator has, and upon request provides evidence of, a good faith claim to a continuing right to operate the well; and

(iv) The operator has tested the well in accordance with the provisions of paragraph (3) of this subsection and files with its application proof of either:

(I) a fluid level test conducted within 90 days prior to the application for a plugging extension demonstrating that any fluid in the wellbore is at least 250 feet below the base of the deepest usable quality water stratum; or,

(II) a hydraulic pressure test conducted during the period the well has been inactive and not more than four years prior to the date of application demonstrating the mechanical integrity of the well.

(B) Plugging of inactive wells operated by bonded operators. An operator that maintains valid, Commission-approved financial security in the form of an individual performance bond, blanket performance bond, letter of credit, or cash deposit as provided in §3.78 of this title (relating to Fees and Financial Security Requirements) (Statewide Rule 78) will be granted a one-year plugging extension for each well it operates that has been inactive for 12 months or more at the time its annual organizational report is approved by the Commission if the following criteria are met:

(i) The well and associated facilities are in compliance with all laws and Commission rules; and,

(ii) The operator has, and upon request provides evidence of, a good faith claim to a continuing right to operate the well.

(C) Revocation or denial of plugging extension.

(i) The Commission or its delegate may revoke a plugging extension if the operator of the well that is the subject of the extension fails to maintain the well and all associated facilities in compliance with Commission rules; fails to maintain a current and accurate organizational report on file with the Commission; fails to provide the Commission, upon request, with evidence of a continuing good faith claim to operate the well; or fails to obtain or maintain financial security as required by §3.78 of this title (relating to Fees and Financial Security Requirements) (Statewide Rule 78).

(ii) If the Commission or its delegate declines to grant or continue a plugging extension or revokes a previously granted extension, the operator shall either return the well to active operation or, within 30 days, plug the well or request a hearing on the matter.

(3) The operator of any well more than 25 years old that becomes inactive and subject to the provisions of this subsection or the operator of any well for which a plugging extension is sought under the terms of subparagraph (A) of paragraph (2) of this subsection shall plug the well or successfully conduct a fluid level or hydraulic pressure test establishing that the well does not pose a potential threat of harm to natural

resources, including surface and subsurface water, oil and gas.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.13	**Casing, Cementing, Drilling, and Completion Requirements**

(a) General.

(1) The operator is responsible for compliance with this section during all operations at the well. It is the intent of all provisions of this section that casing be securely anchored in the hole in order to effectively control the well at all times, all usable-quality water zones be isolated and sealed off to effectively prevent contamination or harm, and all potentially productive zones be isolated and sealed off to prevent vertical migration of fluids or gases behind the casing. When the section does not detail specific methods to achieve these objectives, the responsible party shall make every effort to follow the intent of the section, using good engineering practices and the best currently available technology.

(2) Definitions. The following words and terms, when used in this chapter, shall have the following meanings, unless the context clearly indicates otherwise.

(A) Stand under pressure--To leave the hydrostatic column pressure in the well acting as the natural force without adding any external pump pressure. The provisions are complied with if a float collar is used and found to be holding at the completion of the cement job.

(B) Zone of critical cement--For surface casing strings shall be the bottom 20% of the casing string, but shall be no more than 1,000 feet nor less than 300 feet. The zone of critical cement extends to the land surface for surface casing strings of 300 feet or less.

(C) Protection depth--Depth to which usable-quality water must be protected, as determined by the Texas Commission on Environmental Quality (TCEQ) or its successor agencies, which may include zones that contain brackish or saltwater if such zones are correlative and/or hydrologically connected to zones that contain usable-quality water.

(D) Productive horizon--Any stratum known to contain oil, gas, or geothermal resources in commercial quantities in the area.

(b) Onshore and inland waters.

(1) General.

(A) All casing cemented in any well shall be steel casing that has been hydrostatically pressure tested with an applied pressure at least equal to the maximum pressure to which the pipe will be subjected in the well. For new pipe, the mill test pressure may be used to fulfill this requirement. As an alternative to hydrostatic testing, a full length electromagnet, ultrasonic, radiation thickness gauging, or magnetic particle inspection may be employed.

(B) Wellhead assemblies shall be used on wells to maintain surface control of the well. Each component of the wellhead shall have a pressure rating equal to or greater than the anticipated pressure to which that particular component might be exposed during the course of drilling, testing, or producing the well.

(C) A blowout preventer or control head and other connections to keep the well under control at all times shall be installed as soon as surface casing is set. This equipment shall be of such construction and capable of such operation as to satisfy any reasonable test which may be required by the commission or its duly accredited agent.

(D) When cementing any string of casing more than 200 feet long, before drilling the cement plug the operator shall test the casing at a pump pressure in pounds per square inch (psi) calculated by multiplying the length of the casing string by 0.2. The maximum test pressure required, however, unless otherwise ordered by the commission, need not exceed 1,500 psi. If, at the end of 30 minutes, the pressure shows a drop of 10% or more from the original test pressure, the casing shall be condemned until the leak is corrected. A pressure test demonstrating less than a 10% pressure drop after 30 minutes is proof that the condition has been corrected.

(E) Wells drilling to formations where the expected reservoir pressure exceeds the weight of the drilling fluid column shall be equipped to divert any wellbore fluids away from the rig floor. All diverter systems shall be maintained in an effective working condition. No well shall continue drilling operations if a test or other information indicates the diverter system is unable to function or operate as designed.

(2) Surface casing.

(A) Amount required.

(i) An operator shall set and cement sufficient surface casing to protect all usable-quality water strata, as defined by the TCEQ. Before drilling any well in any field or area in which no field rules are in effect or in which surface casing requirements are not specified in the applicable field rules, an operator shall obtain a letter from the TCEQ stating the protection depth. In no case, however, is surface casing to be set deeper than 200 feet below the specified depth without prior approval from the commission.

(ii) Any well drilled to a total depth of 1,000 feet or less below the ground surface may be drilled without setting surface casing provided no shallow gas sands or abnormally high pressures are known to exist at depths shallower than 1,000 feet below the ground surface; and further, provided that production casing is cemented from the shoe to the ground surface by the pump and plug method.

(B) Cementing. Cementing shall be by the pump and plug method. Sufficient cement shall be used to fill the annular space outside the casing from the shoe to the ground surface or to the bottom of the cellar. If cement does not circulate to ground surface or the bottom of the cellar, the operator or his representative shall obtain the approval of the district director for the procedures to be used to perform additional cementing operations, if needed, to cement surface casing from the top of the cement to the ground surface.

(C) Cement quality.

(i) Surface casing strings must be allowed to stand under pressure until the cement has reached a compressive strength of at least 500 psi in the zone of critical cement before drilling plug or initiating a test. The cement mixture in the zone of critical cement shall have a 72-hour compressive strength of at least 1,200 psi.

(ii) An operator may use cement with volume extenders above the zone of critical cement to cement the casing from that point to the ground surface, but in no case shall the cement have a compressive strength of less than 100 psi at the time of drill out nor less than 250 psi 24 hours after being placed.

(iii) In addition to the minimum compressive strength of the cement, the API free water separation shall average no more than six milliliters per 250 milliliters of cement tested in accordance with the current API

RP 10B.

(iv) The commission may require a better quality of cement mixture to be used in any well or any area if evidence of local conditions indicates a better quality of cement is necessary to prevent pollution or to provide safer conditions in the well or area.

(D) Compressive strength tests. Cement mixtures for which published performance data are not available must be tested by the operator or service company. Tests shall be made on representative samples of the basic mixture of cement and additives used, using distilled water or potable tap water for preparing the slurry. The tests must be conducted using the equipment and procedures adopted by the American Petroleum Institute, as published in the current API RP 10B. Test data showing competency of a proposed cement mixture to meet the above requirements must be furnished the commission prior to the cementing operation. To determine that the minimum compressive strength has been obtained, operators shall use the typical performance data for the particular cement used in the well (containing all the additives, including any accelerators used in the slurry) at the following temperatures and at atmospheric pressure.

(i) For the cement in the zone of critical cement, the test temperature shall be within 10 degrees Fahrenheit of the formation equilibrium temperature at the top of the zone of critical cement.

(ii) For the filler cement, the test temperature shall be the temperature found 100 feet below the ground surface level, or 60 degrees Fahrenheit, whichever is greater.

(E) Cementing report. Upon completion of the well, a cementing report must be filed with the commission furnishing complete data concerning the cementing of surface casing in the well as specified on a form furnished by the commission. The operator of the well or his duly authorized agent having personal knowledge of the facts, and representatives of the cementing company performing the cementing job, must sign the form attesting to compliance with the cementing requirements of the commission.

(F) Centralizers. Surface casing shall be centralized at the shoe, above and below a stage collar or diverting tool, if run, and through usable-quality water zones. In nondeviated holes, pipe centralization as follows is required: a centralizer shall be placed every fourth joint from the cement shoe to the ground surface or to the bottom of the cellar. All centralizers shall meet API spec 10D specifications. In deviated holes, the operator shall provide additional centralization.

(G) Alternative surface casing programs.

(i) An alternative method of fresh water protection may be approved upon written application to the appropriate district director. The operator shall state the reason (economics, well control, etc.) for the alternative fresh water protection method and outline the alternate program for casing and cementing through the protection depth for strata containing usable-quality water. Alternative programs for setting more than specified amounts of surface casing for well control purposes may be requested on a field or area basis. Alternative programs for setting less than specified amounts of surface casing will be authorized on an individual well basis only. The district director may approve, modify, or reject the proposed program. If the proposal is modified or rejected, the operator may request a review by the director of field operations. If the proposal is not approved administratively, the operator may request a public hearing. An operator shall obtain approval of any alternative program before commencing operations.

(ii) Any alternate casing program shall require the first string of casing set through the protection depth to be cemented in a manner that will effectively prevent the migration of any fluid to or from any stratum exposed to the wellbore outside this string of casing. The casing shall be cemented from the shoe to ground surface in a single stage, if feasible, or by a multi-stage process with the stage tool set at least 50 feet below the protection depth.

(iii) Any alternate casing program shall include pumping sufficient cement to fill the annular space from the shoe or multi-stage tool to the ground surface. If cement is not circulated to the ground surface or the bottom of the cellar, the operator shall run a temperature survey or cement bond log. The appropriate district office shall be notified prior to running the required temperature survey or bond log. After the top of cement outside the casing is determined, the operator or his representative shall contact the appropriate district director and obtain approval for the procedures to be used to perform any required additional cementing operations. Upon completion of the well, a cementing report shall be filed with the commission on the prescribed form.

(iv) Before parallel (nonconcentric) strings of pipe are cemented in a well, surface or intermediate casing must be set and cemented through the protection depth.

(3) Intermediate casing.

(A) Cementing method. Each intermediate string of casing shall be cemented from the shoe to a point at least 600 feet above the shoe. If any productive horizon is open to the wellbore above the casing shoe, the casing shall be cemented from the shoe up to a point at least 600 feet above the top of the shallowest productive horizon or to a point at least 200 feet above the shoe of the next shallower casing string that was set and cemented in the well.

(B) Alternate method. In the event the distance from the casing shoe to the top of the shallowest productive horizon make cementing, as specified above, impossible or impractical, the multi-stage process may be used to cement the casing in a manner that will effectively seal off all such possible productive horizons and prevent fluid migration to or from such strata within the wellbore.

(4) Production casing.

(A) Cementing method. The producing string of casing shall be cemented by the pump and plug method, or another method approved by the commission, with sufficient cement to fill the annular space back of the casing to the surface or to a point at least 600 feet above the shoe. If any productive horizon is open to the wellbore above the casing shoe, the casing shall be cemented in a manner that effectively seals off all such possibly productive horizons by one of the methods specified for intermediate casing in paragraph (3) of this subsection.

(B) Isolation of associated gas zones. The position of the gas-oil contact shall be determined by coring, electric log, or testing. The producing string shall be landed and cemented below the gas-oil contact, or set completely through and perforated in the oil-saturated portion of the reservoir below the gas-oil contact.

(5) Tubing and storm choke requirements.

(A) Tubing requirements for oil wells. All flowing oil wells shall be equipped with and produced through tubing. When tubing is run inside casing in any flowing oil well, the bottom of the tubing shall be at a point not higher than 100 feet above the top of the producing interval nor more than 50 feet above the top of a line, if one is used. In a multiple zone structure, however, when an operator elects to equip a well in such a manner that small through-the-tubing type tools may be used to perforate, complete, plug back, or recomplete without the necessity of removing the installed tubing, the bottom of the tubing may be set at a distance up to, Cont'd...

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.12	**Directional Survey Company Report**

(a) For each well drilled for oil, gas, or geothermal resources for which a directional survey report is required by rule, regulation, or order, there shall be prepared and filed the following information. The information shall be certified by the person having personal knowledge of the facts, by execution and dating of the data compiled:

(1) name of surveying company;

(2) name of person performing the survey for the company;

(3) the position the person holds with the company;

(4) the date on which the survey was performed;

(5) type of survey conducted and whether multishot;

(6) a complete identification of the well so as to include the name of the operator of the well; the fee owner; the commission lease number, if assigned; the well number; the land survey; the field name; and the county and state;

(7) survey conducted from a depth of ____ feet to ____ feet.

(b) Each directional survey, with its accompanying certification and a certified plat on which the bottom hole location is oriented both to the surface location and to the lease lines (or unit lines in case of pooling) shall be mailed by registered, certified, or overnight mail direct to the commission in Austin by the surveying company making the survey.

Source Note: The provisions of this §3.12 adopted to be effective January 1, 1976; amended to be effective August 25, 2003, 28 TexReg 6816

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.11	**Inclination and Directional Surveys Required**

(a) General. All wells shall be drilled as nearly vertical as possible by normal, prudent, practical drilling operations. Nothing in this section shall be construed to permit the drilling of any well in such a manner that the wellbore crosses lease and/or property lines (or unit lines in cases of pooling) without special permission.

(b) Inclination surveys.

(1) Requirements.

(A) An inclination survey made by persons or concerns approved by the commission shall be filed on a form prescribed by the commission for each well drilled or deepened with rotary tools, except as hereinafter provided, or when, as a result of any operation, the course of the well is changed. The first shot point of such inclination survey shall be made at a depth not greater than 500 feet below the surface of the ground, and succeeding shot points shall be made either at 500-foot intervals or at the nearest drill bit change thereto, but not to exceed 1,000 feet apart.

(B) Inclination surveys conforming to these requirements may be made either during the normal course of drilling or after the well has reached total depth. Acceptable directional surveys may be filed in lieu of inclination surveys.

(C) Copies of all directional or inclination surveys, regardless of the reason for which they are run, shall be filed as a part of or in addition to the inclination surveys otherwise required by this section. If computations are made from dipmeter surveys to determine the course of the wellbore in any portion of the surveyed interval, a report of such computations shall be required.

(D) Inclination surveys shall not be required in any well drilled to a total depth of 2,000 feet or less on a regular location at least 150 feet from the nearest lease line, provided the well is not intentionally deviated from the vertical in any manner whatsoever.

(E) Inclination surveys shall not be required on wells deepened with rotary tools if the well is deepened no more than 300 feet or the distance from the surface location to the nearest lease or boundary line, whichever is the lesser, and provided that the well was not intentionally deviated from the vertical at any time before or after the beginning of deepening operations.

(F) Inclination surveys will not be required on wells that are drilled and completed as dry holes and are permanently plugged and abandoned. If such wells are reentered at a later date and completed as producers or injection or disposal wells, inclination reports will be required and must be filed with the appropriate completion form for the well.

(G) Inclination survey filings will not be required on wells that are reentries within casing of previously producing wells if inclination data are already on file with the Railroad Commission of Texas (commission). If such data are not on file with the commission, the results of an inclination survey must be reported on the appropriate form and filed with the completion form, except as provided by subparagraph (D) of this paragraph.

(2) Reports.

(A) The report form shall be signed and certified by a party having personal knowledge of the facts therein contained. The report shall include a tabulation of the maximum drifts which could occur between the surface and the first shot point, and each two successive shot points, assuming that all of the unsurveyed hole between any two shot points has the same inclination as that measured at the lowest shot point, and the total possible accumulative drift, assuming that all measured angles of inclination are in the same direction.

(B) In addition, the report shall be accompanied by a certified statement of the operator, or of someone acting at his direction on his behalf, either:

(i) that the well was not intentionally deviated from vertical; or

(ii) that the well was deviated at random, with an explanation of the circumstances.

(C) The report shall be filed in the district office by attaching one copy to each appropriate completion form for the well.

(D) The commission may require the submittal of the original charts, graphs, or discs resulting from the surveys.

(c) Directional surveys.

(1) When required.

(A) When the maximum displacement indicated by an inclination survey is greater than the actual distance from the surface location to the nearest lease line or pooled unit boundary, it will be considered to be a violating well subject to plugging and to penalty action. However, an operator may submit a directional survey, run at his own expense by a commission approved surveying company, to show the true bottom hole location of the well to be within the prescribed limits. When such directional survey shows the well to be bottomed within the confines of the lease, but nearer to a well or lease line or pooled unit boundary than allowed by applicable rules, or by the permit for the well if the well has been granted an exception to §3.37 of this title (relating to Statewide Spacing Rule), a new permit will be required if it is established that the bottom hole location or completion location is not a reasonable location.

(B) Directional surveys shall be required on each well drilled under the directional deviation provisions of this section.

(C) No oil, gas, or geothermal resource allowable shall be assigned any well on which a directional survey is required under any provision of this section until a directional survey has been filed with and accepted by the commission.

(2) Filing and type of survey.

(A) Directional surveys required under this section must be run by competent surveying companies, approved by the commission, signed and certified by a person having actual knowledge of the facts, in the manner prescribed by the commission in accordance with §3.12 of this title (relating to Directional Survey Company Report).

(B) All directional surveys, unless otherwise specified by the commission, shall be either single shot surveys or multi-shot surveys with the shot points not more than 200 feet apart, beginning within 200 feet of the surface, and the bottom hole location must be oriented both to the surface location and to the lease lines (or unit lines in cases of pooling).

(C) If more than 200 feet of surface casing has been run, the operator may begin the directional survey immediately below the surface casing depth. However, if such method is used, the inclination drifts from the surface of the ground to the surface casing depth must be added cumulatively and reported on the appropriate form. This total shall be assumed to be in the direction least favorable to the operator, and such point shall be considered the starting point of the directional survey.

(d) Intentional deviation of wells.

(1) Definitions.

(A) Directional deviation--The intentional deviation of a well from vertical in a predetermined compass direction.

(B) Random deviation--The intentional deviation of a well without regard to compass direction for one of the following reasons:

(i) to straighten a hole which has become crooked in the normal course of drilling;

(ii) to sidetrack a portion of a hole because of mechanical difficulty in drilling.

(2) When permitted.

(A) Directional deviation. A permit for directionally deviating a well may be granted by the commission:

(i) for the purpose of seeking to reach and control another well which is out of control or threatens to evade control;

(ii) where conditions on the surface of the ground prevent or unduly complicate the drilling of a well at a regular location;

(iii) where conditions are encountered underground which prevent or unduly hinder the normal completion of the well;

(iv) where it can be shown to be advantageous from the standpoint of mechanical operation to drill more than one well from the same surface location to reach the productive horizon at essentially the same positions as would be reached if the several wells were normally drilled from regular locations prescribed by the well spacing rules in effect;

(v) for the purpose of drilling a horizontal drainhole; or

(vi) for other reasons found by the commission to be sufficient after notice and hearing.

(B) Random deviation. Permission for the random deviation of a well may be granted by the commission whenever the necessity for such deviation is shown, as prescribed in paragraph (3)(C) of this subsection.

(3) Applications for deviation.

(A) Applications for wells to be directionally deviated must specify on the application to drill both the surface location of the well and the projected bottom hole location of the well. On the plat, in addition to the plat requirements provided for in §3.5 of this title (relating to Application to Drill, Deepen, Reenter, or Plug

Back) (Statewide Rule 5), the following shall be included:

(i) two perpendicular lines providing the distance in feet from the projected bottomhole location, rather than the surface location, to the nearest points on the lease, pooled unit, or unitized tract line. If there is an unleased interest in a tract of the pooled unit or unitized tract that is nearer than the pooled unit or unitized tract line, the nearest point on that unleased tract boundary shall be used;

(ii) a line providing the distance in feet from the projected bottomhole location to the nearest point on the lease line, pooled unit line, or unitized tract line. If there is an unleased interest in a tract of the pooled unit that is nearer than the pooled unit line, the nearest point on that unleased tract boundary shall be used;

(iii) a line providing the distance in feet from the projected bottomhole location, rather than the surface location, to the nearest oil, gas, or oil and gas well, identified by number, applied for, permitted, or completed in the same lease, pooled unit, or unitized tract and in the same field and reservoir; and

(iv) perpendicular lines providing the distance in feet from the two nearest non-parallel survey/section lines to the projected bottomhole location.

(B) If the necessity for directional deviation arises unexpectedly after drilling has begun, the operator shall give written notice by letter or telegram of such necessity to the appropriate district office and to the commission office in Austin, and upon giving such notice, the operator may proceed with the directional deviation. The commission may, at its discretion, accept written notice electronically transmitted. If the operator proceeds with the drilling of a deviated well under such circumstances, he proceeds at his own risk. Before any allowable shall be assigned to such well, a permit for the subsurface location of each completion interval shall be obtained from the commission under the provisions set out in the commission rules. However, should the operator fail to show good and sufficient cause for such deviation, no permit will be granted for the well.

(C) If the necessity for random deviation arises unexpectedly after the drilling has begun, the operator shall give written notice by letter or telegram of such necessity to the appropriate district office and to the commission office in Austin, and, upon giving such notice, the operator may proceed with the random deviation, subject to compliance with the provisions of this section on inclination surveys. The commission may, at its discretion, accept written notice electronically transmitted.

(e) Surveys on request of other operators. The commission, at the written request of any operator in a field, shall determine whether a directional survey, an inclination survey, or any other type of survey approved by the commission for the purpose of determining bottom hole location of wells, shall be made in regard to a well complained of in the same field.

(1) The complaining party must show probable cause to suspect that the well complained of is not bottomed within its own lease lines.

(2) The complaining party must agree to pay all costs and expenses of such survey, shall assume all liability, and shall be required to post bond in a sufficient sum as determined by the commission as security against all costs and risks associated with the survey.

(3) The complaining party and the commission shall agree upon the selection of the well surveying company to conduct the survey, which shall be a surveying company on the commission's approved list.

(4) The survey shall be witnessed by the commission, and may be witnessed by any party, or his agent, who has an interest in the field.

(5) Nothing in these rules shall be construed to prevent or limit the commission, acting on its own authority, from conducting spot checks and surveys at any time and place for the purpose of determining compliance with the commission rules and regulations.

(f) Penalties.

(1) False reports. The filing of a false or incorrect directional survey shall be grounds for cancellation of the well permit, for pipeline severance of the lease on which the well is located, for penalty action under the applicable statutes, and/or for such other and further action as may be appropriate.

(2) Other. The same penalties and actions as set forth in paragraph (1) of this subsection shall be assessable against any operator who refuses to comply with a commission order which issues under subsection (e) of this section.

Source Note: The provisions of this §3.11 adopted to be effective January 1, 1976; amended to be effective July 4, 1979, 4 TexReg 2197; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective May 23, 1990, 15 TexReg 2634; amended to be effective June 11, 2001, 26 TexReg 4088

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.10	**Restriction of Production of Oil and Gas from Different Strata**

(a) General prohibition. Oil or gas shall not be produced from different strata through the same string of tubulars except as provided in this section. As used in this section, "different strata" means two or more different commission-designated fields, or one or more commission-designated fields and any other hydrocarbon reservoir.

(b) Exception. After notice and an opportunity for a hearing, the commission or its delegate may grant an exception to subsection (a) of this section to permit production from a well or wells commingling oil or gas or oil and gas from different strata, if commingled production will prevent waste or promote conservation or protect correlative rights.

(c) Notice of Application for Exception.

(1) Timing of Notice.

(A) The applicant shall give notice of each request for an exception by serving a copy of the application to commingle production on all affected operators at the same time the application is filed with the commission.

(B) Service shall be accomplished by delivering a copy of the application to the operator to be served, or to the operator's duly authorized representative, in person, by agent, by courier receipted delivery, by first class mail to the operator's mailing address as shown on the operator's most recently filed Form P-5 (Organization Report) or the most recently filed letter notification of change of address, or by such other manner as the commission may direct.

(2) Operators Presumptively Affected By Application.

(A) An initial exception to commingle production exclusively from different commission-designated fields is presumed to affect all operators in each of the commission-designated fields proposed to be produced through the same string of tubulars.

(B) An initial exception to commingle production from a commission-designated field with production from one or more hydrocarbon reservoirs that have not been designated by the commission as a field is presumed to affect all operators in each of the different commission-designated fields proposed to be produced through the same string of tubulars and all operators of adjacent tracts, and of tracts nearer to the well for which a commingling exception is sought than the longest applicable minimum lease-line distance.

(C) An exception to commingle production exclusively from the same commission-designated fields for which an initial commingling application has previously been granted is presumed to affect all operators of adjacent tracts, and of tracts nearer to the well for which a subsequent commingling exception is sought than the longest applicable minimum lease-line distance, who have a well completed in one or more of the commission-designated fields for which commingling is sought.

(D) An exception to commingle production from a commission-designated field and one or more hydrocarbon reservoirs in specified correlative intervals that have not been designated by the commission as fields, for which an initial commingling exception involving the same fields and hydrocarbon reservoirs has previously been granted, is presumed to affect all operators of adjacent tracts, and of tracts nearer to the well for which a commingling exception is sought than the longest applicable minimum lease-line distance.

(3) Notice Required Only to Affected Operators.

(A) Except as provided in subparagraph (B) of this paragraph, all operators described in paragraph (2)(A)-(D) of this subsection are affected by a requested exception to allow commingling and the applicant shall give each of them notice of the application as provided in paragraph (1)(A) of this subsection.

(B) The commission or its delegate may determine that an operator described in paragraph (2)(A)-(D) will be unaffected by a requested exception to allow commingling. This determination shall be made only upon the applicant's written request and provision to the commission of competent geological or engineering data establishing conclusively that commingling production as requested by the applicant will not physically interfere with the production of hydrocarbons by the operator for which an unaffected determination is requested. An applicant for an exception to allow commingling is not required to give notice of the application to an operator who has been determined to be unaffected as provided in this subparagraph.

(d) Commingled production. Commingled production of gas from different strata pursuant to subsection (b) of this section shall be considered production from a common source of supply for purposes of proration and allocation.

Source Note: The provisions of this §3.10 adopted to be effective January 1, 1976; amended to be effective February 23, 1979, 4 TexReg 436; amended to be effective September 12, 1979, 4 TexReg 3082; amended to be effective May 14, 1996, 21 TexReg 3791.

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RULE §3.9	**Disposal Wells**

Any person who disposes of saltwater or other oil and gas waste by injection into a porous formation not productive of oil, gas, or geothermal resources shall be responsible for complying with this section, Texas Water Code, Chapter 27, and Title 3 of the Natural Resources Code.

(1) General. Saltwater or other oil and gas waste, as that term is defined in the Texas Water Code, Chapter 27, may be disposed of, upon application to and approval by the commission, by injection into nonproducing zones of oil, gas, or geothermal resources bearing formations that contain water mineralized by processes of nature to such a degree that the water is unfit for domestic, stock, irrigation, or other general uses. Every applicant who proposes to dispose of saltwater or other oil and gas waste into a formation not productive of oil, gas, or geothermal resources must obtain a permit from the commission authorizing the disposal in accordance with this section. Permits from the commission issued before the effective date of this section shall continue in effect until revoked, modified, or suspended by the commission.

(2) Geological requirements. Before such formations are approved for disposal use, the applicant shall show that the formations are separated from freshwater formations by impervious beds which will give adequate protection to such freshwater formations. The applicant must submit a letter from the Texas Commission on Environmental Quality or its successor agencies stating that the use of such formation will not endanger the freshwater strata in that area and that the formations to be used for disposal are not freshwater-bearing.

(3) Application. The application to dispose of saltwater or other oil and gas waste by injection into a porous formation not productive of oil, gas, or geothermal resources shall be filed with the commission in Austin accompanied by the prescribed fee. On the same date, one copy shall be filed with the appropriate district office.

(4) Commercial disposal well. An applicant for a permit to dispose of oil and gas waste in a commercial disposal well shall clearly indicate on the application and in the published notice of application that the application is for a commercial disposal well permit. For the purposes of this rule, "commercial disposal well" means a well whose owner or operator receives compensation from others for the disposal of oil field fluids or oil and gas wastes that are wholly or partially trucked or hauled to the well, and the primary business purpose for the well is to provide these services for compensation.

(5) Notice and opportunity for hearing.

(A) The applicant shall give notice by mailing or delivering a copy of the application to affected persons who include the owner of record of the surface tract on which the well is located; each commission-designated operator of any well located within one-half mile of the proposed disposal well; the county clerk of the county in which the well is located; and the city clerk or other appropriate city official of any city where the well is located within the municipal boundaries of the city, on or before the date the application is mailed to or filed with the commission. For the purposes of this section, the term "of record" means recorded in the real property or probate records of the county in which the property is located.

(B) In addition to the requirements of subsection (a)(5)(A) of this section, a commercial disposal well permit applicant shall give notice to owners of record of each surface tract that adjoins the proposed disposal tract by mailing or delivering a copy of the application to each such surface owner.

(C) If, in connection with a particular application, the commission or its delegate determines that another class of persons should receive notice of the application, the commission or its delegate may require the applicant to mail or deliver a copy of the application to members of that class. Such classes of persons could include adjacent surface owners or underground water districts.

(D) In order to give notice to other local governments, interested, or affected persons, notice of the application shall be published once by the applicant in a newspaper of general circulation for the county where the well will be located in a form approved by the commission or its delegate. The applicant shall file with the commission in Austin proof of publication prior to the hearing or administrative approval.

(E) Protested applications:

(i) If a protest from an affected person or local government is made to the commission within 15 days of receipt of the application or of publication, whichever is later, or if the commission or its delegate determines that a hearing is in the public interest, then a hearing will be held on the application after the commission provides notice of hearing to all affected persons, local governments, or other persons, who express an interest, in writing, in the application.

(ii) For purposes of this section, "affected person" means a person who has suffered or will suffer actual injury or economic damage other than as a member of the general public or as a competitor, and includes surface owners of property on which the well is located and commission-designated operators of wells located within one-half mile of the proposed disposal well.

(F) If no protest from an affected person is received by the commission, the commission's delegate may administratively approve the application. If the commission's delegate denies administrative approval, the applicant shall have a right to a hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(6) Subsequent commission action.

(A) A permit for saltwater or other oil and gas waste disposal may be modified, suspended, or terminated by the commission for just cause after notice and opportunity for hearing, if:

(i) a material change of conditions occurs in the operation or completion of the disposal well, or there are material changes in the information originally furnished;

(ii) freshwater is likely to be polluted as a result of continued operation of the well;

(iii) there are substantial violations of the terms and provisions of the permit or of commission rules;

(iv) the applicant has misrepresented any material facts during the permit issuance process;

(v) injected fluids are escaping from the permitted disposal zone; or

(vi) waste of oil, gas, or geothermal resources is occurring or is likely to occur as a result of the permitted operations.

(B) A disposal well permit may be transferred from one operator to another operator provided that the commission's delegate does not notify the present permit holder of an objection to the transfer prior to the date the lease is transferred on Commission records.

(C) Voluntary permit suspension.

(i) An operator may apply to temporarily suspend its injection authority by filing a written request for permit suspension with the commission in Austin, and attaching to the written request the results of an MIT test performed during the previous three-month period in accordance with the provisions of paragraph (12)(D) of this section. The provisions of this subparagraph shall not apply to any well that is permitted as a commercial disposal well.

(ii) The commission or its delegate may grant the permit suspension upon determining that the results of the MIT test submitted under clause (i) of this subparagraph indicate that the well meets the performance standards of paragraph (12)(D) of this section.

(iii) During the period of permit suspension, the operator shall not use the well for injection or disposal purposes.

(iv) During the period of permit suspension, the operator shall comply with all applicable well testing requirements of §3.14 of this title (relating to plugging, and commonly referred to as Statewide Rule 14) but need not perform the MIT test that would otherwise be required under the provisions of paragraph (12)(D) of this section or the permit. Further, during the period of permit suspension, the provisions of paragraph (11)(A) - (C) of this section shall not apply.

(v) The operator may reinstate injection authority under a suspended permit by filing a written notification with the commission in Austin. The written notification shall be accompanied by an MIT test performed during the three-month period prior to the date notice of reinstatement is filed. The MIT test shall have been performed in accordance with the provisions and standards of paragraph (12)(D) of this section.

(7) Area of Review.

(A) Except as otherwise provided in this paragraph, the applicant shall review the date of public record for wells that penetrate the proposed disposal zone within a 1/4 mile radius of the proposed disposal well to determine if all abandoned wells have been plugged in a manner that will prevent the movement of fluids from the disposal zone into freshwater strata. The applicant shall identify in the application any wells which appear from such review of public records to be unplugged or improperly plugged and any other unplugged or improperly plugged wells of which the applicant has actual knowledge.

(B) The commission or its delegate may grant a variance from the area-of-review requirements of subparagraph (A) of this paragraph upon proof that the variance will not result in a material increase in the risk of fluid movement into freshwater strata or to the surface. Such a variance may be granted for an area defined both vertically and laterally (such as a field) or for an individual well. An application for an areal variance need not be filed in conjunction with an individual permit application or application for permit amendment. Factors that may be considered by the commission or its delegate in granting a variance include:

(i) the area affected by pressure increases resulting from injection operations;

(ii) the presence of local geological conditions that preclude movement of fluid that could endanger freshwater strata or the surface; or

(iii) other compelling evidence that the variance will not result in a material increase in the risk of fluid movement into freshwater strata or to the surface.

(C) Persons applying for a variance from the area-of-review requirements of subparagraph (A) of this paragraph on the basis of factors set out in subparagraph (B)(ii) or (iii) of this paragraph for an individual well shall provide notice of the application to those persons given notice under the provisions of paragraph (5)(A) of this subsection. The provisions of paragraph (5)(D) and (E) shall apply in the case of an application for a variance from the area-of-review requirements for an individual well.

(D) Notice of an application for an areal variance from the area-of-review requirements under subparagraph (A) of this paragraph shall be given on or before the date the application is filed with the commission:

(i) by publication once in a newspaper having general circulation in each county, or portion thereof, where the variance would apply. Such notice shall be in a form approved by the commission or its delegate prior to publication and must be at least three inches by five inches in size. The notice shall state that protests to the application may be filed with the commission during the 15-day period following the date of publication. The notice shall appear in a section of the newspaper containing state or local news items;

(ii) by mailing or delivering a copy of the application, along with a statement that any protest to the application should be filed with the commission within 15 days of the date of the application is filed with the commission, to the following:

(I) the manager of each underground water conservation district(s) in which the variance would apply, if any;

(II) the city clerk or other appropriate official of each incorporated city in which the variance would apply, if any;

(III) the county clerk of each county in which the variance would apply; and

(IV) any other person or persons that the commission or its delegate determine should receive notice of the application.

(E) If a protest to an application for an areal variance is made to the commission by an affected person, local government, underground water conservation district, or other state agency within 15 days of receipt of the application or of publication, whichever is later, or if the commission's delegate determines that a hearing on the application is in the public interest, then a hearing will be held on the application after the commission provides notice of the hearing to all local governments, underground water conservation districts, state agencies, or other persons, who express an interest, in writing, in the application. If no protest from an affected person is received by the commission, the commission's delegate may administratively approve the application. If the application is denied administratively, the person(s) filing the application shall have a right to hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(F) An areal variance granted under the provisions of this paragraph may be modified, terminated, or suspended by the commission after notice and opportunity for hearing is provided to each person shown on commission records to operate an oil or gas lease in the area in which the proposed modification, termination, or suspension would apply. If a hearing on a proposal to modify, terminate, or suspend an areal variance is held, any applications filed subsequent to the date notice of hearing is given must include the area-of-review information required under subparagraph (A) of this paragraph pending issuance of a final order.

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RULE §3.8	**Water Protection**

(a) The following words and terms when used in this section shall have the following meanings, unless the context clearly indicates otherwise.

(1) Basic sediment pit--Pit used in conjunction with a tank battery for storage of basic sediment removed from a production vessel or from the bottom of an oil storage tank. Basic sediment pits were formerly referred to as burn pits.

(2) Brine pit--Pit used for storage of brine which is used to displace hydrocarbons from an underground hydrocarbon storage facility.

(3) Collecting pit--Pit used for storage of saltwater prior to disposal at a tidal disposal facility, or pit used for storage of saltwater or other oil and gas wastes prior to disposal at a disposal well or fluid injection well. In some cases, one pit is both a collecting pit and a skimming pit.

(4) Completion/workover pit--Pit used for storage or disposal of spent completion fluids, workover fluids and drilling fluid, silt, debris, water, brine, oil scum, paraffin, or other materials which have been cleaned out of the wellbore of a well being completed or worked over.

(5) Drilling fluid disposal pit--Pit, other than a reserve pit, used for disposal of spent drilling fluid.

(6) Drilling fluid storage pit--Pit used for storage of drilling fluid which is not currently being used but which will be used in future drilling operations. Drilling fluid storage pits are often centrally located among several leases.

(7) Emergency saltwater storage pit--Pit used for storage of produced saltwater for limited period of time. Use of the pit is necessitated by a temporary shutdown of disposal well or fluid injection well and/or associated equipment, by temporary overflow of saltwater storage tanks on a producing lease or by a producing well loading up with formation fluids such that the well may die. Emergency saltwater storage pits may sometimes be referred to as emergency pits or blowdown pits.

(8) Flare pit--Pit which contains a flare and which is used for temporary storage of liquid hydrocarbons which are sent to the flare during equipment malfunction but which are not burned. A flare pit is used in conjunction with a gasoline plant, natural gas processing plant, pressure maintenance or repressurizing plant, tank battery, or a well.

(9) Fresh makeup water pit--Pit used in conjunction with drilling rig for storage of water used to make up drilling fluid.

(10) Gas plant evaporation/retention pit--Pit used for storage or disposal of cooling tower blowdown, water condensed from natural gas, and other wastewater generated at gasoline plants, natural gas processing plants, or pressure maintenance or repressurizing plants.

(11) Mud circulation pit--Pit used in conjunction with drilling rig for storage of drilling fluid currently

being used in drilling operations.

(12) Reserve pit--Pit used in conjunction with drilling rig for collecting spent drilling fluids; cuttings, sands, and silts; and wash water used for cleaning drill pipe and other equipment at the well site. Reserve pits are sometimes referred to as slush pits or mud pits.

(13) Saltwater disposal pit--Pit used for disposal of produced saltwater.

(14) Skimming pit--Pit used for skimming oil off saltwater prior to disposal of saltwater at a tidal disposal facility, disposal well, or fluid injection well.

(15) Washout pit--Pit located at a truck yard, tank yard, or disposal facility for storage or disposal of oil and gas waste residue washed out of trucks, mobile tanks, or skid-mounted tanks.

(16) Water condensate pit--Pit used in conjunction with a gas pipeline drip or gas compressor station for storage or disposal of fresh water condensed from natural gas.

(17) Generator--Person who generates oil and gas wastes.

(18) Carrier--Person who transports oil and gas wastes generated by a generator. A carrier of another person's oil and gas wastes may be a generator of his own oil and gas wastes.

(19) Receiver--Person who stores, handles, treats, reclaims, or disposes of oil and gas wastes generated by a generator. A receiver of another person's oil and gas wastes may be a generator of his own oil and gas wastes.

(20) Director--Director of the Oil and Gas Division or his staff delegate designated in writing by the director of the Oil and Gas Division or the commission.

(21) Person--Natural person, corporation, organization, government or governmental subdivision or agency, business trust, estate, trust, partnership, association, or any other legal entity.

(22) Affected person--Person who, as a result of the activity sought to be permitted, has suffered or may suffer actual injury or economic damage other than as a member of the general public.

(23) To dewater--To remove the free water.

(24) To dispose--To engage in any act of disposal subject to regulation by the commission including, but not limited to, conducting, draining, discharging, emitting, throwing, releasing, depositing, burying, landfarming, or allowing to seep, or to cause or allow any such act of disposal.

(25) Landfarming--A waste management practice in which oil and gas wastes are mixed with or applied to the land surface in such a manner that the waste will not migrate off the landfarmed area.

(26) Oil and gas wastes--Materials to be disposed of or reclaimed which have been generated in connection with activities associated with the exploration, development, and production of oil or gas or geothermal resources, as those activities are defined in paragraph (30) of this subsection, and materials to be disposed of or reclaimed which have been generated in connection with activities associated with the solution mining of brine. The term "oil and gas wastes" includes, but is not limited to, saltwater, other mineralized water, sludge, spent drilling fluids, cuttings, waste oil, spent completion fluids, and other liquid, semiliquid, or solid waste material. The term "oil and gas wastes" includes waste generated in connection with activities associated with gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance plants, or repressurizing plants unless that waste is a hazardous waste as defined by the administrator of the

United States Environmental Protection Agency pursuant to the federal Solid Waste Disposal Act, as amended (42 United States Code §6901 et seq.).

(27) Oil field fluids--Fluids to be used or reused in connection with activities associated with the exploration, development, and production of oil or gas or geothermal resources, fluids to be used or reused in connection with activities associated with the solution mining of brine, and mined brine. The term "oil field fluids" includes, but is not limited to, drilling fluids, completion fluids, surfactants, and chemicals used to detoxify oil and gas wastes.

(28) Pollution of surface or subsurface water--The alteration of the physical, thermal, chemical, or biological quality of, or the contamination of, any surface or subsurface water in the state that renders the water harmful, detrimental, or injurious to humans, animal life, vegetation, or property, or to public health, safety, or welfare, or impairs the usefulness or the public enjoyment of the water for any lawful or reasonable purpose.

(29) Surface or subsurface water--Groundwater, percolating or otherwise, and lakes, bays, ponds, impounding reservoirs, springs, rivers, streams, creeks, estuaries, marshes, inlets, canals, the Gulf of Mexico inside the territorial limits of the state, and all other bodies of surface water, natural or artificial, inland or coastal, fresh or salt, navigable or nonnavigable, and including the beds and banks of all watercourses and bodies of surface water, that are wholly or partially inside or bordering the state or inside the jurisdiction of the state.

(30) Activities associated with the exploration, development, and production of oil or gas or geothermal resources--Activities associated with:

(A) the drilling of exploratory wells, oil wells, gas wells, or geothermal resource wells;

(B) the production of oil or gas or geothermal resources, including:

(i) activities associated with the drilling of injection water source wells that penetrate the base of usable quality water;

(ii) activities associated with the drilling of cathodic protection holes associated with the cathodic protection of wells and pipelines subject to the jurisdiction of the commission to regulate the production of oil or gas or geothermal resources;

(iii) activities associated with gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance plants, or repressurizing plants;

(iv) activities associated with any underground natural gas storage facility, provided the terms "natural gas" and "storage facility" shall have the meanings set out in the Texas Natural Resources Code, §91.173;

(v) activities associated with any underground hydrocarbon storage facility, provided the terms "hydrocarbons" and "underground hydrocarbon storage facility" shall have the meanings set out in the Texas Natural Resources Code, §91.201; and

(vi) activities associated with the storage, handling, reclamation, gathering, transportation, or distribution of oil or gas prior to the refining of such oil or prior to the use of such gas in any manufacturing process or as a residential or industrial fuel;

(C) the operation, abandonment, and proper plugging of wells subject to the jurisdiction of the commission to regulate the exploration, development, and production of oil or gas or geothermal resources;

and

(D) the discharge, storage, handling, transportation, reclamation, or disposal of waste or any other substance or material associated with any activity listed in subparagraphs (A)-(C) of this paragraph, except for waste generated in connection with activities associated with gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance plants, or repressurizing plants if that waste is a hazardous waste as defined by the administrator of the United States Environmental Protection Agency pursuant to the federal Solid Waste Disposal Act, as amended (42 United States Code §6901, et seq.).

(31) Mined brine--Brine produced from a brine mining injection well by solution of subsurface salt formations. The term "mined brine" does not include saltwater produced incidentally to the exploration, development, and production of oil or gas or geothermal resources.

(32) Brine mining pit--Pit, other than a fresh mining water pit, used in connection with activities associated with the solution mining of brine. Most brine mining pits are used to store mined brine.

(33) Fresh mining water pit--Pit used in conjunction with a brine mining injection well for storage of water used for solution mining of brine.

(34) Inert wastes--Nonreactive, nontoxic, and essentially insoluble oil and gas wastes, including, but not limited to, concrete, glass, wood, metal, wire, plastic, fiberglass, and trash.

(35) Coastal zone--The area within the boundary established in Title 31, Texas Administrative Code, §503.1 (Coastal Management Program Boundary).

(36) Coastal management program (CMP) rules--The enforceable rules of the Texas Coastal Management Program codified at Title 31, Texas Administrative Code, Chapters 501, 505, and 506.

(37) Coastal natural resource area (CNRA)--One of the following areas defined in Texas Natural Resources Code, §33.203: coastal barriers, coastal historic areas, coastal preserves, coastal shore areas, coastal wetlands, critical dune areas, critical erosion areas, gulf beaches, hard substrate reefs, oyster reefs, submerged land, special hazard areas, submerged aquatic vegetation, tidal sand or mud flats, water in the open Gulf of Mexico, and water under tidal influence.

(38) Coastal waters--Waters under tidal influence and waters of the open Gulf of Mexico.

(39) Critical area--A coastal wetland, an oyster reef, a hard substrate reef, submerged aquatic vegetation, or a tidal sand or mud flat as defined in Texas Natural Resources Code, §33.203.

(40) Practicable--Available and capable of being done after taking into consideration existing technology, cost, and logistics in light of the overall purpose of the activity.

(b) No pollution. No person conducting activities subject to regulation by the commission may cause or allow pollution of surface or subsurface water in the state.

(c) Exploratory wells. Any oil, gas, or geothermal resource well or well drilled for exploratory purposes shall be governed by the provisions of statewide or field rules which are applicable and pertain to the drilling, safety, casing, production, abandoning, and plugging of wells.

(d) Pollution control.

(1) Prohibited disposal methods. Except for those disposal methods authorized for certain wastes by paragraph (3) of this subsection, subsection (e) of this section, or §3.98 of this title (relating to Standards for

Management of Hazardous Oil and Gas Waste), or disposal methods required to be permitted pursuant to §3.9 of this title (relating to Disposal Wells) (Rule 9) or §3.46 of this title (relating to Fluid Injection into Productive Reservoirs) (Rule 46), no person may dispose of any oil and gas wastes by any method without obtaining a permit to dispose of such wastes. The disposal methods prohibited by this paragraph include, but are not limited to, the unpermitted discharge of oil field brines, geothermal resource waters, or other mineralized waters, or drilling fluids into any watercourse or drainageway, including any drainage Cont'd...

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RULE §3.7	**Strata To Be Sealed Off**

Whenever hydrocarbon or geothermal resource fluids are encountered in any well drilled for oil, gas, or geothermal resources in this state, such fluid shall be confined in its original stratum until it can be produced and utilized without waste. Each such stratum shall be adequately protected from infiltrating waters. Wells may be drilled deeper after encountering a stratum bearing such fluids if such drilling shall be prosecuted with diligence and any such fluids be confined in its stratum and protected as aforesaid upon completion of the well. The commission will require each such stratum to be cased off and protected, if in its discretion it shall be reasonably necessary and proper to do so.

Source Note: The provisions of this §3.7 adopted to be effective January 1, 1976.

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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.6	**Application for Multiple Completion**

(a) Authority will be granted to multicomplete a well in separate reservoirs that are not in communication without the necessity of notice and hearing on each separate application; provided, that an application for multiple completion on the form prescribed and the required accompanying data, as hereafter listed, is filed with the Engineering unit of the Commission's Permitting and Production Section for its consideration and approval.

(b) If the proposed zones of completion are not presently recognized by the commission as being acceptable for multicompletion approval, all data necessary to substantiate a conclusion by the commission that the proposed zones of completion are feasible and reasonably susceptible of having multicompleted and producing wells drilled thereto and therein must be filed with the application.

(c) If the additional data furnished with the application is not considered by the commission to be sufficient to establish the proposed zones of completion as separate zones of production which are feasible and reasonably susceptible of having multicompleted and producing wells drilled thereto and therein, or if any party protests such an application, then, if an operator so elects, his application will be set for hearing.

(d) Multiple completion authority for a well will not be granted unless the following required data have been filed with the Engineering unit of the Commission's Permitting and Production Section:

(1) application for multiple completion properly executed and attested;

(2) electrical log or portion of the electric log of the well or a type electric log or a portion of the type electric log showing clearly thereon the subsurface location of the separate reservoirs claimed. Any electric log filed will be considered public information pursuant to §3.16 of this title (relating to Log and Completion Report (Statewide Rule 16);

(3) packer setting report where applicable;

(4) packer leakage test or communication test;

(5) diagrammatic sketch of the mechanical installation;

(6) letters of waiver from offset operators, or evidence that notice of application to multicomplete was given to said operators.

Source Note: The provisions of this §3.6 adopted to be effective January 1, 1976; amended to be effective February 28, 1986, 11 TexReg 545; amended to be effective November 24, 2004, 29 TexReg 10728

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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.5	**Application To Drill, Deepen, Reenter, or Plug Back**

(a) Requirements for spacing, density, and units. An application for a permit to drill, deepen, plug back, or reenter any oil well, gas well, or geothermal resource well shall be made under the provisions of §§3.37, 3.38, 3.39, and/or 3.40 of this title (relating to Statewide Spacing Rule; Well Densities; Proration and Drilling Units: Contiguity of Acreage and Exception Thereto; and Assignment of Acreage to Pooled Development and Proration Units) (Statewide Rules 37, 38, 39, and 40), or as an exception thereto, or under special rules governing any particular oil, gas, or geothermal resource field or as an exception thereto and filed with the commission on a form approved by the commission. An application must be accompanied by any relevant information, form, or certification required by the Railroad Commission or a commission representative necessary to determine compliance with this rule and state law.

(b) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Application--Request by an organization made either on the prescribed form or electronically pursuant to procedures for electronic filings adopted by the commission for a permit to drill, deepen, plug back, or reenter any oil well, gas well, or geothermal resource well.

(2) Commission--The Railroad Commission of Texas.

(3) Commission representative--A commission employee authorized to act for the commission. Any authority given to a commission representative is also retained by the commission. Any action taken by the commission representative is subject to review by the commission.

(c) Commencement of operations. Operations of drilling, deepening, plugging back, or reentering shall not be commenced until the permit has been granted by the commission and the waiting period, if any, has terminated, or authorization has been granted pursuant to subsection (d) of this section.

(d) Testing of existing wells in other reservoirs inside the casing. For an existing well, an operator may request authorization to commence operations to deepen inside the casing or plug back prior to the granting of a permit to deepen or plug back.

(1) This authorization shall be requested by submitting a request with the district office to deepen inside the casing or plug back. The request shall include:

(A) the operator name;

(B) the lease name;

(C) the lease number or gas identification number;

(D) well number;

(E) county;

(F) field name;

(G) a list of all reservoir(s) to be tested;

(H) the casing setting depth and the depth of the deepest reservoir to be tested;

(I) a plat showing the well location; and

(J) a statement as to whether or not the well location would require an exception to §§3.37, 3.38, 3.39, and/or 3.40 of this title (relating to Statewide Spacing Rule; Well Densities; Proration and Drilling Units: Contiguity of Acreage and Exception Thereto; and Assignment of Acreage to Pooled Development and Proration Units) (Statewide Rules 37, 38, 39, and 40) if completed in any of the reservoirs to be tested. If an exception would be required, the request shall also include a statement that all affected offsets have been given written notice of the intent to test with the opportunity to witness the testing and the offsets shall be identified on the plat.

(2) Operations of deepening inside the casing or plugging back shall not be commenced until the district office has reviewed and approved the request. Testing pursuant to this authorization shall be completed within 90 days from the date the district office approves the request.

(A) No reservoir tested pursuant to the provisions of this subsection shall be tested for more than 15 days.

(B) If the operator desires to place the well on production, the operator shall shut in the well, with no production being sold, and file a permit application for the tested reservoirs with the appropriate fees. If the permit application for the tested reservoirs requires an exception to §§3.37, 3.38, 3.39, and/or 3.40 of this title (relating to Statewide Spacing Rule; Well Densities; Proration and Drilling Units: Contiguity of Acreage and Exception Thereto; and Assignment of Acreage to Pooled Development and Proration Units) (Statewide Rules 37, 38, 39, and 40), no consideration will be given by the commission to the cost of recompleting and testing the well in determining whether or not to grant the exception.

(C) Within 30 days of completion of testing, the operator must either file an application for a permit to produce a reservoir tested pursuant to this subsection or file an amended completion report in accordance with §3.16 of this title (relating to Log and Completion or Plugging Report) (Statewide Rule 16) with a copy of the request signed by the district office and a statement that a permit to produce a tested reservoir is not being sought, or if the well has been plugged and abandoned, a plugging report including reservoir and perforation data. If a permit is not obtained for the tested reservoirs and/or an allowable is not assigned, the producer shall report all test production in the producer's monthly report filed for the last permitted reservoir in which the well was completed and may request authorization to sell the test production. The test production may be sold after such authorization is granted.

(e) Exploratory and specialty wells. An application for any exploratory well or cathodic protection well that penetrates the base of the fresh water strata, fluid injection well, injection water source well, disposal well, brine solution mining well, or underground hydrocarbon storage well shall be made and filed with the commission on a form approved by the commission. Operations for drilling, deepening, plugging back, or reentering shall not be commenced until the permit has been granted by the commission. For an exploratory well, an exception to filing such form prior to commencing operations may be obtained if an application for a core hole test is filed with the commission.

(f) Drilling permit fee. With each application or materially amended application, the applicant shall submit to the commission a nonrefundable fee as determined by §3.78 of this title (relating to Fees and Financial Security Requirements) (Statewide Rule 78).

(g) Expiration. Any permit to drill, deepen, plug back, or reenter granted by the commission expires no later than two years after the date of original approval.

(h) Plats. An application to drill, deepen, plug back, or reenter shall be accompanied by a neat, accurate plat, with a scale of one inch equals 1,000 feet. The plat for the initial well on the lease, pooled unit, or unitized tract shall show the entire lease, pooled unit, or tract, including all tracts being pooled. If necessary to show the entire lease, the scale may be one inch equals 2,000 feet. Plats for subsequent wells on a lease or pooled unit shall show at least the lease or pooled unit line nearest the proposed location and the nearest survey/section lines. The Division Director or the director's delegate may approve plats with other scales upon request.

(1) The lease shall be outlined on the plat using either a heavy line or crosshatching.

(2) The plat is to include the following:

(A) surface location of the proposed drilling site;

(B) perpendicular lines providing the distance in feet from two nearest non-parallel survey/section lines to the surface location;

(C) perpendicular lines providing the distance in feet from two nearest non-parallel lease lines to the surface location;

(D) a line providing the distance in feet from the surface location to the nearest point on the lease line, pooled unit line, or unitized tract line. If there is an unleased interest in a tract of the pooled unit that is nearer than the pooled unit line, the nearest point on that unleased tract boundary shall be used;

(E) a line providing the distance in feet from the surface location to the nearest oil, gas, or oil and gas well identified by number either applied for, permitted, or completed in the same lease, pooled unit, or unitized tract and in the same field and reservoir;

(F) the geographic location information;

(G) a labeled scale bar; and

(H) northerly direction.

(3) Requirements for plats as provided for in §3.11, §3.37, §3.38, and §3.86 of this title (relating to Inclination and Directional Surveys Required, Statewide Spacing Rule, Well Densities, and Horizontal Drainhole Wells) may supplement or replace the plat requirements set out above.

Source Note: The provisions of this §3.5 adopted to be effective January 1, 1976; amended to be effective September 1, 1983, 8 TexReg 3184; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective October 30, 1986, 11 TexReg 4214; amended to be effective February 24, 1992, 17 TexReg 1225; amended to be effective September 1, 1992, 17 TexReg 5283; amended to be effective July 10, 2000, 25 TexReg 6487; amended to be effective June 11, 2001, 26 TexReg 4088; amended to be effective September 1, 2004, 29 TexReg 8271

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.4	**Oil and Geothermal Lease Numbers and Gas Well ID Numbers Required on All Forms**

(a) Lease name and number.

(1) All operators with oil and geothermal producing properties must ascertain from the appropriate proration schedule the lease number assigned to each separate lease, and thereafter include on each commission-required form or report the exact lease name and its number as they appear on the current proration schedule for all leases.

(2) No commission-required form or report will be accepted until the form or report is properly completed, including both the lease name and lease number applicable thereto.

(3) If a lease has not been issued a lease number on the current proration schedule, the lease shall have assigned to it the exact lease name as shown on the form first submitted, and in addition thereto a lease number will be assigned at the same time the form reflecting the potential test is submitted and processed. Subsequent to the assignment of a lease number, such number together with the exact lease name as submitted on the appropriate form must appear on all future forms and reports submitted to the commission, the lease number and lease name as assigned by the commission to be evidenced to the operator on the face of the supplement establishing the allowable for the lease.

(b) Gas well identification numbers shall be assigned by the commission for each separate gas well completion, and such gas well identification number shall be used on all forms and reports required by and filed with the commission concerning operations for such well so long as it remains a gas well, such commission gas well identification number to be effective as provided in the following paragraphs.

(1) All operators having a gas well must ascertain from the appropriate current gas allowable schedule the commission gas well identification number assigned to each separate gas well completion, and thereafter include on each commission required form or report its exact well lease name and number and its commission gas well identification number as they appear on the current gas allowable schedule for all gas wells completed in the same reservoir.

(2) No commission-required form or report will be accepted until the form or report is properly completed, including both the well lease name and number and the commission gas well identification number applicable thereto.

(3) If a gas well has not been assigned a gas well identification number on the current gas allowable schedule, such well shall have assigned to it the exact well lease name and number as shown on the appropriate form and, in addition thereto, a gas well identification number will be assigned at the time the commission-required form is submitted and processed. After the assignment of a gas well identification number, such number together with the exact well lease name and number on the form first submitted, must appear on all future forms and reports submitted to the commission, the gas well lease name and gas well identification number as assigned by the commission to be evidenced to the operator on the face of the supplement establishing the initial allowable for such well.

Source Note: The provisions of this §3.4 adopted to be effective January 1, 1976.

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Texas Administrative Code

TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.3	**Identification of Properties, Wells, and Tanks**

Each property that produces oil, gas, or geothermal resources and each oil, gas, or geothermal resource well and tank, or other approved crude oil measuring facility where tanks are not utilized thereon, shall at all times be clearly identified as follows.

(1) A sign shall be posted at the principal entrance to each such property which shall show the name by which the property is commonly known and is carried on the records of the commission, the name of the operator, and the number of acres in the property.

(2) A sign shall be posted at each well site which shall show the name of the property, the name of the operator, and the well number.

(3) A sign shall be posted at or painted on each oil stock tank and on each remotely located satellite tank, or on each approved crude oil measuring facility where tanks are not utilized, that is located on or serving each property, which signs shall show, in addition to the information provided for in paragraph (1) of this section, the commission lease number for the formation from which oil in the tank, or in an approved crude oil measuring facility, is produced, and where oil from more than one formation is commingled in the same tank, or in an approved crude oil measuring facility, the sign shall show the number of the commission permit that authorized the commingling of the oil; provided that, if there is more than one tank in a battery which contains oil from only one formation or oil from different formations that is commingled pursuant to a single commingling permit, it will not be necessary for the sign to be posted at or painted on each tank if the sign posted at or painted on a tank in the battery shows the required information and clearly identifies, by tank number or otherwise, the tanks to which the information is applicable.

(4) If a well is separately completed in two or more producing formations, the wellhead valve and flow line serving each separate formation shall be identified by a metal tag or other lettering attached to or painted on either the valve or flow line which shows the name of the formation and identifies the completion string of casing or tubing, as for example "C" for casing; "UT" for upper tubing; "LT" for lower tubing, etc., each being preceded or followed by the name of the producing formation.

(5) The signs and identification required by this section shall be in the English language, clearly legible, and in the case of the signs required by paragraphs (1), (2), and (3) of this section shall be in letters and numbers at least one inch in height.

Source Note: The provisions of this §3.3 adopted to be effective January 1, 1976.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.2	**Commission Access to Properties**

(a) The commission or its representatives shall have access to come upon any lease or property operated or controlled by an operator, producer, or transporter of oil, gas, or geothermal resources, and to inspect any and all leases, properties, and wells and all records of said leases, properties, and wells.

(b) Designated agents of the commission are authorized to make any tests on any well at any time necessary to conservation regulation, and the owner of such well is hereby directed to do all things that may be required of him by the commission's agent to make such tests in a proper manner.

Source Note: The provisions of this §3.2 adopted to be effective January 1, 1976.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.106	**Sour Gas Pipeline Facility Construction Permit**

(a) Definitions. The following words and terms when used in this section shall have the following meanings, unless the context clearly indicates otherwise.

(1) Affected person--The owner or occupant of real property located in the area of influence of the proposed route of a sour gas pipeline facility. If the final proposed route of the pipeline is unknown at the time of application, then an affected person is any person who owns or occupies real property located within the area of influence associated with any possible pipeline route identified by the applicant. For purposes of this definition, the owner shall be the owner of record as of the final day to protest an application. The occupant shall be the occupant as of the final day to protest an application.

(2) Applicant--A person who has filed an application for a permit to construct a sour gas pipeline facility, or a representative of that person.

(3) Application--Application for a Permit to Construct a Sour Gas Pipeline Facility, and all required attachments.

(4) Area of influence--Area along a sour gas pipeline facility represented by all possible areas of exposure using the 100 ppm radius.

(5) Construction of a facility--Any activity conducted during the initial construction of a pipeline including the removal of earth, vegetation, or obstructions along the proposed pipeline right-of-way. The term does not include:

(A) surveying or acquiring the right-of-way;

(B) clearing the right-of-way with the consent of the owner;

(C) repairing or maintaining an existing sour gas pipeline facility; or

(D) installing valves or meters or other devices or fabrications on an existing pipeline if such devices or fabrication do not result in an increase in the area of influence.

(6) Extension of a sour gas pipeline facility--An addition to an operating sour gas pipeline facility regardless of ownership of the addition.

(7) Nominal pipe size--The industry convention for naming pipe. Six inch nominal size pipe corresponds to pipe with an approximate inner diameter of six inches. The actual inner diameter varies based on the wall thickness of the pipe.

(8) Person--An individual, partnership, firm, corporation, joint venture, trust, association, or any other business entity, a state agency or institution, county, municipality, school district, or other governmental subdivision.

(9) Preliminary contingency plan--A contingency plan containing all of the elements required for a

contingency plan under §3.36 of this title (relating to oil, gas, or geothermal resource operation in hydrogen sulfide areas), except that:

(A) the plan need not contain the list of names and telephone numbers of residents within the area of influence if required under §3.36(c)(9)(I) of this section. In lieu of this list of names and telephone numbers, the plan shall contain a detailed explanation of the manner in which the names and telephone numbers of residents within the area of influence will be compiled prior to commencement of operations;

(B) the plat detailing the area of influence may be:

(i) the detailed plat required under §3.36(c)(9)(H);

(ii) a plat containing the information required under §3.36(c)(9)(H), that identifies residential, business, and industrial areas with an estimate of the number of people that may be within any such areas; or

(iii) one or more aerial photographs covering the area and providing the information required under §3.36(c)(9)(H); and

(C) a fixed pipeline route need not be specified in the preliminary plan provided the preliminary plan identifies the boundaries of the area within which the pipeline will be constructed and provided that all public notices of the application required under this section note such boundaries and identify the potential area of influence as the total area encompassed by the area of influence associated with all possible pipeline routes.

(10) Sour gas pipeline facility--A pipeline and ancillary equipment that:

(A) contains a concentration of 100 parts per million or more of hydrogen sulfide;

(B) is located outside the tract of production; and

(C) is subject to the requirements of §3.36 of this title.

(11) Tract of production--The surface area which overlies the area encompassed by a mineral lease or unit from which oil, gas, or other minerals are produced if such area is treated by the Oil and Gas Division of the commission as a single tract.

(12) 100 ppm radius--The 100 parts per million radius of exposure as calculated in §3.36(c)(1) - (3) of this title (relating to oil, gas, or geothermal resource operation in hydrogen sulfide areas) for the sour gas pipeline facility.

(b) Permit Required; Exceptions. No person may commence construction of a facility within this State without a permit if the facility is initially used as a sour gas pipeline facility except for the following:

(1) an extension of an existing sour gas pipeline facility that at the time of construction of the extension is in compliance with §3.36 of this title (relating to oil, gas, or geothermal resource operation in a hydrogen sulfide area) if:

(A) the extension is not longer than five miles;

(B) the nominal pipe size is not larger than six inches; and

(C) the operator causes to be delivered to the Safety Division written notice of construction of the extension not later than 24 hours before the start of construction;

(2) a new gathering system that operates at a working pressure of less than 50 pounds per square inch gauge;

(3) an extension of a gathering system which operates at a working pressure of less than 50 pounds per square inch gauge;

(4) an interstate gas pipeline facility, as defined by 49 U.S.C. §60101, that is used for the transportation of sour gas; or

(5) replacement of all or part of a sour gas pipeline facility if the area of influence of the replaced portion of the facility does not increase so as to include a public area, as defined in §3.36(b)(5) of this title, not included in the area of influence of the portion of the replaced sour gas pipeline facility.

(c) Filing and Assignment of Docket Number. Upon filing of an application with the Oil and Gas Division, staff will assign a docket number to the application and will notify the applicant of the assigned docket number. Staff will also assign and provide a docket number to a person who submits a notice of intent to file an application.

(d) Application. A complete application consists of:

(1) a properly completed application Form PS-79, with the original signature, in ink, of the applicant;

(2) if applicant desires notification under subsection (h)(1) by electronic mail, a written request for electronic mail notification and the applicant's electronic mail address;

(3) a plat which meets the requirements of subsection (f)(4) of this section and identifies the boundaries of surveys and blocks or sections as appropriate within the area of influence;

(4) a copy of the applicant's Application for Permit to Operate a Pipeline, Form T-4, if applicable, including all attachments; and

(5) a copy of the completed application for a Statewide Rule 36 Certificate of Compliance, Form H-9, including any attachment required under §3.36 of this title. A preliminary contingency plan may be filed in lieu of a contingency plan if required under §3.36 of this title.

(e) Notice.

(1) For each county that contains all or part of the area of influence of a proposed sour gas pipeline facility, the applicant shall:

(A) cause to be delivered to the county clerk no later than the first date of publication in that county a copy of the items described in subsection (d)(1) - (3) of this section;

(B) publish notice of its application in a newspaper of general circulation in each county that contains all or a portion of the area of influence of the proposed sour gas pipeline facility. Such notice shall meet the requirements of subsection (f) of this section and be published in a section of the newspaper containing news items of state or local interest.

(2) Final action may not be taken on any application under this section until proof of notice, evidenced as follows, is provided:

(A) a return receipt from each county clerk with whom an application form and plat is required to be filed pursuant to paragraph (1) of this subsection; and

(B) the full page or pages of the newspaper containing the published notice required under paragraph (2) of this subsection including the name of the paper, the date the notice was published, and the page number.

(f) The published notice of application shall be at least three inches by five inches in size, exclusive of the plat, and shall contain the following:

(1) the name, business address, and telephone number of the applicant and of the applicant's authorized representative, if any;

(2) a description of the geographic location of the sour gas pipeline facility and the area of influence, to the extent not clearly identified in the plat required to be published in subsection (f)(4) of this section;

(3) the following statement, completed as appropriate: "This proposed pipeline facility will transport sour gas that contains 100 parts per million, or more, of hydrogen sulfide. A copy of application forms and a map showing the location of the pipeline is available for public inspection at the offices of the (insert County name) County Clerk, located at the following address: (insert address of County Clerk). Any owner or occupant of land located within the area of influence of the proposed sour gas pipeline facility desiring to protest this application can do so by mailing or otherwise delivering a letter referring to the application (by docket number if available) and stating their desire to protest to: Docket Services, Office of General Counsel, Railroad Commission of Texas, P.O. Box 12967, Austin, Texas 78711-2967. Protests shall be in writing and received by Docket Services not later than (specify 30th day after the first date notice of the application is to be published). The letter shall include the name, address, and telephone number of every person on whose behalf the protest is filed and shall state the reasons each such person believes that he or she is the owner or occupant of property within the area of influence of the proposed pipeline facility. It is recommended that a copy of this notice be included with the letter."; and

(4) a plat identifying:

(A) the location of the pipeline facility;

(B) area of influence;

(C) north arrow;

(D) scale;

(E) geographic subdivisions appropriate for the scale; and

(F) by inset or otherwise, landmarks or other features such as roads and highways in relation to the proposed route of the sour gas pipeline facility. These landmarks or other features shall be of sufficient detail to allow a person to reasonably ascertain whether an owned or occupied property that is within the area of influence of the proposed sour gas pipeline facility. Examples of acceptable plats are included in this subsection.

Attached Graphic

(g) Protests. Affected persons have standing to file a protest to an application. In the event the final proposed pipeline route is not known at the time of application, any person who owns or occupies real property located within the area of influence identified in the application shall have standing to file a protest to an application. All such protests shall:

(1) be in writing and filed at the commission no later than the 30th day after the notice is published in a newspaper in the county in which the person filing the protest owns or occupies real property;

(2) state the name, address, and telephone number of every person on whose behalf the protest is being filed; and

(3) include a statement of the facts on which the person filing the protest relies to conclude that each person on whose behalf the protest is being filed is an affected person, as defined in subsection (a)(1) of this section.

(h) Division Review.

(1) Within 14 days of receipt of the application, the commission's designee will provide notice to the applicant that the application is either complete and accepted for filing, or incomplete and specify the additional information required for acceptance. Such notice shall be provided in writing by mail or by electronic mail if the applicant submits with the application a written request that communications regarding application completeness or deficiencies be communicated by electronic mail and provides an accurate electronic mail address. The application shall be completed within 30 days of notification that the application is incomplete or such longer time as may be requested by the applicant, in writing, and approved by the commission's designee. If the application is not completed within the specified time period, the commission's designee shall send notice of intent to deny the application to the applicant. Within ten days of issuance of a notice of intent to deny the application for failure to complete the application, the applicant may request a hearing on the application as it exists at that time. If a request for hearing is not filed within ten days of issuance of a notice of intent to deny the application for failure to complete the application, the application shall be Cont'd...

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Appendix F – Utah Regulatory Summary (General)

Utah Division of Oil, Gas, and Mining

R649. Natural Resources; Oil, Gas and Mining; Oil and Gas.
R649-1. Oil and Gas General Rules.
R649-1-1. Definitions.

"Authorized Agent" means a representative of the director as authorized by the board.

"Aquifer" means a geological formation including a group of formations or part of a formation which is capable of yielding a significant amount of water to a well or spring.

"Artificial Liner" means a pit liner made of material other than clay or other in situ material and which meets the requirements of R649-9-3, Permitting of Disposal Pits.

"Barrel" means 42 (US) gallons at 60 degrees Fahrenheit at atmospheric pressure.

"Board" means the Board of Oil, Gas and Mining.

"Carrier, Transporter or Taker" means any person moving or transporting oil or gas away from a well or lease or from any pool.

"Casing Pressure" means the pressure within the casing or between the casing and tubing at the wellhead.

"Central Disposal Facility" means a facility which is used by one or more producers for disposal of exempt E and P wastes and for which the operator of the facility receives no monetary remuneration, other than operating cost sharing.

"Class II Injection Well" means a well which is used for:

(a) The disposal of fluids which are brought to the surface in connection with conventional oil or natural gas production and which may be commingled with wastewater produced from the operation of a gas plant that is an integral part of production operations, unless that wastewater is classified as a hazardous waste at the time of injection, or

(b) Enhanced recovery of oil or gas, or

(c) Storage of hydrocarbons which are liquids at standard temperature and pressure conditions.

"Closed System" means but is not limited to, the use of a combination of solids control equipment (i.e., shale shakers, flowline cleaners, desanders, desilters, mud cleaners, centrifuges, agitators, and necessary pumps and piping) incorporated in a series on the rig's steel mud tanks, or a self contained unit that eliminates the use of a reserve pit for the purpose of dumping and dilution of drilling fluids for the removal of entrained drill solids. A closed system for the purpose of these rules may with Division approval include the use of a small pit to receive cuttings, but does not include the use of trenches for the collection of fluids of any kind.

"Coalbed Methane" means natural gas that is produced, or may be produced, from coalbeds and rock strata associated with the coalbed.

"Commercial Disposal Facility" means a disposal well, pit or treatment facility whose owner(s) or operator(s) receives compensation from others for the temporary storage, treatment, and disposal of produced water, drilling fluids, drill cuttings, completion fluids, and any other exempt E and P wastes, and whose primary business objective is to provide these services.

"Completion of a Well" means that the well has been adequately worked to be capable of producing oil or gas or that well testing as required by the division has been concluded.

"Confining Strata" refers to a body of material that is relatively impervious to the passage of liquids or gases and that occurs either below, above, or lateral to a more permeable material in such a way that it confines or limits the movement of liquids or gases that may be present.

"Correlative Rights" means the opportunity of each owner in a pool to produce his just and equitable share of the oil and gas in the pool without waste.

"Cubic Foot" of gas means the volume of gas contained in one cubic foot of space at a standard pressure base of 14.73 psia and a standard temperature base of 60 degrees Fahrenheit.

"Day" means a period of 24 consecutive hours.

"Development Wells" means all oil and gas producing wells other than wildcat wells.

"Director" means the executive and administrative head of the division.

"Disposal Facility" means an injection well, pit, treatment facility or combination thereof which receives E and P Wastes for the purpose of disposal. This includes both commercial and noncommercial facilities.

"Disposal Pit" means a lined or unlined pit approved for the disposal and/or storage of E and P Wastes.

"Division" means the Division of Oil, Gas and Mining.

"Drilling Fluid" means a circulating fluid usually called mud, which is introduced in a drill hole to lubricate the action of the rotary bit, remove the drilling cuttings, and control formation pressures.

"E and P Waste" means those wastes resulting from the drilling of and production from oil and gas wells as determined by the Environmental Protection Agency (EPA), prior to January 1, 1992, to be exempt from Subtitle C of the Resource Conservation and Recovery Act (RCRA).

"Emergency Pit" means a pit used for containing fluids at an operating well during an actual emergency or for a temporary period of time.

"Enhanced Recovery" means the process of introducing fluid or energy into a pool for the purpose of increasing the recovery of hydrocarbons from the pool.

"Enhanced Recovery Project" means the injection of liquids or hydrocarbon or nonhydrocarbon gases directly into a reservoir for the purpose of augmenting reservoir energy, modifying the properties of the fluids or gases in the reservoir, or changing the reservoir conditions to increase the recoverable oil, gas, or oil and gas through the joint use of two or more well bores.

"Entity" means a well or a group of wells that have identical division of interest, have the same operator, produce from the same formation, have product sales from a common tank, LACT meter, gas meter, or are in the same participating area of a properly designated unit. Entity number assignments are made by the division in cooperation with the Division of State Lands and

Forestry and the State Tax Commission.

"Field" means the general area underlaid by one or more pools.

"Gas" means natural gas or natural gas liquids or other gas or any mixture thereof defined as follows:

"Natural Gas" means those hydrocarbons, other than oil and other than natural gas liquids separated from natural gas, that occur naturally in the gaseous phase in the reservoir and are produced and recovered at the wellhead in gaseous form. Natural gas includes coalbed methane.

"Other Gas" means hydrogen sulfide, carbon dioxide, helium, nitrogen, and other nonhydrocarbon gases that occur naturally in the gaseous phase in the reservoir or are injected into the reservoir in connection with pressure maintenance, gas cycling, or other secondary or enhanced recovery projects.

"Natural Gas Liquids" means those hydrocarbons initially in reservoir natural gas, regardless of gravity, that are separated in gas processing plants from the natural gas as liquids at the surface through the process of condensation, absorption, adsorption, or other methods.

"Gas-Oil Ratio" means the ratio of the number of cubic feet of natural gas produced to the number of barrels of oil concurrently produced during any stated period. The term GOR is synonymous with gas-oil ratio.

"Gas Processing Plant" means a facility in which liquefiable hydrocarbons are removed from natural gas, including wet gas or casinghead gas, and the remaining residue gas is conditioned for delivery for sale, recycling or other use.

"Gas Well" means any well capable of producing gas in substantial quantities that is not an oil well.

"Ground Water" means water in a zone of saturation below the ground surface.

"Hearing" means any matter heard before the board or its designated hearing examiner.

"Horizontal Well" means a well bore drilled laterally at an angle of at least eighty (80) degrees to the vertical or with a horizontal projection exceeding one hundred (100) feet measured from the initial point of penetration into the productive formation through the terminus of the lateral in the same common source of supply.

"Illegal Oil or Illegal Gas" means oil or gas that has been produced from any well within the state in violation of Chapter 6 of Title 40, or any rule or order of the board.

"Illegal Product" means any product derived in whole or in part from illegal oil or illegal gas.

"Incremental Production" means that part of production which is achieved from an enhanced recovery project that would not have economically occurred under the reservoir conditions existing before the project and that has been approved by the division as incremental production.

"Injection or Disposal Well" means any Class II Injection Well used for the injection of air, gas, water or other substance into any underground stratum.

"Interest Owner" means a person owning an interest (working interest, royalty interest, payment out of production, or any other interest) in oil or gas, or in the proceeds thereof.

"Load Oil" means any oil or liquid hydrocarbon which is used in any remedial operation in an oil or gas well.

"Log or Well Log" means the written record progressively describing the strata, water, oil or gas encountered in drilling a well with such additional information as is usually recorded in the normal procedure of drilling including electrical, radioactivity, or other similar conventional logs, a lithologic description of samples and drill stem test information.

"Multiple Zone Completion" means a well completion in which two or more separate zones, mechanically segregated one from the other, are produced simultaneously from the same well.

"Oil" means crude oil or condensate or any mixture thereof, defined as follows:

"Crude Oil" means those hydrocarbons, regardless of gravity, that occur naturally in the liquid phase in the reservoir and are produced and recovered at the wellhead in liquid form.

"Condensate" means those hydrocarbons, regardless of gravity, that occur naturally in the gaseous phase in the reservoir that are separated from the natural gas as liquids through the process of condensation either in the reservoir, in the well bore or at the surface in field separators.

"Oil and Gas" shall not include gaseous or liquid substances derived from coal, oil shale, tar sands or other hydrocarbons classified as synthetic fuel.

"Oil and Gas Field" means a geographical area overlying an oil and gas pool.

"Oil Well" means any well capable of producing oil in substantial quantities.

"Operator or Designated Agent" means the person who has been designated by the owners or the board to operate a well or unit.

"Owner" means the person who has the right to drill into and produce from a reservoir and to appropriate the oil and gas that he produces, either for himself or for himself and others.

"Person" means and includes any natural person, bodies politic and corporate, partnerships, associations and companies.

"Pit" means an earthen surface impoundment constructed to retain fluids and oil field wastes.

"Pollution" means such contamination or other alteration of the physical, chemical or biological properties of any waters of the state, or the discharge of any liquid, gaseous or solid substance into any waters of the state in such manner as will create a nuisance or render such waters harmful, detrimental or injurious to the public health, safety or welfare; to domestic, commercial, industrial, agricultural, recreational, or other legitimate beneficial uses; or to livestock, wild animals, birds, fish or other aquatic life.

"Pool" means an underground reservoir containing a common accumulation of oil or gas or both. Each zone of a general structure that is completely separated from any other zone in the structure is a separate pool. "Common source of supply" and "reservoir" are synonymous with "pool."

"Pressure Maintenance" means the injection of gas, water or other fluids into a reservoir, either to increase or maintain the existing pressure in such reservoir or to retard the natural decline in the reservoir pressure.

"Produced Water" means water produced in conjunction with the conventional production of oil and/or gas.

"Producer" means the owner or operator of a well capable of producing oil or gas.

"Producing Well" means a well capable of producing oil or gas.

"Product" means any commodity made from oil and gas.

"Production Facilities" means all storage, separation, treating, dehydration, artificial lift, power supply, compression, pumping, metering, monitoring, flowline, and other equipment directly associated with oil wells, gas wells or injection wells, prior to any processing plant or refinery.

"Purchaser or Transporter" means any person who, acting alone or jointly with any other person, by means of his own, an affiliated, or designated carrier, transporter or taker, shall directly or indirectly purchase, take or transport by any means whatsoever, or who shall otherwise remove from any well or lease, oil or gas produced from any pool, excepting royalty portions of oil or gas taken in kind by an interest owner who is not the operator.

"Recompletion" means any completion in a new perforated interval or pool within an established wellbore and approved as a recompletion by the division.

"Refinery" means a facility, other than a gas processing plant, where controlled operations are performed by which the physical and chemical characteristics of petroleum or petroleum products are changed.

"Reserve Pit" means a pit used to retain fluid during the drilling, completion, and testing of a well.

"Seismic Operator" means a person who conducts seismic exploration for oil or gas, whether for himself or as a contractor for others.

"Shut-in Well" means a well that is completed, is shown to be capable of production in paying quantities, and is not presently being operated.

"Spud In" means the first boring of a hole in the drilling of a well by any type of rig.

"State" means the State of Utah.

"Stratigraphic Test or Core Hole" means any hole drilled for the sole purpose of obtaining geological information. The general rules applicable to the drilling of a well will apply to the drilling of a stratigraphic test or core hole.

"Temporarily Abandoned Well" means a well that is completed, is not shown capable of production in paying quantities, and is not presently being operated.

"Temporary Spacing Unit" means a specified area of land designated by the board for purposes of determining well density and location. A temporary spacing unit shall not be a drilling unit as provided for in U.C.A. 40-6-6, Drilling Units, and does not provide a basis for pooling the interest therein as does a drilling unit.

"Underground Source of Drinking Water" means a fresh water aquifer or a portion thereof that supplies drinking water for human consumption or that contains less than 10,000 mg/1 total dissolved solids and that is not an exempted aquifer under R649-5-4.

"Waste" means:

The inefficient, excessive or improper use or the unnecessary dissipation of oil or gas or reservoir energy.

The inefficient storing of oil or gas.

The locating, drilling, equipping, operating, or producing of any oil or gas well in a manner that causes reduction in the quantity of oil or gas ultimately recoverable from a reservoir under prudent and economical operations, or that causes unnecessary wells to be drilled, or that causes the loss or destruction of oil or gas either at the surface or subsurface.

The production of oil or gas in excess of:

Transportation or storage facilities.

The amount reasonably required to be produced in the proper drilling, completing, testing, or operating of a well or otherwise utilized on the lease from which it is produced.

Underground or above ground waste in the production or storage of oil or gas.

"Waste Crude Oil Treatment Facility" means any facility or site constructed or used for the purpose of wholly or partially reclaiming, treating, processing, cleaning, purifying or in any manner making nonmerchantable waste crude oil marketable.

"Well" means an oil or gas well, injection or disposal well, or a hole drilled for the purpose of producing oil or gas or both. The definition of well shall not include water wells, or seismic, stratigraphic test, core hole, or other exploratory holes drilled for the purpose of obtaining geological information only.

"Well Site" means the areas which are directly disturbed during the drilling and subsequent use of, or affected by production facilities directly associated with any oil well, gas well or injection well.

"Wildcat Wells" means oil and gas producing wells which are drilled and completed in a pool in which a well has not been previously completed as a well capable of producing in commercial quantities.

"Working Interest Owner" means the owner of an interest in oil or gas burdened with a share of the expenses of developing and operating the property.

"Workover" means any operation designed to sustain, to restore, or to increase the production rate, the ultimate recovery, or the reservoir pressure system of a well or group of wells and approved as a workover, a secondary recovery, a tertiary recovery, or a pressure maintenance project by the division. The definition shall not include operations which are conducted principally as routine maintenance or the replacement of worn or damaged equipment.

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June 2, 1998 **40-6-1 et seq.**
Notice of Continuation March 26, 2002

R649. Natural Resources; Oil, Gas and Mining; Oil and Gas.

R649-2. General Rules.

R649-2-1. Scope of Rules.

The following general rules adopted by the board pursuant to Chapter 6 of Title 40 shall apply to all lands in the state in order to conserve the natural resources of oil and gas in the state, to protect human health and the environment, to prevent waste, to protect the correlative rights of all owners and to realize the greatest ultimate recovery of oil and gas. Special rules and orders have been and will be issued by the board when required and shall prevail as against the general rules and orders of the board if in conflict therewith. Exceptions to the general rules may also be granted by the director or authorized agent for good cause shown and shall prevail as against the general rules. No exceptions granted by the board, director, or authorized agent to the rules applicable to the Underground Injection Control Program will be effective without the consent of the federal Environmental Protection Agency.

R649-2-2. Application Of Rules To Lands Owned Or Controlled By The United States.

These general rules shall apply to all lands in the state including lands of the United States and lands subject to the jurisdiction of the United States to the extent lawfully subject to the state's power.

R649-2-3. Application Of Rules To Unit Agreements.

The board may suspend the application of the general rules or orders or any part thereof, with regard to any unit agreement approved by a duly authorized officer of the appropriate federal agency, so long as the conservation of oil or gas and the prevention of waste is accomplished thereby, but such suspension shall not relieve any operator from making such reports as are otherwise required by the general rules or orders, or as may reasonably be requested by the board or the division in order to keep the board and the division fully informed as to operations under such unit agreements.

R649-2-4. Designation Of Agent Or Operator.

A designation of agent or operator shall be submitted to the division prior to the commencement of operations. A designation of agent or operator will, for purposes of the general rules and orders, be accepted as evidence of authority of agent to fulfill the obligations of the owner, to sign any required documents or reports on behalf of the owner, and to receive all authorized orders or notices given by the board or the division. All changes of address and any termination of the designated agent's or operator's authority shall be promptly reported in writing to the division, and in the latter case a designation of a new agent or operator shall be promptly made.

R649-2-5. Right To Inspect.

1. The director or authorized agent shall have the right at

all reasonable times to go upon and inspect any oil or gas properties and wells for the purpose of making any investigations or tests reasonably necessary to ensure compliance with the provisions of the statutes, the general rules and orders of the board or any special field rules and orders. The director or authorized agent shall report any observed violation to the board.

2. The documentation of off lease transportation of crude oil required by R649-2-6, Access to Records, shall be carried in the motor vehicle during transportation and shall be available for examination and inspection by the director or an authorized agent upon request.

R649-2-6. Access To Records.

1. Any person who produces, operates, sells, purchases, acquires, stores, transports, refines, or processes oil or gas or who injects fluids for cycling, pressure maintenance, secondary or enhanced recovery, or disposal of salt water or oil field waste within the state, shall make and keep appropriate books and records covering his operations in the state from which he shall be able to make and substantiate all reports required by the board or the division. Such books and records, together with copies of all reports and notices submitted to the board or the division shall be kept on file and available for inspection by the director or an authorized agent at all reasonable times for a period of at least six years. The director or the authorized agent shall also have access to all pertinent well records wherever located.

2. Each owner or operator shall permit the director or authorized agent at his sole risk and expense, in the absence of negligence on the part of the owner or operator, to come upon any lease, property or well operated or controlled by him; to inspect the records pertaining to and the manner of operation of such property or well; and to have access at all reasonable times to any and all records pertaining to such well. All information so obtained by the director or authorized agent shall be kept confidential and shall be reported only to the division or its authorized agent, unless the owner or operator gives written permission to the director to release such information.

3. All off lease transportation of oil by motor vehicle shall be accompanied by a run ticket or equivalent document. The documentation shall identify the name and address of the transporter, the name of the operator, the lease or facility from which the oil was taken, the date of removal, the API gravity of the oil, the calculated percentage of BS and W, the volume of oil or the opening and closing tank gauges or meter readings, and the destination of the oil.

R649-2-7. Naming of Oil and Gas Fields or Pools.

The division shall name oil and gas fields or pools within the state in cooperation with a Fields Names Advisory Committee and with due regard and consideration for any recommendation from the owners or operators of such fields or pools. The Field Names Advisory Committee shall be composed of a representative of the United States Bureau of Land Management and representatives of appropriate state agencies and the oil and gas industry.

R649-2-8. Measurement of Production.

1. The volume of oil production shall be computed in barrels of clean oil on the basis of acceptable meter measurements, tank measurements, or with such greater accuracy as may be required by the division. Computations of the volume of oil production shall be subject to the following corrections:

1.1. The gross volume of oil shall be corrected to exclude the entire volume of impurities not constituting a natural component part of the oil.

1.2. The observed volume of oil after correction for impurities shall be further corrected to the standard volume at 60 degrees Fahrenheit, in accordance with Table 6A of the API/ASTM D-1250, Chapter 11.1, Manual of Petroleum Measurement (1980), or any revisions or supplements, or any alternative publication or tables approved by the division.

1.3. The observed gravity of oil shall be corrected to the standard API gravity at 60 degrees Fahrenheit in accordance with Table 5A of API/ASTM, D-1250, Chapter 11.1, Manual of Petroleum Measurement (1980), or any revisions or supplements, or any alternative publication or tables approved by the division.

2. All gas shall be measured by an orifice type meter unless otherwise authorized by the division. In computing the volumes of all gas produced, sold, or injected, the standard pressure base shall be 14.73 pounds per square inch absolute (psia), and the standard temperature base shall be 60 degrees Fahrenheit. All measurements of gas shall be adjusted by computation to these standards, regardless of the pressure and temperature at which the gas was actually measured, unless otherwise authorized by the division.

R649-2-9. Refusal To Agree.

1. An owner shall be deemed to have refused to agree to bear his proportionate share of the costs of the drilling and operation of a well under Section 40-6-6(6) if:

1.1. The operator of the proposed well has, in good faith, attempted to reach agreement with such owner for the leasing of the owner's mineral interest or for that owner's voluntary participation in the drilling of the well.

1.2. The owner and the operator have been unable to agree upon terms for the leasing of the owner's interest or for the owner's participation in the drilling of the well.

2. If the operator of the proposed well shall fail to attempt, in good faith, to reach agreement with the owner for the leasing of that owner's mineral interest or for voluntary participation by that owner in the well prior to the filing of a Request for Agency Action for involuntary pooling of interests in the drilling unit under Section 40-6-6(6) then, upon written request and after notice and hearing, the hearing on the Request for Agency Action for involuntary pooling may, at the discretion of the board or its designated hearing examiner, be delayed for a period not to exceed 30 days, to allow for negotiations between the operator and the owner.

R649-2-10. Notification of Lease Sale or Transfer.

The owner of a lease shall provide notification to any person with an interest in such lease, when all or part of that interest in the lease is sold or transferred.

R649-2-11. Confidentiality Of Well Log Information.

1. Well logs marked confidential shall be kept confidential for one year after the date on which the log is required to be filed with the division, unless the operator gives written permission to release the log at an earlier date.

2. Information on a newly permitted well will be held confidential only upon receipt by the division of a written request from the owner or operator.

3. The period of confidentiality may begin at the time the APD is submitted for approval if a request for confidentiality is received at that time, although the information on the application itself will not be considered confidential.

4. Information which shall be held confidential includes well logs, electrical or radioactivity logs, electromagnetic, electrical, or magnetic surveys, core descriptions and analysis, maps, other geological, geophysical, and engineering information, and well completion reports which contain such information.

5. The owner or operator shall clearly mark documents as confidential. Such marking shall be in red to be clearly visible.

6. Confidential wells or information shall be reported separately from wells or information that is not in confidential status.

R649-2-12. Tests and Surveys.

When deemed necessary or advisable the Director or authorized agent is authorized to require that test or surveys be made to determine the presence of waste or oil, gas, water, or reservoir energy; the quantity of oil, gas or water; the amount and direction of deviation of any well from the vertical; formation, casing, tubing, or other pressures; or any other test or survey deemed necessary to carry out the purposes of the Oil and Gas Conservation Act. Directional, deviation, and/or measurements-while-drilling (MWD) surveys must be run on horizontal wells and submitted in accordance with R649-3-21, Well Completion and Filing of Well Logs, as amended for horizontal wells.

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R649. Natural Resources; Oil, Gas and Mining; Oil and Gas.
R649-3. Drilling and Operating Practices.
R649-3-1. Bonding.

1. An owner or operator shall furnish a bond to the division prior to approval of a permit to drill a new well, reenter an abandoned well or assume responsibility as operator of existing wells.

1.1. An owner or operator shall furnish a bond to the division on Form 4, for wells located on lands with fee or privately owned minerals.

1.2. An owner or operator shall furnish evidence to the division that a bond has been filed in accordance with state, federal or Indian lease requirements and approved by the appropriate agency for all wells located on state, federal or Indian leases.

2. A bond furnished to the division shall be payable to the division and conditioned upon the faithful performance by the operator of the duty to plug each dry or abandoned well, repair each well causing waste or pollution, and maintain and restore the well site.

3. Bond liability shall be for the duration of the drilling, operating and plugging of the well and restoration of the well site.

3.1. The bond for drilling or operating wells shall remain in full force and effect until liability thereunder is released by the division.

3.2. Release of liability shall be conditioned upon compliance with the rules and orders of the Board.

4. For all drilling or operating wells, the bond amounts for individual wells and blanket bonds required in subsections 5. and 6. represent base amounts adjusted to year 2002 average costs for well plugging and site restoration. The base amounts are effective immediately upon adoption of this bonding rule, subject to division notification as described in subsection 4.1.

4.1. The division shall provide written notification to each operator of the need to revise or establish bonds in amounts required by this bonding rule. Within 120 days of such notification by the division, the operator shall post a bond with the division in compliance with this bonding rule.

4.2. If the division finds that a well subject to this bonding rule is in violation of Rule R649-3-36., Shut-in and Temporarily Abandoned Wells, the division shall require a bond amount for the applicable well in the amount of actual plugging and site restoration costs.

4.3. The division shall provide written notification to an operator found in violation of Rule R649-3-36., and identify the need to establish increased bonding for shut-in wells. Within 30 days of notification by the division, the operator shall submit to the division an estimate of plugging and site restoration costs for division review and approval. Upon review and approval of the cost estimate, the division will provide a notice of approval back to the operator specifying the approved bond amount for shut-in wells. Within 120 days of receiving such notice of approval, the operator shall post a bond with the division in compliance with this bonding rule.

5. The bond amount for drilling or operating wells located on lands with fee or privately owned minerals shall be one of the following:

5.1. For wells of less than 1,000 feet in depth, an individual well bond in the amount of at least $1,500, for each such well.

5.2. For wells of more that 1,000 feet in depth but less than 3,000 feet in depth, an individual well bond in the amount of at least $15,000 for each such well.

5.3. For wells of more that 3,000 feet in depth but less than 10,000 feet in depth, an individual well bond in the amount of at least $30,000 for each such well.

5.4. For wells of more than 10,000 feet in depth, an individual well bond in the amount of at least $60,000 for each such well.

6. If, prior to the January 1, 2003 revision of this bonding rule, an operator is drilling or operating more than one well on lands with fee or privately owned minerals, and a blanket bond was furnished and accepted by the division in lieu of individual well bonds, that operator shall remain qualified for a blanket bond with the division subject to the amounts described by this bonding rule.

6.1. A blanket bond shall be conditioned in a manner similar to individual well bonds and shall cover all wells that the operator may drill or operate on lands with fee or privately owned minerals within the state.

6.2. For wells of less than 1,000 feet in depth, a blanket bond in the amount of at least $15,000 shall be required.

6.3. For wells of more than 1,000 feet in depth, a blanket bond in the amount of at least $120,000 shall be required.

6.4. Subsequent to the January 1, 2003 revision of this rule, operators who desire to establish a new blanket bond that consists either fully or partially of a collateral bond as described in subsection 10.2. shall be qualified by the division for such blanket bond. Operators who elect to establish a surety bond as a blanket bond shall not require qualification by the division. In those cases where operator qualification for blanket bond is required, the division will review the following criteria and make a written finding of the operator's adequacy to meet the criteria before accepting a new blanket bond:

6.4.1. The ratio of current assets to current liabilities shall be 1.20 or greater, as evidenced by audited financial statements for the previous two years and the most current quarterly financial report.

6.4.2. The ratio of total liabilities to stockholder's equity shall be 2.50 or less, as evidenced by audited financial statements for the previous two years and the most current quarterly financial report.

7. If an operator desires bond coverage in a lesser amount than required by these rules, the operator may file a Request for Agency Action with the Board for a variance from the requirements of these rules.

7.1. Upon proper notice and hearing and for good cause shown, the Board may allow bond coverage in a lesser amount for specific wells.

8. If after reviewing an application to drill or reenter a well or when reviewing a change of operator for a well, the division determines that bond coverage in accordance with these rules will be insufficient to cover the costs of plugging the well and restoring the well site, the division may require a change in the form or the amount of bond coverage. In such cases, the

division will support its case for a change of bond coverage in the form of written findings to the operator of record of the well and provide a schedule for completion of the requisite changes.

8.1 Appeals of mandated bond amount changes will follow procedures established by Rule R649-10., Administrative Procedures.

9. The bond shall provide a mechanism for the surety or other guarantor of the bond, to provide prompt notice to the division and the operator of any action alleging the insolvency or bankruptcy of the surety or guarantor, or alleging any violations which would result in suspension or revocation of the surety's or guarantor's charter or license to do business.

9.1. Upon the incapacity of the surety or guarantor to guarantee payment of the bond by reason of bankruptcy, insolvency, or suspension or revocation of a charter or license, the operator shall be deemed to be without bond coverage.

9.2. Upon notification of insolvency or bankruptcy, the division shall notify the operator in writing and shall specify a reasonable period, not to exceed 90 days, to provide bond coverage.

9.3. If an adequate bond is not furnished within the allowed period, the operator shall be required to cease operations immediately, and shall not resume operations until the division has received an acceptable bond.

10. The division shall accept a bond in the form of a surety bond, a collateral bond or a combination of these bonding methods.

10.1. A surety bond is an indemnity agreement in a sum certain payable to the division, executed by the operator as principal and which is supported by the performance guarantee of a corporation authorized to do business as a surety in Utah.

10.1.1. A surety bond shall be executed by the operator and a corporate surety authorized to do business in Utah that is listed in "A.M. Best's Key Rating Guide" at a rating of A- or better or a Financial Performance Rating (FPR) of 8 or better, according to the "A.M. Best's Guide". All surety companies also will be continuously listed in the current issue of the U.S. Department of the Treasury Circular 570. Operators who do not have a surety bond with a company that meets the standards of subsection 10.1.1. will have 120 days from the date of division notification after enactment of the changes to subsection 10.1.1., or face enforcement action. When the division in the course of examining surety bonds notifies an operator that a surety company guaranteeing its performance does not meet the standards of subsection 10.1.1., the operator has 120 days after notice from the division by mail to correct the deficiency, or face enforcement action.

10.1.2. Surety bonds shall be noncancellable during their terms, except that surety bond coverage for wells not drilled may be canceled with the prior consent of the division.

10.1.3. The division shall advise the surety, within 30 days after receipt of a notice to cancel a bond, whether the bond may be canceled on an undrilled well.

10.2. A collateral bond is an indemnity agreement in a sum certain payable to the division, executed by the operator which is supported by one or more of the following:

10.2.1. A cash account.

10.2.1.1. The operator may deposit cash in one or more accounts at a federally insured bank authorized to do business in Utah, made payable upon demand only to the division.

10.2.1.2. The operator may deposit the required amount directly with the division.

10.2.1.3. Any interest paid on a cash account shall be retained in the account and applied to the bond value of the account unless the division has approved the payment of interest to the operator.

10.2.1.4. The division shall not accept an individual cash account in an amount in excess of $100,000 or the maximum insurable amount as determined by the Federal Deposit Insurance Corporation.

10.2.2. Negotiable bonds of the United States, a state, or a municipality.

10.2.2.1. The negotiable bond shall be endorsed only to the order of and placed in the possession of the division.

10.2.2.2. The division shall value the negotiable bond at its current market value, not at face value.

10.2.3. Negotiable certificates of deposit.

10.2.3.1. The certificates shall be issued by a federally insured bank authorized to do business in Utah.

10.2.3.2. The certificates shall be made payable or assigned only to the division both in writing and upon the records of the bank issuing the certificate.

10.2.3.3. The certificates shall be placed in the possession of the division or held by a federally insured bank authorized to do business in Utah.

10.2.3.4. If assigned, the division shall require the banks issuing the certificates to waive all rights of setoff or liens against those certificates.

10.2.3.5. The division shall not accept an individual certificate of deposit in an amount in excess of $100,000 or the maximum insurable amount as determined by the Federal Deposit Insurance Corporation.

10.2.4. An irrevocable letter of credit.

10.2.4.1. Letters of credit shall be placed in the possession of and payable upon demand only to the division.

10.2.4.2. Letters of credit shall be issued by a federally insured bank authorized to do business in Utah.

10.2.4.3. Letters of credit shall be irrevocable during their terms.

10.2.4.4. Letters of credit shall be automatically renewable or the operator shall ensure continuous bond coverage by replacing letters of credit, if necessary, at least 30 days before their expiration date with other acceptable bond types or letters of credit.

11. The required bond amount specified in subsections 5. and 6. of all collateral posted as assurance under this section shall be subject to a margin determined by the division which is the ratio of the face value of the collateral to market value, as determined by the division.

11.1. The margin shall reflect legal and liquidation fees, as well as value depreciation, marketability and fluctuations which might affect the net cash available to the division to complete plugging and restoration.

12. The market value of collateral may be evaluated at any time, and in no case shall the market value of collateral be less than the required bond amount specified in subsections 5. and 6.

12.1. Upon evaluation of the market value of collateral by the division, the division will notify the operator of any required changes in the amount of the bond and shall allow a reasonable period, not to exceed 90 days, for the operator to establish acceptable bond coverage.

12.2. If an adequate bond is not furnished within the allowed period the operator shall be required to cease operations immediately and shall not resume operations until the division has received an acceptable bond.

13. Persons with an interest in collateral posted as a bond, and who desire notification of actions pursuant to the bond, shall request the notification in writing from the division at the time collateral is offered.

14. The division may allow the operator to replace existing bonds with other bonds that provide sufficient coverage.

14.1. Replacement of a bond pursuant to this section shall not constitute a release of bond under subsection 15.

14.2. The division shall not allow liability to cease under an existing bond until the operator has furnished, and the division has approved, an acceptable replacement bond.

14.3. When the operator of wells covered by a blanket bond changes, the division will review the financial eligibility of a new operator for blanket bonding as described in subsection 6.4., and the division will make a written finding concerning the applicability of blanket bonding to the prospective new operator.

14.4. Transfer of the ownership of property does not cancel liability under an existing bond until the division reviews and approves a change of operator for any wells affected by the transfer of ownership.

14.5. If a transfer of the ownership of property is made and an operator wishes to request a change to a new operator of record for the affected wells, then the following requirements shall be met:

14.5.1. The operator shall notify the division in writing when ownership of any well associated with the property has been transferred to a named transferee, and the operator shall request a change of operator for the affected wells.

14.5.2. The request shall describe each well by reference to its well name and number, API number, and its location, as described by the section, township, range, and county,and shall also include a proposed effective date for the operator change.

14.5.3. The request shall contain the endorsement of the new operator accepting such change of operator.

14.5.4. The request shall contain evidence of the new operator's bond coverage.

14.5.5. The request may include a request to cancel liability for the well(s) included in the operator change that are listed under the existing operator's bond upon approval by the division of an adequate replacement bond in the name of the new operator.

14.6. Upon receipt of a request for change of operator, the division will review the proposed new operator's bond coverage, and if bond coverage is acceptable, the division will issue a notice of approval of the change of operator.

14.6.1. If the division determines that the new operator's bond coverage will be insufficient to cover the costs of plugging and site restoration for the applicable well(s), the division may deny the change of operator, or the division may require a change in the form and amount of the new operator's bond coverage in order to approve the change of operator. In such cases, the division will support its case for a change of the new operator's bond coverage in the form of written findings, and the division will provide a schedule for completion of the requisite changes in order to approve the operator change. The written findings and schedule for changes in bond coverage will be sent to both the operator of record of the applicable well(s) and the proposed new operator.

14.7. If the request for operator change included a request to cancel liability under the existing operator's bond in accordance with subsection 14.5.5., and the division approves the operator change, then the division will issue a notice of approval of termination of liability under the existing bond for the wells included in the operator change. When the division has approved the termination of liability under a bond, the original operator is relieved from the responsibility of plugging or repairing any wells and restoring any well site affected by the operator change.

14.8. If all of the wells covered by a bond are affected by an operator change, the bond may be released by the division in accordance with subsection15.

15. Bond release procedures are as follows:

15.1. Requests for release of a bond held by the division may be submitted by the operator at any time after a subsequent notice of plugging of a well has been submitted to the division or the division has issued a notice of approval of termination of liability for all wells covered by an existing bond.

15.1.1. Within 30 days after a request for bond release has been filed with the division, the operator shall submit signed affidavits from the surface landowner of any previously plugged well site certifying that restoration has been performed as required by the mineral lease and surface agreements.

15.1.2. If such affidavits are not submitted, the division shall conduct an inspection of the well site in preparation for bond release as explained in subsection 15.2.

15.1.3. Within 30 days after a request for bond release has been filed with the division, the division shall publish notice of the request in a daily newspaper of general circulation in the city and county of Salt Lake and in a newspaper of general circulation in the county in which the proposed well is located.

15.1.4. If a written objection to the request for bond release is not received by the division within 15 days after publication of the notice of request, the division may release liability under the bond as an administrative action.

15.1.5. If a written objection to the request for bond release is received by the division within 15 days after publication of the notice of request, the request shall be set for hearing and notice thereof given in accordance with the procedural rules of the Board.

15.2. If affidavits supporting the bond release application are not received by the division in accordance with subsection 15.1.1., the division shall within 30 days or as soon thereafter as weather conditions permit, conduct an inspection and evaluation of the well site to determine if restoration has been adequately performed.

15.2.1. The operator shall be given notice by the division of the date and time of the inspection, and if the operator is unable to attend the inspection at the scheduled date and time, the division may reschedule the inspection to allow the operator to participate.

15.2.2. The surface landowner, agent or lessee shall be given notice by the operator of such inspection and may participate in the inspection; however, if the surface landowner is unable to attend the inspection, the division shall not be required to reschedule the inspection in order to allow the surface landowner to participate.

15.2.3. The evaluation shall consider the adequacy of well site restoration, the degree of difficulty to complete any remaining restoration, whether pollution of surface and subsurface water is occurring, the probability of future occurrence of such pollution, and the estimated cost of abating such pollution.

15.2.4. Upon request of any person with an interest in bond release, the division may arrange with the operator to allow access to the well site or sites for the purpose of gathering information relevant to the bond release.

15.2.5. The division shall retain a record of the inspection and the evaluation, and if necessary and upon written request by an interested party, the division shall provide a copy of the results.

15.3. Within 60 days from the filing of the bond release request, if a public hearing is not held pursuant to subsection 15.1.5., or within 30 days after such public hearing has been held, the division shall provide written notification of the decision to release or not release the bond to the following parties:

15.3.1. The operator.

15.3.2. The surety or other guarantor of the bond.

15.3.3. Other persons with an interest in bond collateral who have requested notification under R649-3-1.13.

15.3.4. The persons who filed objections to the notice of application for bond release.

15.4. If the decision is made to release the bond, the notification specified in subsection 15.3. shall also state the effective date of the bond release.

15.5. If the division disapproves the application for release of the bond or portion thereof, the notification specified in subsection 15.3. shall also state the reasons for disapproval, recommending corrective actions necessary to secure the release, and allowing an opportunity for a public hearing.

15.6. The division shall notify the municipality in which the well is located by certified mail at least 30 days prior to the release of the bond.

16. The following guidelines will govern the Forfeiture of Bonds.

16.1. The division shall take action to forfeit the bond if any of the following occur:

16.1.1. The operator refuses or is unable to conduct plugging and site restoration.

16.1.2. Noncompliance as to the conditions of a permit issued by the division.

16.1.3. The operator defaults on the conditions under which the bond was accepted.

16.2. In the event forfeiture of the bond is necessary, the matter will be considered by the Board.

16.3. For matters of bond forfeiture, the division shall send written notification to the parties identified in subsection 15.3., in addition to the notice requirements of the Board procedural rules.

16.4. After proper notice and hearing, the Board may order the division to do any of the following:

16.4.1. Proceed to collect the forfeited amount as provided by applicable laws for the collection of defaulted bonds or other debts.

16.4.2. Use funds collected from bond forfeiture to complete the plugging and restoration of the well or wells to which bond coverage applies.

16.4.3. Enter into a written agreement with the operator or another party to perform plugging and restoration operations in accordance with a compliance schedule established by the division as long as such party has the ability to perform the necessary work.

16.4.4. Allow a surety to complete the plugging and restoration, if the surety can demonstrate an ability to complete the plugging and restoration.

16.4.5. Any other action the Board deems reasonable and appropriate.

16.5. In the event the amount forfeited is insufficient to pay for the full cost of the plugging and restoration, the division may complete or authorize completion of plugging and restoration and may recover from the operator all costs of plugging and restoration in excess of the amount forfeited.

16.6. In the event the amount of bond forfeited was more than the amount necessary to complete plugging and restoration, the unused funds shall be returned by the division to the party from whom they were collected.

16.7. In the event the bond is forfeited and there exists any unplugged well or wells previously covered under the forfeited bond, then the operator must establish new bond coverage in accordance with these rules.

16.8. If the operator requires new bond coverage under the provisions of subsection 16.7., then the division will notify the operator and specify a reasonable period, not to exceed 90 days, to establish new bond coverage.

R649-3-2. Location And Siting Of Vertical Wells and Statewide Spacing for Horizontal Wells.

1. In the absence of special orders of the board establishing drilling units or authorizing different well density or location patterns for particular pools or parts thereof, each oil and gas well shall be located in the center of a 40 acre quarter-quarter section, or a substantially equivalent lot or tract or combination of lots or tracts as shown by the most recent governmental survey, with a tolerance of 200 feet in any direction from the center location, a "window" 400 feet square. No oil or gas well shall be drilled less than 920 feet from any other well drilling to or capable of producing oil or gas from the same pool, and no oil or gas well shall be completed in a known pool unless it is located more than 920 feet from any other well completed in and capable of producing oil or gas from the same pool.

2. The division shall have the administrative authority to determine the pattern location and siting of wells adjacent to an area for which drilling units have been established or for which a request for agency action to establish drilling units has been filed with the board and adjacent to a unitized area, where there is sufficient evidence to indicate that the particular pool underlying the drilling unit or unitized area may extend beyond the boundary of the drilling unit or unitized area and the uniformity of location patterns is necessary to ensure orderly development of the pool.

3. In the absence of special orders of the Board, no portion of the horizontal interval within the potentially productive formation shall be closer than six hundred-sixty (660) feet to a drilling or spacing unit boundary, federally unitized area boundary, uncommitted tract within a unit, or boundary line of a lease not committed to the drilling of such horizontal well.

4. The surface location for a horizontal well may be anywhere on the lease.

5. Any horizontal interval shall be not closer than one thousand three hundred and twenty (1,320) feet to any vertical well completed in and producing from the same formation. Vertical wells drilled to and completed in the same formation as in a horizontal well are subject to applicable drilling unit orders of the board or the other conditions of this rule which do not specifically pertain to horizontal wells and may be drilled and produced as provided therein.

6. A temporary six hundred and forty (640) acre spacing unit, consisting of the governmental section in which the horizontal well is located, is established for the orderly development of the anticipated pool.

7. In addition to any other notice required by the statute or these rules, notice of the Application for Permit to Drill for a horizontal well shall be given by certified mail to all owners within the boundaries of the designated temporary spacing unit.

8. Horizontal wells to be located within federally supervised units are exempt from the above referenced conditions

of 5, 6 and 7.

9. Exceptions to any of the above referenced conditions of 3 through 7 may be approved upon proper application pursuant to R649-3-3, Exception to Location and Siting of Wells, or R649-10, Administrative Procedures.

10. Additional horizontal wells may be approved by order of the Board after hearing brought upon by a Request for Agency Action (Petition) filed in accordance with the Board's Procedural Rules.

R649-3-3. Exception to Location and Siting of Wells.

1. The division shall have the administrative authority to grant an exception to the locating and siting requirements of R649-3-2 or an order of the board establishing oil or gas well drilling units after receipt from the operator of the proposed well of the following items:

1.1. Proper written application for the exception well location.

1.2. Written consent from all owners within a 460 foot radius of the proposed well location when such exception is to the requirements of R649-3-2, or;

1.3. Written consent from all owners of directly or diagonally offsetting drilling units when such exception is to an order of the board establishing oil or gas well drilling units.

2. If for any reason the division shall fail or refuse to approve such an exception, the board may, after notice and hearing, grant an exception.

3. The application for an exception to R649-3-2 or board drilling unit order shall state fully the reasons why such an exception is necessary or desirable and shall be accompanied by a plat showing:

3.1. The location at which an oil or gas well could be drilled in compliance with R649-3-2 or Board drilling unit order.

3.2. The location at which the applicant requests permission to drill.

3.3. The location at which oil or gas wells have been drilled or could be drilled, in accordance with R649-3-2 or board drilling unit order, directly or diagonally offsetting the proposed exception.

3.4. The names of owners of all lands within a 460 foot radius of the proposed well location when such exception is to the requirements of R649-3-2, or

3.5. The names of owners of all directly or diagonally offsetting drilling units when such exception is to an order of the board establishing oil or gas drilling units.

4. No exception shall prevent any owner from drilling an oil or gas well on adjacent lands, directly or diagonally offsetting the exception, at locations permitted by R649-3-2, or any applicable order of the board establishing oil or gas well drilling units for the pool involved.

5. Whenever an exception is granted, the board or the division may take such action as will offset any advantage that the person securing the exception may obtain over other producers by reason of the exception location.

R649-3-4. Permitting of Wells to be Drilled, Deepened or Plugged-Back.

1. Prior to the commencement of drilling, deepening or plugging back of any well, exploratory drilling such as core holes and stratigraphic test holes, or any surface disturbance associated with such activity, the operator shall submit Form 3, Application for Permit to Drill, Deepen, or Plug Back and obtain approval. Approval shall be given by the division if it appears that the contemplated location and operations are not in violation of any rule or order of the board for drilling a well.

2. The following information shall be included as part of the complete Application for Permit to Drill, Deepen, or Plug Back.

2.1. The telephone number of the person to contact if additional information is needed.

2.2. Proper identification of the lease as state, federal, Indian, or fee.

2.3. Proper identification of the unit, if the well is located within a unit.

2.4. A plat or map, preferably on a scale of one inch equals 1,000 feet, prepared by a licensed surveyor or engineer, which shows the proposed well location. For directional wells, both surface and bottomhole locations should be marked.

2.5. A copy of the Division of Water Rights approval or the identifying number of the approval for use of water at the drilling site.

2.6. A drilling program containing the following information shall also be submitted as part of a complete APD.

2.6.1. The estimated tops of important geologic markers.

2.6.2. The estimated depths at which the top and the bottom of anticipated water, oil, gas, or other mineral-bearing formations are expected to be encountered, and the owner's or operator's plans for protecting such resources.

2.6.3. The owner's or operator's minimum specifications for pressure control equipment to be used and a schematic diagram thereof showing sizes, pressure ratings or API series, proposed testing procedures and testing frequency.

2.6.4. Any supplementary information more completely describing the drilling equipment and casing program as required by Form 3, Application for Permit to Drill, Deepen, or Plug Back.

2.6.5. The type and characteristics of the proposed circulating medium or mediums to be employed in drilling, the quantities and types of mud and weighting material to be maintained, and the monitoring equipment to be used on the mud system.

2.6.6. The anticipated type and amount of testing, logging, and coring.

2.6.7. The expected bottomhole pressure and any anticipated abnormal pressures or temperatures or potential hazards, such as hydrogen sulfide, expected to be encountered, along with contingency plans for mitigating such identified hazards.

2.6.8. Any other facets of the proposed operation which the lessee or operator desires to point out for the division's consideration of the application.

2.6.9. If an Application for Permit to Drill, Deepen, or Plug Back is for a proposed horizontal well, a horizontal well diagram clearly showing the well bore path from the surface through the terminus of the lateral shall be submitted.

2.7. Form 5, Designation of Agent or Operator shall be filed when the operator is a person other than the owner.

2.8. If located on State or Fee surface, an APD will not be approved until an Onsite Predrill Evaluation is performed as outlined in R649-3-18.

3. Two legible copies, carbon or otherwise, of the APD filed with the appropriate federal agency may be used in lieu of the forms prescribed by the board.

4. Approval of the APD shall be valid for a period of 12 months from the date of such approval. Upon approval of an APD, a well will be assigned an API number by the division. The API number should be used to identify the permitted well in all future correspondence with the division.

5. If a change of location or drilling program is desired, an amended APD shall be filed with the division and its approval obtained. If the new location is at an authorized location in the approved drilling unit, or the change in drilling program complies with the rules for that area, the change may be approved verbally or by telegraph. Within five days after obtaining verbal or telegraphic authorization, the operator shall file a written change application with the division.

6. After a well has been completed or plugged and abandoned, it shall not be reentered without the operator first submitting a new APD and obtaining the division's approval. Approval shall be given if it appears that a bond has been furnished or waived, as required by R649-3-1, Bonding, and the contemplated work is not in violation of any rule or order of the board.

7. An operator or owner who applies for an APD in an area not subject to a special order of the board establishing drilling units, may contemporaneously or subsequently file a Request for Agency Action to establish drilling units for an area not to exceed the area reasonably projected by the operator or owner to be underlaid by the targeted reservoir.

8. An APD for a well within the area covered by a proper Request for Agency Action which has been filed by an interested person, or the division or the board on its own motion, for the establishment of drilling units or the revision of existing drilling units for the spacing of wells shall be held in abeyance by the division until such time as the matter has been noticed, fully heard and determined.

9. An exception to R649-3-4-8 shall be made and a permit shall be issued by the division if an owner or operator files a sworn statement demonstrating to the division's satisfaction that on and after the date the Request for Agency Action requesting the establishment of drilling units was filed, or the action of the division or board was taken; and

9.1. The owner or operator has the right or obligation under the terms of an existing contract to drill the requested well; or

9.2. The owner or operator has a leasehold estate or right to acquire a leasehold estate under a contract that will be terminated unless he is permitted to commence the drilling of the required well before the matter can be fully heard and determined by the board.

R649-3-5. Identification.

Every drilling and producible well shall be identified by a sign posted on the derrick or in a conspicuous place near the well. The sign shall be of durable construction. The lettering on the sign shall be kept in a legible condition and shall be large enough to be legible under normal conditions at a distance of 25 feet. The wells on each lease or property shall be numbered in nonrepetitive, logical, and distinctive sequence. Each sign shall show the number of the well, the name of the owner or operator, the lease name, and the location of the well by quarter section, township, and range.

R649-3-6. Drilling Operations.

1. Drilling operations shall be conducted according to the drilling program submitted on the original APD and as approved by the division. Any change of plans to the original drilling program shall be submitted to the division by using Form 9, Sundry Notices and Reports on Wells and shall receive division approval prior to implementation. A change of plans necessary because of emergency conditions may be implemented without division approval. The operator shall provide the division with verbal notice of the emergency change within 24 hours and written notice within five days.

2. An operator of a drilling well as designated in R649-2-4 shall comply with reporting requirements as follows:

2.1. The spudding in of a well shall be reported to the division within 24 hours. The report should include the well name and number, drilling contractor, rig number and type, spud date and time, the date that continuous drilling will commence, the name of the person reporting the spud, and a contact telephone number.

2.2. The operator shall file Form 6, Entity Action Form with the division within five working days of spudding in a well. The division will assign the well an entity number which will identify the well on the operator's monthly oil and gas production and disposition reports.

2.3. The operator shall notify the division 24 hours in advance of all testing to be performed on the blowout preventor equipment on a well.

2.4. The operator shall submit a monthly status report for each drilling well on Form 9, Sundry Notices and Reports on Wells. The report should include the well depth and a description of the operations conducted on the well during the month. The report shall be submitted no later than the fifth day of the following calendar month until such time as the well is completed and the well completion report is filed.

2.5. The operator shall notify the division 24 hours in advance of all casing tests performed in accordance with R649-3-13.

2.6. The operator shall report to the division all fresh water sand encountered during drilling on Form 7, Report of Water Encountered During Drilling, The report shall be filed with Form 8, Well Completion or Recompletion Report and Log.

R649-3-7. Well Control.

1. When drilling in wildcat territory, the owner or operator shall take all reasonably necessary precautions for keeping the well under control at all times and shall provide, at the time the well is started, proper high pressure fittings and equipment. All pressure control equipment shall be maintained in good working condition at all times.

2. In all proved areas, the use of blowout prevention equipment "BOPE" shall be in accordance with the established and approved practice in the area. All pressure control equipment shall be maintained in good working condition at all times.

3. Upon installation, all ram type BOPE and related equipment, including casing, shall be tested to the lesser of the full manufacturer's working pressure rating of the equipment, 70% of the minimum internal yield pressure of any casing subject to test, or one psi/ft of the last casing string depth. Annular type BOPE are to be tested in conformance with the manufacturer's published recommendations. The operator shall maintain records of such testing until the well is completed and will submit copies of such tests to the division if required.

4. In addition to the initial pressure tests, ram and annular type preventers shall be checked for physical operation each trip. All BOPE components, with the exception of an annular type blowout preventer, shall be tested monthly to the lesser of 50% of the manufacturer's rated pressure of the BOPE, the maximum anticipated pressure to be contained at the surface, one psi/ft of the last casing string depth, or 70% of the minimum internal yield pressure of any casing subject to test.

5. If a pressure seal in the assembly is disassembled, a test of that seal shall be conducted prior to the resumption of any drilling operation. A shell test of the affected seal shall be adequate. If the affected seal is integral with the BOP stack, either pipe or blind ram, necessitating a test plug to be set in order to test the seal, the division may grant approval to proceed without testing the seal if necessary for prudent operations.

6. All tests of BOPE shall be noted on the driller's log, IADC report book, or equivalent and shall be available for examination by the director or an authorized agent during routine inspections.

7. BOPE used in possible or probable hydrogen sulfide or sour gas formations shall be suitable for use in such areas.

R649-3-8. Casing Program.

1. The method of cementing casing in the hole shall be by pump and plug method, displacement method, or other method approved by the division.

2. When drilling in wildcat territory or in any field where high pressures are probable, the conductor and surface strings of casing must be cemented throughout their lengths, unless another

procedure is authorized or prescribed by the division, and all subsequent strings of casing must be securely anchored.

3. In areas where the pressures and formations to be encountered during drilling are known, sufficient surface casing shall be run to:

3.1. Reach a depth below all known or reasonably estimated, utilizable, domestic, fresh water levels.

3.2. Prevent blowouts or uncontrolled flows.

4. The casing program adopted must be planned to protect any potential oil or gas horizons penetrated during drilling from infiltration of waters from other sources and to prevent the migration of oil, gas, or water from one horizon to another.

R649-3-9. Protection Of Upper Productive Strata.

1. No well shall be deepened for the purpose of producing oil or gas from a lower stratum until all upper productive strata are protected, either permanently by casing and cementing or temporarily through the use of tubing and packer, to the satisfaction of the division.

2. In any well that appears to have defective, poorly cemented, or corroded casing that will permit or may create underground waste or may contaminate underground or surface fresh water, the operator shall proceed with diligence to use the appropriate method and means to eliminate such hazard of underground waste or contamination of fresh water. If such hazard cannot be eliminated, the well shall be properly plugged and abandoned.

3. Natural gas that is encountered in substantial quantities in any section of a cable tool drilled hole above the ultimate objective shall be shut off with reasonable diligence, either by mudding, casing or other approved method, and shall be confined to its original source to the satisfaction of the division.

R649-3-10. Tolerances For Vertical Drilling.

Deviation from the vertical for short distances is permitted in the drilling of a well without special approval to straighten the hole, sidetrack junk, or correct other mechanical difficulties. All wells shall be drilled such that the surface location of the well and all points along the intended well bore shall be within the tolerances allowed by R649-3-2, Location and Siting of Vertical Wells and Statewide Spacing for Horizontal Wells, or the appropriate board order.

R649-3-11. Directional Drilling.

1. Except for the tolerances allowed under R649-3-10, no well may be intentionally deviated unless the operator shall first file application and obtain approval from the division. An application for directional drilling may be approved by the division without notice and hearing when the applicant is the owner of all the oil and gas within a radius of 460 feet from all points along the intended well bore, or the applicant has obtained the written consent of the owner to the proposed directional drilling program. An application for directional drilling may be included as part of the initial APD for a proposed well.

2. An application for directional drilling shall include the following information:

2.1. The name and address of the operator.

2.2. The lease name, well number, field name, reservoir name, and county where the proposed well is located.

2.3. A plat or sketch showing the distance from the surface location to section and lease lines, the target location within the intended producing interval, and any point along the intended well bore outside the 460 foot radius for which the consent of the owner has been obtained.

2.4. The reason for the intentional deviation.

2.5. The signature of designated agent or representative of operator.

3. Within 30 days following completion of a directionally drilled well, a complete angular deviation and directional survey of the well obtained by an approved well survey company shall be filed with the division, together with other regularly required reports.

R649-3-12. Drilling Practices For Hydrogen Sulfide Areas And Formations.

1. This rule shall apply to drilling, redrilling, deepening, or plugging back operations in areas where the formations to be penetrated are known to contain or are expected to contain H_2S in excess of 20 ppm and to areas where the presence or absence thereof is unknown.

2. A written contingency plan, providing details of actions to be taken to alert and protect operating personnel and members of the public in the event of an accidental release of H_2S gas shall be submitted to the division as part of the initial APD for a well or as a sundry notice.

3. All proposed drill site locations shall be planned to obtain the maximum safety benefits consistent with the rig configuration, terrain, prevailing winds, etc. The drilling rig shall, where possible, be situated so that prevailing winds blow across the rig in a direction toward the reserve pit and away from escape routes. On-site trailers shall be located to allow reasonably safe distances from both the well and the outlet of the flare line.

4. At least two cleared areas shall be designated as crew briefing or safety areas. Both areas shall be located at least 200 feet from the well, with at least one area located generally upwind from the well.

5. Protective equipment shall be provided by the operator or its drilling contractor for operating personnel and shall include the following:

5.1. An adequate number of positive pressure type self-contained breathing apparatus to allow all personnel normally involved in the drilling operation immediate access to such equipment, with a minimum of one working apparatus available for the immediate use of each rig hand in emergencies.

5.2. Chalk boards or note pads to be used for communication when wearing protective breathing apparatus.

5.3. First aid supplies.

5.4. One resuscitator complete with medical oxygen.
5.5. A litter or stretcher.
5.6. Harnesses and lifelines.
5.7. A telephone, radio, mobile phone, or other communication device that provides emergency two-way communication from a safe area at the well location.

6. Each drill site shall have an H_2S detection and monitoring system that activates audible and visible alarms when the concentration of H_2S reaches the threshold limit of 20 ppm in air. This equipment shall have a rapid response time and be capable of sensing a minimum of ten ppm H_2S in air, with at least three sensing points, located at the shale shaker, on the derrick floor, and in the cellar. Other sensing points shall be located at other critical areas where H_2S might accumulate. Portable H_2S detection equipment capable of sensing an H_2S concentration of 20 ppm shall be available for all working personnel and shall be equipped with an audible warning signal.

7. Equipment to indicate wind direction at all times shall be installed at prominent locations. At least two wind socks or streamers shall be located at separate elevations at the well location and shall be easily visible from all areas of the location. Windsocks or streamers shall be located in illuminated areas for night operations.

8. When H_2S is encountered during drilling, well marked, highly visible warning signs shall be displayed at the rig and along all access routes to the well location. The signs shall warn of the presence of H_2S and shall prohibit approach to the well location when red flags are displayed. Red flags shall be displayed when H_2S is present in concentrations greater than 20 ppm in air as measured on the equipment required under R649-3-12-6.

9. Unless adequate natural ventilation is present, portable fans or ventilation equipment shall be located in work areas to disperse H_2S when it is encountered.

10. A flare system shall be utilized to safely gather and burn H_2S bearing gas. Flare lines shall be located as far from the operating site as feasible and shall be located in a manner to compensate for wind changes. The outlets of all flare lines shall be located at least 150 feet from the well head unless otherwise approved by the division.

11. Sufficient quantities of additives shall be maintained on location to add to the mud system to scavenge or neutralize H_2S.

R649-3-13. Casing Tests.

In order to determine the integrity of the casing string set in the well, the operator shall, unless otherwise requested by the division, perform a pressure test of the casing to the pressures specified under R649-3-7-4 before drilling out of any casing string, suspending drilling operations, or completing the well.

R649-3-14. Fire Hazards On The Surface.

1. All rubbish or debris that might constitute a fire hazard shall be removed to a distance of a least 100 feet from the well location, tanks, separator, or any structure. All waste oil or gas shall be burned or disposed of in a manner to avert creation

of a fire hazard.

2. Any gas other than poisonous gas escaping from the well during drilling operations shall be, so far as practicable, conducted to a safe distance from the well site and burned in a suitable flare.

R649-3-15. Pollution And Surface Damage Control.

The operator shall take all reasonable precautions to avoid polluting lands, streams, reservoirs, natural drainage ways, and underground water. The owner or operator shall carry on all operations and maintain the property at all times in a safe and workmanlike manner having due regard for the preservation and conservation of the property and for the health and safety of employees and people residing in close proximity to those operations. At a minimum, the owner or operator shall:

1.1. Take reasonable steps to prevent and shall remove accumulations of oil or other materials deemed to be fire hazards from the vicinity of well locations, lease tanks and pits.

1.2. Remove from the property or store in an orderly manner, all scrap or other materials not in use.

1.3. Provide secure workmanlike storage for chemical containers, barrels, solvents, hydraulic fluid, and other non-exempt materials.

1.4. Maintain tanks in a workmanlike manner which will preclude leakage and provide for all applicable safety measures, and construct berms of sufficient height and width to contain the quantity of the largest tank at the storage facility. The use of crude or produced water storage tanks without tops is strictly prohibited except during well testing operations.

1.5. Catch leaks and drips, contain spills, and cleanup promptly. Waste reduction and recycling should be practiced in order to help reduce disposal volumes. Produced water, tank bottoms and other miscellaneous waste should be disposed of in a manner which is in compliance with these rules and other state, federal, or local regulations or ordinances. In general, good housekeeping practices should be used.

R649-3-16. Reserve Pits and Other Onsite Pits.

1. Small onsite oil field pits including but not limited to reserve pits, emergency pits, workover and completion pits, storage pits, pipeline drip pits, and sumps shall be located and constructed in such a manner as to contain fluids and not cause pollution of waters and soils. They shall be located and constructed according to the Division guidelines for onsite pits.

2. Reserve pit location and construction requirements including liner requirements will be discussed at the predrill site evaluation. Special stipulations concerning the reserve pit will be included as part of the Division's approval to drill.

3. Following drilling and completion of the well the reserve pit shall be closed within one year, unless permission is granted by the Division for a longer period. Pit contents shall meet the Division's Cleanup Levels (guidance document for numeric clean-up levels) or background levels prior to burial. The contents may require treatment to reduce mobility and/or toxicity in order to

meet cleanup levels. The alternative to meeting cleanup levels would be transporting of material to an appropriate disposal facility.

R649-3-17. Inspection.

Inspection of wells shall be performed by the division to determine operator compliance with the rules and orders of the board. The inspection shall not interfere with the mechanical operation of facilities or equipment used in drilling and production operations. Inspections of operations involving a safety hazard shall not be conducted, nor shall an inspection be conducted that may cause a safety hazard.

R649-3-18. On-site Predrill Evaluation.

1. An on-site predrill evaluation of drilling operations located on state or private land shall be scheduled and conducted by the division prior to approval of an APD and no later than 30 days after receipt by the division of a complete APD. An on-site predrill evaluation may be performed by the division prior to submittal of a complete APD at the written request of the operator. The division, the operator, and other persons associated with the surface management or construction of the well site shall attend the predrill evaluation. When appropriate, the operator's surveyor and archaeologist may also participate in the predrill evaluation. When the surface of the land involved is privately owned, the operator shall include in the APD the name, address, and telephone number of the private surface owner as shown on the real property records of the county where the well is located. The surface owner shall be invited by the division to attend the predrill evaluation. The surface owner's inability to attend the predrill evaluation shall not delay the scheduled evaluation.

2. Special stipulations concerning surface use or justifications for well spacing exceptions may be addressed and developed at the predrill evaluations. Special stipulations shall be incorporated as conditions of the approved APD, together with any additional conditions determined by the division to be necessary following a review of the complete application.

R649-3-19. Well Testing.

1. Each operator shall conduct a stabilized production test of at least 24 hours duration not later than 15 days following the completion or recompletion of any well for the production of oil or gas.

The results of the test shall be reported in writing to the division within 15 days after completion of the test. Additional tests shall be taken as requested by the division.

2. The division may request subsurface pressure measurements on a sufficient number of wells in any pool to provide adequate data to determine reservoir characteristics.

3. Upon written request, the division may waive or extend the time for conducting any test.

4. A gas-oil ratio "GOR" test shall be conducted not later than 15 days following the completion or recompletion of each well

in a pool which contains both oil and gas. The average daily oil production, the average daily gas production and the average GOR shall be recorded. The results of the GOR test shall be reported in writing to the division within 15 days after completion of the test. A GOR test of at least 24 hours duration shall satisfy the requirements of R649-3-19-1.

5. When the results of a multipoint test or other approved test for the determination of gas well potential have not been submitted to the division within 30 days after completion or recompletion of any producible gas well, the division may order that this test be made. All data pertinent to the test shall be submitted to the division in legible, written form within 15 days after completion of the test. The performance of a multipoint or other approved test shall satisfy the requirements of R649-3-19-1.

6. All tests of any producible gas well will be taken in accordance with the Manual of Back-Pressure Testing of Gas Wells published by the Interstate Oil Compact Commission, with necessary modifications as approved by the division.

R649-3-20. Gas Flaring Or Venting.

1. Produced gas from an oil well, also known as associated gas or casinghead gas, may be flared or vented only in the following amounts:

1.1. Up to 1,800 MCF of oil well gas may be vented or flared from an individual well on a monthly basis at any time without approval.

1.2. During the period of time allowed for conducting the stabilized production test or other approved test as required by R649-3-19, the operator may vent or flare all produced oil well gas as needed for conducting the test. The operator shall not vent or flare gas which is not necessary for conducting the test or beyond the time allowed for conducting the test.

1.3. During the first calendar month immediately following the time allowed for conducting the initial stabilized production test as required by R649-3-19.1, the operator may vent or flare up to 3,000 MCF of oil well gas without approval.

1.4. Unavoidable or short-term oil well gas venting or flaring may occur without approval in accordance with R649-3-20.4, 4.1, 4.2, and 4.3.

2. Produced gas from a gas well may be vented or flared only in the following amounts:

2.1. During the period of time allowed for conducting the stabilized production test, the multipoint test, or other approved test as required by R649-3-19, the operator may vent or flare all produced gas well gas as needed for conducting the test. The operator shall not vent or flare gas which is not necessary for conducting the tests or beyond the time allowed for conducting the tests.

2.2. Unavoidable or short-term gas well gas venting or flaring may occur without approval in accordance with R649-3-20.4, 4.1, 4.2, and 4.3.

3. If an operator desires to produce a well for the purpose of testing and evaluation beyond the time allowed by R649-3-19 and vent or flare gas in excess of the aforementioned limits of gas

venting or flaring, the operator shall make written request for administrative action by the division to allow gas venting or flaring during such testing and evaluation. The operator shall provide any information pertinent to a determination of whether marketing or otherwise conserving the produced gas is economically feasible. Upon such request and based on the justification information presented, the division may authorize gas venting or flaring at unrestricted rates for up to 30 days of testing or no more than 50 MMCF of gas vented or flared, whichever is less.

4. Once a well is completed for production and gas is being transported or marketed, the operator is allowed unavoidable or short-term gas venting or flaring without approval only in the following cases:

4.1. Gas may be vented or released from oil storage tanks or other low pressure oil production vessels unless the division determines that the recovery of such vapors is warranted.

4.2. Gas may be vented or flared from a well during periods of line failures, equipment malfunctions, blowouts, fires, or other emergencies if shutting in or restricting production from the well would cause waste or create adverse impact on the well or producing reservoir. The operator shall provide immediate notification to the division in all such cases in accordance with R649-3-32, Reporting of Undesirable Events. Upon notification, the division shall determine if gas venting or flaring is justified and specify conditions of approval if necessary.

4.3. Gas may be vented or flared from a well during periods of well purging or evaluation tests not exceeding a period of 24 hours or a maximum of 144 hours per month. The operator shall provide subsequent written notification to the division in all such cases.

5. If an operator wishes to flare or vent a greater amount of produced gas than allowed by this rule, the operator must submit a Request for Agency Action to the board to be considered as a formal board docket item. The request should include the following items:

5.1. A statement justifying the need to vent or flare more than the allowable amount.

5.2. A description of production test results.

5.3. A chemical analysis of the produced gas.

5.4. The estimated oil and gas reserves.

5.5. A description of the reinjection potential or other conservation oriented alternative for disposition of the produced gas.

5.6. A description of the amount of gas used in lease operations.

5.7. An economic evaluation supporting the operator's determination that conservation of the gas is not economically viable. The evaluation should utilize any engineering or geologic data available and should consider total well production, not just gas production, in presenting the profitability and costs for beneficial use of the gas.

5.8. Any other information pertinent to a determination of whether marketing or otherwise conserving the produced gas is economically feasible.

6. Upon review of the request for approval to vent or flare gas from a well, the board may elect to:

6.1. Allow the requested venting or flaring of gas.

6.2. Restrict production until the gas is marketed or otherwise beneficially utilized.

6.3. Take any other action the board deems appropriate in the circumstances.

7. When gas venting or flaring from a well has not been approved by the division or the magnitude and duration of venting or flaring exceeds the amounts specified in these rules or any division or board approval, then the board may issue a formal order to alleviate the noncompliance and/or require the operator to appear before the board to provide justification of such venting or flaring. The division shall notify the appropriate governmental taxing and royalty agencies of any unapproved venting or flaring and of any subsequent board action.

8. No extraction plant processing gas in Utah shall flare or vent such gas unless such venting or flaring is made necessary by mechanical difficulty of a very limited temporary nature or unless the gas vented or flared is of no commercial value. In the event of a more prolonged mechanical difficulty or in the event of plant shut-downs or curtailment because of scheduled or nonscheduled maintenance or testing operations or other reasons, or in the event a plant is unable to accept, process, and market all of the casinghead gas produced by wells connected to its system, the plant operator shall notify the division as soon as possible of the full details of such shut-down or curtailment, following which the division shall take such action as is necessary.

R649-3-21. Well Completion And Filing Of Well Logs.

1. For the purposes of this rule only, a well shall be determined to be completed when the well has been adequately worked to be capable of producing oil or gas or when well testing as required by the division is concluded.

2. Within 30 days after the completion of any well drilled or redrilled for the production of oil or gas, Form 8, Well Completion or Recompletion Report and Log, shall be filed with the division, together with a copy of the electric and radioactivity logs, if run.

3. In addition, one copy of all drillstem test reports, formation water analyses, porosity, permeability or fluid saturation determinations, core analyses and lithologic logs or sample descriptions if compiled, shall be filed with the division.

4. As prescribed under R649-2-12, Test and Surveys, the directional, deviation and/or measurement-while-drilling (MWD) survey for a horizontal well shall be filed within 30 days of being run. Such directional, deviation and/or MWD survey specifically related to well location or well bore path shall not be held confidential. Other MWD survey data which presents well log, or other geological, geophysical, or engineering information may be held confidential as provided in R649-2-11, Confidentiality of Well Log Information.

R649-3-22. Completion Into Two Or More Pools.

1. The completion of a single well into more than one pool may be permitted by submitting an application to the division and securing its approval. The application shall be submitted on Form 9, Sundry Notice and Report and shall be accompanied by an exhibit showing the location of all wells on contiguous oil and gas leases or drilling units overlying the pool. The application shall set forth all material facts involved and the manner and method of completion proposed.

2. If oil or gas is to be produced from two or more pools open to each other through the same string of casing so that commingling will take place, the application must also be accompanied by a description of the method used to account for and to allocate production from each pool so commingled.

3. The application shall include an affidavit showing that the operator has provided a copy of the application to the owners of all contiguous oil and gas leases or drilling units overlying the pool. If none of these owners file a written objection to the application within 15 days after the date the application is filed with the division, the application may be considered and approved by the division without a hearing. If a written objection is filed that cannot be resolved administratively, the application may be approved only after notice and hearing by the board.

R649-3-23. Well Workover and Recompletion.

1. Requests for approval of a notice of intention to perform a workover or recompletion shall be filed by an operator with the division on Form 9, Sundry Notices and Reports on Wells, or if the operation includes substantial redrilling, deepening, or plugging back of an existing well, on Form 3, Application for Permit to Drill, Deepen or Plug Back.

2. The division shall review the proposed workover or recompletion for conformance with the Oil and Gas Conservation General Rules and advise the operator of its decision and any necessary conditions of approval.

3. Recompletions shall be conducted in a manner to protect the original completion interval(s) and any other known productive intervals.

4. The same tests and reports are required for any well recompletion as are required following an original well completion.

5. The applicant shall file a subsequent report of workover on Form 9, Sundry Notices and Reports, or a subsequent report of recompletion on Form 8, Well Completion or Recompletion Report and Log, within 30 days after completing the workover or recompletion operations.

6. For the purpose of qualifying for a tax credit under Utah Code Ann. Section 59-5-102(3), the operator on his behalf and on behalf of each working interest owner must file a request with the division on Form 15, Designation of Workover or Recompletion. The request must be filed within 90 days after completing the workover or recompletion operations.

7. A workover which may qualify under Utah Code Ann. Section 59-5-102(3) shall be downhole operations conducted to maintain, restore or increase the producibility or serviceability of a well

in the geologic interval(s) that the well is currently completed in, but shall not include:

7.1. Routine maintenance operations such as pump changes, artificial lift equipment or tubing repair, or other operations which do not involve changes to the wellbore configuration or the geologic interval(s) that it penetrates and which do not stimulate production beyond that which would be anticipated as the result of routine maintenance.

7.2. Operations to convert any well for use as a disposal well or other use not associated with enhancing the recovery of hydrocarbons. Operations to convert a well to a Class II injection well for enhanced recovery purposes may qualify if the secondary or enhanced recovery project has received the necessary board approval.

8. A recompletion which may qualify under Utah Code Ann. Section 59-5-102(3) shall be downhole operations conducted to reestablish producibility or serviceability of a well in any geologic interval(s).

9. The division shall review the request for designation of a workover or recompletion and advise the operator and the State Tax Commission of its decision to approve or deny the operations for the purposes of Utah Code Ann. Section 59-5-102(3).

10. The division is responsible for approval of workover and recompletion operations which qualify for the tax credit. If the operator disagrees with the decision of the division, the decision may be appealed to the board. Appeals of all other workover and recompletion tax credit decisions should be made to the State Tax Commission.

R649-3-24. Plugging And Abandonment Of Wells.

1. Before operations are commenced to plug and abandon any well the owner or operator shall submit a notice of intent to plug and abandon to the division for its approval. The notice shall be submitted on Form DOGM-5, Sundry Notice and Report on Wells. A legible copy of a similar report and form filed with the appropriate federal agency may be used in lieu of the forms prescribed by the board. In cases of emergency the operator may obtain verbal or telegraphic approval to plug and abandon. Within five days after receiving verbal or telegraphic approval, the operator shall submit a written notice of intent to plug and abandon on Form 9.

2. Both verbal and written notice of intent to plug and abandon a well shall contain the following information.

2.1. The location of the well described by section, township, range, and county.

2.2. The status of the well, whether drilling, producing, injecting or inactive.

2.3. A description of the well bore configuration indicating depth, casing strings, cement tops if known, and hole size.

2.4. The tops of known geologic markers or formations.

2.5. The plugging program approved by the appropriate federal agency if the well is located on federal or Indian land.

2.6. An indication of when plugging operations will commence.

3. A dry or abandoned well must be plugged so that oil, gas, water, or other substance will not migrate through the well bore from one formation to another. Unless a different method and procedure is approved by the division, the method and procedure for plugging the well shall be as follows:

3.1. The bottom of the hole shall be filled to, or a bridge shall be placed at, the top of each producing formation open to the well bore, and a cement plug not less than 100 feet in length shall be placed immediately above each producing formation open to the well bore.

3.2. A solid cement plug shall be placed from 50 feet below a fresh water zone to 50 feet above the fresh water zone, or a 100 foot cement plug shall be centered across the base of the fresh water zone and a 100 foot plug shall be centered across the top of the fresh water zone.

3.3. At least ten sacks of cement shall be placed at the surface in a manner completely plugging the entire hole. If more than one string of casing remains at the surface, all annuli shall be so cemented.

3.4. The interval between plugs shall be filled with noncorrosive fluid of adequate density to prevent migration of formation water into or through the well bore.

3.5. The hole shall be plugged up to the base of the surface string with noncorrosive fluid of adequate density to prevent migration of formation water into or through the well bore, at which point a plug of not less than 50 feet of cement shall be placed.

3.6. Any perforated interval shall be plugged with cement and any open hole porosity zone shall be adequately isolated to prevent migration of fluids.

3.7. A cement plug not less than 100 feet in length shall be centered across the casing stub if any casing is cut and pulled, a second plug of the same length shall be centered across the casing shoe of the next larger casing.

4. An alternative method of plugging required under a federal or Indian lease, will be accepted by the division.

5. Within 30 days after the plugging of any well has been accomplished, the owner or operator shall file a subsequent report of plugging with the division. The report shall give a detailed account of the following items:

5.1. The manner in which the plugging work was carried out, including the nature and quantities of materials used in plugging and the location, nature, and extent by depths, of the plugs.

5.2. Records of any tests or measurements made.

5.3. The amount, size, and location, by depths of any casing left in the well.

5.4. A statement of the volume of mud fluid used.

5.5. A complete report of the method used and the results obtained, if an attempt was made to part any casing.

6. Upon application to and approval by the division, and following assumption of liability for the well by the surface owner, a well or other exploratory hole that may safely be used as a fresh water well need not be filled above the required sealing plugs set below the fresh water formation. The owner of the

surface of the land affected may assume liability for any well capable of conversion to a water well by sending a letter assuming such liability to the division and by filing an application with and obtaining approval for appropriation of underground water from the Division of Water Rights.

7. Unless otherwise approved by the division, all abandoned wells shall be marked with a permanent monument showing the well number, location, and name of the lease. The monument shall consist of a portion of pipe not less than four inches in diameter and not less than ten feet in length, of which four feet shall be above the ground level and the remainder shall be securely embedded in cement. The top of the pipe must be permanently sealed.

8. If any casing is to be pulled after a well has been abandoned, a notice of intent to pull casing must be filed with the division and its approval obtained before the work is commenced. The notice shall include full details of the contemplated work. If a log of the well has not already been filed with the division, the notice shall be accompanied by a copy of the log showing all casing seats as well as all water strata and oil and gas shows. Where the well has been abandoned and liability has been terminated with respect to the bond previously furnished under R649-3-1, a $10,000 plugging bond shall be filed with the division by the applicant.

R649-3-25. Underground Disposal Of Drilling Fluids.

1. Operators shall be permitted to inject and dispose of reserve pit drilling fluids downhole in a well upon submitting an application for such operations to the division and obtaining its approval. Injection of reserve pit fluids shall be considered by the division on a case-by-case basis.

2. Each proposed injection procedure will be reviewed by the division for conformance to the requirements and standards for permitting disposal wells under R649-5-2 to assure protection of fresh-water resources.

3. The subsurface disposal interval shall be verified by temperature log, or suitable alternative, during the disposal operation.

4. The division shall designate other conditions for disposal, as necessary, in order to ensure safe, efficient fluid disposal.

R649-3-26. Seismic Exploration.

1. Form 1, Application for Permit to Conduct Seismic Exploration shall be submitted to the division by the seismic contractor at least seven days prior to commencing any type of seismic exploration operations. In cases of emergency, approval may be obtained either verbally or by telegraphic communication. Changes of plans or line locations may be implemented in an emergency situation without division approval. Within five days after the change is performed, the seismic contractor shall submit written notice of the change to the division.

1.1 The permit may be revoked at any time by the division for failure to comply with the rules and orders of the board.

1.2. Any request to deviate from the general plugging and operations procedures of these rules shall be included on the permit application.

1.3. The name, address, and telephone number of the seismic contractor's local contact shall be submitted to the division as soon as determined if not available when the permit application is submitted.

1.4. After review of the application for a seismic permit, the division may require written permission of the owner of the surface of the affected land if it is determined that the seismic operation may significantly impact any building, pipeline, water well, flowing spring, or other cultural or natural feature in the area.

1.5. The permit will be in effect for six months from the date of approval. The permit may be extended upon application to and approval by the division.

2. Bonding shall not be required for seismic exploration requiring the drilling of shot holes.

3. Seismic contractors shall give the division at least 24 hours advance notice of the plugging of seismic holes. The notice shall include the date and time the plugging activities are expected to commence, the name and address of the seismic contractor responsible for the holes, and, if different, the name and address of the hole plugging company.

4. Unless the seismic contractor can prove to the satisfaction of the division that another method will provide adequate protection to ground water resources and other man-made or natural features and will provide long-term land stability, the following procedures shall be required for the conduct of seismic operations and hole plugging:

4.1. Seismic contractors shall take reasonable precautions to avoid conducting shot hole operations closer than 1,320 feet to any building, pipeline, water well, flowing spring, or other cultural/natural feature, e.g., a historical monument, marker, or structure, which may be adversely affected by the seismic operations.

4.2. When nonartesian water is encountered while drilling seismic shot holes, the holes shall be filled from the bottom up with a high grade bentonite/water slurry mixture. The slurry shall have a density that is at least four percent greater than the density of fresh water and shall have a marsh funnel viscosity of at least 60 seconds per quart. The density and viscosity of the slurry are to be measured prior to adding cuttings. Cuttings not added to the slurry are to be disposed of in accordance with R649-3-26-4.6. Upon approval by the division, any other suitable plugging material commonly used in the industry may be substituted for the bentonite/water slurry as long as the physical characteristics of the substitute plugging material are at least comparable to those of the bentonite/water slurry. The hole shall be filled with the substitute plugging material from the bottom up to a depth of three feet below ground level. A nonmetallic permaplug shall be set at a depth of three feet. The remaining hole shall be filled and tamped to the surface with cuttings and native soil. The permaplug shall be imprinted with an approved identification number or mark.

4.3. When drilling with air only, and in completely dry holes, plugging may be accomplished by returning the cuttings to the holes, tamping the returned cuttings to the depth of three feet below ground level, and setting the permaplug topped with more cuttings and soil. A small mound shall be left over the hole for settling allowance.

4.4. If artesian flow, water flowing at the surface, is encountered in the drilling of any seismic hole, cement shall be used to seal off the water flow to prevent cross-flow, erosion, or contamination of fresh water supplies. Unless severe weather conditions prevent access, the holes shall be cemented immediately. Approval may be granted to seismic operator to plug a flowing hole in another manner, if it is proved to this division that the alternate method will provide adequate protection to ground water resources and provide long term land stability. The owner of the surface of the land affected may assume liability for a seismic hole capable of conversion to a water well by sending a letter assuming such liability to the division and by filing an application with and obtaining approval for appropriation of underground water from the Division of Water Rights.

4.5. Shotholes shall be properly plugged and abandoned as soon as practical after the shot has been fired. No shothole shall be left unplugged for more than 30 days without approval of the division. Until properly plugged, shotholes shall be covered with a tin hat or other similar cover. The hats shall be imprinted with the seismic contractor's name or initials.

4.6. Any slurry, drilling fluids, or cuttings which are deposited on the surface around the seismic hole shall be raked or otherwise spread out to a height of not more than one inch above the surface, so that the growth of the natural grasses or foliage will not be impaired.

4.7. Restoration plans required by the Mined Land Reclamation Act, Chapter 8 of Title 40, or by any other surface management agency will be accepted by the division. The surface area around each seismic shothole shall be reclaimed and reseeded to its original condition insofar as such restoration is practical and is required by the surface management agency. All flagging, stakes, cables, cement, or mud sacks shall be removed from the drill site and disposed of in an acceptable manner.

5. Upon application to the division, approval may be obtained for preplugging of shotholes using coarse bentonite material or a suitable alternative used in the industry. Preplugging of holes in this manner shall be performed according to the following procedures:

5.1. A sales receipt indicating proof of purchase of an adequate amount of coarse bentonite to properly plug all shotholes shall be submitted to the division upon request.

5.2. For shotholes drilled with air which are completely dry, the seismic contractor shall have the option of preplugging with the coarse bentonite material or of using an alternate plugging material under R649-3-26-4.3.

5.3. For conventionally drilled, wet holes, enough approved material shall be used to cover the initial water level, i.e., the depth of the initial water level in the hole prior to adding coarse bentonite material shall be equal to the final plug depth. An additional ten feet of approved material shall be placed above this depth and hole cuttings shall be used to fill the remainder of the hole to a depth of three feet below ground level. A nonmetallic plug imprinted with an approved identification number or mark shall be installed at this depth. The remaining three feet of hole shall be filled and tamped to the surface with cuttings and native soil. The remaining cuttings shall be raked or spread to a height not to exceed one inch above ground level.

5.4. When using heliportable drills and insufficient cuttings are available, the hole shall be preplugged with bentonite plugging material or an approved alternate material to a depth of three feet below ground level. Installation of a nonmetallic plug and filling the remainder of the hole shall be performed as required by R649-3-26-5.3.

5.5. The coarse bentonite plugging material shall have the following specifications - chemically unaltered sodium bentonite, coarse ground, three quarter inch maximum size, not more than 19% moisture content and not more than 15% inert solids by volume.

6. Form 2, Seismic Exploration Completion Report shall be submitted to the Division within 60 days after completion of each seismic exploration project. The report shall include:

Certification by the seismic contractor that all shot holes have been plugged as prescribed by the division.

R649-3-27. Multiple Mineral Development.

1. Drilling operations conducted in areas designated by the board for multiple mineral development shall comply with all rules or orders of the board for drilling, casing, cementing, and plugging except as the general rules or orders may be modified by this rule.

2. It is the policy of the division to promote the development of all mineral resources on land under its jurisdiction. Consistent with that policy, operators engaged in oil and gas operations on lands on which operators are exploring for and developing mineral resources other than oil and gas may enter into a cooperative agreement with these other operators with respect to multiple mineral development. The agreement shall define:

2.1. The extent and limits of liability when one operator, either intentionally or unintentionally, interferes with or damages the deposits of another.

2.2. The coordination of access to and development of the area.

2.3. Mitigation of surface impact including but not limited to issues pertaining to relocation of natural gas pipeline gathering and distribution systems and other surface facilities occasioned by placement of a spent shale pile; phased or coordinated surface occupancy so as to allow each operator to enjoy his respective mineral estate with the least disruption of operations and damage to the oil and gas deposits, either directly or indirectly, through waste; and limitation of oil and gas operations in areas of concentrated surface oil shale facilities.

2.4. Mitigation of subsurface impact including but not limited to issues pertaining to the interface in the underground environment of oil shale mining operations with other mineral operations.

2.5. The extent of exchange of geological, engineering, and production data.

2.6. Other cooperative efforts consistent with multiple mineral development under the rules and orders of the board pertaining to oil and gas operations, oil shale operations, and mined land reclamation.

3. The division, together with the Division of State Lands and Forestry, where applicable, shall be signatory to the agreement.

4. In the event the operators cannot agree on cooperative development of their respective mineral deposits, or having once entered into a cooperative agreement subsequently disagree on the application of the terms and provisions thereof, any operator whose oil and gas or mining operation or deposit may be adversely affected or damaged by the operations of another operator may apply to the board for, or the board may on its own motion enter an order, after notice and hearing, delineating the respective rights and obligations of all operators with respect to development of all minerals concerned.

5. After notice and hearing the board may modify its order to more effectively carry out the policies of multiple mineral development.

R649-3-28. Designated Potash Areas.

1. In any area designated as a potash area, either by the board, the Division of State Lands and Forestry or an appropriate federal agency, all wells shall be drilled, cased, cemented, and plugged in accordance with the rules and orders of the board. The following minimum requirements and definitions shall also apply to the drilling, logging, casing, and plugging operations within the Salt Section to protect against migration of oil, gas, or water into or within any formation or zone containing potash. As used in this rule, Salt Section shall mean the Paradox Salt Section of Pennsylvanian Age.

2. Any drilling media used through the Salt Section shall be such that sodium chloride is not soluble in the media at normal temperatures.

3. Gamma ray-neutron, gamma ray-sonic or other appropriate logs shall be run promptly through the Salt Section. One field copy of the log through the Salt Section shall be submitted to the division within ten days, or upon the request of the division, whichever is the earlier.

4. A directional survey shall be run from a point at least 20 feet below the Salt Section to the surface. The survey shall be filed with the division prior to completion or plugging and abandonment of the well.

5. In addition to the requirements of the R649-3-8, any casing set into or through the Salt Section shall be cemented solidly through the Salt Section above the casing shoe.

6. Any cement used in setting casing or in plugging which

comes in contact with the Salt Section shall be of such chemical composition as to avoid dissolution of the Salt Section and to provide weight, strength, and physical properties sufficient to protect uphole formations and prevent blowouts or uncontrolled flows.

7. If a well is dry, cement plugs at least 200 feet in length shall be placed across the top and the base of the Salt Section, across any oil, gas or water show, and across any potash zone. Plugs shall not be required inside a properly cemented casing string. The division shall approve the location of the plugs after examining the appropriate logs, drilling and testing records for the well. No well shall be temporarily abandoned with open hole in the Salt Section.

8. The division may inspect the drilling operations at all times, including any mining operations that may affect any drilling or producing well bores. A potash owner, if contributing by agreement to the logging and directional survey costs of a well, may inspect the well for compliance with this rule.

9. Before commencing drilling operations for oil or gas on any land within designated potash area, the operator shall furnish by registered mail, a copy of the APD, together with the plat or map required under R649-3-4, to all potash owners and lessees whose interests are within a radius of 2,640 feet of the proposed well.

10. After proper notice and hearing, the board may modify this rule for a particular well or area by requiring that greater or lesser precautions be taken to prevent the escape of oil, gas, or water from one stratum into another. The board may also expand or contract from the designated potash areas.

R649-3-29. Workable Coal Beds.

1. Prior to commencing drilling operations for oil and gas on any lands where there are mine workings, the operator shall furnish a copy of the APD, a plat or map as required under R649-3-4, and a designation of the proposed angle and direction of the well, if the well is to be deviated substantially from a vertical course, to all coal owners and lessees whose interests are within a radius of 5,280 feet of the proposed well.

2. A well penetrating one or more workable coal beds or mine workings shall be drilled to a depth and shall be of a size, to permit the placing of casing in the hole at the points and in the manner necessary to exclude all oil, gas or gas pressure from the coal bed, other than oil, gas or gas pressure originating in the coal bed.

3. Unless otherwise authorized by the division, the casing run through a coal bed shall be seated at least 50 feet into the closest impervious formation below the coal bed. The casing shall be cemented solidly through the coal bed to a height at least 50 feet into the closest impervious formation above the coal bed.

4. A directional survey or a cement bond log shall be performed and furnished to the division upon written request by the division.

5. Upon penetrating a coal bed the operator shall notify the division, in writing, before completing or plugging and abandoning

the well.

R649-3-30. Underground Mining Operations.

1. Prior to commencing drilling operations for oil and gas on any land where there are known or suspected underground mining operations, solution mining operations or surface mining operations, including solar evaporation ponds, the operator shall include in the APD or in a separate cover letter, any information known to the operator concerning the name and address of the owner or operator of the mining workings.

2. The division may, with the concurrence of the operator, change the surface location of the proposed well if there appears to be any possibility of interference between the proposed well bore and the mine workings.

R649-3-31. Designated Oil Shale Areas.

1. Designated oil shale areas are subject to the general drilling, plugging and other performance standards described in this section, except where the board has adopted, by order, specific standards for individual oil shale areas. As of June 8, 2001, the board has adopted specific standards for individual oil shale areas by board orders in Cause Nos. 190-5(b), 190-3, and 190-13. The board may adopt specific standards in other areas, or modify the above orders, in the future.

2. Lands may be designated as an oil shale area by the board, either upon its own motion, or upon the petition of an interested person following notice and hearing.

3. As used in this rule, oil shale section means the sequence of strata containing oil shale beds, including any interbedded strata not containing oil shale, consisting of the Parachute Creek Member of the Green River Formation of Tertiary Age, defined as the stratigraphic equivalent of the interval between 1,428 feet and 2,755 feet below the Kelly Bushing on the induction-electrical log of the Ute Trail No. 10 well drilled by Dekalb Agricultural Association, Inc. and located in the NE 1/4 of Section 34, Township 9 South, Range 21 East, S.L.M., Uintah County, Utah.

The Mahogany Zone is defined as the stratigraphic equivalent of the interval between 2,230 feet and 2,360 feet below the Kelly Bushing on the induction-electrical log of the Ute Trail No. 10 well drilled by Dekalb Agricultural Association, Inc., and located in the NE 1/4 of Section 34, Township 9 South, Range 21 East, S.L.M., Uintah County, Utah.

4. For purposes of identifying the oil shale intervals, an appropriate electrical log shall be run through the oil shale section. One field copy of the log through the oil shale section shall be made available to the division pursuant to R649-3-23 or upon written request by the division.

5. On all wells which are intentionally deviated from the vertical within the oil shale section, pursuant to the provisions of R649-3-10 and R649-3-11, a directional survey shall be run from a point at least 20 feet below the oil shale section to the surface and shall thereafter be filed with the division within 20 days after reaching total depth.

6. Any oil shale lessee or operator whose oil shale mine

workings reach a distance of 2,640 feet from a producing well or any oil and gas lessee or operator whose producing well is approached by oil shale mine workings within a distance of 2,640 feet shall request agency action with the board. The board may promulgate an order after notice and hearing with respect to the running of a directional survey through the oil shale section, the cost and potential resource loss liability and responsibility as to the oil and gas operator and the oil shale lessee or operator and any other issues regarding multiple mineral development.

7. The directional survey shall be the confidential property of the parties paying for the survey and shall be kept confidential until released by said parties or the division.

8. In addition to the requirements pertaining to the cementing of casing contained in the R649-3-8, any casing set into or through the oil shale section shall be cemented over the entire oil shale section.

9. If a well is dry, junked or abandoned, a cement plug shall be placed across that portion of the oil shale section extending 200 feet above and 200 feet below the longitudinal center of the Mahogany Zone. The cement plug shall not be required inside a casing cemented in accordance with R649-3-31-7. When the casing is cemented, cement plugs 200 feet in length shall be centered across the top and across the base of the Parachute Creek Member of the Green River Formation.

10. In the event the casing is not cemented in accordance with R649-3-31-7, the division shall approve the method and procedure to prevent the migration of oil, gas, and other substances through the wellbore from one formation to another.

11. The division shall approve the adequacy and location of the cement plugs after examining the appropriate logs and drilling and testing records for the well, to ensure that the oil shale section is adequately protected.

12. Upon written request of the owner or operator under R649-8-6, the division shall keep all well logs confidential. The division may inspect the drilling operations at all times, including any mining operations that may affect drilling or producing well bores.

13. Before commencing drilling operations for oil or gas on any land within a designated oil shale area, the operator shall furnish a copy of the APD, together with a plat or map as directed under R649-3-4, to all oil shale owners or their lessees whose interests are within a radius of 2,640 feet of the proposed well. A notice of intention to plug and abandon any well in the oil shale area, as required under R649-3-24-1, shall be furnished to the owners or their lessees prior to commencement of plugging operations.

14. The operator shall use generally accepted techniques for vertical or directional drilling as defined under R649-3-10 and R649-3-11 to maintain the well bore within an intact core of a mine pillar. Within 20 days of reaching the total depth or before completion of the well, whichever is the earlier, a directional survey shall be run as prescribed by this rule.

R649-3-32. Reporting of Undesirable Events.

1. The division shall be notified of all fires, leaks, breaks, spills, blowouts, and other undesirable events occurring at any oil or gas drilling, producing, or transportation facility, or at any injection or disposal facility.

2. Immediate notification shall be required for all major undesirable events as outlined in R649-3-32-5. Immediate notification shall mean a verbal report submitted to the division as soon as practical but within a maximum of 24 hours after discovery of an undesirable event. A complete written report of the incident shall also be submitted to the division within five days following the conclusion of an undesirable event. The requirements for written reports are specified in R649-3-32-4.

3. Subsequent notification shall be required for all minor undesirable events as outlined in R649-3-32-6. Subsequent notification shall mean a complete written report of the incident submitted to the division within five days following the conclusion of an undesirable event. The requirements for written reports are specified in R649-3-32-4.

4. Complete written reports of undesirable events may be submitted on Form 9, Sundry Notice and Report on Wells. The report shall include:

4.1. The date and time of occurrence and, if immediate notification was required, the date and time the occurrence was reported to the Division.

4.2. The location where the incident occurred described by section, township, range, and county.

4.3. The specific nature and cause of the incident.

4.4. A description of the resultant damage.

4.5. The action taken, the length of time required for control or containment of the incident, and the length of time required for subsequent cleanup.

4.6. An estimate of the volumes discharged and the volumes not recovered.

4.7. The cause of death if any fatal injuries occurred.

5. Major undesirable events include the following:

5.1. Leaks, breaks or spills of oil, salt water or oil field wastes which result in the discharge of more than 100 barrels of liquid, which are not fully contained on location by a wall, berm, or dike.

5.2. Equipment failures or other accidents which result in the flaring, venting, or wasting of more than 500 Mcf of gas.

5.3. Any fire which consumes the volumes of liquid or gas specified in R649-3-32-5.1 and R649-3-32-5.2.

5.4. Any spill, venting, or fire, regardless of the volume involved, which occurs in a sensitive area stipulated on the approval notice of the initial APD for a well, e.g., parks, recreation sites, wildlife refuges, lakes, reservoirs, streams, urban or suburban areas.

5.5. Each accident which involves a fatal injury.

5.6. Each blowout, loss of control of a well.

6. Minor undesirable events include the following:

6.1. Leaks, breaks or spills or oil, salt water, or oil field wastes which result in the discharge of more than ten barrels of liquid and are not considered major events in R649-3-

32-5.

6.2 Equipment failures or other accidents which result in the flaring, venting or wasting of more than 50 Mcf of gas and are not considered major events in R649-3-32-5.

6.3. Any fire which consumes the volumes of liquid or specified in R649-3-32-6.1 and R649-3-32-6.2.

6.4. Each accident involving a major or life-threatening injury.

R649-3-33. Drilling Procedures in the Great Salt Lake.

1. For all drilling activities proposed within the Great Salt Lake, the APD required by R649-3-4 shall be filed at least 30 days prior to the date on which the operator intends to commence operations. As part of the APD, the operator shall include:

1.1. The name of the drilling contractor and the number and type of rig to be used.

1.2. An illustration of the boundaries of all state or federal parks, wildlife refuges, or waterfowl management areas within one mile of the proposed well location.

1.3. An illustration of the locations of all evaporation pits, producing wells, structures, buildings, and platforms within one mile of the proposed well location.

1.4. An oil spill emergency contingency plan.

2. Unless permitted by the board after notice and hearing, no well shall be drilled which has a surface location:

2.1. Within 1,320 feet from an evaporation pit without the consent of the operator of such pit.

2.2. Within one mile from the boundary of a state or federal park, wildlife refuge, or waterfowl management area without the consent of the appropriate state or federal regulatory agency.

2.3. Within three miles of Gunnison Island during the Pelican nesting season (March 15 through September 30) or within one mile from said island at any other time.

2.4. Within any area south of the Salt Lake Base Meridian Line.

2.5. Within any area north of Township 10 North.

2.6. Within one mile inside of what would be the water's edge if the water level of the Great Salt Lake were at the elevation of 4,193.3 feet above sea level.

3. Well casing and cementing shall be subject to the following special requirements for the purpose of this rule, the several casing strings in order of normal installation are drive or structural casing, conductor casing, surface casing, intermediate casing, and production casing. All depths refer to true vertical depth:

3.1. The drive or structural casing shall be set by drilling, driving or jetting to a minimum depth of 50 feet below the floor of the lake bed or to such greater depth required to support unconsolidated deposits and to provide hole stability for initial drilling operations. If drilled in, the drilling fluid shall be a type that will not pollute the lake; in addition, a quantity of cement sufficient to fill the annular space back to the lake floor with returns circulated, must be used.

3.2. The conductor casing shall be set at a minimum depth of

200 feet below the floor of the lake, and shall be cemented with a quantity sufficient to fill the annular space back to the lake surface with returns circulated.

3.3. The surface casing shall be set at a minimum depth of 500 feet if the proposed depth of the well is less than 7,000 feet; or 1,000 feet if the proposed depth is over 7,000 feet but less than 11,000 feet; or 1,500 feet if the depth is 11,000 feet. The casing shall be cemented with a quantity sufficient to fill the annular space back to the lake surface with returns circulated, and the bottom of the casing shall be in competent rock.

3.4. The intermediate and production casing shall be set at any time when drilling below the surface casing and hole conditions justify setting casing. This casing will be cemented in such a manner that all hydrocarbons, water aquifers, lost-circulation or zones of significant porosity and permeability, significant beds containing priority minerals, and abnormal pressure intervals are covered or isolated.

3.5. Prior to drilling the plug after cementing, all casing strings except the drive or structural casing, shall be pressure tested. This test shall not exceed the rated working pressure of the casing. If the pressure declines more than ten percent in 30 minutes, or if there are other indications of a leak, corrective measures must be taken until a satisfactory test is obtained. All casing pressure tests shall be recorded on the driller's log.

4. Blowout preventers and related well control equipment shall be installed, and tested in a manner necessary to prevent blowouts and shall be subject to the following special conditions:

4.1. Prior to drilling below the surface casing, blowout prevention equipment shall be installed and maintained ready for use until drilling operations are completed.

4.2. An inside blowout preventer assembly and a full opening string safety valve in the open position shall be maintained on the rig floor at all times while drilling operations are being conducted. Valves shall be maintained on the rig floor to fit all pipe in the drill string. A top kelly cock shall be installed below the swivel and another at the bottom of the kelly of such design that it can be run through the blowout preventers.

4.3. Before drilling below the surface casing the blowout prevention equipment shall include a minimum of:

4.3.1. Three remotely and manually controlled, hydraulically operated blowout preventers with a rated working pressure which exceeds the maximum anticipated surface pressure, including one equipped with pipe rams, one with blind rams and one hydril type.

4.3.2. A drilling spool with side outlets, if side outlets are not provided in the blowout preventer body.

4.3.3. A choke manifold.

4.3.4. A kill line.

4.3.5. A fill-up line.

4.4. Ram-type blowout preventers and related control equipment shall be tested to the rated working pressure of the stack assembly or to the working pressure of the casing, whichever is the lesser, at the following times:

4.4.1. When installed.

4.4.2. Before drilling out after each string of casing is set.

4.4.3. Not less than once each week while drilling.

4.4.4. Following repairs that require disconnecting a pressure seal in the assembly.

4.5. The hydril-type blowout preventer shall be tested to 70 percent of the pressure testing requirements of ram-type blowout preventers. The hydril-type blowout preventer shall be actuated on the drill pipe once each week.

4.6. Accumulators or accumulators and pumps shall maintain a reserve capacity at all times to provide for repeated operation of hydraulic preventers.

4.7. A blowout prevention drill shall be conducted weekly for each drilling crew to insure that all equipment is operational and that crews are properly trained to carry out emergency duties. All blowout preventer tests and crew drills shall be recorded on the driller's log.

5. The characteristics and use of drilling mud and the conduct of related drilling procedures shall be such as are necessary to maintain the well in a safe condition to prevent uncontrolled blowouts of any well. Quantities of mud materials sufficient to insure well control shall be maintained and readily accessible for use at all times.

6. Mud testing equipment shall be maintained on the derrick floor at all times, and mud tests consistent with good operating practice shall be performed daily, or more frequently as conditions warrant. The following mud system monitoring equipment must be installed, with derrick floor indicators, and used throughout the period of drilling after setting and cementing the surface casing:

6.1. A recording mud pit level indicator including a visual and audio warning device to determine mud pit volume gains and losses.

6.2. A mud return indicator to determine when returns have been obtained, or when they occur unintentionally, and additionally to determine that returns essentially equal the pump discharge rate.

7. In the conduct of all oil and gas operations, the operator shall prevent pollution of the waters of the Great Salt Lake. The operator shall comply with the following pollution prevention requirements:

7.1. Oil in any form, liquid or solid wastes containing oil, shall not be disposed of into the waters of the lake.

7.2. Liquid or solid waste materials containing substances which may be harmful to aquatic life or wildlife, or injurious in any manner to life and property, or which in any way unreasonably adversely affects the chemicals or minerals in the lake shall not be disposed of into the waters of the lake.

7.3. Waste materials, exclusive of cuttings and drilling media, shall be transported to shore for disposal.

8. All spills or leakage of oil and liquid or solid pollutants shall be immediately reported to the division. A complete written statement of all circumstances, including subsequent clean-up operation, shall be forwarded to said agencies

within 72 hours of such occurrences.

9. Standby pollution control equipment consistent with the state of the art, shall be maintained by, and shall be immediately available to, each operator.

R649-3-34. Well Site Restoration.

1. The operator of a well shall upon plugging and abandonment of the well restore the well site in accordance with these rules.

2. For all land included in the well site for which the surface is federal, Indian, or state ownership, the operator shall meet the well site restoration requirements of the appropriate surface management agency.

3. For all land included in the well site for which the surface is fee or private ownership, the operator shall meet the well site restoration requirements of the private landowner or the minimum well site restoration requirements established by the division.

4. Well site restoration on lands with fee or private ownership shall be completed within one (1) year following the plugging of a well unless an extension is approved by the division for just and reasonable cause.

5. These rules shall not preclude the opportunity for a private landowner to assume liability for the well as a water well in accordance with R649-3-24.6.

6. The operator shall make a reasonable effort to establish surface use agreements with the owners of land included in the well site prior to the commencement of the following actions on fee or private surface:

6.1 Drilling a new well.

6.2. Reentering an abandoned well.

6.3. Assuming operatorship of existing wells.

7. Upon application to the division to perform any of the aforementioned and prior to approval of such actions by the division, the operator shall submit an affidavit to the division stating whether appropriate surface use agreements have been established with and approved by the surface landowners of the well site.

8. If necessary and upon request by the division, the operator shall submit a copy of the established surface use agreements to the division.

9. If no surface use agreement can be established, the division shall establish minimum well site restoration requirements for any well located on fee or private surface for the purposes of final bond release.

10. Established surface use agreements may be modified or terminated at any time by mutual consent of the involved parties; however, the operator shall notify the division if such is the case and if a surface use agreement is terminated without a new agreement established, the division shall establish minimum well site reclamation requirements.

11. The operator shall be responsible for meeting the requirements of any surface use agreement, and it shall be assumed by the division until notified otherwise that surface use

agreements remain in full force and effect until all the requirements of the agreement are satisfied or until the agreement has been terminated by mutual consent of the involved parties.

12. The surface use agreement shall stipulate the minimum well site restoration to be performed by the operator in order to allow final release of the bond.

13. The final bond release by the division shall include a determination by the division whether or not the operator has met the requirements of an established surface use agreement, and the division may suspend final bond release until the operator has completed all the requirements of the surface use agreement.

14. The agreement may state requirements for well site grading, contouring, scarification, reseeding, and abandonment of any equipment or facilities for which the landowner agrees to assume liability.

15. The agreement shall not address operations regulated by the rules and orders of the board such as:

15.1. Disposal of drilling fluid, produced fluid, or other fluid waste associated with the drilling and production of the well.

15.2. Reclamation or treating of waste crude oil.

15.3. Any other operation or condition for which the board has jurisdiction.

16. If the operator cannot establish surface use agreements then the operator shall so notify the division.

17. Within 30 days of the notification or as soon as weather conditions permit, the division shall conduct an inspection and evaluation of the well site in order to establish minimum well site restoration requirements for the purpose of final bond release.

18. The operator shall be given notice by the division of the date and time of the inspection, and if the operator cannot attend the inspection at the scheduled date and time, the division may reschedule the inspection to allow the operator to participate.

19. The surface landowner, agent or lessee shall be given notice by the operator of such inspection and may participate in the inspection; however, if the surface landowner cannot attend the inspection, the division shall not be required to reschedule the inspection in order to allow the surface landowner to participate.

20. The evaluation shall consider the condition of the land prior to disturbance, the extent of proposed disturbance, the degree of difficulty to conduct complete restoration, the potential for pollution, the requirements for abating pollution, and the possible land use after plugging and restoration are completed.

21. Within 30 days after performing the inspection, the division shall provide the operator with the results of the inspection and the evaluation listing the minimum well site restoration requirements established by the division.

22. The division shall retain a record of the inspection and the evaluation, and if necessary and upon written request by an interested party, the division shall provide a copy of the minimum

well site restoration requirements established by the division.

23. If any person disagrees with the results of the inspection and the evaluation and desires a reconsideration of the minimum well site restoration requirements established by the division, such person may submit a request to the board for a hearing and order to modify the requirements.

24. The board, after proper notice and hearing, may issue an order modifying the minimum well site restoration requirements established by the division.

25. The minimum well site restoration requirements established by the division or by board order shall be considered part of any permit granted by the division to conduct operations at a well site, and the inability of the operator to meet such requirements shall be considered grounds for forfeiture of the bond.

26. If the minimum well site restoration requirements suggest to the division that bond coverage for a well should be increased, the division shall take action as stated in R649-3-1.

R649-3-35. Wildcat Wells.

1. For purposes of qualifying for a severance tax exemption under Section 59-5-102(2)(d), an operator must file an application with the division for designation of a wildcat well. The application may be filed prior to drilling the well, and a tentative determination of the wildcat designation will be issued at that time. An application or request for final designation of wildcat status as appropriate, must be filed at the time of filing of Form 8, Well Completion or Recompletion Report and Log. The application shall contain, where applicable, the following information:

1.1. A plat map showing the location of the well in relation to producing wells within a one mile radius of the wellsite.

1.2. A statement concerning the producing formation or formations in the wildcat well and also the producing formation or formations of the producing wells in the designated area, including completion reports and other appropriate data.

1.3. Stratigraphic cross sections through the producing wells in the designated area and the proposed wildcat well.

1.4. A statement as to whether the well is in a known geologic structure. However, whether the well is in a known geologic structure shall not be the sole basis of determining whether the well is a wildcat.

1.5. Bottomhole pressures, as applicable, in a wildcat well compared to the wells producing in the designated area from the same zone.

1.6. Any other information deemed relevant by the applicant or requested by the division.

2. Information derived from well logs, including certain information in completion reports, stratigraphic cross sections, bottomhole pressure data, and other appropriate data provided in R649-3-35-1 will be held confidential in accordance with R649-2-11 at the request of the operator.

3. The division shall review the submitted information and advise the operator and the State Tax Commission of its decision

regarding the wildcat well designation as related to Section 59-5-102(2)(d).

4. The division is responsible for approval of a request for designation of a well as a wildcat well. If the operator disagrees with the decision of the division, the decision maybe appealed to the board. Appeals of all other tax-related decisions concerning wildcat wells should be made to the State Tax Commission.

R649-3-36. Shut-in and Temporarily Abandoned Wells.

1. Wells may be initially shut-in or temporarily abandoned for a period of twelve (12) consecutive months. If a well is to be shut-in or temporarily abandoned for a period exceeding twelve (12) consecutive months, the operator shall file a Sundry Notice providing the following information:

1.1. Reasons for shut-in or temporarily abandonment of the well,

1.2. The length of time the well is expected to be shut-in or temporarily abandoned, and

1.3. An explanation and supporting data if necessary, for showing the well has integrity, meaning that the casing, cement, equipment condition, static fluid level, pressure, existence or absence of Underground Sources of Drinking Water and other factors do not make the well a risk to public health and safety or the environment.

2. After review the Division will either approve the continued shut-in or temporarily abandoned status or require remedial action to be taken to establish and maintain the well's integrity.

3. After five (5) years of nonactivity or nonproductivity, the well shall be plugged in accordance with R649-3-24, unless approval for extended shut-in time is given by the Division upon a showing of good cause by the operator.

4. If after a five (5) year period the well is ordered plugged by the Division, and the operator does not comply, the operator shall forfeit the drilling and reclamation bond and the well shall be properly plugged and abandoned under the direction of the Division.

R649-3-37. Enhanced Recovery Project Certification.

1. In order for incremental production achieved from an enhanced recovery project to qualify for the severance tax rate reduction provided under Subsection 59-5-102(4), the operator on behalf of the producers shall present evidence demonstrating that the recovery technique or techniques utilized qualify for an enhanced recovery determination and the Board must certify the project as an enhanced recovery project.

2. For enhanced recovery projects certified by the Board after January 1, 1996:

2.1. As part of the process of certifying incremental production which qualifies for a reduction in the severance tax rate under Subsection 59-5-102(4), the operator shall furnish the Division an extrapolation (projection) and tabulation of expected non-enhanced recovery of oil and gas production from the project.

The projection shall be for not less than seventy-two (72) months commencing with the first month following the project certification by the Board. The projection shall be based on production history of all wells within the project area for not less than twelve (12) months immediately preceding either certification or commencement of the project; reservoir and production characteristics; and the application of generally accepted petroleum engineering practices. The projected production volumes approved by the division shall serve as the base level production for purposes of determining the incremental oil and gas production which qualifies for a reduction in the severance tax rate.

2.2. The operator shall provide a statement as to all assumptions made in preparing the projection and any other information concerning the project that the division may reasonably require in order to evaluate the operator's projection.

2.3. An operator's request for incremental production certification may be approved administratively by the Director or authorized agent. The Director or authorized agent shall review the request within 30 days after its receipt and advise the operator of the decision. If the operator disagrees with the Director or authorized agent's decision, the operator may request a hearing before the Board at its next regularly scheduled hearing. The Director or authorized agent may also refer the matter to the Board if a decision is in doubt.

2.4. Upon approval of a request for incremental production certification, the Director or authorized agent shall forward a copy of the certification to the Utah Tax Commission.

KEY: oil and gas law
July 1, 2003 **40-6-1 et seq.**
Notice of Continuation March 26, 2002

R649. Natural Resources; Oil, Gas and Mining; Oil and Gas.
R649-4. Determination of Well Categories Under the Natural Gas Policy Act of 1978.
R649-4-1. Definitions.

1. Unless the context specifically requires otherwise, any special words, terms, or phrases used in the Section and not defined in Section 1 have the meanings defined under the Natural Gas Policy Act of 1978 (NGPA), and applicable Federal Energy Regulatory Commission (FERC) rules and regulations.

R649-4-2. Applications.

An operator requesting the classification of a well or reservoir pursuant to the authority granted to the Board by Section 503 of the NGPA, in order to enable the Board to determine the applicable category for any such well or reservoir pursuant to Title 1 of the NGPA, shall:

1. File the original and two copies of a written application made upon forms prescribed by the Board together with supporting documentation, including all information, data, forms, plats, maps, exhibits, and evidence as may be required by the applicable

statutes, rules, and regulations. An application may be amended, supplemented, or withdrawn by the applicant at any time prior to the Board determination.

1.1. Complete an individual application as to each well for which a status determination is being requested. If more than one status determination is being requested for a single well, all forms and information required for each requested determination shall be submitted jointly under one application, with notice to the Board that multiple determinations for one well are being sought under the application.

1.2. File an affidavit as to the truthfulness and correctness of all information contained in the application, including all documents, testimony, and evidence attached to or submitted with the application.

1.3. Certify that the purchaser and owners of the natural gas for which the determination is being submitted, have been served by personal delivery or by mail, postage prepaid, with a copy of the application, including a complete FERC Form 121, excluding required supporting documents.

R649-4-3. Notice and Hearing.

1. Upon receipt of an application for a well status determination under the NGPA, the Board shall:

1.1. Notify the applicant of the receipt of the application;

1.2. Determine the completeness of the application. If the application is incomplete in any respect, the Board shall indicate to the applicant the items to be filed which would make the application complete;

1.3. Assign a cause number to each application, determine a hearing date for each complete application, and notify the applicant of the cause number and hearing date;

1.4. Cause notice of hearing to be given.

2. If the same applicant has filed for multiple well determinations or for multiple determinations as to any well, the published notice of hearing may include more than one well or reservoir in one notice.

R649-4-4. Determination and Orders.

1. Following notice and hearing, the Board shall issue a determination and order for each complete application.

2. If no response or protest to the application is filed with the Board, an application may be considered and a determination may be made by the Director or a designated hearing examiner on the basis of sworn testimony, depositions, or affidavits, together with all exhibits, forms, and other matters properly filed with the Board. Such matters shall comprise the transcript of the hearing on which the determination is based.

3. An applicant may also request consideration and a determination by the Director or a designated hearing examiner by filing a letter with the Board agreeing that the determination can be made by the Director without the necessity of an appearance by the applicant. The Board may, however, upon its own motion, require an evidentiary hearing with sworn testimony to be held upon any application following proper notice. In the event the

Board determines that a hearing is required, the Board shall notify the applicant at least ten days prior to the scheduled hearing date.

R649-4-5. Notice of Determination.

Within five days after the last day for filing a motion for rehearing, or, if such a motion is filed, within 15 days after it is denied or overruled by operation of law, the Board shall give written notice to the FERC of its determination and order.

KEY: oil and gas law
January 3, 2001 40-6-1 et seq.

R649. Natural Resources; Oil, Gas and Mining; Oil and Gas.
R649-5. Underground Injection Control of Recovery Operations and Class II Injection Wells.
R649-5-1. Requirements For Injection Of Fluids Into Reservoirs.

1. Operations to increase ultimate recovery, such as cycling of gas, the maintenance of pressure, the introduction of gas, water or other substances into a reservoir for the purpose of secondary or other enhanced recovery or for storage and the injection of water into any formation for the purpose of water disposal shall be permitted only by order of the board after notice and hearing.

2. A petition for authority for the injection of gas, liquefied petroleum gas, air, water, or any other medium into any formation for any reason, including but not necessarily limited to the establishment of or the expansion of waterflood projects, enhanced recovery projects, and pressure maintenance projects shall contain:

2.1. The name and address of the operator of the project.

2.2. A plat showing the area involved and identifying all wells, including all proposed injection wells, in the project area and within one-half mile radius of the project area.

2.3. A full description of the particular operation for which approval is requested.

2.4. A description of the pools from which the identified wells are producing or have produced.

2.5. The names, description and depth of the pool or pools to be affected.

2.6. A copy of a log of a representative well completed in the pool.

2.7. A statement as to the type of fluid to be used for injection, its source and the estimated amounts to be injected daily.

2.8. A list of all operators or owners and surface owners within a one-half mile radius of the proposed project.

2.9. An affidavit certifying that said operators or owners and surface owners within a one-half mile radius have been provided a copy of the petition for injection.

2.10. Any additional information the board may determine is necessary to adequately review the petition.

3. Applications as required by R649-5-2 for injection wells

which are located within the project area, may be submitted for board consideration and approval with the request for authorization of the recovery project.

4. Established recovery projects may be expanded and additional wells placed on injection only upon authority from the board after notice and hearing or by administrative approval.

5. If the proposed injection interval can be classified as an USDW, approval of the project is subject to the requirements of R649-5-4.

R649-5-2. Requirements For Class II Injection Wells Including Water Disposal, Storage And Enhanced Recovery Wells.

1. Injection wells shall be completed, equipped, operated, and maintained in a manner that will prevent pollution and damage to any USDW, or other resources and will confine injected fluids to the interval approved.

2. The application for an injection well shall include a properly completed UIC Form 1 and the following:

2.1. A plat showing the location of the injection well, all abandoned or active wells within a one-half mile radius of the proposed well, and the surface owner and the operator of any lands or producing leases, respectively, within a one-half mile radius of the proposed injection well.

2.2. Copies of electrical or radioactive logs, including gamma ray logs, for the proposed well run prior to the installation of casing and indicating resistivity, spontaneous potential, caliper, and porosity.

2.3. A copy of a cement bond or comparable log run for the proposed injection well after casing was set and cemented.

2.4. Copies of logs already on file with the division should be referenced, but need not be refiled.

2.5. A description of the casing or proposed casing program of the injection well and of the proposed method for testing the casing before use of the well.

2.6. A statement as to the type of fluid to be used for injection, its source and estimated amounts to be injected daily.

2.7. Standard laboratory analyses of (1) the fluid to be injected, (2) the fluid in the formation into which the fluid is being injected, and (3) the compatibility of the fluids.

2.8. The proposed average and maximum injection pressures.

2.9. Evidence and data to support a finding that the proposed injection well will not initiate fractures through the overlying strata or a confining interval that could enable the injected fluid or formation fluid to enter the fresh water strata.

2.10. Appropriate geological data on the injection interval and confining beds, and nearby Underground Sources of Drinking Water, including the geologic name, lithologic description, thickness, depth, water quality, and lateral extent; also information relative to geologic structure near the proposed well which may effect the conveyance and/or storage of the injected fluids.

2.11. A review of the mechanical condition of each well within a one-half mile radius of the proposed injection well to assure that no conduit exists that could enable fluids to migrate up or down the wellbore and enter improper intervals.

2.12. An affidavit certifying that a copy of the application has been provided to all operators, owners, and surface owners within a one-half mile radius of the proposed injection well.

2.13. Any other additional information that the board or division may determine is necessary to adequately review the application.

3. Applications for injection wells which are within a recovery project area will be considered for approval:

3.1. Pursuant to R649-5-1-3.

3.2. Subsequent to board approval of a recovery project pursuant to R649-5-1-1.

4. Approval of an injection well is subject to the requirements of R649-5-4, if the proposed injection interval can be classified as an USDW.

5. In addition to the requirements of this section, the provisions of R649-3-1, R649-3-4, R649-3-24, R649-3-32, and R649-8-1 and R649-10 shall apply to all Class II injection wells.

R649-5-3. Noticing and Approval Of Injection Wells.

1. Applications for injection wells submitted pursuant to R649-5-1-3 shall be noticed in conformance with the procedural rules of the board as part of the hearing for the recovery project. Any person desiring to object to approval of such an application for an injection well shall file the objection in conformance with the procedural rules of the board.

2. The receipt of a complete and technically adequate application, other than an application submitted pursuant to R649-5-3-1, shall be considered as a request for agency action by the Division and shall be published in a daily newspaper of general circulation in the city and county of Salt Lake and in a newspaper of general circulation in the county where the proposed well is located. A copy of the notice of agency action shall also be sent to all parties including government agencies. The notice of agency action shall contain at least the following information:

2.1. The applicant's name, business address, and telephone number.

2.2. The location of the proposed well.

2.3. A description of proposed operation.

3. If no written objection to the application for administrative approval of an injection well is received by the division within 15 days after publication of the notice of agency action, or an aquifer exemption is not required in accordance with R649-5-4, and a board hearing is not otherwise required, the application may be considered and approved administratively.

4. If a written objection to an application for administrative approval of an injection well is received by the division within 15 days after publication of the notice of application, or if a hearing is required by these rules or deemed advisable by the director, the application shall be set for notice and hearing by the board.

5. The director shall have the authority to grant an exception to the hearing requirements of R649-5-1.1 for conversion to injection of additional wells which constitute a modification

or expansion of an authorized project provided that any such well is necessary to develop or maintain thorough and efficient recovery operations for any authorized project and provided that no objection is received pursuant to R649-5-3-3.

6. The director shall have authority to grant an exception to the hearing requirements of R649-5-1-1 for water disposal wells provided disposal is into a formation or interval that is not currently nor anticipated to be an underground source of drinking water and provided that no objection is received pursuant to R649-5-3-3.

R649-5-4. Aquifer Exemption.

1. The board may, after notice and hearing and subject to the EPA approval, authorize the exemption of certain aquifers from classification as an USDW based upon the following findings:

1.1. The aquifer does not currently serve as a source of drinking water.

1.2. The aquifer cannot now and will not in the future serve as a source of drinking water for any of the following reasons:

1.2.1. The aquifer is mineral, hydrocarbon or geothermal energy producing, or it can be demonstrated by the applicant as part of a permit application for a Class II well operation, to contain minerals or hydrocarbons that, considering their quantity and location, are expected to be commercially producible.

1.2.2. The aquifer is situated at a depth or location that makes recovery of water for drinking water purposes economically or technologically impractical.

1.2.3. The aquifer is contaminated to the extent that it would be economically or technologically impractical to render water from the aquifer fit for human consumption.

1.2.4. The aquifer is located above a Class III well mining area subject to subsidence or catastrophic collapse.

1.3. The total dissolved solids content of the water from the aquifer is more than 3,000 and less than 10,000 mg/l, and the aquifer is not reasonably expected to be used as a source of fresh or potable water.

2. Interested parties desiring to have an aquifer exempted from classification as a USDW, shall submit to the division an application that includes sufficient data to justify the proposal. The division shall consider the application and if appropriate, will advise the applicant to submit a request to the board for an aquifer exemption.

R649-5-5. Testing And Monitoring Of Injection Wells.

1. Before operating a new injection well, the casing shall be tested to a pressure not less than the maximum authorized injection pressure, or to a pressure of 300 psi, whichever is greater.

2. Before operating an existing well newly converted to an injection well, the casing outside the tubing shall be tested to a pressure not less than the maximum authorized injection pressure, or to a pressure of 1,000 psi, whichever is lesser, provided that each well shall be tested to a minimum pressure of 300 psi.

3. In order to demonstrate continuing mechanical integrity

after commencement of injection operations, all injection wells shall be pressure tested or monitored as follows:

3.1. Pressure Test. The casing-tubing annulus above the packer shall be pressure tested not less than once each five years to a pressure equal to the maximum authorized injection pressure or to a pressure of 1,000 psi, whichever is lesser, provided that no test pressure shall be less than 300 psi. A report documenting the test results shall be submitted to the division.

3.2. Monitoring. If approved by the director, and in lieu of the pressure testing requirement, the operator may monitor the pressure of the casing-tubing annulus monthly during actual injection operations and report the results to the division.

3.3. Other test procedures or devices such as tracer surveys, temperature logs or noise logs may be required by the division on a case-by-case basis.

3.4. The operator shall sample and analyze the fluids injected in each disposal well or enhanced recovery project at sufficiently frequent time intervals to yield data representative of fluid characteristics, and no less frequently than every year. The operator shall submit a copy of the fluid analysis to the division with the Annual Fluid Injection Report, UIC Form 4.

R649-5-6. Duration Of Approval For Injection Wells.

1. Approvals or orders authorizing injection wells shall be valid for the life of the well, unless revoked by the board for just cause, after notice and hearing.

2. An approval may be administratively amended if:

2.1. There is a substantial change of conditions in the injection well operation.

2.2. There are substantial changes to the information originally furnished.

2.3. Information as to the permitted operation indicates that an USDW is no longer being protected.

R649-5-7. Unit or Cooperative Development Or Operation.

Any person desiring to obtain the benefits of Section 40-6-7(1) insofar as the same relates to any method of unit or cooperative development or operation of a field or pool or a part of either, shall file a Request for Agency Action and a copy of such agreement with the board for approval after notice and hearing.

KEY: oil and gas law
June 2, 1998 **40-6-1 et seq.**
Notice of Continuation March 26, 2002

R649. Natural Resources; Oil, Gas and Mining; Oil and Gas.
R649-6. Gas Processing and Waste Crude Oil Treatment.
R649-6-1. Gas Processing Plants.

1. In accordance with Section 40-6-16 any operator of a facility or plant in which liquefiable hydrocarbons are removed from natural gas, including wet gas or casinghead gas, and the remaining residue gas is conditioned for delivery for sale,

recycling, or other use, shall file monthly, Form 13-A and Form 13-B.

1.1. Reports shall be filed for all gas processing plants or facilities to account for the receipt, processing, and disposition of all gas by the plant.

1.2. Plant operators that are required by contractual arrangements to allocate the residue gas and extracted liquids processed by the plant or facility to the individual producing wells, shall identify each well connected to the plant or facility by API number and report the metered wet gas volumes, residue gas volumes returned to the field, and all allocated residue gas and natural gas liquid volumes.

R649-6-2. Waste Crude Oil Treatment Facilities.

1. Prior to the construction of a waste crude oil treatment facility, an application shall be submitted to the division describing the ownership, location, type, and capacity of the facility contemplated; the extent and location of the surface area to be disturbed, including any pit, pond, or land associated with the facility; and a reclamation plan for the site. Approval of the application must be issued by the division before any ground clearing or construction shall occur.

2. As a condition for approval of any application, the owner or operator shall post a bond in an amount determined by the division to cover reclamation costs for the site. Failure to post the bond shall be considered sufficient grounds for denial of the application.

3. No waste crude oil treatment facility operator shall accept delivery of crude oil obtained from any tank, reserve pit, disposal pond or pit, or similar facility unless the delivery is accompanied by a run ticket, invoice, receipt or similar document showing the origin and quantity of the crude oil.

KEY: oil and gas law
1989 40-6-1 et seq
Notice of Continuation December 19, 2003

R649. Natural Resources; Oil, Gas and Mining; Oil and Gas.
R649-8. Reporting and Report Forms.
R649-8-1. General Report Forms.

1. The forms listed below, as modified by the Division from time to time shall be used for the purpose indicated in accordance with the instructions and the applicable rule.

Form 1 Application for Permit to Conduct Seismic Exploration R649-8-2

Form 2 Seismic Exploration Completion Report R649-8-3

Form 3 Application for Permit to Drill, Deepen, or Plug Back (APD) R649-8-4

Form 4 Bond R649-8-5

Form 5 Designation of Agent or Operator R649-8-6

Form 6 Entity Action Form R649-8-7

Form 7 Report of Water Encountered During Drilling R649-8-8

Form 8 Well Completion or Recompletion Report and Log R649-

8-9

Form 9 Sundry Notices and Reports on Wells R649-8-10

Form 10 Monthly Oil and Gas Production Report R649-8-11

Form 11 Monthly Oil and Gas Disposition Report R649-8-12

Form 12 Report of Transferred Oil R649-8-13

Form 13-A Monthly Summary Report of Gas Processing Plant Operations R649-8-14

Form 13-B Monthly Report of Gas Processing Plant Product Allocations R649-8-15

Form 14 Monthly Report of Waste Crude Oil Treatment Facility Operations R649-8-16

Form 15 Designation of Workover or Recompletion R649-8-17

UIC Form 1 Application for Injection Well R649-8-23

UIC Form 2 Monthly Report of Enhanced Recovery Project R649-8-24

UIC Form 3 Monthly Injection Report R649-8-25

UIC Form 4 Annual Fluid Injection Report R649-8-26

UIC Form 5 Transfer of Authority to Inject R649-8-27

UIC Form 6 Monthly Produced Water Disposition Report R649-8-28

2. Any permitted well which is referenced on a report form, correspondence, or well log should be identified by its assigned API number.

R649-8-2. Form 1, Application for Permit to Conduct Seismic Exploration.

At least seven days prior to commencing any type of seismic exploration operations, an Application for Permit to Conduct Seismic Exploration shall be submitted in duplicate to the division by the seismic contractor in accordance with R649-3-26.

R649-8-3. Form 2, Seismic Exploration Completion Report.

Within 60 days of the completion of each seismic exploration project, a Seismic Exploration Completion Report shall be submitted to the division by the seismic contractor in accordance with R649-3-26.

R649-8-4. Form 3, Application for Permit to Drill, Deepen, or Plug Back (APD).

Prior to the commencement of drilling, deepening, or plugging back any well or the commencement of exploratory drilling such as core holes and stratigraphic test holes, and prior to the commencement of any surface disturbance associated with such activity, the operator shall submit in duplicate an Application for Permit to Drill, Deepen, or Plug Back in accordance with R649-3-4.

R649-8-5. Form 4, Bond.

Except where a bond in satisfactory form has been filed by the operator in accordance with state, federal, or Indian lease requirements and evidence has been furnished to the division that such bond has been approved by the appropriate agency, the division shall require from the operator a good and sufficient bond in accordance with R649-3-1.

R649-8-6. Form 5, Designation of Agent or Operator.

Prior to the commencement of operations, a Designation of Agent or Operator shall be filed with the division in accordance with R649-2-4.

R649-8-7. Form 6, Entity Action Form.

1. For the purpose of accurately establishing the division's computerized oil and gas production accounting system and properly maintaining division of interest data for each well in the system, the operator shall file an Entity Action Form with the division within five working days of any of the following actions:

1.1. Spudding of a well, R649-3-6.

1.2. A change in operations which requires adding or removing a well from a group of wells that have identical division of interests, produce from the same formation, have product sales from a common tank, LACT meter, or gas meter, and have the same operator.

1.3. A change in operations when a service well is converted to a producing oil or gas well.

1.4. A change in operations when a well is recompleted and is capable of producing from another formation, R649-3-23.

1.5. A change in interest which requires adding or removing a well from a participating area of a properly designated unit.

2. Upon receipt of an Entity Action Form, the division will assign an entity number to a new well or change the entity number as needed for an existing well. This number identifies the well on the operator's monthly oil and gas production and disposition reports. Entity numbers are used by the State Tax Commission and the Division of State Lands and Forestry to properly account for all production taxes and the divisions of royalty interest on state leases.

3. This form does not take the place of Form 9, Sundry Notices and Reports on Wells, which is to be used to provide detailed accounts of physical operations on wells.

R649-8-8. Form 7, Report of Water Encountered During Drilling.

The operator shall report to the division all fresh water sands encountered during drilling in accordance with R649-3-6. The report shall be filed with the Well Completion or Recompletion Report and Log, Form 8.

R649-8-9. Form 8, Well Completion or Recompletion Report and Log.

In accordance with R649-3-11, R649-3-21, R649-3-23, and R649-3-24, the operator shall file a Well Completion or Recompletion Report and Log and a copy of the electric and radioactivity logs, if run, within 30 days after completing, recompleting, or plugging a well.

R649-8-10. Form 9, Sundry Notices and Reports on Wells.

1. This report form shall be used to notify the division of the intention to do miscellaneous work on any well for which a specific report form is not provided, and to report the subsequent results of that work. A notice of intention to do work on a well

located on lands with state, fee or privately owned minerals or to change plans previously approved shall be submitted in duplicate and must be received and approved by the division before the work is commenced. The operator is responsible for receipt of the notice by the division in ample time for proper consideration and action. In cases of emergency the operator may obtain verbal approval to commence work. Within five days after receiving verbal approval, the operator shall submit a Sundry Notice describing the work and acknowledging the verbal approval.

2. In addition to the types of work listed on the form, a Sundry Notice is required for the following:

2.1. Monthly status report for each drilling well in accordance with R649-3-6.

2.2. Application for permit to complete a well into more than one pool in accordance with R649-3-22.

2.3. Notice of intent to plug and abandon a well in accordance with R649-3-24.

2.4. Notice of intent to pull casing in accordance with R649-3-24.

2.5. Notice of change of operator. The report form should be submitted by both the previous operator and the new operator.

R649-8-11. Form 10, Monthly Oil and Gas Production Report.

1. The division will provide this report monthly to operators of all oil and gas wells within the state. Each operator shall complete the form to properly account for all oil, gas, and water produced from each well.

2. This report shall be submitted in conjunction with Form 11, Monthly Oil and Gas Disposition Report before the fifteenth day of the second calendar month following the month of production.

R649-8-12. Form 11, Monthly Oil and Gas Disposition Report.

1. All oil and gas well operators shall complete this form monthly to account for all oil and gas dispositions from each entity.

1.1. The report should account for the physical dispositions of all oil and gas produced during the report month from each well or group of wells (entity). Only the initial disposition of each product as it leaves the well site or is used at the well site should be reported. Residue gas and/or load oil received from another well, plant, or field should not be shown on this report.

2. This report shall be submitted in conjunction with Form 10, Monthly Oil and Gas Production Report and Form 12, Report of Transferred Oil on or before the fifteenth day of the second calendar month following the month of production.

R649-8-13. Form 12, Report of Transferred Oil.

1. This report is to be used only in accounting for oil that is transferred from one entity to another entity or oil that is acquired and used during remedial operations on a well. This includes situations such as (1) oil that is produced at one entity or is acquired from another company, is then used as load oil at a "second" entity, and is then recovered and sold, or (2) oil that

is produced and then transferred to a "second" entity for treatment and sale due to mechanical problems at the producing entity.

1.1. Load oil that is recovered at the "second" entity and non-load oil that is transferred to the "second" entity should be excluded from all reported production, dispositions, and stocks of the "second" entity on Form 11, Monthly Oil and Gas Disposition Report. This allows the reporting of the "second" entity's true production and sales on Form 11, while the remainder of any sales is accounted for on this form. The transported volumes reported on this form plus the transported volume for the "second" entity on Form 11 should equal the total run ticket volume as reported by the trucking or pipeline company serving this entity.

2. This report is to be filed as an attachment to Form 11, Monthly Oil and Gas Disposition Report during the month in which recovered load oil or any other transferred oil (non-load oil) is sold from the "second" entity.

R649-8-14. Form 13-A, Monthly Summary Report of Gas Processing Plant Operations.

1. Gas processing plant operators shall complete and submit a monthly report in accordance with R649-6-1, to account for the receipt, processing and disposition of all gas by the plant.

2. The report is due on or before the fifteenth day of the second calendar month following the operations month covered by the report.

R649-8-15. Form 13-B, Monthly Report of Gas Processing Plant Product Allocations.

1. Gas processing plant operators that are required by contractual arrangements to allocate residue gas and extracted liquids to the individual producing wells must complete and submit this form monthly in accordance with R649-6-1.

2. The report is to be filed as an attachment to Form 13-A, Monthly Summary Report of Gas Processing Plant Operations on or before the fifteenth day of the second calendar month following the operations month covered by the report.

R649-8-16. Form 14, Monthly Report of Waste Crude Oil Treatment Facility Operations.

1. Each operator of treatment or reclaiming facilities handling tank bottoms, oil from pits or ponds, or any other waste crude oil, shall complete and submit this report monthly in accordance with R649-6-2 to account for stocks, receipts, and deliveries of processed and unprocessed waste crude oil.

2. The report is due on or before the fifteenth day of the second calendar month following the operations month covered by the report.

R649-8-17. Form 15, Designation of Workover or Recompletion.

1. In accordance with Rule R649-3-23, each operator desiring to claim a tax credit for workover or recompletion work performed must submit this report within 90 days after the workover or recompletion work is completed. Upon determination and

notification by the division that the described work qualifies for a tax credit under this rule, the operator may claim the tax credit on reports submitted to the Tax Commission during the third quarter after completion of the work.

2. The following workover and recompletion operations qualify for a tax credit: perforating, stimulation (e.g., acid jobs, frac jobs, solvent treatments, nitrogen cleanouts), sand control, water control or shut-off, wellbore cleanout, casing or liner repair, well deepening, initiation of enhanced recovery (excluding surface equipment and associated costs), change of lift system (excluding surface equipment and associated costs), gas well tubing changes (i.e., down-sizing), thief zone identification and elimination. The following workover and recompletion operations do not qualify for a tax credit: pump changes, rod string fishing and repair/replacement, tubing repair/replacement, surface equipment installation and repair, operations generally classified as routine maintenance or repair. Division approval is conditional subject to audit, and actual final expenses may be disallowed if they are not appropriate workover or recompletion expenses.

R649-8-18. UIC Form 1, Application for Injection Well.

Prior to the commencement of operations for injecting any fluid into a well for the purpose of enhanced recovery, disposal, or storage, the operator shall submit an Application for Injection Well and obtain division approval in accordance with R649-5-2.

R649-8-19. UIC Form 2, Monthly Report of Enhanced Recovery Project.

1. The operator shall submit this report monthly to report the injection pressure, rate, and volume for each enhanced recovery injection well or project.

2. The report is due within 30 days following the end of the month of operations.

R649-8-20. UIC Form 3, Monthly Injection Report.

1. The operator shall submit this report monthly to report the daily injection pressure, rate, and volume for each disposal well and/or storage well.

2. The report is due within 30 days following the end of the month of operations.

R649-8-21. UIC Form 4, Annual Fluid Injection Report.

1. The operator of disposal wells, storage wells, or enhanced recovery projects shall file an annual report with the division using this form.

2. The report is due within 60 days following the end of the year.

R649-8-22. UIC Form 5, Transfer of Authority to Inject.

1. The authority to inject for any injection well shall not be transferred from one operator to another without the approval of the division. The transfer of authority to inject for any injection well from one operator to another shall be submitted to

the division on this form prior to the date of the proposed transfer.

2. The division shall, within 30 days after receipt of a properly completed form, return a copy of the form to each operator indicating approval or denial of the transfer of authority to inject. If approved, a copy of the order authorizing injection shall be attached to the form returned to the new operator.

KEY: oil and gas conservation, reporting
June 2, 1998 **40-6-1 et seq.**
Notice of Continuation March 26, 2002

R649. Natural Resources; Oil, Gas and Mining; Oil and Gas.
R649-9. Waste Management and Disposal.
R649-9-1. Introduction.

1. Section 40-6-5 UCA authorizes the board to regulate the disposal of salt water and oil-field wastes. It is the intent of the Board and Division to regulate E and P Wastes and facilities for the disposal of these wastes in a manner which protects the environment, limits liability to producers, and minimizes the volume of waste.

2. These rules specify the informational and procedural requirements for waste management and disposal, the permitting of disposal facilities, and cleanup requirements for E and P related sites.

R649-9-2. General Waste Management.

1. Wastes addressed by these rules are E and P Wastes which are exempt from the RCRA hazardous waste management requirements.

2. Reduction of the amount of material generated which must be disposed of is the preferred practice. Recycling should be used whenever possible and practical. In general, good housekeeping practices shall be used. Operators shall catch leaks and drips, contain spills, and cleanup promptly.

3. The method of disposal used shall be compatible with the waste which is the subject of disposal. RCRA exempt waste shall not be mixed with nonexempt waste. Before using a commercial disposal facility the Division may be contacted to verify the status of the facility.

4. The operator shall file an Annual Waste Management Plan by January 15 of each year to account for the proper disposition of produced water and other E and P Wastes. If changes are made to the plan during the year, then the operator shall notify the division in writing of this change. This plan will include the type and estimated volume of wastes to be generated, the disposal facilities (central and commercial) to be used for disposal, and the description of any waste reduction or minimization procedures and any onsite disposal/treatment to be implemented by the operator. Each site and/or facility used for disposal must be permitted and in good standing with the division.

R649-9-3. Permitting of Disposal Pits.

1. All commercial disposal pits and disposal pits located off of an existing mineral lease shall be bonded in accordance with R649-9-9, Bonding of Disposal Facilities to assure proper operation, maintenance, and closure of the pits.

2. Application shall be made to the Division for approval of any disposal pit. The pit shall be designed appropriately for the intended purpose. Commercial disposal pits shall be designed and constructed under the supervision of a registered professional engineer. The application and site shall meet the following requirements:

2.1 The pit shall be located on level, stable ground, and an acceptable distance away from any established or intermittent drainage.

2.2. The pit shall not be located in a geologically and hydrologically unsuitable area, such as aquifer recharge areas, flood plains, drainage bottoms, and areas near faults.

2.3. The pit shall have adequate storage capacity to safely contain all produced water even during those periods when evaporation rates are at a minimum.

2.4. The pit shall be designed and constructed so as to prevent the entrance of surface water.

2.5. The pit shall be designed, maintained and operated to prevent unauthorized surface or subsurface discharge of water.

2.6. The pit shall be fenced and maintained to prevent access by livestock, wildlife and unauthorized personnel and if required, equipped with flagging or netting to deter entry by birds and waterfowl.

2.7. The pit levees for produced water pits receiving volumes in excess of five barrels per day, shall be constructed so that the inside grade of the levee is no steeper than 3:1 and the outside grade no steeper than 2:1. The top of the levee shall be level and of sufficient width to allow for adequate compaction.

2.8 All approved produced water pits not located at a well site shall be identified with a suitable sign.

2.9. The artificial materials used in lining pits shall be impervious and resistant to weather, sunlight, hydrocarbons, aqueous acids, alkalies, salt, fungi, or other substances which might be contained in the produced water.

3. If rigid materials are used, leak proof expansion joints shall be provided, or the material shall be of sufficient thickness and strength to withstand, without cracking, expansion, contraction and settling movements in the underlying earth.

3.1. If flexible materials are used, they shall be of sufficient thickness and strength to be resistant to tears and punctures. Commercial disposal pits shall be lined with a minimum liner thickness of 40 mils or as approved by the Division.

3.2. Lined pits constructed in relatively impermeable soils shall have an underlaying gravel filled sump and lateral system or suitable leak detection system.

3.3 Lined pits constructed in relatively permeable soils shall have a secondary liner underlaying the leak detection system, which is graded so as to direct leakages to the observation sump.

3.4. Test borings shall be taken in sufficient quantity and to an adequate depth to satisfactorily define subsurface conditions and assure that the liner will be placed on a firm stable base and to determine the appropriate leak detection system.

4. Requirements for Unlined Disposal Pits.

4.1 An application for disposal of produced water into an unlined pit will be considered if such disposal does not demonstrate significant pollution potential to surface or ground water and meets at least one of the following criteria:

4.2. The water to be disposed of does not have a higher total dissolved solids "TDS" content than ground water that could be affected and provided that the water does not contain objectionable levels of constituents and characteristics including chlorides, sulfates, pH, oil, grease, heavy metals and aromatic hydrocarbons.

4.3. That all, or a substantial part of the produced water is being used for beneficial purposes such as irrigation and livestock or wildlife watering and a water analysis indicates that the water is acceptable for the intended use.

4.4. The volume of water to be disposed of does not exceed five barrels per day on a monthly basis.

5. Application Requirements for Produced Water Pits.

5.1. Applications for disposal of produced water into lined pits shall include the following information:

5.2. A topographic map and drawing of the site on a suitable scale that indicate the pit dimensions, cross section, side slopes, leak detection system and location relative to other site facilities. The drawings shall be of professional quality.

5.3. The maximum daily quantity of water to be disposed of and a representative water analysis of such water that includes the concentrations of chlorides and sulfates, pH, total dissolved solids "TDS", and information regarding any other significant constituents if requested.

5.4. Climatological data indicating the average annual evaporation and precipitation for the area.

5.5. The method and schedule for disposal of precipitated solids.

5.6. Drawings of unloading facilities and explanation of the method for controlling and disposing of any liquid hydrocarbon accumulation so that the evaporation process is not hampered.

5.7. The engineering data and design criteria used to determine the pit size which includes a 2-foot free-board.

5.8. The type, thickness, strength, and life span of material to be used for lining the pit and the method of installation.

5.9. A description of the leak detection method to be utilized and the proposed inspection frequency of the detection system. Also the proposed procedures for repair of the liner should leakage occur.

6. Applications for disposal of produced water into unlined pits shall include the following information:

6.1. A topographic map and drawing of the site on a suitable scale that indicate the pit dimensions, cross section, side slopes, size and location relative to other site facilities.

6.2. The daily quantity of water to be disposed of and a representative water analysis of such water that includes the total dissolved solids "TDS", pH, oil and grease content, the concentrations of chlorides and sulfates, and information regarding any other significant constituents if required.

6.3. Climatological data indicating the average annual evaporation and precipitation for the area.

6.4. The estimated percolation rate based on soil characteristics under and adjacent to the pit.

6.5. Estimated depth and areal extent of any USDW in the area and an indication of any effect or interaction of the produced water with any such water resources present at or near the surface.

6.6. If beneficial use is the basis for the application, written confirmation from the user should be submitted.

6.7. If the application is made on the basis that surface and subsurface waters will not be adversely affected by disposal in an unlined pit, the following additional information is required:

6.7.1. A map showing the location of surface waters, water wells, and existing water disposal facilities within a one mile radius of the proposed disposal facility.

6.7.2. The weighted average concentration of total dissolved solids "TDS" of all surface and subsurface waters within a one mile radius that might be affected by the proposed disposal.

6.7.3. Any reasonable geological and hydrological evidence showing that the proposed disposal method will not adversely affect existing water quality or major uses of such waters.

7. Within 30 days of the submission of an application for disposal of produced water into a commercial disposal pit, the division shall review the application as to its completeness and adequacy for the intended purpose and shall require such changes that are found necessary to assure compliance with the applicable rules. If the application is in order, the Division shall provide for a public notice to be published in a newspaper of general circulation in the county where the pit is to be located.

R649-9-4. Permitting of Other Disposal Facilities.

1. Facilities used for the treatment and disposal of E and P wastes other than evaporation pits shall be permitted by the Division. This would include such activities as landfarming, composting, solidifying, bioremediation, and others.

2. All commercial treatment and disposal facilities must be bonded in accordance with R649-9-9, Bonding of Disposal Facilities, to assure proper operation, maintenance, and closure of the facility.

3. Application Requirements for Treatment and Disposal Facilities. The application shall contain the following:

3.1 A complete description of the proposed facility and processes involved including a complete list of all wastes to be accepted at the facility and products generated.

3.2 Maps and drawings of suitable scale showing all facilities and equipment.

3.3 Materials or products to be applied to the land surface or subsurface shall meet the Division's cleanup levels for contaminated soil and other wastes. If leachability and/or toxicity is of concern due to the type or source(s) of wastes, tests will be required and may utilize the Toxicity Characteristic Leaching Procedure (TCLP).

3.4 The submission of an application to the Division of Water Quality, Department of Environmental Quality, for a discharge permit may be required if it is determined that the facility and associated activity will not have a de minimus actual or potential effect on ground water quality. If the Division determines there is potential for discharge, or if the proposal involves a commercial disposal operation it will be forwarded to the Division of Water Quality for their review.

R649-9-5. Construction and Inspection Requirements for Disposal Facilities.

1. Division personnel shall be afforded a reasonable opportunity for inspection of any proposed disposal facility during the construction and operation of the facility.

2. The division shall be notified at least two working days prior to the installation of a pit liner so that an inspection of the leak detection system can be conducted.

3. In any case, the division shall be notified after completion of facility construction, at least two working days prior to its use, so that an inspection can be conducted to verify that the facility has been constructed in accordance with the approved application.

4. Disposal facilities shall be operated in accordance with an approved application and in a manner which does not cause pollution or safety and health hazards.

5. Failure to meet the requirements and standards for construction and operation of a disposal facility shall be considered as noncompliance and will result in the imposition of corrective actions and compliance schedules or a cessation of operations order.

R649-9-6. Reporting and Recordkeeping Requirements for Disposal Facilities.

1. All unauthorized discharges or spills from disposal facilities including water observed in a leak detection system shall be promptly reported to the division.

2. Each producer who utilizes any approved produced water disposal facility shall comply with the reporting requirements of R649-8-10.

3. Each operator of a disposal facility, excluding disposal wells, shall report to the Division on a quarterly basis. This report shall include the volume and type of wastes received at the facility during the quarter and results of the leak detection system inspections.

4. The occurrence of water in a leak detection system during operation of a pit constitutes liner failure and requires immediate action. The Division has the option of allowing the operator a short period of time to take corrective action. Further utilization of the pit will be allowed only after liner

repairs and an inspection by the Division.

5. Each owner/operator of a commercial disposal facility shall keep records showing at a minimum the following: date and time waste was received, origin, volume, type, transporter, and generator of the waste. These records shall be available for inspection by the Division for at least six years.

R649-9-7. Final Closure and Cleanup of Disposal Facilities.

1. A plan for final closure of a disposal facility shall be submitted to the Division for approval. The closure plan shall include the following:

1.1 Provisions for removal of all equipment at the site.

1.2 Proposed plans and procedures for sampling and testing soils and ground water at the site. Soils will need to meet the Division's Cleanup Levels for Contaminated Soils or background levels whichever is less stringent.

1.3 Provisions for a monitoring plan if required by the Division, and

1.4 A consideration of post disposal land use and landowner requests when the closure plan is developed.

2. A bond for a disposal facility will be released when the requirements of a closure plan approved by the Division has been met as determined by the Division.

R649-9-8. Variances from Requirements and Standards.

Requests for approval of a variance from any of the requirements or standards of these rules shall be submitted to the director in writing and provide information as to the circumstances which warrant approval of the requested variance and the proposed alternative means by which the requirements or standards will be satisfied. Variances may be approved only after proper notice and public hearing before the board.

R649-9-9. Bonding of Disposal Facilities.

1. Disposal facilities, other than injection wells, shall be bonded according to this rule in order to protect the State and oil and gas producers from unnecessary liabilities and cleanup costs in the future. The objectives are to provide the State with adequate security to allow rehabilitation of a site to the point of preventing further or future pollution, and health and safety hazards should a facility owner default.

1.1. The parameters used to calculate the proper bond amount are: pit area, storage capacity, and volume of waste stored.

1.2. Bonds accepted shall be of the same type as those accepted for wells i.e. surety, collateral, or a combination of the two as described in the R649-3-1. In order to assist facility owners in providing bonding, the total bond amount provided may consist of an initial amount as determined by the division and an additional amount collected at a price per barrel and/or price per cubic yard of waste collected until the total bond amount is reached. The total bond will be held by the division or financial institution until the facility has been closed and inspected by the division in accordance with a division approved closure plan.

1.3. Total bond amount is calculated using values for pit area, pit storage capacity, and volume of stock piled waste material. No salvage value of equipment or removal cost is used. This bond will only be used by the State to treat or remove waste from the site and secure the facility to prevent any future contamination should the facility owner default on cleanup responsibilities. Bond amounts will be calculated as follows, and the per volume or per acre figures may be adjusted periodically to compensate for change in cost to perform the necessary cleanup work:

$14,000 per acre of pit, partial acres will be calculated at the rate of $14,000 per acre; plus

$1.00 per barrel of produced water for one-quarter of the total storage capacity of the facility; plus

$30 per cubic yard of solid or semi-solid waste material stockpiled at the facility.

$10,000 Minimum bond amount.

1.4 All commercial disposal facilities (except injection wells covered by R649-3-1) will be covered by an adequate and acceptable bond before being permitted to accept any exploration and production waste. The initial and minimum bond payment will be at least $10,000. The total bond amount will be calculated as described in Subsection R649-9-9(1.3). If requested by the disposal facility owner, the bond beyond the initial amount may be posted at a rate of two cents per barrel of liquid or sixty cents per cubic yard of solid/semi-solid waste material accepted for disposal at the facility.

KEY: oil and gas law
June 2, 1998 **40-6-1 et seq.**
Notice of Continuation March 26, 2002

R649. Natural Resources; Oil, Gas and Mining; Oil and Gas.
R649-10. Administrative Procedures.
R649-10-1. Designation of Informal Adjudicative Proceedings.

1. Adjudicative proceedings which shall be conducted informally before the division in accordance with these rules are all actions prescribed by the Oil and Gas Conservation General Rules as being specifically under the division's authority and jurisdiction including: R649-2 General Rules; R649-3 Drilling and Operating Practices; R649-5 Underground Injection Control of Recovery Operations and Class II Injection Wells; R649-6 Gas Processing and Waste Crude Oil Treatment; R649-8 Reporting and Report Forms; R649-9 Disposal of Produced Water.

2. Prior to the issuance of a final order in any adjudicative proceeding, the presiding officer may convert an informal proceeding to a formal adjudicative proceeding if:

2.1. Conversion of the proceeding is in the public interest.

2.2. Conversion of the proceeding does not unfairly prejudice the rights of any party.

3. Informal adjudicative proceedings shall be commenced and conducted in accordance with these rules and the provisions of the applicable Oil and Gas Conservation General Rules. In case of conflict between these rules and the Oil and Gas Conservation

General Rules, these rules shall govern the informal adjudicative proceedings.

R649-10-2. Definitions.

As used in these rules:

1. "Adjudicative proceeding" means an agency action or proceeding that determines the legal rights, duties, privileges, immunities, or other legal interests of one or more identifiable persons, including all agency actions to grant, deny, revoke, suspend, modify, annul, withdraw, or amend an authority, right, or license; and judicial review of all of such actions.

2. "Agency" means the Board of Oil, Gas and Mining and the Division of Oil, Gas and Mining including the director or division employees acting on behalf of or under the authority of the director or board.

3. "Agency head" means an individual or body of individuals in whom the ultimate legal authority of the agency is vested by statute.

4. "Board" means the Board of Oil, Gas and Mining.

5. "Division" means the Division of Oil, Gas and Mining.

6. "License" means a franchise, permit, certification, approval, registration, charter, or similar form of authorization required by statute.

7. "Party" means the board, division, or other person commencing an adjudicative proceeding, all respondents, all persons permitted by the board to intervene in the proceeding, and all persons authorized by statute or agency rule to participate as parties in an adjudicative proceeding.

8. "Person" means an individual, group of individuals, partnership, corporation, association, political subdivision or its units, governmental subdivision or its units, public or private organization or entity of any character, or another agency.

9. "Presiding Officer" means an agency head, or an individual or body of individuals designated by the agency head, by the agency's rules, or by statute to conduct an adjudicative proceeding. For the purpose of these rules, the board, or its appointed hearing examiner, shall be considered the presiding officer of all appeals or informal adjudicative proceedings which commence before the division as well as all adjudicative proceedings which commence before the board. The director or his designated agent shall be considered a presiding officer for all informal adjudicative proceedings which commence before the division. If fairness to the parties is not compromised, an agency may substitute one presiding officer for another during any proceeding.

10. "Respondent" means any person against whom an adjudicative proceeding is initiated whether by an agency or any other person.

R649-10-3. Commencement of Informal Adjudicative Proceedings.

1. Except for emergency orders, all informal adjudicative proceedings shall be commenced by:

1.1. A Notice of Agency Action, if proceedings are commenced by the board or division; or

1.2. A Request for Agency Action, if proceedings are commenced by persons other than the board or division.

2. A Notice of Agency Action shall be filed and served according to the following requirements:

2.1. The Notice of Agency Action shall be in writing and shall be signed by a presiding officer and shall include:

2.1.1. The names and mailing addresses of all persons to whom notice is being given by the presiding officer, and the name, title, and mailing address of any attorney or employee who has been designated to appear for the agency.

2.1.2. The division's file number or other reference number.

2.1.3. The name of the adjudicative proceeding.

2.1.4. The date that the Notice of Agency Action was mailed.

2.1.5. A statement that the adjudicative proceeding is to be conducted informally according to the provision of these rules and Sections 63-46b-4 and 63-46b-5 if applicable.

2.1.6. A statement that the parties may request an informal hearing before the division within ten days, or such later period as may be provided for in the Oil and Gas Conservation General Rules, of the date of mailing or publication.

2.1.7. A statement of the legal authority and jurisdiction under which the adjudicative proceeding is to be maintained.

2.1.8. The name, title, mailing address, and telephone number of the presiding officer.

2.1.9. A statement of the purpose of the adjudicative proceeding and, to the extent known by the presiding officer, the questions to be decided.

2.2. The Division shall:

2.2.1. Mail the Notice of Agency Action to each party and any other person who has a right to notice under statute or rule.

2.2.2. Publish the Notice of Agency Action as required by statute or by the Oil and Gas Conservation General Rules.

2.2.3 Post a copy of the notice in a public area in the main office of the division at least 24 hours in advance of the scheduled agency proceeding.

2.3. A Request for Agency Action initiated by a person other than the board or the division shall be in writing and signed by the person seeking action by the the agency or by his representative, and shall include:

2.3.1. The names and addresses of all persons to whom a copy of the request for agency action is being sent.

2.3.2. The agency's file number or other reference number, if known.

2.3.3. The date that the request for agency action was mailed.

2.3.4. A statement of the legal authority and jurisdiction under which the agency action is requested.

2.3.5. A statement of the relief or action sought from the division.

2.3.6. A statement of the facts and reasons forming the basis for relief or action.

2.4. The person requesting agency action shall file the request with the division and shall send a copy by mail to each person known to have a direct interest in the requested agency action unless previously waived in writing by each person entitled to receive notice of the requested agency action.

2.5. The person requesting the agency action may use the division forms as specified in the Oil and Gas Conservation General Rules as a request for agency action.

2.6. The presiding officer shall promptly review a Request for Agency Action and shall:

2.6.1. Notify the requesting party in writing whether the request is granted and when the adjudicative proceeding is completed;

2.6.2. Notify the requesting party in writing that the request is denied; or

2.6.3. Notify the requesting party that further proceedings are required to determine the agency's response to the request.

2.7. The division shall mail any required notice to all parties, except that any notice required by R649-10-3-2.6 may be published when publication is required by statute.

2.7.1. Give the division's file number or other reference number.

2.7.2. Give the name of the proceeding.

2.7.3. Designate that the proceeding is to be conducted informally according to the provisions of these rules and Sections 63-46b-4 and 63-46b-5 if applicable.

2.7.4. If a hearing is to be held in an informal adjudicative proceeding, state the time and place of any scheduled hearing, the purpose for which the hearing is to be held, and that a party who fails to attend or participate in a scheduled and noticed hearing may be held in default.

2.7.5. If the adjudicative proceeding is to be informal, and a hearing is required by statute or rule, or if a hearing is permitted by rule and may be requested by a party with the time prescribed by rule, state the parties' right to request a hearing and the time within which a hearing may be requested under the agency's rules.

2.7.6. Give the name, title, mailing address, and telephone number of the presiding officer.

R649-10-4. Procedures for Informal Adjudicative Proceedings.

1. Procedures for informal adjudicative proceedings should include the following:

1.1. Unless the agency by rule provides for and requires a response, no answer or other pleading responsive to the allegations contained in the notice of agency action or the request for agency action need be filed.

1.2. The agency shall hold a hearing if a hearing is requested within ten days or such later period as may be provided for in the Oil and Gas Conservation General Rules.

1.3. In any hearing, the parties named in the Notice of Agency Action or in the Request for Agency Action shall be permitted to testify, present evidence, and comment on the issues.

1.4. Hearings will be held only after timely notice to all parties.

1.5. Discovery is prohibited, but the agency may issue subpoenas or other orders to compel production of necessary evidence.

1.6. All parties shall have access to information contained in the agency's files and to all materials and information gathered in any investigation, to the extent permitted by law.

1.7. Intervention is prohibited, except where a federal statute or rule requires that a state permit intervention.

1.8. All hearings shall be open to all parties.

1.9. Within a reasonable time after the close of an informal adjudicative proceeding, the presiding officer shall issue a signed order in writing that states the following:

1.9.1. The decision.

1.9.2. The reasons for the decision.

1.9.3. A notice of any right of administrative or judicial review available to the parties.

1.9.4. A statement that the filing of an appeal or the requesting of a review shall be accomplished within 30 days of the issuance of the order.

1.10. The presiding officer's order shall be based on the facts appearing in the agency's files and on the facts presented in evidence at any hearings.

1.11. A copy of the presiding officer's order shall be promptly mailed to each of the parties and to all persons who request a copy.

2.1. The agency may record any hearing.

2.2. Any party, at his own expense, may have a reporter, approved by the agency, prepare a transcript from the agency's record of the hearing.

3.0. Nothing in this section restricts or precludes any investigative right or power given to an agency by another statute.

R649-10-5. Default In An Informal Proceeding.

1. The presiding officer may enter an order of default against:

1.1. A party in an informal adjudicative proceeding if after proper notice the party fails to participate in the informal adjudicative proceeding.

2.0. An order of default shall include a statement of the grounds for default and shall be mailed to all parties.

3.1. A defaulted party may seek to have the agency set aside the default order, and any order in the adjudicative proceeding issued subsequent to the default order, by following the procedures outlined in the Utah Rules of Civil Procedure.

3.2. A motion to set aside a default and any subsequent order shall be made to the presiding officer.

3.3. A defaulted party may seek board review under R649-10-6 only on the decision of the presiding officer on the motion to set aside the default.

4.0. In an adjudicative proceeding commenced by the agency, or in an adjudicative proceeding commenced by a party that has other parties besides the party in default, the presiding officer shall, after issuing the order of default, conduct any further proceeding without the participation of the party in default and shall determine all issues in the adjudicative proceeding, including those affecting the defaulting party.

5.0. In an adjudicative proceeding that has no parties other than the agency and the party(ies) in default, the presiding officer may, after issuing the order(s) of default, dismiss the proceeding.

R649-10-6. Appeal of Division Order.

1. A request for review of an order issued by the division shall be filed with the secretary to the Board within 30 days of issuance of the order and:

1.1. Be signed by the party seeking review.

1.2. State the grounds for review and the relief requested.

1.3. State the date upon which it was mailed.

1.4. Be sent by mail to the presiding officer and to each party.

2. Within 15 days of the mailing date of request for review, or within the time period provided by agency rule, whichever is longer, any party may file a response with the board. One copy of the response shall be sent by mail to each of the parties and to the presiding officer.

3. The board shall review the order within a reasonable time or within the time required by statute or the agency's rules.

4. To assist in review, the board may by order or rule permit the parties to file briefs or other papers, or to conduct oral argument.

5. Notice of hearings on review shall be mailed to all parties.

6.1. Within a reasonable time after the filing of any response, other filings, or oral argument, or within the time required by statute or applicable rules, the board shall issue a written order on review.

6.2. The order on review shall be signed by the board chairman or by a person designated by the board for that purpose and shall be mailed to each party.

6.3. The order on review shall contain:

6.3.1. A designation of the statute or rule permitting or requiring review.

6.3.2. A statement of the issues reviewed.

6.3.3. Findings of fact as to each of the issues reviewed.

6.3.4. Conclusions of law as to each of the issues reviewed.

6.3.5. The reasons for the disposition.

6.3.6. Whether the decision of the presiding officer or agency is to be affirmed, reversed, or modified, and whether all or any portion of the adjudicative proceeding is to be remanded.

6.3.7. A notice of any right of further administrative reconsideration or judicial review available to aggrieved parties.

6.3.8. The time limits applicable to any appeal or review.

R649-10-7. Emergency Orders.

Notwithstanding the other provisions of these rules, the director or any member of the board is authorized to issue an emergency order without notice and hearing in accordance with Section 40-6-10. The emergency order shall remain in effect no longer than until the next regular meeting of the board, or such shorter period of time as shall be prescribed by statute.

1. An emergency order may be issued if:

1.1. The facts known by or presented to the director or board member are supported by affidavit to show that an immediate and significant danger of waste or other danger to the public health, safety, or welfare exists; and

1.2. The threat requires immediate action by the director or board member,

2. Limitations. In issuing its emergency order, the director or board member shall:

2.1. Limit its order to require only the action necessary to prevent or avoid the danger to the public health, safety, or welfare;

2.2. Issue promptly a written order, effective immediately, that includes a brief statement of findings of fact, conclusions of law, and reasons for the agency's utilization of emergency adjudicative proceedings;

2.3. Give immediate notice to the persons who are required to comply with the order; and

2.4. If the emergency order issued under this section will result in the continued infringement or impairment of any legal right or interest of any party, the division shall commence a formal adjudicative proceeding in accordance with the procedural rules of the board.

R649-10-8. Exhaustion of Administrative Remedies.

A person aggrieved by a division order in an adjudicative proceeding must seek review of that order by the board as provided in R649-10-6.

R649-10-9. Waivers.

Notwithstanding any other provision of these rules, any procedural matter, including any right to notice or hearing, may be waived by the affected person(s) by a signed, written waiver in a form acceptable to the division.

KEY: oil and gas law
December 18, 1996 **40-6-1 et seq.**
Notice of Continuation July 19, 2001 **63-46b**

Appendix G— Source Location Data for Southwestern U.S.

GASIFICATION AND GAS PROCESSING CENTER

GTI PROJECT 15369.1.01

Source Location Data for SW Regional Carbon Sequestration Partnership - Phase I

TOPICAL REPORT

November 4, 2004

Submitted To:
Prof. B. J. McPherson
New Mexico Institute of Mining and Technology
Petroleum Recovery Research Center
801 Leroy Place
Socorro, NM 87801

GTI Technical Contacts:
Howard S. Meyer
Manager, Gas Processing, 847/768/0955
howard.meyer@gastechnology.org

Dennis Leppin
Associate Director, Gas Processing, 847/768-0521
dennis.leppin@gastechnology.org

Gas Technology Institute
1700 S. Mount Prospect Rd.
Des Plaines, Illinois 60018
www.gastechnology.org

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LEGAL NOTICE

Introduction:

The Regional Partnerships for Carbon Sequestration programs funded by DOE are ultimately required to identify the best carbon sequestration options in their respective regions, consisting of a CO_2 source, applicable CO_2 capture technology, transportation logistics (if applicable) and destination formation for non-terrestial sequestration approaches. In most cases the carbon capture step is the most costly, and selecting the appropriate least-cost options will be of particular importance. GTI was selected to provide advice and consultation on capture technologies for the Southwest Partnership.

This report consists of a summary of various databases assembled to help locate and quantify the CO_2 emissions in the Southwest Region. These point sources in the southwest region are mainly coal-fired power plants. Other sources include natural gas processing plants, refineries, ammonia/fertilizer production, ethylene and ethanol plants, and cement plants.

This information will assist in identifying candidate projects for Phase II.

Scope of Work:

The objective of this project is to delineate technologies applicable to capturing carbon dioxide from point sources and to provide estimates from various sources of the specific costs of such technologies. Research and Development on new technologies will be reviewed and a listing of those that appear promising and are sufficiently in the development cycle will be presented.

Databases:

GTI was requested to assemble a listing of gas treating plants in the Southwest Partnership Region (SW). These are plants that remove CO_2 from natural gas and generally emit the CO_2 at low pressure into the atmosphere. These were assembled and transmitted. However, the original data did not contain any location beyond the state in which the plant was located. GTI was requested to provide any and all location data as well as emission data in addition to facility data required to estimate the cost of capture.

Table 1 provides an index of the various databases assembled to meet the source data needs of the partnership. Some of the databases exist as Microsoft® Access™ databases, but they have all been assembled into Microsoft® Excel™ files to ease transfer. Table 2 is an extended table of the fields contained on each of the worksheets. The Appendices are a partial listing of the complete files. Where the database could be contained in a reasonable number of pages, it has been included in full within the Appendix. Where the worksheets would take hundreds or thousands of pages, a partial listing has been included to indicate the scope of the data.

Data by source

The overwhelming CO_2 emissions in the region are from coal-based power plants. Information on electrical generation plants can be found in the following workbooks/worksheets:

1. Sources in SW_By SIC/SW
2. SW_NATCARB_Data/Emissions and Facilities with RBLCID
3. SW_ElectricPlants_CO_2_Tons_%/ SW_ElectricPlants_CO_2_Tons_%
4. SW_99AirDataFacilitiesFile/RBLC_SW and RBLC_SW_ElectGen
5. SW_Coorid_fromEPA_HAP/SW

6. RACT_BACT_laer/SW
7. SW_NATCARB_Data_Facilities with Match to RACT_BACT_laer/Facilities 1030617920
8. SW_ElectricPlants_eGRID/all

Information on natural gas production and sources of emissions can be found in the following:

1. Sources in SW_BySIC/SW
2. SW_RegionalGasPlants/All
3. RACT_BACT-laer_NonPower/NonPower
4. SW_SubqualityGas Composition/SW_Subquality
5. SW_99AirDataFacilitiesFile/RBLC_SW and RBLC_SW_ElectGen
6. SW_Coorid_fromEPA_HAP/SW
7. RACT_BACT_laer/SW

Information on other CO_2 emitting industries can be found in the following:

1. Sources in SW_BySIC/SW
2. RACT_BACT-laer_NonPower/Portland Cement, Fertilizer, and NonPower
3. SW_NonFuelPlants/CementInRegion, AmmoniaInRegion, ChlorinePlants, EthlyenePlants, and Refineries (to be completed)
4. SW_99AirDataFacilitiesFile/RBLC_SW and RBLC_SW_ElectGen
5. SW_Coorid_fromEPA_HAP/SW
6. RACT_BACT_laer/SW
7. SW_minerals_usgs_gov/SW
8. SW_EthanolPlants/SW_EthanolProduction

Data with Location Information

It is difficult to locate each point source of CO_2. Some data sources will identify the location by latitude and longitude, some by physical address, county map coordinates, or by driving instructions from the red barn with blue shutters. In addition, there is not a consistent identified across the various data sources. Plant names may be the most consistent, but owners change on a regular basis. In some databases, GTI has included cross references to identifiers in other databases. GTI has suggested to the partnership several means to obtain latitude and longitude data where it is not given. Information with latitude and longitude (or x and y coordinate) data can be found in the following:

1. Sources in SW_BySIC/SW
2. SW_RegionalGasPlants/SW_RegionalTreatingPlants
3. SW_NATCARB_Data/FacilitiesWithRBLCID
4. RACT_BACT-laer_NonPower/PortlandCement, Fertilizer, and NonPower
5. SW_99v3AirDataFacilitiesFile/RBLC_SW, RBLC_SW_ElectGen/ORIS_Facility_Code
6. SW_CooridFromEPA_HAP
7. RACT_BACT_laer/SW
8. SW_ElectricPlants_eGRID/EGRDPLNT00

Information with other location data can be found in the following:

1. SW_RegionalGasPlants/H_2S>5% and AcidGas>20%
2. SW_NonFuelPlants/CementInRegion, AmmoniaInRegion, ChlorinePlants, EthylenePlants, and EOR
3. SW_99v3AirDataFacilitesFile/NH_3Releases
4. SW_EthanolPlants/SW_EthanolProduction

Data with CO_2 Emissions

Several data sources provide CO_2 emissions data in various forms. Some are as detailed as monthly emissions on specific units within a facility while some are provided on the facility or even state basis. Several databases contain emission data on other components, such as CO, NO_x, NH_3, and VOC. Information on CO_2 emissions can be found in the following:

1. SW_NATCARB_Data/Emissions
2. SW_NonFuelPlants/EIASummary
3. SW_ElectricPlants_CO_2_Tons_%/ SW_ElectricPlants_CO_2_Tons_%
4. SW_ElectricPlants_eGRID/EGRDBLR00

Data with Process Criteria

In order to estimate CO_2 capture costs from the various sources in the region, certain process criteria must be know. This can vary among the various technologies from simple capacity to specific emission-producing and emission-mitigating equipment. These data are part of the input to GTI's costing protocol. Process criteria information are contained in the following:

1. SW_RegionalGasPlants/SW_RegionalTreatingPlants
2. SW_NATCARB_Data/Emissions, Fuels, and FacilitiesWithRBLCID
3. RACT_BACT-laer_NonPower/PortlandCement, Fertilizer, and NonPower
4. SW_NonFuelPlants/CementInRegion, AmmoniaInRegion, ChlorinePlants, EthylenePlants
5. SW_99v3AirDataFacilitiesFile/ORIS_Facility_Code
6. RACT_BACT-laer/SW
7. SW_ElectricPlants_eGRID/EGRDPLNT00, EGRDBLR00, EGRDPLCH, EGRDPRCH, and EGRDPCCH
8. SW_EthanolPlants/SW_EthanolProduction

Table 1 Index of Data Tables

Workbook	Worksheet	List of Fields
Sources in SW_BySIC	SW	B1
SW_RegionalGasPlants	SW_RegionalTreatingPlants	B2
	H_2S>5%	B3
	Acid Gas >20%	B4
SW_NATCARB_Data	Emissions	B5
	Fuels	B6
	FacilitiesWithRBLCID	B7
RACT_BACT-laer_NonPower	Portland Cement	B8
	Fertilizer	B9
	NonPower	B10
SW_SubqualityGasComposition	SW_Subquality	B11
SW_NonFuelPlants	EIA Summary	B12
	CementInRegion	B13
	CementManufactors	B14
	Anhydrous Ammonia 96	B15
	AmmoniaInRegion	B16
	Chlorine Plants	B17
	EthylenePlants	B18
	EOR	B19
	Refineries	B20
SW_ElectricPlants_CO2_Tons_%	SW_ElectricPlants_CO_2_Tons_%	B21
SW_99v3AirDataFacilitiesFile	RBLC_SW	B22
	RBLC_SW_ElectGen	B23
	NH3Release	B24
	ORIS_Facility_Code	B25
SW_Coorid_fromEPA_HAP	SW	B26
RACT_BACT_laer	SW	B27
SW_NATCARB_Data_Facilities with Match to RACT_BACT_laer	Facilities1030617920	B28
SW_minerals_usgs_gov	SW	B29
SW_ElectricPlants_eGRID	Contents	B30
	EGRDPLNT00	B31
	EGRDBLR00	B32
	EGRDGEN00	B33
	EGRDPLCH	B34
	EGRDEGCH	B35
	EGRDPRCH	B36
	EGRDPCCH	B37
SW_EthanolPlants	EthanolProduction	B38
	SW_EthanolProduction	B39

Table 2 Table Fields

Sources in SW_BySIC
B1. SW
strStateFacilityIdentifier
strSICPrimary
strNAICSPrimary
strFacilityName
strSiteDescription
strLocationAddress
strCity
srtState
strZipCode
strCountry
dblXCoordinate
dblYCoordinate
intUTMZone
strXYCoordinateType

SW_RegionalGasPlants		
B2. SW_RegionalTreating Plants	***B3. H2S>5%***	***B4. Acid Gas >20%***
Operator	STATE	STATE
State	COUNTY	COUNTY
County	BASIN CODE	BASIN
Plantname	FIELD	FIELD
EPA ID	WELL NAME/PLANT	WELL NAME/PLANT
Lat	LOCATION/PIPELINE	LOCATION/PIPELINE
Long	OWNER	OWNER
dblXCoordinate	H2S	H2S
dblYCoordinate	CO2	CO2
Installed Capacity MMcf/d		SUM
Design Inlet CO2 Mol%		
Inlet CO2 Mol%		
Design Inlet H2S Mol%		
Inlet H2S Mol%		

SW_NATCARB_Data		
B5. Emissions	***B6. Fuels***	***B7. FacilitiesWithRBLCID***
ORIS_CODE	ID	RBLCID
UNIT_ID	EGRID_CODE	ORIS_CODE
YEAR	EPA_CODE	FACILITY_NAME
MONTH	DESCRIPTION_SPECIFIC	FACILITY_TYPE
CO2_TONS	DESCRIPTION_GENERIC	OWNER_NAME
CO2_CONCENTRATION	CO2_CONCENTRATION	OWNER_TYPE
SO2_TONS		OPERATOR_NAME
NOX_TONS		COMPANY_NAME
MERCURY_LBS		STREET_ADDRESS
HEAT_INPUT		CITY
TOTAL_OPERATING_HOURS		COUNTY_NAME
FUEL_TYPE_COMBUSTED		COUNTY_CODE_FIPS
		STATE
		ZIP_PLUS_4
		LATITUDE
		LONGITUDE
		LAT_LONG_DATUM
		LAT_LONG_SOURCE
		POWER_CAPACITY_MW

RACT_BACT-laer_NonPower		
B8. Portland Cement	***B9. Fertilizer***	***B10. NonPower***
RBLCID	RBLCID	RBLCID
FACILITY	FACILITY	FACILITY
COMPANY	COMPANY	COMPANY
COUNTY	COUNTY	COUNTY
CONTACT	CONTACT	CONTACT
ADDRESS	ADDRESS	ADDRESS
CITY	CITY	CITY
STATE	STATE	STATE
ZIP	ZIP	ZIP
PHONE	PHONE	PHONE
EMAIL	EMAIL	EMAIL
REGION	REGION	REGION
AGENCYCODE	AGENCYCODE	AGENCYCODE
AGENCYNAME	AGENCYNAME	AGENCYNAME
AGENCYCONTACT	AGENCYCONTACT	AGENCYCONTACT
AGENCYPHONE	AGENCYPHONE	AGENCYPHONE
AGENCYEMAIL	AGENCYEMAIL	AGENCYEMAIL
PERMITNUM	PERMITNUM	PERMITNUM
SIC	SIC	SIC
NAICS	NAICS	NAICS
AIRSID	AIRSID	AIRSID
EPAID	EPAID	EPAID
UTMZONE	UTMZONE	UTMZONE
XCOORD	XCOORD	XCOORD
YCOORD	YCOORD	YCOORD
RCVDDATE	RCVDDATE	RCVDDATE
PERMITDATE	PERMITDATE	PERMITDATE
STARTUPDATE	STARTUPDATE	STARTUPDATE
VERIFYDATE	EMISLIMIT2UNIT	VERIFYDATE
ENTRYDATE	STOTHERCONDITIONS	ENTRYDATE
LASTUPDATE	CAPCOST	LASTUPDATE
NEW_MOD	OMCOST	NEW_MOD
PUBLICHEAR	COSTEFFECT	PUBLICHEAR
FUEL	COSTVERIFY	FUEL
EMISSSOURCES	DOLLARYEAR	EMISSSOURCES
ABATEMENT	POLNOTES	ABATEMENT
NARRATIVE		NARRATIVE
NOTES		NOTES
PROCESS		PROCESS
PROCTYPE		PROCTYPE
SCC		SCC
FUEL		FUEL
THRUPUT		THRUPUT
THRUPUTUNIT		THRUPUTUNIT
COMPVERIFY		COMPVERIFY
STACKTEST		STACKTEST

INSPECTION	INSPECTION
CALCULATED	CALCULATED
OTHERTEST	OTHERTEST
OTHERMETHD	OTHERMETHD
PRNOTES	PRNOTES
POLLUTANT	POLLUTANT
CAS	CAS
CONTROLCOD	CONTROLCOD
CTRLDESC	CTRLDESC
RANKOPTS	RANKOPTS
RANKSEL	RANKSEL
EMISLIMIT1	EMISLIMIT1
EMISLIMIT1UNIT	EMISLIMIT1UNIT
EMISLIMIT1CONDITION	EMISLIMIT1CONDITION
BASIS	BASIS
PCTEFFIC	PCTEFFIC
EMISLIMIT2	EMISLIMIT2
EMISLIMIT2UNIT	EMISLIMIT2UNIT
EMISLIMIT2CONDITION	EMISLIMIT2CONDITION
STDEMISS	STDEMISS
STDUNIT	STDUNIT
STOTHERCONDITIONS	STOTHERCONDITIONS
EMISSTYPE	EMISSTYPE
CAPCOST	CAPCOST
ANNUALCOST	ANNUALCOST
OMCOST	OMCOST
COSTEFFECT	COSTEFFECT
COSTVERIFY	COSTVERIFY
DOLLARYEAR	DOLLARYEAR
POLNOTES	POLNOTES

SW_SubqualityGasComposition	
B11. SW_Subquality	
HCMREG	Hydrocarbon Supply Model Region (see map)
BASCODE	AAPG Basin Code
BASIN	Basin name
FORMATION	Formation name
NRES	Number of reservoirs
NCOMP	Number of gas well completions
ULT_COMP	Average recovery per completion
AVDEPTH	Average depth
CO2AV	Carbon dioxide average
CO2MIN	Carbon dioxide minimum
CO2MAX	Carbon dioxide maximum
CO2STD	Carbon dioxide standard deviation
RAW_RUR	Heating value standard deviation
R_SAMP	Proven raw gas reserves as of 12/32/99
GASAN	Fraction of raw gas reserves sampled
CONVGROW	1999 raw gas production
CONVNEWF	Reserve growth in existing conventional fields
UNCONV	Conventional new field potential
TYPUNCNV	Type of unconventional gas: TIGHT, COAL, SHALE, LOW_Btu, CoProduction
PRD	1999 production CO2>2%
RUR	1999 reserves of CO2>2%
UND	Undiscovered resources of CO2>2%

SW_NonFuelPlants								
B12. EIA Summary	***B13. Cement In Region***	***B14. Cement Manufactors***	***B15. Anhydrous Ammonia 96***	***B16. Ammonia In Region***	***B17. Chlorine Plants***	***B18. Ethylene Plants***	***B19. EOR***	***B20. Refineries***
CO2 Emissions	Company	Company	Licensor/ Construction	Company	Company	Company	Type	
States	Plant Name	Website	City	City	City	Location	Operator	
Energy - Residential	address	US?	State	State	State	State	Field	
Energy - commercial	City		Tonnes/year	k METRIC TONS/YEAR	Capacity (Kt/year)	Year of start up	State	
Energy - Industrial	State		Feedstock		Age of Process in 1994	Ethylene Capacity (ktonne/a)	County	
Energy - Transport	Zip				Process	Ethane	Pay zone	
Energy- Utility	Phone					Propane	Formation	
Energy - Exported Electricity	PhoneFree					Butane	Project Maturity	
Energy - Other	Fax					Naphtha	Proj. Eval	
Total Energy	NoKilms					Gas oil	Profit	
Waste	K ton/y					Other	Project Scope	
Agriculture						Licensor, Remarks		
Industry								
Land Use								
Total								

SW_ElectricPlants_CO_2_Tons_%	
B21.	***SW_ElectricPlants_CO2_Tons_%***

STATE
ORIS_CODE
FACILITY_NAME
UNIT_ID
YEAR
SumOfCO2_TONS
SumOfSO2_TONS

SumOfNOX_TONS
SumOfHEAT_INPUT
SumOfTOTAL_OPERATING_HOURS
DESCRIPTION_SPECIFIC
DESCRIPTION_GENERIC
CO2_CONCENTRATION

SW_99v3AirDataFacilitiesFile				
B22. BLC_SW	***B23. RBLC_SW_ElectGen***	***B24. NH3 Release***	***B25. ORIS_Facility_Code***	
STATE FIPS	STATE FIPS	P200_STATE_FIPS	ORISPL	ORIS Plant Code in eGRID 1999
COUNTY FIPS	COUNTY FIPS	P200_COUNTY_FIPS	FIPST	State FIPS code (text field for matching to NEI)
STATE ABBREV	STATE ABBREV	P200_SITE_ID	FIPSCNY	County FIPS code
COUNTY NAME	COUNTY NAME	P200_ORIS_FACILITY_CODE	ORISPL_In_NEI_V300_Draft	Identifies the codes that have been entered in the ORIS facility Code field in the Site table of draft Version 3 of the 1999 NEI
FACILITY ID	FACILITY ID	P200_SIC_PRIMARY	SiteID_In_NEI_V300_Draft	Identifies the site ID associated with the ORIS Facility Code in the Site table of draft Version 3 of the 1999 NEI
FACILITY NAME	FACILITY NAME	P200_FACILITY_NAME	FIPST_NUM	State FIPS code (text field for matching to NEI)
STREET	STREET	P200_SITE_DESCRIPTION	FIPSCNY_NUM	County FIPS code
CITY	CITY	P200_STREET_LINE_1	PSTATABB	Postal code abbreviation of the State where the plant is located
STATE	STATE	P200_STREET_LINE_2	CNTYNAME	County name
ZIP	ZIP	P200_STREET_LINE_3	PNAME	Plant name
FACILITY ADDRESS	FACILITY ADDRESS	P200_CITY	OPRNAME	Plant operator name
EPAREGION	EPA REGION	P200_STATE	OPPRNAME	Operator parent company name
INVENTORY YEAR	INVENTORY YEAR	P200_ZIP_CODE	PCANAME	Physical (operator) based power control area name
SIC	SIC	P200_NH3_EMISSION_TON_SUM	PLTYPE	Plant type (utility or nonutility)
LATITUDE	LATITUDE	MATCH_TYPE	PREVUTIL	Previously a utility plant flag (this field has a value of 1 if the plant has been sold by a utility to a nonutility; it has a value of 0 otherwise)
LONGITUDE	LONGITUDE	MATCH_MULTIPLE	LAT	Plant latitude
CO	CO	MATCH_RATIO	LON	Plant longitude

NH3	NH3	NH3_TO_APPLY_ EMISSION_TON_ SUM	NUMBLR	Number of utility boilers within a plant
NOX	NOX	P300_STATE_ FIPS	NUMGEN	Number of generators within a plant
PMCON	PMCON	P300_COUNTY_ FIPS	SOURCEM	The source(s) of emissions data for the plant. The choices are: T- ETS/CEM Knox, SO2, and CO2 emissions reported to EPA; E=Emissions estimated by applying EPA AP-42 emission factors to fuel data from EIA-767, EIA-759/FERC-423, EIA-860B, r default values: and Z=Plant utilizes energy resources with zero emissions.
PMFIL	PMFIL	P300_SITE_ID	PLPRIMFL	Plant's primary fuel based on maximum heat input or assignment (if plant is solar, wind, nuclear, geothermal, or hydro) (see eGRID technical support document for definition of codes used in this field).
PMPRI	PMPRI	P300_ORIS_ FACILITY_CODE	PLFFLCTG	Plant Fossil Fuel Category (field contains a "C" if PLPRIMPL is derived from coal, "O" if it derived from oil, or "G" if it is derived from gas. The value is blank otherwise. Fossil Fuel refers to any naturally occurring organic fuel, such as petroleum, coal, and natural gas)
PM10FIL	PM10FIL	P300_SIC_PRIMARY	CAPFAC	Plant capacity factor
PM10PRI	PM10PRI	P300_FACILITY_ NAME	BOILCAP	Utility plant boiler capacity (MW)
PM25FIL	PM25FIL	P300_SITE_ DESCRIPTION	NAMEPCAP	Plant Generator capacity (MW)
PM25PRI	PM25PRI	P300_STREET_ LINE_1	CHPFLAG	Combined heat and power (CHP) (cogenerator) 1998 plant flag
SO2	SO2	P300_STREET_ LINE_2	USETHRMO	CHP plant 1998 useful thermal output (MMBtu)
VOC	VOC	P300_STREET_ LINE_3	PWRTOHT	CHP plant 1998 power to heat ratio
		P300_CITY	ELCALLOC	CHP plant 1998 electric allocation factor
		P300_STATE	PLNUCONN	Nonutility plant connected to grid flag (Y=yes, N=no)
		P300_ZIP_CODE		
		P300_NH3_ EMISSION _TON_SUM		

SW_Coorid fromEPA_HAP
B26. SW
strState Facility Identifier
strSICPrimary
strNAICSPrimary
strFacilityName
strSite Description
strLocation Address
strCity
srtState
strZipCode
strCountry
dblXCoordinate
dblYCoordinate
intUTMZone
strXY Coordinate Type

RACT_BACT_laer	SW_NATCARB_Data_Facilities with Match to RACT_BACT_laer	SW_minerals_usgs_gov
B27. SW	***B28. Facilities1030617920***	***B29. SW***
ORIS_CODE	RBLCID	Mineral
RBLCID	ORIS_CODE	Beryllium concentrates
FACILITY	FACILITY_NAME	Cement:
COMPANY		Masonry
COUNTY		Portland
CONTACT		Clays:
ADDRESS		Bentonite
CITY		Common
STATE		Fuller's earth
ZIP		Kaolin
PHONE		Copper[3]
EMAIL		Gemstones
REGION		Gold[3]
AGENCYCODE		Gypsum, crude
AGENCYNAME		Helium, crude
AGENCYCONTACT		Grade-A
AGENCYPHONE		Iodine, crude
AGENCYEMAIL		Lime
PERMITNUM		Salt
SIC		Sand and gravel:
NAICS		Construction
AIRSID		Industrial
EPAID		Silver[3]
UTMZONE		Stone:
XCOORD		Crushed
YCOORD		Dimension
RCVDDATE		Talc, crude
PERMITDATE		Tripoli
STARTUPDATE		
VERIFYDATE		
ENTRYDATE		
LASTUPDATE		
NEW_MOD		
PUBLICHEAR		
FUEL		
EMISSSOURCES		
ABATEMENT		
NARRATIVE		
NOTES		
PROCESS		
PROCTYPE		

SCC
FUEL
THRUPUT
THRUPUTUNIT
COMPVERIFY
STACKTEST
INSPECTION
CALCULATED
OTHERTEST
OTHERMETHD
PRNOTES
POLLUTANT
CAS
CONTROLCOD
CTRLDESC
RANKOPTS
RANKSEL
EMISLIMIT1
EMISLIMIT1UNIT
EMISLIMIT1CONDITION
BASIS
PCTEFFIC
EMISLIMIT2
EMISLIMIT2UNIT
EMISLIMIT2CONDITION
STDEMISS
STDUNIT
STOTHERCONDITIONS
EMISSTYPE
CAPCOST
ANNUALCOST
OMCOST
COSTEFFECT
COSTVERIFY
DOLLARYEAR
POLNOTES

SW_ElectricPlants_eGRID							
B30. Contents	*B31. EGRDPLNT00*	*B32. EGRDBLR00*	*B33. EGRDGEN00*	*B34. EGRDPLCH*	*B35. EGRDEGCH*	*B36. EGRDPRCH*	*B37. EGRDPCCH*
	SEQPLT00 eGRID2002 2000 file plant sequence number	**SEQBLR00** eGRID2002 2000 file boiler sequence number	**SEQGEN00** eGRID2002 2000 file generator sequence number	**SEQPLCH** eGRID2002 plant change sequence number	**SEQEGCH** eGRID2002 EGC change sequence number	**SEQPRCH** eGRID2002 parent company change sequence number	**SEQPCCH** eGRID2002 PCA change sequence number
	SEQPLT99 eGRID2002 1999 file plant sequence number	**SEQBLR99** eGRID2002 1999 file boiler sequence number	**SEQGEN99** eGRID2002 1999 file generator sequence number	**SEQPLT00** eGRID2002 2000 file plant sequence number	**SEQEGO00** eGRID2002 2000 file owner-based EGC sequence number	**SEQPRO00** eGRID2002 2000 file owner-based parent company sequence number	**SEQPCO00** eGRID2002 2000 file owner-based PCA sequence number
	PSTATABB State abbreviation	**PSTATABB** State abbreviation	**PSTATABB** State abbreviation	**SEQPLT98** eGRID2002 1998 file plant sequence number	**SEQEGP00** eGRID2002 2000 file location (operator)-based EGC sequence number	**SEQPRP00** eGRID2002 2000 file location (operator)-based parent company sequence number	**SEQPCP00** eGRID2002 2000 file location (operator)-based PCA sequence number
	PNAME Plant name	**PNAME** Plant name	**PNAME** Plant name	**PNAME** Plant name	**SEQEGO98** eGRID2002 1998 file owner-based EGC sequence number	**SEQPRO98** eGRID2002 1998 file owner-based parent company sequence number	**SEQPCO98** eGRID2002 1998 file owner-based PCA sequence number
	ORISPL DOE/EIA ORIS plant or facility code	**ORISPL** DOE/EIA ORIS plant or facility code	**ORISPL** DOE/EIA ORIS plant or facility code	**ORISPL** DOE/EIA ORIS plant or facility code	**SEQEGP98** eGRID2002 1998 file location (operator)-based EGC sequence number	**SEQPRP98** eGRID2002 1998 file location (operator)-based parent company sequence	**SEQPCP98** eGRID2002 1998 file location (operator)-based PCA sequence number

number

PLTYPE Plant type	BLRID Boiler ID	GENID Generator ID or grouped identifier	CHTYPE Type of note	EGCNAME EGC name	PRNAME Parent company name	PCANAME PCA name
PREVUTIL Previously a utility plant flag	AFFECTED Affected flag	GENTYPE Generator type	CHDATE Change date (yymm)	EGCID EGC ID	PRNUM Parent company ID	PCAID PCA ID
CHANGE Change? – If Y, go to EGRDPLCH file	BOTFIRTY Boiler bottom and firing types	NUMBLR Number of associated boilers	OLDNAME Old name	CHTYPE Type of note	CHTYPE Type of note	CHTYPE Type of note
OPRNAME Plant operator name	BOILCAP Boiler capacity (MMBtu/hr)	GENSTAT Generator 2000 status	OLDID Old ID	CHDATE Change year	CHDATE Change year	CHDATE Change year
OPRCODE Plant operator ID	NUMGEN Number of associated generators	PRMVR Prime mover type	NEWNAME New name	CHDESC Note text	CHDESC Note text	CHDESC Note text
UTLSRVNM Nonutility's service area name	FUELB1 Primary boiler fuel	FUELG1 Primary generator fuel	NEWID New ID	OLDNAME Old name	OLDNAME Old name	OLDNAME Old name
UTLSRVID Nonutility's service area ID	LOADHRS Hours connected to load	NAMEPCAP Generator nameplate capacity (MW)	PRVOWNTY Previous owner type, if CHTYPE= OWN or OPR	OLDID Old ID	OLDID Old ID	OLDID Old ID
OPPRNUM Location (operator)-based parent company ID	HTIEAN Boiler 2000 annual ETS/CEM heat input (MMBtu)	CFACT Generator 2000 capacity factor	OLDPERC Old percent, if CHTYPE=OWN	NEWNAME New name	NEWNAME New name	NEWNAME New name

OPPRNAME
Location (operator)-based parent company name

PCANAME
Location (operator)-based power control area name

PCAID
Location (operator)-based power control area ID

NERC
Location (operator)-based NERC region acronym

NERCNUM
NERC number associated with NERC region

SUBRGN
eGRID subregion acronym

HTIEOZ
Boiler 2000 ozone season ETS/CEM heat input (MMBtu)

HTIFAN
Boiler 2000 annual total EIA-based calculated heat input (MMBtu)

HTIFOZ
Boiler 2000 ozone season EIA-based calculated heat input (MMBtu)

HTICL
Boiler 2000 annual EIA-based calculated coal heat input (MMBtu)

HTIOL
Boiler 2000 annual EIA-based calculated oil heat input (MMBtu)

HTIGS
Boiler 2000 annual EIA-based calculated gas heat input (MMBtu)

GENNTAN
Generator 2000 annual net generation (MWh)

GENNTOZ
Generator 2000 ozone season net generation (MWh)

GENYRONL
Generator year on-line

SEQGEN
eGRID96 1996 file generator sequence number

SEQGEN97
eGRID97 1997 file generator sequence number

SEQGEN98
eGRID2000 1998 file generator sequence number

NEWPERC
New percent, if CHTYPE=OWN

NEWID
New ID

NEWID
New ID

NEWID
New ID

SRNAME
eGRID subregion name

FIPST
Plant FIPS State code

FIPSCNY
Plant FIPS county code

CNTYNAME
Plant county name

LAT
Plant latitude

LON
Plant longitude

HTIBM
Boiler 2000 annual EIA-based calculated biomass/ wood heat input (MMBtu)

HTISW
Boiler 2000 annual EIA-based calculated solid waste heat input (MMBtu)

HTIOT
Boiler 2000 annual EIA-based calculated other fuel heat input (MMBtu)

HTIBAN
Boiler 2000 annual best heat input (MMBtu)

HTIBOZ
Boiler 2000 ozone season best heat input (MMBtu)

NOXEAN
Boiler 2000 annual ETS/CEM NOx emissions (tons)

NUMBLR
Number of utility boilers

NUMGEN
Number of generators

SOURCEM
Plant emissions source(s)

PLPRIMFL
Plant primary fuel

PLFFLCTG
Plant fossil fuel category

CAPFAC
Plant capacity factor

NOXEOZ
Boiler 2000 ozone season ETS/CEM NOx emissions (tons)

NOXFAN
Boiler 2000 annual EIA-based calculated NOx emissions (tons)

NOXFOZ
Boiler 2000 ozone season EIA-based calculated NOx emissions (tons)

SO2EAN
Boiler 2000 annual ETS/CEM SO2 emissions (tons)

SO2FAN
Boiler 2000 annual EIA-based calculated SO2 emissions (tons)

CO2EAN
Boiler 2000 annual ETS/CEM CO2 emissions (tons)

BOILCAP
Utility plant boiler capacity (MMBtu/hr)

NAMEPCAP
Plant generator capacity (MW)

CHPFLAG
Combined heat and power (CHP) (cogenerator) 2000 plant flag

USETHRMO
CHP plant 2000 useful thermal output (MMBtu)

PWRTOHT
CHP plant 2000 power to heat ratio

ELCALLOC
CHP plant 2000 electric allocation factor

PLNUCONN
Nonutility plant connected to grid flag

CO2FAN
Boiler 2000 annual EIA-based calculated CO2 emissions (tons)

SRCBEST
Source of "best" 2000 heat input, NOx, SO2, and CO2 data

NOXBAN
Boiler 2000 annual best NOx emissions (tons)

NOXBOZ
Boiler 2000 ozone season best NOx emissions (tons)

SO2BAN
Boiler 2000 annual best SO2 emissions (tons)

CO2BAN
Boiler 2000 annual best CO2 emissions (tons)

SO2CTLDV
2000 SO2 (scrubber) control device for utilities

PSFLG
Plant pumped storage flag

ARDBNU
ARD nonutility flag

LMSWFLG
Nonutility plant landfill methane or solid waste flag

PLNUCMBS
Plant nonutility combustion flag

PLNUCOAL
Plant nonutility coal flag

UTNOWNU
Now nonutility flag

GENERVAL
Generation value source

NOXCTLDV
2000 NOx control device for utilities

T4A00
Year 2000 Title IV SO2 1998 reallocation plus repowering allowance (tons)

T4A10
Year 2010 Title IV SO2 1998 reallocation plus repowering allowance (tons)

BLRYRONL
Boiler year on-line

BLRSEQ
Unique boiler identifier originating in NADB, and continuing in ARDB and IMDB data files

SEQBLR
eGRID96 1996 file boiler sequence number

SEQBLR97
eGRID97 1997 file boiler sequence number

EMISVAL Emission value source

RESMXVAL Resource mix value source

PLHTIAN Plant 2000 annual heat input (MMBtu)

PLHTIOZ Plant 2000 ozone season heat input (MMBtu)

PLGGENAN Plant 2000 annual gross generation (MWh)

PLNGENAN Plant 2000 annual net generation (MWh)

PLNGENOZ Plant 2000 ozone season net generation (MWh)

PLNOXAN Plant 2000 annual NOx emissions (tons)

PLNOXOZ Plant 2000 ozone season NOx emissions (tons)

SEQBLR98 eGRID2000 1998 file boiler sequence number

PLSO2AN
Plant 2000 annual SO2 emissions (tons)
PLCO2AN
Plant 2000 annual CO2 emissions (tons)

PLHGAN
Plant 2000 annual mercury emissions (lbs)
PLNOXRTA
Plant 2000 annual NOx output emission rate (lbs/MWh)
PLNOXRTO
Plant 2000 ozone season NOx output emission rate (lbs/MWh)
PLSO2RTA
Plant 2000 annual SO2 output emission rate (lbs/MWh)
PLCO2RTA
Plant 2000 annual CO2 output emission rate (lbs/MWh)

PLHGRTA
Plant 2000 annual mercury output emission rate (lbs/GWh)
PLNOXRA
Plant 2000 annual NOx input emission rate (lbs/MMBtu)
PLNOXRO
Plant 2000 ozone season NOx input emission rate (lbs/MMBtu)
PLSO2RA
Plant 2000 annual SO2 input emission rate (lbs/MMBtu)
PLCO2RA
Plant 2000 annual CO2 input emission rate (lbs/MMBtu)

PLHGRA
Plant 2000 annual mercury input emission rate (lbs/BBtu)
PLHTRT
Plant 2000 nominal heat rate (Btu/kWh)

PLGENACL
Plant 2000 annual coal net generation (MWh)
PLGENAOL
Plant 2000 annual oil net generation (MWh)
PLGENAGS
Plant 2000 annual gas net generation (MWh)
PLGENANC
Plant 2000 annual nuclear net generation (MWh)
PLGENAHY
Plant 2000 annual hydro net generation (MWh)
PLGENABM
Plant 2000 annual biomass/ wood net generation (MWh)
PLGENAWI
Plant 2000 annual wind net generation (MWh)
PLGENASO
Plant 2000 annual solar net generation (MWh)

PLGENAGT
Plant 2000 annual geothermal net generation (MWh)
PLGENAOF
Plant 2000 annual other fossil (tires, batteries, chemicals, etc.) net generation (MWh)
PLGENASW
Plant 2000 annual solid waste net generation (MWh)
PLGENATN
Plant 2000 annual total nonrenewables net generation (MWh)
PLGENATR
Plant 2000 annual total renewables net generation (MWh)
PLGENATH
Plant 2000 annual total nonhydro renewables net generation (MWh)

PLCLPR
Plant 2000 coal generation percent (resource mix)
PLOLPR
Plant 2000 oil generation percent (resource mix)
PLGSPR
Plant 2000 gas generation percent (resource mix)
PLNCPR
Plant 2000 nuclear generation percent (resource mix)
PLHYPR
Plant 2000 hydro generation percent (resource mix)
PLBMPR
Plant 2000 biomass/ wood generation percent (resource mix)
PLWIPR
Plant 2000 wind generation percent (resource mix)
PLSOPR
Plant 2000 solar generation percent

(resource mix)

PLGTPR
Plant 2000 geothermal generation percent (resource mix)
PLOFPR
Plant 2000 other fossil (tires, batteries, chemicals, etc.) generation percent (resource mix)
PLSWPR
Plant 2000 solid waste generation percent (resource mix)
PLTNPR
Plant 2000 total nonrenewables generation percent (resource mix)
PLTRPR
Plant 2000 total renewables generation percent (resource mix)

PLTHPR
Plant 2000 total nonhydro renewables generation percent

(resource mix)

OWNRNM01
Plant 2000 owner name (first)
OWNRUC01
Plant 2000 owner code (first)
OWNRPR01
Plant 2000 owner percent (first)
OWNRTY01
Plant 2000 owner type (first)
OWNRNM02
Plant 2000 owner name (second)
OWNRUC02
Plant 2000 owner code (second)
OWNRPR02
Plant 2000 owner percent (second)
OWNRTY02
Plant 2000 owner type (second)
OWNRNM03
Plant 2000 owner name (third)

OWNRUC03
Plant 2000 owner code (third)
OWNRPR03
Plant 2000 owner percent (third)
OWNRTY03
Plant 2000 owner type (third)
OWNRNM04
Plant 2000 owner name (fourth)
OWNRUC04
Plant 2000 owner code (fourth)
OWNRPR04
Plant 2000 owner percent (fourth)
OWNRTY04
Plant 2000 owner type (fourth)
OWNRNM05
Plant 2000 owner name (fifth)
OWNRUC05
Plant 2000 owner code (fifth)
OWNRPR05
Plant 2000 owner percent (fifth)

OWNRTY05
Plant 2000 owner type (fifth)
OWNRNM06
Plant 2000 owner name (sixth)
OWNRUC06
Plant 2000 owner code (sixth)
OWNRPR06
Plant 2000 owner percent (sixth)
OWNRTY06
Plant 2000 owner type (sixth)
OWNRNM07
Plant 2000 owner name (seventh)
OWNRUC07
Plant 2000 owner code (seventh)
OWNRPR07
Plant 2000 owner percent (seventh)
OWNRTY07
Plant 2000 owner type (seventh)
OWNRNM08
Plant 2000 owner name (eighth)

OWNRUC08
Plant 2000 owner code (eighth)
OWNRPR08
Plant 2000 owner percent (eighth)
OWNRTY08
Plant 2000 owner type (eighth)
OWNRNM09
Plant 2000 owner name (ninth)
OWNRUC09
Plant 2000 owner code (ninth)
OWNRPR09
Plant 2000 owner percent (ninth)
OWNRTY09
Plant 2000 owner type (ninth)
OWNRNM10
Plant 2000 owner name (tenth)
OWNRUC10
Plant 2000 owner code (tenth)
OWNRPR10
Plant 2000 owner percent (tenth)

OWNRTY10
Plant 2000 owner type (tenth)
OWNRNM11
Plant 2000 owner name (eleventh)
OWNRUC11
Plant 2000 owner code (eleventh)
OWNRPR11
Plant 2000 owner percent (eleventh)
OWNRTY11
Plant 2000 owner type (eleventh)
OWNRNM12
Plant 2000 owner name (twelfth)
OWNRUC12
Plant 2000 owner code (twelfth)
OWNRPR12
Plant 2000 owner percent (twelfth)
OWNRTY12
Plant 2000 owner type (twelfth)
OWNRNM13
Plant 2000 owner name (thirteenth)

OWNRUC13
Plant 2000
owner code
(thirteenth)
OWNRPR13
Plant 2000
owner percent
(thirteenth)
OWNRTY13
Plant 2000
owner type
(thirteenth)
OWNRNM14
Plant 2000
owner name
(fourteenth)
OWNRUC14
Plant 2000
owner code
(fourteenth)
OWNRPR14
Plant 2000
owner percent
(fourteenth)
OWNRTY14
Plant 2000
owner type
(fourteenth)
SEQPLT
eGRID96 1996
file plant
sequence
number
SEQPLT97
eGRID97 1997
file plant
sequence
number
SEQPLT98
eGRID2000
1998 file plant
sequence
number

SW_EthanolPlants	
B38. Ethanol Production	*B39. SW_Ethanol Production*
COMPANY	**COMPANY**
LOCATION	**LOCATION**
STATE	**STATE**
FEEDSTOCK	**FEEDSTOCK**
Current Capacity (mmgy)	**Current Capacity (mmgy)**
Under Construction/ Expansion (mmgy)	**Under Construction/ Expansions (mmgy)**
	Address
Ethanol Plants Currently Operating	**City/State/Zip**
City	
State	
MGY	

SUB-APPENDICES – WORKSHEETS

strStateFacilit	strSIC	strNAICS	strFacilityName	srtState	dblXCoord	dblYCoord	intUTMZo	strXYCoor
T$12468	1061	2122	AMERICAN MINERALS INC.	NM	-107.7336	32.27778		LATLON
T$12022	1061	2122	AMERICAN MINERALS INC.	TX	-106.5518	31.8093		LATLON
0278	1311	211111	AMOCO PROD. CO. - J.B. GARDNER A #1	CO	-107.9203	37.005	13	LATLON
0280	1311	211111	AMOCO PRODUCTION - EVELYN PAYNE GU #1	CO	-107.5511	37.258	13	LATLON
0083	1311	211111	AMOCO PRODUCTION CO PICNIC FLATS	CO	-107.9898	37.0732	13	LATLON
0279	1311	211111	AMOCO PRODUCTION CO - ROBERT DULIN D #1	CO	-107.6046	37.2725	13	LATLON
0273	1311	211111	AMOCO PRODUCTION CO GEARHART WELL #1-6	CO	-107.6778	37.244	13	LATLON
0274	1311	211111	AMOCO PRODUCTION CO LORETT FEDERAL GU #1	CO	-107.6679	37.1913	13	LATLON
0025	1311	211111	AMOCO PRODUCTION CO WATTENBERG PLT	CO	-104.6779	39.7448	13	LATLON
0277	1311	211111	AMOCO PRODUCTION CO.- ROBIN FRAZIER A	CO	-107.9027	37.005	13	LATLON
0444	1311	211111	ANTELOPE ENERGY COMPANY-TERANCE PLANT	CO	-103.8969	40.8454	13	LATLON
081230099	1311	211111	ASSOCIATED NATURAL GAS GREELEY PLT	CO	-104.8525	40.49639		LATLON
081230074	1311	211111	ASSOCIATED NATURAL GAS INC SINGLETREE	CO	-104.8122	40.14556		LATLON
081230015	1311	211111	ASSOCIATED NATURAL GAS INC SPINDLE PLT	CO	-104.8825	40.08917		LATLON
081230075	1311	211111	ASSOCIATED NATURAL GAS INC SURREY PLT	CO	-104.8864	40.01583		LATLON
081230076	1311	211111	ASSOCIATED NATURAL GAS INC WEST SPINDLE	CO	-104.8858	40.0875		LATLON
081230125	1311	211111	ASSOCIATED NATURAL GAS SPINDLE AIR PLT	CO	-104.885	40.0875		LATLON
081230068	1311	211111	ASSOCIATED NATURAL GAS WATTENBERG	CO	-104.8944	40.12111		LATLON
0145	1311	211111	BARGARTH INC GRAND VALLEY GAS PROC	CO	-108.1116	39.3219	12	LATLON
0089	1311	211111	BARRETT RESOURCES CORP RULISON ANVIL PTS	CO	-107.9096	39.4961	13	LATLON
0029	1311	211111	BITTER CREEK PIPELINES - YENTER C.S.	CO	-103.3965	40.6909	13	LATLON
0016	1311	211111	BURR OIL & GAS INC. - CROSS CANYON #1	CO	-108.9854	37.566	12	LATLON
1189	1311	211111	CASCADE OIL & GAS INC	CO	-104.5176	39.9776	13	LATLON
080330012	1311	211111	CELSIUS ENERGY CO DOVE CREEK PLT	CO	-108.87	37.76		LATLON
080810066	1311	211111	CELSIUS ENERGY CO HIAWATHA CO2 EXTR FAC	CO	-108.6247	40.99028		LATLON
0153	1311	211111	CER CORP MWX-1 GAS WELL	CO	-107.8811	39.4833	13	LATLON
0034	1311	211111	CHEVRON USA PRODUCTION CO RANGELY FIELD	CO	-108.9281	40.1042	12	LATLON
081030055	1311	211111	COLORADO INTERSTATE GAS CO GREASEWOOD	CO	-108.1906	39.89694		LATLON
0001	1311	211111	COLORADO INTERSTATE GAS CO KIT CARSON	CO	-102.6206	38.673	13	LATLON
0007	1311	211111	COLORADO INTERSTATE GAS CO VILAS C S	CO	-102.472	37.3237	13	LATLON
081030036	1311	211111	CONOCO INC DRAGON TRAIL GAS PROC PLT	CO	-108.8089	39.83139		LATLON
081030032	1311	211111	CONOCO INC NATURAL GAS WEST DOUGLAS	CO	-108.7567	39.81111		LATLON
0103	1311	211111	CUSTOM ENERGY CONSTRUCTION INC BUCK PEAK	CO	-107.4977	40.4858	13	LATLON
0099	1311	211111	DUKE ENERGY FIELD SERVICES - GREELEY	CO	-104.8525	40.4965	13	LATLON
0049	1311	211111	DUKE ENERGY FIELD SERVICES - ROGGEN	CO	-104.3898	40.1193	13	LATLON
0015	1311	211111	DUKE ENERGY FIELD SERVICES - SPINDLE	CO	-104.8827	40.0893	13	LATLON
0036	1311	211111	EL PASO CORPORATION - DRAGON TRAIL GAS	CO	-108.809	39.8308	12	LATLON
0016	1311	211111	EL PASO CORPORATION - EAST DRAGON TRAIL	CO	-108.7904	39.8296	12	LATLON
081010098	1311	211111	FUEL RESOURCES DEV SYNHYTEC	CO	-104.7144	38.21917		LATLON
0333	1311	211111	GATEWAY PROCESSING CO	CO	-108.22	38.931		LATLON
080810124	1311	211111	GRYNBERG PETROLEUM COMPANY SUGAR LOAF	CO	-108.6833	40.94472		LATLON
080810123	1311	211111	GRYNBERG PETROLEUM COMPANY BLUE GRAVEL	CO	-107.6508	40.69417		LATLON
0019	1311	211111	HORSESHOE OPERATING INC LA DRY CREEK	CO	-102.8027	37.8602	13	LATLON
080110018	1311	211111	HORSESHOE OPERATING INC WAGON TRAIL	CO	-102.8211	38.06417		LATLON
080010501	1311	211111	IRONDALE GAS PROCESSING CO IRONDALE CS2	CO	-104.3803	39.86694		LATLON
0082	1311	211111	KN GAS GATHERING BLACK SULPHUR LIQUIDS	CO	-108.3053	39.8625	12	LATLON
081030083	1311	211111	KN GAS GATHERING PICEANCE CREEK	CO	-108.2661	40.04056		LATLON
080050519	1311	211111	KOCH HYDROCARBON CO DENVER CTL PLT	CO	-104.3544	39.64139		LATLON

strStateFacilit	strSIC	strNAICS	strFacilityName	srtState	dblXCoord	dblYCoord	intUTMZo	strXYCoor
080010628	1311	211111	KOCH HYDROCARBON CO KALLSEN PLT	CO	-104.3333	39.87861		LATLON
080010629	1311	211111	KOCH HYDROCARBON CO LINNEBURG PLT	CO	-103.9558	39.94056		LATLON
080010627	1311	211111	KOCH HYDROCARBON CO STATE PLT	CO	-104.6767	39.96222		LATLON
080310950	1311	211111	KOCH HYDROCARBON CO THIRD CREEK PLT	CO	-104.6969	39.88472		LATLON
080990057	1311	211111	MARATHON OIL CO SNIFF E1	CO	-102.7844	38.04944		LATLON
080830033	1311	211111	MID AMERICA PIPELINE CO DOLORES STA	CO	-108.4328	37.41444		LATLON
0031	1311	211111	MITCHELL ENERGY CORP HELLS HOLE CANYON	CO	-109.005	39.9236	12	LATLON
0005	1311	211111	MULL DRILLING CO INC SORRENTO FIELD	CO	-102.6025	38.8709	13	LATLON
080770180	1311	211111	NATL FUEL CORP	CO	-108	39.26583		LATLON
081230127	1311	211111	NORTH AMERICAN RESOURCES CO ARISTOCRAT	CO	-104.6167	40.25		LATLON
0319	1311	211111	NORTH AMERICAN RESOURCES CO FT LUPTON	CO	-104.7394	40.1486	13	LATLON
0950	1311	211111	NORTH AMERICAN RESOURCES CO THIRD CREEK	CO	-104.7487	39.78118	13	LATLON
0628	1311	211111	NORTH AMERICAN RESOURCES CO_ KALLSEN	CO	-104.3311	39.8811	13	LATLON
081070047	1311	211111	NORTHERN NATURAL GAS CO ENRON ROUTT NO 1	CO	-107.3942	40.29889		LATLON
080770183	1311	211111	PUBLIC SERVICE CO ASBURY	CO	-108.6472	39.23028		LATLON
0121	1311	211111	PUBLIC SERVICE CO BAXTER STATION	CO	-108.8633	39.3958	12	LATLON
081030016	1311	211111	PUBLIC SERVICE CO DRAGON TRAIL	CO	-108.79	39.82972		LATLON
0086	1311	211111	PUBLIC SERVICE CO GREASEWOOD STATION	CO	-108.1925	39.9058	12	LATLON
080770182	1311	211111	PUBLIC SERVICE CO HUNTER CANYON	CO	-108.5914	39.33139		LATLON
081030056	1311	211111	PUBLIC SERVICE CO INDIAN VALLEY	CO	-108.1928	40.10139		LATLON
0087	1311	211111	PUBLIC SERVICE CO NORTH DOUGLAS STATION	CO	-108.7745	39.9599	12	LATLON
0122	1311	211111	PUBLIC SERVICE CO RIFLE COMP STA	CO	-107.8166	39.5254	13	LATLON
081030048	1311	211111	PUBLIC SERVICE CO WHITE RIVER DOME	CO	-108.1908	40.09861		LATLON
0024	1311	211111	PUBLIC SERVICE CO WILLIAMS FORK STATION	CO	-106.0896	39.8626	13	LATLON
081230141	1311	211111	PUBLIC SERVICE CO YOSEMITE	CO	-104.8856	40.01472		LATLON
0024	1311	211111	QUESTAR EXPLORATION & PROD -CUTTHROAT A	CO	-108.9272	37.4723	12	LATLON
0132	1311	211111	QUESTAR GAS MANAGEMENT - AVALANCHE	CO	-107.6493	40.993	13	LATLON
0135	1311	211111	QUESTAR GAS MANAGEMENT CO E.HIAWATHA	CO	-108.1817	40.6116	13	LATLON
0131	1311	211111	QUESTAR GAS MANAGEMENT CO SAND HILL	CO	-107.6209	40.9514	13	LATLON
0006	1311	211111	QUESTAR GAS MANAGEMENT DOVE CREEK PLT	CO	-108.8651	37.7857	12	LATLON
080330006	1311	211111	QUESTAR PIPELINE CO DOVE CREEK PLT	CO	-108.8647	37.78556		LATLON
081030037	1311	211111	ROCKY MOUNTAIN NATURAL GAS CO PICEANCE	CO	-108.2628	40.04333		LATLON
081130007	1311	211111	ROCKY MOUNTAIN NATURAL GAS CO SLICK ROCK	CO	-108.8925	38.02056		LATLON
081130016	1311	211111	ROCKY MOUNTAIN NATURAL GAS NICHOLAS DRAW	CO	-108.8192	38.03083		LATLON
0068	1311	211111	ROCKY MTN NATURAL GAS CO BLACK SULPHUR	CO	-107.8557	40.03395	13	LATLON
0108	1311	211111	ROCKY MTN NATURAL GAS CO DEBEQUE C S	CO	-108.2598	39.3885	12	LATLON
0037	1311	211111	ROCKY MTN NATURAL GAS CO PICEANCE	CO	-108.263	40.0435	12	LATLON
0018	1311	211111	ROCKY MTN NATURAL GAS CO WOLF CREEK	CO	-107.407	39.3202	13	LATLON
080870034	1311	211111	ROGGEN GAS PROCESSING CO SITE NAME UNK	CO	-104.0503	40.46861		LATLON
0018	1311	211111	SHELL CO2 COMPANY - YELLOW JACKET	CO	-108.787	37.4715	12	LATLON
0020	1311	211111	SHELL CO2 COMPANY, LTD. - HOVENWEEP CO2 SOURCE	CO	-108.8623	37.49	12	LATLON
081230422	1311	211111	SNYDER OIL CO WEST GAS PLT	CO	-104.7967	40.23361		LATLON
081230049	1311	211111	SNYDER OIL CORP ROGGEN GAS PLT	CO	-104.3897	40.11944		LATLON
081230111	1311	211111	SNYDER OIL CORP THOMPSON VALLEY GAS PLA	CO	-104.9414	40.31472		LATLON
080870012	1311	211111	SNYDER OIL CORP VALLERY GAS PLT	CO	-103.9658	40.22278		LATLON
0098	1311	211111	SOUTHWESTERN PRODUCTION - GILCREST GAS	CO	-104.8059	40.2739	13	LATLON
0018	1311	211111	TBI FIELD SERVICES, INC- N DOUGLAS CREEK	CO	-108.6761	40.1336	12	LATLON
0077	1311	211111	TBI FIELD SERVICES, INC. - CLOUGH COMP.	CO	-107.862	39.527	13	LATLON

strStateFacilit	strSIC	strNAICS	strFacilityName	srtState	dblXCoord	dblYCoord	intUTMZo	strXYCoor
0020	1311	211111	TBI FIELD SERVICES, INC. - FOUNDATION CR	CO	-108.8035	39.6731	12	LATLON
0004	1311	211111	TBI FIELD SERVICES, INC. - GREASEWOOD	CO	-108.1891	39.9021	12	LATLON
0010	1311	211111	TEXACO E&P INC WILSON CREEK GAS PLT	CO	-107.9169	40.194	13	LATLON
0120	1311	211111	TEXACO EXPLOR & PROD - VAN SCHAIK B-3	CO	-108.696	40.9852	12	LATLON
0015	1311	211111	TOM BROWN INC - ANDY'S MESA	CO	-108.6398	38.0441	12	LATLON
0065	1311	211111	TOM BROWN INC TAIGA MTN 1-29	CO	-108.9809	40.0258	12	LATLON
0015	1311	211111	UNION PACIFIC RES CO ARAPAHOE PLT	CO	-102.7948	38.76645	13	LATLON
0010	1311	211111	UNION PACIFIC RES CO BLEDSOE RANCH	CO	-103.059	38.9541	13	LATLON
0008	1311	211111	UNION PACIFIC RES CO MT PEARL PLT	CO	-102.7523	38.8738	13	LATLON
080170014	1311	211111	UNION PACIFIC RESOURCES FRONTERA PLT	CO	-102.0406	38.795		LATLON
1274	1311	211111	UNITED STATES EXPLOR.-CARLSON 2 32-33	CO	-104.5546	39.8329	13	LATLON
081230119	1311	211111	VESSELS GAS PROC LTD FT LUPTON PROC PLT	CO	-104.8883	40.01639		LATLON
081230367	1311	211111	VESSELS GAS PROCESSING INC	CO	-104.995	40.00056		LATLON
081230148	1311	211111	VESSELS GAS PROCESSING LTD SPACE CITY	CO	-104.6317	40.08139		LATLON
081230132	1311	211111	VESSELS OIL &GAS FT LUPTON FRACTIONATION	CO	-104.8872	40.01583		LATLON
0468	1311	211111	WALSH PRODUCTION INC - LILLI GAS PROC.	CO	-103.8876	40.6922	13	LATLON
0128	1311	211111	WEST TEXAS GAS dba DAVIS GAS PROCESSING-	CO	-108.1542	39.8985	12	LATLON
080010228	1311	211111	WESTERN GAS RESOURCES INC CABIN CREEK	CO	-104.0392	39.75222		LATLON
0115	1311	211111	WILDHORSE ENERGY RIFLE BOULTON COMP	CO	-107.6159	39.4166	13	LATLON
081030020	1311	211111	WILLIAMS FIELD SVCS FOUNDATION CREEK	CO	-108.8033	39.67306		LATLON
081030018	1311	211111	WILLIAMS FIELD SVCS N DOUGLAS SITE	CO	-108.72	39.86		LATLON
0011	1311	211111	WILLIFORD ENERGY CO	CO	-102.8214	38.8752	13	LATLON
081230098	1311	211111	WINDSOR GAS PROCESSING INC	CO	-104.8056	40.27389		LATLON
00099	1311	211111	AMOCO PRODUCTION ULYSSES DEHY	KS	-101.3507	37.57915		LATLON
350150024	1311	211111	AGAVE ENERGY/YATES PLANT_____________1M3	NM	-104.4442	32.71222		LATLON
350150002	1311	211111	AMOCO PROD/EMPIRE ABO GAS PLNT_____126M3	NM	-104.2633	32.77167		LATLON
350250001	1311	211111	AMOCO PROD/S HOBBS CO2 INJECT STA___79M3	NM	-103.1553	32.66056		LATLON
350390028	1311	211111	APACHE CORP/BEAR CANYON______________814	NM	-107.0203	36.49		LATLON
350150101	1311	211111	ARCO PERMIAN/EMPIRE ABO INJECTION___12M1	NM	-104.2586	32.77306		LATLON
350450068	1311	211111	BURLINGTON RES/VALVERDE_______PSDNM728M6	NM	-107.9564	36.73139		LATLON
350150045	1311	211111	CONOCO/TURKEY TRACK GAS PLANT______457M1	NM	-104.04	32.65278		LATLON
350310004	1311	211111	CONOCO/WINGATE FRACTION PLANT_____1313R2	NM	-108.6392	35.54278		LATLON
350150102	1311	211111	EL PASO NATL GAS/BURTON FLATS______157M2	NM	-104.1486	32.56861		LATLON
350250006	1311	211111	EL PASO NATL GAS/JAL #1_____________0007	NM	-103.2097	32.06611		LATLON
350450042	1311	211111	FIVE OAKS/GALLEGOS CANYON__________131M1	NM	-107.8431	36.40111		LATLON
350450045	1311	211111	GULF ENERGY PROCESSING/GALLUP PLANT__458	NM	-108.3869	36.7475		LATLON
350410003	1311	211111	H.L.BROWN JR/BLUITT PLANT____________567	NM	-103.1833	33.635		LATLON
350250007	1311	211111	J.L.DAVIS GAS PROCESS/DENTON________65M2	NM	-103.1697	33.04611		LATLON
350390071	1311	211111	NIJECT/SAN JUAN 28-7 UNIT NITRO_____1495	NM	-107.5317	36.65611		LATLON
350150172	1311	211111	PARKER & PARSLEY/LOVING GAS PLNT____1172	NM	-104.0753	32.24028		LATLON
350250052	1311	211111	TEXACO/EUNICE NORTH GAS PLANT_______57M3	NM	-103.1628	32.44972		LATLON
350250051	1311	211111	TEXACO/EUNICE SOUTH GAS PLANT______278M4	NM	-103.1581	32.36139		LATLON
350410001	1311	211111	WARREN PETROLEUM/BLUITT GAS PLANT____563	NM	-103.2375	33.62056		LATLON
350150043	1311	211111	WARREN PETROLEUM/SNYDER RANCH FACIL__228	NM	-103.8694	32.65139		LATLON
350450247	1311	211111	WESTERN GAS RESOURCES/SAN JUAN RVR____GF	NM	-108.3675	36.75694		LATLON
0004	1311	211111	Wingate Fraction Plant	NM	-108.6394	35.5427	12	LATLON
350050050	1311	211111	YATES PETROLEUM/PATHFINDER AMINE___848M1	NM	-104.1983	33.42861		LATLON
401370203	1311	211111	MOBIL/SHOLEM ALECHEM GAS PLANT	OK	-97.605	34.4225		LATLON

strStateFacilit	strSIC	strNAICS	strFacilityName	srtState	dblXCoord	dblYCoord	intUTMZo	strXYCoor
2482	1311	211111	Swift Energy Company Weatherford Facility	OK	-98.728	35.4851	14	LATLON
483230006	1311	211111	ALKEK GAS PLANT	TX	-100.3891	28.64302		LATLON
481690005	1311	211111	CEDAR HILL GAS PLANT	TX	-101.2328	33.09556		LATLON
483230002	1311	211111	CRUDE OIL PRODUCTION	TX	-100.3891	28.64302		LATLON
48320	1311	211111	DAVIS GAS PROCESSING	TX	-101.3964	33.1635	14	LATLON
AG0002Q	1311	211111	EOG RESOURCES INC JOURDANTON GAS SWEETENING	TX	-98.59443	28.87301	14	LATLON
483230003	1311	211111	FESSMAN PLANT	TX	-100.3891	28.64302		LATLON
482250002	1311	211111	LAURA LAVELLE SOUTH	TX	-95.3658	31.25965		LATLON
481590004	1311	211111	NEW HOPE GAS PLANT	TX	-95.07278	33.23194		LATLON
BI0009J	1311	211111	WEST TEXAS GAS PROCESSING LP	TX	-101.2602	32.57091	14	LATLON
BI0011W	1311	211111	WEST TEXAS GAS PROCESSING LP	TX	-101.6003	32.61674	14	LATLON
HT0016G	1311	211111	WEST TEXAS GAS PROCESSING LP	TX	-101.3526	32.49712	14	LATLON
HT0059L	1311	211111	WEST TEXAS GAS PROCESSING LP	TX	-101.5234	32.51563	14	LATLON
484930005	1311	211111	WILSON COUNTY PLANT	TX	-98.06785	29.1603		LATLON
490139013	1311	211111	ALTONAH GAS PLANT	UT	-110.4395	40.3199		LATLON
55529	1311	211111	COASTAL FIELD ALTAMONT EAST	UT	-110.4395	40.3199	12	LATLON
55530	1311	211111	COASTAL FIELD ALTAMONT SOUTH	UT	-110.4395	40.3199	12	LATLON
55531	1311	211111	COASTAL FIELD ALTAMONT WEST	UT	-110.4395	40.3199	12	LATLON
490079095	1311	211111	DEW POINT PLANT	UT	-110.5648	39.64065		LATLON
490070013	1311	211111	DRUNKARDS WASH	UT	-110.86	39.58944		LATLON
55552	1311	211111	GARY-WILLIAMS BLUEBELL GAS PLANT	UT	-110.4395	40.3199	12	LATLON
10034	1311	211111	Lisbon Plant-Hook & Ladder	UT	-110.2266	37.7491		LATLON
560070006	1311	211111	AMOCO BAIROIL CO2	WY	-107.5142	42.22917		LATLON
560130008	1311	211111	AMOCO BEAVER CREEK	WY	-108.3139	42.84778		LATLON
560290012	1311	211111	AMOCO PROD CO.-ELK BASIN GAS PLANT	WY	-108.8539	44.52944		LATLON
560410006	1311	211111	AMOCO PRODUCTION COMPANY - ANSCHUTZ	WY	-111.0406	41.07528		LATLON
560070017	1311	211111	AMOCO PRODUCTION COMPANY - WERTZ PL	WY	-106.9999	41.71695		LATLON
5604100006	1311	211111	AMOCO PRODUCTION COMPANY _ ANSCHUTZ	WY	-111.0404	41.0755	12	LATLON
560410012	1311	211111	AMOCO WHITNEY CANYON	WY	-110.8897	41.45444		LATLON
5600300012	1311	22121	BIG HORN GAS PROCESSING-BYRON GAS PLANT	WY	-108.5534	44.8022	12	LATLON
5601300028	1311	211111	BURLINGTON RESOURCES_LOST CABIN	WY	-107.6327	43.28651		LATLON
5604100009	1311	211111	CHEVRON CARTER CREEK	WY	-110.9123	41.5735	12	LATLON
560410030	1311	211111	CHEVRON USA - PAINTER RESERVOIR EAST	WY	-110.8675	41.31194		LATLON
5604100030	1311	211111	CHEVRON USA _ PAINTER RESERVOIR EAST	WY	-110.8675	41.3116	12	LATLON
560070019	1311	211111	CIG RAWLINS COMP	WY	-107.0578	41.75667		LATLON
5603700014	1311	211111	COLORADO INTER GAS_TABLE ROCK GAS PLANT	WY	-108.4176	41.6074	12	LATLON
560290006	1311	211111	COLORADO INTERSTATE GAS - ELK BASIN	WY	-109.8025	44.40953		LATLON
58193	1311	211111	CONOCO - SHERIDAN	WY	-106.9753	44.6637	13	LATLON
560250011	1311	211111	EREC-BALCRON OIL DIV -NORTH GRIEVE	WY	-106.8064	42.96618		LATLON
560350001	1311	211111	EXXON -LABARGE DEHYDRATION FACILITY	WY	-110.3489	42.3725		LATLON
560230013	1311	211111	EXXON SHUTE CREEK I	WY	-110.0873	41.8838	12	LATLON
5602900012	1311	211111	HOWELL PET CORP_ELK BASIN GAS PLANT	WY	-108.8539	44.5292	12	LATLON
560430003	1311	211111	INTERENERGY CORP.- HILAND GAS PLANT	WY	-107.8511	44.03056		LATLON
560090021	1311	211111	INTERLINE GAS (LIGHTNING CREEK)	WY	-105.2111	43.0392	13	LATLON
560090019	1311	211111	INTERLINE GAS (SOUTH WELL DRAW)	WY	-111.0368	42.9178	12	LATLON
560410022	1311	211111	KERN RIVER GAS - PAINTER RESERVIOR	WY	-110.5468	41.28735		LATLON
560230025	1311	211111	KERN RIVER GAS TRANS. - MUDDY CREEK	WY	-110.3619	41.69111		LATLON
560410001	1311	211111	KERN RIVER GTC-ANSCHUTZ (CT-742)	WY	-111.0272	41.06278		LATLON

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560130027	1311	211111	KN GAS GATHERING - PAVILLION STATION	WY	-108.7768	43.1348		LATLON
560070026	1311	211111	NORTHERN GAS CO. - OIL SPRINGS	WY	-106.9999	41.71695		LATLON
560230023	1311	211111	NORTHWEST PIPELINE-MUDDY CREEK COMP STN	WY	-110.546	42.44677		LATLON
560290007	1311	211111	OREGON BASIN GAS PLANT OP-184	WY	-108.9033	44.35278		LATLON
560090026	1311	211111	PHILLIPS PETROLEUM (YOSS)	WY	-105.2586	43.01		LATLON
560350006	1311	211111	QUESTAR PIPELINE - DRY PINEY	WY	-109.8339	42.86412		LATLON
5603500006	1311	211111	QUESTAR PIPELINE _ DRY PINEY	WY	-110.3439	42.3492	12	LATLON
560410023	1311	211111	QUESTAR PIPELINE-LEROY STORAGE COMP STN	WY	-110.6161	41.32972		LATLON
560290005	1311	211111	RALSTON PROCESSING ASSOCIATES	WY	-108.8986	44.40917		LATLON
5601300008	1311	211111	SANTA FE SNYDER_BEAVER CREEK	WY	-108.3139	42.8474	12	LATLON
560130011	1311	211111	SNYDER OIL CORP.-RIVERTON PLANT	WY	-108.3428	42.94111		LATLON
T$12143	1311	211111	U.S. DOE NAVAL PETROLEUM RESERVE NO. 3	WY	-106.25	43.31667		LATLON
560410040	1311	211111	UNIVERSAL RESOURCES CORP - CLEAR CREEK	WY	-110.8394	41.38028		LATLON
560090039	1311	211111	WESTERN GAS RESOURCES - SPEARHEAD	WY	-105.4846	42.89442		LATLON
560090033	1311	211111	WESTERN GAS RESOURCES-SOUTH SAND DUNES	WY	-105.4846	42.89442		LATLON
5603700052	1311	22121	WEXPRO CANYON CREEK/VERMILLION	WY	-108.7785	41.634		LATLON
0069	1321	211112	BEAR PAW ENERGY - WIGGINS GAS PLANT	CO	-103.9709	40.2542	13	LATLON
0183	1321	211112	CALPINE NATURAL GAS (WAS VESSELS OIL & G	CO	-107.53	39.727		LATLON
0107	1321	211112	DUKE ENERGY FIELD SERVICES - LUCERNE	CO	-104.658	40.4502	13	LATLON
0189	1321	211112	DUKE ENERGY FIELD SERVICES - N ARROWHEAD	CO	-102.515	38.6699	13	LATLON
080690274	1321	211112	INDUSTRIAL GAS SERVICES INC WELLINGTON	CO	-105.0472	40.77639		LATLON
0473	1321	211112	SW PRODUCTION CO (WAS COSTILLA PETRO)	CO	-104.3121	40.50103	13	LATLON
0006	1321	211112	WILLIAMS FIELD SERVICES IGNACIO B PLT	CO	-107.7844	37.1449	13	LATLON
080670006	1321	211112	WILLIAMS FIELD SVCS IGNACIO B PLT	CO	-107.7858	37.13889		LATLON
201750038	1321	211112	ANADARKO PETROLEUM CORP.	KS	-101.0131	37.15528		LATLON
201710011	1321	211112	KN ENERGY, INC. SUNFLOWER HELIUM PLANT	KS	-100.9819	38.48306		LATLON
00011	1321	211112	ONEOK FIELD SERVICES COMPANY	KS	-100.9897	38.48944		LATLON
200070022	1321	211112	TEXACO PRODUCING, INC.	KS	-98.57333	37.25528		LATLON
200770017	1321	211112	TRIDENT NGL, INC.	KS	-98.21278	37.37667		LATLON
200950002	1321	211112	TRIDENT NGL, INC.	KS	-97.84583	37.65		LATLON
350250018	1321	211112	AMERICAN PROCESSING/HOBBS PLANT____320M3	NM	-103.3578	32.71306		LATLON
0072	1321	211112	Antelope Ridge Gas Plant	NM	-103.4537	32.2996	13	LATLON
350390027	1321	211112	BENSON-MONTIN-GREER/CANADA OJITOS__914M1	NM	-106.9008	36.39639		LATLON
0140	1321	211112	Carlsbad Gas Plant	NM	-104.0769	32.3184	13	LATLON
350250004	1321	211112	CONOCO/MALJAMAR GAS PLANT__________319M3	NM	-103.7683	32.8125		LATLON
350450062	1321	211112	CONOCO/SAN JUAN PLANT______________613M2	NM	-107.9594	36.73167		LATLON
0285	1321	211112	Dagger Draw Gas Plant	NM	-104.4452	32.7183	13	LATLON
350450009	1321	211112	EL PASO NATL GAS/CHACO GAS PLANT__1555M1	NM	-108.12	36.48833		LATLON
350150011	1321	211112	GPM GAS/ARTESIA GAS PLANT__________434M5	NM	-104.2308	32.7625		LATLON
350150169	1321	211112	GPM GAS/AVALON GASOLINE PLNT______1148M1	NM	-104.2092	32.5025		LATLON
350250044	1321	211112	GPM GAS/EUNICE GAS PLANT____________44M6	NM	-103.2994	32.52056		LATLON
350250046	1321	211112	GPM GAS/LEE GAS PLANT______________276M1	NM	-103.5136	32.80528		LATLON
350250035	1321	211112	GPM GAS/LINAM RANCH GAS PLANT_______39M2	NM	-103.3022	32.69833		LATLON
350150140	1321	211112	HIGHLANDS GATHERING/CARLSBAD PLT___927M3	NM	-104.0767	32.31806		LATLON
350250072	1321	211112	LG&E/HADSON/ANTELOPE RDG GAS PLNT__401M4	NM	-103.4503	32.29639		LATLON
350250122	1321	211112	LG&E/HADSON/MINERALS PLANT_________166M1	NM	-103.3247	32.70806		LATLON
350050014	1321	211112	LIQUID ENERGY/WHITE RANCH_______PSD356M1	NM	-103.9456	33.46361		LATLON
0004	1321	211112	Maljamar Gas Plant	NM	-103.7685	32.8125	13	LATLON

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350150008	1321	211112	MARATHON OIL/INDIAN BSN GAS PLT_PSD295M3	NM	-104.5742	32.46639		LATLON
350310023	1321	211112	MERRION OIL & GAS/OJO ENCINO_________936	NM	-107.3272	35.92556		LATLON
350450196	1321	211112	MERRION OIL & GAS/SNAKE EYES PLANT___950	NM	-107.6311	36.05417		LATLON
350150035	1321	211112	OXY USA/ABO GAS PROCESSING____G__102,256	NM	-104.2525	32.78472		LATLON
350150138	1321	211112	PAN ENERGY/BURTON FLATS GAS PLT____913M1	NM	-103.7206	32.40111		LATLON
350150285	1321	211112	PAN ENERGY/DAGGER DRAW GAS PLT__PSD753M2	NM	-104.4447	32.71833		LATLON
350150095	1321	211112	PAN ENERGY/PECOS DIAMND GAS PLT___PSD389	NM	-104.2736	32.76861		LATLON
0062	1321	211112	San Juan Gas Plant	NM	-107.9644	36.7398	13	LATLON
350250008	1321	211112	SID RICHARDSON GASOLINE/JAL #3______1092	NM	-103.1756	32.17417		LATLON
350250009	1321	211112	SID RICHARDSON GASOLINE/JAL #4______70M1	NM	-103.195	32.25528		LATLON
350250055	1321	211112	TEXACO/BUCKEYE GASOLINE PLANT_________60	NM	-103.5081	32.78444		LATLON
350250060	1321	211112	WARREN PETROLEUM/EUNICE GAS PLANT___67M3	NM	-103.1439	32.42583		LATLON
350250061	1321	211112	WARREN PETROLEUM/MONUMENT PLANT____110M3	NM	-103.3075	32.61056		LATLON
350250063	1321	211112	WARREN PETROLEUM/SAUNDERS PLANT____315M1	NM	-103.6097	33.05694		LATLON
350250064	1321	211112	WARREN PETROLEUM/VADA GAS PLANT____203M1	NM	-103.5442	33.43417		LATLON
350450026	1321	211112	WILLIAMS FIELD SERV/KUTZ GAS PLANT_301M	NM	-107.9536	36.66833		LATLON
350390010	1321	211112	WILLIAMS FIELD SERV/LYBROOK PLANT___81M2	NM	-107.5453	36.23194		LATLON
1055	1321	211112	Anadarko Gathering Company-Panther Creek Gas Plant	OK	-97.4716	34.7079	14	LATLON
400390351	1321	211112	ANR PRODUCTION CO.	OK	-99.01417	35.63556		LATLON
400370204	1321	211112	ASSOCIATED NATURAL GAS/MILFAY GAS PLANT	OK	-96.33	35.9		LATLON
2089	1321	211112	Carrera Gas Compranies, LLC Madill Gas Plant	OK	-96.5918	34.0858	14	LATLON
400070231	1321	211112	CIMARRON GAS HOLDING COMPANY	OK	-100.9433	36.50167		LATLON
400070385	1321	211112	COLORADO INTERSTATE GAS	OK	-100.3969	36.89889		LATLON
400510363	1321	211112	CONOCO INC.	OK	-97.76333	35.305		LATLON
400870201	1321	211112	CONOCO/GOLDSBY CONTRAL GAS PLANT	OK	-97.50667	35.10167		LATLON
2843	1321	211112	Continental Gas, Inc.Eagle Chief Gas Plant	OK	-98.5111	36.6109	14	LATLON
1310	1321	211112	Continental Laverne Gas Processing, LLC Laverne Gas Plant	OK	-99.9263	36.7117	14	LATLON
400070361	1321	211112	CONTINENTAL NATURAL GAS INC.(NICOL	OK	-100.2931	36.72583		LATLON
1308	1321	211112	Duke Energy Goldsby Gas Plant	OK	-97.507	35.1032	14	LATLON
2299	1321	211112	Duke Energy Hillsboro Gas Plant	OK	-98.0801	34.9567	14	LATLON
2315	1321	211112	Duke Energy Milfay Gas Plant	OK	-96.5674	35.7695	14	LATLON
2365	1321	211112	Duke Energy West Edmond Gas Plant	OK	-97.622	35.7535	14	LATLON
2366	1321	211112	Duke Energy West Guthrie	OK	-97.4529	35.747	14	LATLON
1481	1321	211112	Enerfin Resources Co. Tecumseh Gas Plant	OK	-96.9447	35.2088	14	LATLON
401090130	1321	211112	ENOGEX, INC	OK	-97.245	35.43556		LATLON
1488	1321	211112	Enogex, Inc. Calumet Gas Processing Plant	OK	-98.1549	35.6665	14	LATLON
2565	1321	211112	Enogex, Inc. Cox City Processing Plant	OK	-97.7923	34.7933	14	LATLON
1079	1321	211112	Enogex, Inc. Custer Gas Plant	OK	-99.0144	35.6369	14	LATLON
400730203	1321	211112	EXXON/DOVER-HENNESSEY	OK	-97.90278	36.07194		LATLON
1531	1321	211112	ExxonMobile Production Company Dover Hennessey Gas Plant	OK	-97.904	36.0729	14	LATLON
1042	1321	211112	GPM Gas Company LLC. Mooreland Plant	OK	-99.1574	36.4408	14	LATLON
400730220	1321	211112	GPM GAS CORP. KINGFISHER PLANT	OK	-97.73278	35.79083		LATLON
400730224	1321	211112	GPM GAS CORP. OKARCHE PLANT	OK	-98.08556	35.73639		LATLON
400030202	1321	211112	GPM/ALINE BOOSTER	OK	-98.38917	36.51444		LATLON
400930218	1321	211112	GPM/CEDAR BOOSTER	OK	-98.82139	36.31611		LATLON
400070208	1321	211112	MAPLE GAS CORP.	OK	-100.5156	36.87306		LATLON
400390358	1321	211112	MOBIL EXPLORATION & PRODUCING U.S.	OK	-98.87944	35.82806		LATLON
400190205	1321	211112	MOBIL OIL CO - FOX	OK	-97.50944	34.34833		LATLON

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401390212	1321	211112	MOBIL OIL CORPORATION WEST HOUGH	OK	-101.6406	36.90139		LATLON
400030200	1321	211112	NGC ENERGY RESOURCES LIMITED PARTNE	OK	-98.26194	36.58194		LATLON
400150205	1321	211112	NGC ENERGY RESOURCES LIMITED PARTNE	OK	-98.32667	35.3175		LATLON
400950201	1321	211112	NGC ENERGY RESOURCES LIMITED PARTNE	OK	-96.76056	34.11917		LATLON
400470203	1321	211112	NGC ENERGY RESOURCES, L.P.	OK	-97.81944	36.42694		LATLON
400950200	1321	211112	NGC ENERGY RESOURCES/MADILL GAS PLANT	OK	-96.59028	34.08583		LATLON
400930203	1321	211112	NGC ENERGY, INC/RINGWOOD PLANT	OK	-98.24167	36.36556		LATLON
400450201	1321	211112	NORTHERN NATURAL GAS CO.	OK	-99.85556	36.45222		LATLON
400070212	1321	211112	NORTHERN NATURAL GAS ELMWOOD	OK	-100.5228	36.61417		LATLON
401390206	1321	211112	OKLAHOMA GAS PIPELINE CO/TYRONE	OK	-101.0878	36.99472		LATLON
2523	1321	211112	ONEOK Field Services Co. Antelope Hills Plant	OK	-99.7841	35.8307	14	LATLON
2524	1321	211112	ONEOK Field Services Co. Beaver Gas Plant	OK	-100.1466	36.5718	14	LATLON
2525	1321	211112	ONEOK Field Services Co. Cimarron Gas Plant	OK	-98.5417	36.0247	14	LATLON
2526	1321	211112	ONEOK Field Services Co. Custer Gas Plant	OK	-98.8918	35.6496	14	LATLON
2527	1321	211112	ONEOK Field Services Co. El Reno Gas Facility	OK	-97.9522	35.6302	14	LATLON
2074	1321	211112	ONEOK Field Services Co. Enid Plant	OK	-97.8188	36.4263	14	LATLON
2679	1321	211112	ONEOK Field Services Co. Leedey Plant	OK	-99.4659	35.8092	14	LATLON
2092	1321	211112	ONEOK Field Services Co. Ringwood Gas Plant	OK	-98.2421	36.3658	14	LATLON
2531	1321	211112	ONEOK Field Services Co. Stephens Plant	OK	-97.7011	34.47	14	LATLON
400530205	1321	211112	ORYX ENERGY	OK	-97.90417	36.84639		LATLON
400590200	1321	211112	ORYX ENERGY COMPANY	OK	-99.92556	36.70889		LATLON
401390200	1321	211112	PARKER & PARSLEY	OK	-101.2558	36.83417		LATLON
2658	1321	211112	Questar Gas Management Company Beaver Gas Plant	OK	-100.9533	36.7783	14	LATLON
2509	1321	211112	Spectrum Field Services Velma Gas Plant	OK	-97.6919	34.4617	14	LATLON
3082	1321	211112	Superior Pipeline Co. Butler Gas Plant	OK	-99.1997	35.6246	14	LATLON
400490219	1321	211112	TEXACO EXPLORATION & PRODUCTION, IN	OK	-97.44417	34.81417		LATLON
400850201	1321	211112	TEXACO EXPLORATION & PRODUCTION, IN	OK	-97.02806	33.96333		LATLON
2508	1321	211112	Texaco Exploration & Production, Inc. Maysville Gas Plant	OK	-97.4456	34.815	14	LATLON
401370200	1321	211112	TEXACO PRODUCTS - VELMA GAS PLANT	OK	-97.67806	34.46083		LATLON
2517	1321	211112	Timberland Gathering & Processing Company Tyrone	OK	-101.0892	36.9973	14	LATLON
400170203	1321	211112	TONKAWA GAS PROCESSING CO.	OK	-97.95167	35.63056		LATLON
401290203	1321	211112	TONKAWA GAS PROCESSING CO.	OK	-99.78333	35.83056		LATLON
401370208	1321	211112	TONKAWA GAS PROCESSING CO.	OK	-97.70083	34.46917		LATLON
400390205	1321	211112	TRANSOK, INC.	OK	-98.7975	35.73833		LATLON
400630200	1321	211112	TRANSOK, INC.	OK	-96.16917	35.1375		LATLON
400830200	1321	211112	TRANSOK, INC.	OK	-97.61667	35.89917		LATLON
401290202	1321	211112	TRANSOK, INC.	OK	-99.48306	35.74778		LATLON
400470218	1321	211112	TRIDENT NGL, INC.	OK	-98.0325	36.17806		LATLON
400470358	1321	211112	TRIDENT NGL, INC.	OK	-97.56306	36.36556		LATLON
400730236	1321	211112	TRIDENT NGL, INC.	OK	-98.12417	35.79667		LATLON
400710204	1321	211112	TRIDENT NGL, INC/AMBROSE	OK	-97.31333	36.82667		LATLON
2946	1321	211112	Tri-Star Energy, LLC Braman Gas Processing Plant	OK	-97.2406	36.9863	14	LATLON
400070214	1321	211112	WARREN PERTOLEUM COMPANY MOCANE	OK	-100.3958	36.89889		LATLON
401290204	1321	211112	WARREN PETROLEUM CO., DIVISION CHEV	OK	-99.46556	35.80917		LATLON
2683	1321	211112	Westana Gathering Company Chester Gas Plant	OK	-98.9789	36.2474	14	LATLON
400930222	1321	211112	WESTERN GAS RESOURCES/CHANEY DELL	OK	-98.24444	36.43222		LATLON
2928	1321	211112	Williams Field Services Co.Dry Trails Gas Plant	OK	-101.6162	36.9058	14	LATLON
400530211	1321	211112	WILLIAMS NATURAL GAS CO.	OK	-97.47778	36.85306		LATLON

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SD0048I	1321	211112	ABRAXAS PETROLEUM CORP	TX	-97.12951	28.18036	14	LATLON
MQ0303C	1321	211112	ACACIA NATURAL GAS CORP	TX	-95.09162	30.02799	15	LATLON
EA0085H	1321	211112	ALLIANT ENERGY DESDEMONA LP	TX	-98.51673	32.30843	14	LATLON
CF0017D	1321	211112	AMERICAN GATHERING LP	TX	-101.121	35.56446	14	LATLON
CF0005K	1321	211112	AMERICAN PROCESSING	TX	-101.1363	35.52877	14	LATLON
HL0019O	1321	211112	AMERICAN PROCESSING LP	TX	-100.4764	35.73454	14	LATLON
PG0036K	1321	211112	AMERICAN PROCESSING LP	TX	-101.639	35.5433	14	LATLON
MR0026R	1321	211112	ANADARKO GATHERING CO	TX	-101.6296	35.80891	14	LATLON
WF0098I	1321	211112	APACHE CORPORATION	TX	-96.07695	29.14636	14	LATLON
480090001	1321	211112	ARCHER CITY PLT	TX	-98.6871	33.6156		LATLON
HL0101F	1321	211112	BP AMOCO	TX	-100.27	35.84	10	LATLON
EA0007E	1321	211112	CANTERA RESOURCES INC	TX	-99.09271	32.50563	14	LATLON
EA0008C	1321	211112	CANTERA RESOURCES INC	TX	-98.79008	32.46883	14	LATLON
PA0009K	1321	211112	CANTERA RESOURCES INC	TX	-98.33891	32.53763	14	LATLON
PC0140M	1321	211112	CANTERA RESOURCES INC	TX	-97.68349	32.98432	14	LATLON
481010001	1321	211112	CHALK PLANT	TX	-100.2576	34.07462		LATLON
480210001	1321	211112	CHEROKEE GATHERING COMPAN	TX	-97.33635	30.1029		LATLON
WJ0002I	1321	211112	CITATION OIL & GAS CORP WILLAMAR PLANT	TX	-97.57094	26.40943	14	LATLON
CC0005U	1321	211112	CMS TAURUS FIELD SERVICES LP	TX	-99.18664	32.27621	14	LATLON
FD0003I	1321	211112	CMS TAURUS FIELD SERVICES LP	TX	-100.6624	32.96172	14	LATLON
CI0042R	1321	211112	CONOCO INC	TX	-94.91884	29.85177	15	LATLON
IA0001R	1321	211112	CONOCO INCORPORATED	TX	-100.9076	31.18384	14	LATLON
SF0008V	1321	211112	CONOCO INCORPORATED	TX	-100.6829	30.9914	14	LATLON
SD0022D	1321	211112	CORPUS CHRISTI NAT GAS GPLP	TX	-97.26329	27.93952	14	LATLON
CZ0011M	1321	211112	CROCKETT GAS PROCESSING CO	TX	-101.237	30.73371	14	LATLON
484510003	1321	211112	DOUBLE A GAS PLANT	TX	-100.4097	31.35		LATLON
481770001	1321	211112	DUBOSE PLANT	TX	-97.33472	29.09194		LATLON
ML0024S	1321	211112	DUKE ENERGY	TX	-101.7939	31.85784	14	LATLON
MF0012R	1321	211112	DUKE ENERGY	TX	-101.9683	32.26804	14	LATLON
PB0067I	1321	211112	DUKE ENERGYFIELD SERVICES	TX	-94.34317	32.24294	15	LATLON
PB0002N	1321	211112	DUKE ENERGYFIELD SERVICES INC	TX	-94.26366	32.18816	15	LATLON
SF0001M	1321	211112	DUKE ENERGYFIELD SERVICES INC	TX	-100.5191	31.00091	14	LATLON
SQ0006B	1321	211112	DUKE ENERGYFIELD SERVICES INC	TX	-100.5893	30.50798	14	LATLON
LE0012W	1321	211112	DUKE ENERGYFIELD SERVICES INC	TX	-96.95005	29.50857	14	LATLON
NE0028T	1321	211112	DUKE ENERGYFIELD SERVICES INC	TX	-97.90158	27.68646	14	LATLON
ML0020D	1321	211112	DUKE ENERGYFIELD SERVICES INC	TX	-102.1332	31.66262	13	LATLON
PE0024Q	1321	211112	DUKE ENERGYFIELD SERVICES INC	TX	-103.0865	31.26842	13	LATLON
PE0025O	1321	211112	DUKE ENERGYFIELD SERVICES INC	TX	-103.0373	31.18308	13	LATLON
WF0095O	1321	211112	DUKE ENERGYFIELD SERVICES LLC	TX	-96.20963	29.2059	14	LATLON
HW0020F	1321	211112	DUKE ENERGYFIELD SERVICES LLC	TX	-101.411	35.67427	14	LATLON
HD0055B	1321	211112	DUKE ENERGYFIELD SERVICES LLC	TX	-101.3883	36.19576	14	LATLON
CI0022A	1321	211112	DYNEGY MIDSTREAM SERVICES LP	TX	-94.90304	29.84173	15	LATLON
CY0018J	1321	211112	DYNEGY MIDSTREAM SERVICES LP	TX	-102.6406	31.50153	13	LATLON
GA0011C	1321	211112	DYNEGY MIDSTREAM SERVICES LP	TX	-102.7998	32.76063	13	LATLON
GH0007I	1321	211112	DYNEGY MIDSTREAM SERVICES LP	TX	-100.7625	35.43211	14	LATLON
GI0012E	1321	211112	DYNEGY MIDSTREAM SERVICES LP	TX	-96.6344	33.68186	14	LATLON
HH0005S	1321	211112	DYNEGY MIDSTREAM SERVICES LP	TX	-94.07232	32.46927	15	LATLON
HL0008T	1321	211112	DYNEGY MIDSTREAM SERVICES LP	TX	-100.4021	35.86848	14	LATLON

strStateFacilit	strSIC	strNAICS	strFacilityName	srtState	dblXCoord	dblYCoord	intUTMZo	strXYCoor
SH0003J	1321	211112	DYNEGY MIDSTREAM SERVICES LP	TX	-99.21747	32.85847	14	LATLON
WG0011M	1321	211112	DYNEGY MIDSTREAM SERVICES LP	TX	-100.5002	35.34575	14	LATLON
WN0005E	1321	211112	DYNEGY MIDSTREAM SERVICES LP	TX	-97.87754	33.31185	14	LATLON
WN0045P	1321	211112	DYNEGY MIDSTREAM SERVICES LP	TX	-97.39594	32.98941	14	LATLON
HE0012I	1321	211112	ECHO PRODUCTION INC	TX	-99.64688	34.25581	14	LATLON
MC0006W	1321	211112	EGS HYDROCARBONS INC	TX	-98.45715	28.44476	14	LATLON
CB0063R	1321	211112	EL PASO FIELD SERVICES	TX	-96.63	28.4	14	LATLON
MH0039V	1321	211112	EL PASO FIELD SERVICES	TX	-96.18275	28.80017	14	LATLON
MH0057T	1321	211112	EL PASO FIELD SERVICES	TX	-96.13367	28.61693	14	LATLON
LK0044R	1321	211112	ENRON PROCESSING PROPERTIES INC	TX	-98.1206	28.36758	14	LATLON
WB0003U	1321	211112	EXXON COMPANY	TX	-95.87722	29.81367	15	LATLON
WC0010M	1321	211112	EXXON COMPANY USA	TX	-103.107	31.4882	13	LATLON
WO0009I	1321	211112	EXXON COMPANY USA	TX	-95.19792	32.61159	15	LATLON
HG0234M	1321	211112	EXXON CORPORATION	TX	-95.12229	29.63141	15	LATLON
RL0007C	1321	211112	EXXON CORPORATION	TX	-94.92893	32.27045	15	LATLON
KJ0003N	1321	211112	EXXON USA INC KING RANCH	TX	-98.05826	27.46553	14	LATLON
CB0053U	1321	211112	FORMOSA HYDROCARBONS CO INC	TX	-96.55861	28.66372	14	LATLON
GJ0003W	1321	211112	GAS SOLUTIONS	TX	-94.86644	32.50383	15	LATLON
HD0014P	1321	211112	GPM GAS CORPORATION	TX	-101.35	36.28	14	LATLON
MR0030D	1321	211112	GPM GAS CORPORATION	TX	-102.0277	35.82075	13	LATLON
FC0033K	1321	211112	GPM GAS SERVICES CO	TX	-96.98674	30.03686	14	LATLON
FC0049S	1321	211112	GPM GAS SERVICES CO	TX	-96.89193	29.99269	14	LATLON
LF0019U	1321	211112	GPM GAS SERVICES CO	TX	-96.80767	30.29071	14	LATLON
LF0022I	1321	211112	GPM GAS SERVICES CO	TX	-96.77428	30.26542	14	LATLON
LF0024E	1321	211112	GPM GAS SERVICES CO	TX	-96.86028	30.20506	14	LATLON
482250005	1321	211112	GRAPELAND PLANT	TX	-95.31444	31.30278		LATLON
KA0013M	1321	211112	GULF ENERGYGATHERING PROCESSING	TX	-97.6316	28.79102	14	LATLON
RG0069H	1321	211112	H & D OPERATING CO	TX	-97.38844	28.20168	14	LATLON
BL0005M	1321	211112	HILCORP ENERGY CO SWEENY	TX	-95.75015	29.0415	15	LATLON
HM0010V	1321	211112	HUNT OIL CO	TX	-95.58218	32.08478	15	LATLON
CA0011B	1321	211112	JL DAVIS	TX	-97.72817	29.73106	14	LATLON
FJ0045A	1321	211112	JL DAVIS GAS PROC INC	TX	-99.03089	28.81301	14	LATLON
IA0009B	1321	211112	JL DAVIS GAS PROCESSING INC	TX	-101.1616	31.28765	14	LATLON
RC0001Q	1321	211112	JL DAVIS GAS PROCESSING INC	TX	-101.3422	31.16433	14	LATLON
CI0005A	1321	211112	KOCH HYDROCARBON CO	TX	-94.90867	29.85413	15	LATLON
480710032	1321	211112	KOCH HYDROCARBON COMPANY	TX	-94.54278	29.51167		LATLON
482490001	1321	211112	LA GLORIA GAS PLANT	TX	-98.09139	27.16278		LATLON
483130003	1321	211112	MADISONVILLE GAS PROCESSI	TX	-95.92925	30.958		LATLON
484030001	1321	211112	MAGASCO COMPRESSOR STN.	TX	-93.58306	31.17139		LATLON
35868	1321	211112	MARATHON OIL COMPANY	TX	-100.301	31.2625	14	LATLON
JE0746E	1321	211112	MARINER ENERGY INC	TX	-94.17923	30.16773	15	LATLON
LK0001M	1321	211112	MERIT ENERGY CO	TX	-98.01317	28.48416	14	LATLON
483630008	1321	211112	MINERAL WELLS PLANT	TX	-98.31573	32.7596		LATLON
MQ0335M	1321	211112	MITCHELL ENERGY CORP	TX	-95.64011	30.23659	15	LATLON
WN0021G	1321	211112	MITCHELL GAS SERVCS LMTD PARTNERSHIP	TX	-97.80758	33.19607	14	LATLON
CN0003A	1321	211112	MITCHELL GAS SERVICES LP	TX	-100.6798	32.04785	14	LATLON
JA0026U	1321	211112	MITCHELL GAS SERVICES LP	TX	-98.18834	33.07295	14	LATLON
PA0015P	1321	211112	MITCHELL GAS SERVICES LP	TX	-98.31161	32.66187	14	LATLON

strStateFacilit	strSIC	strNAICS	strFacilityName	srtState	dblXCoord	dblYCoord	intUTMZo	strXYCoor
36659	1321	211112	MOBIL EXPLORATION AND PRODUCING US I	TX	-100.8673	33.235	14	LATLON
483390032	1321	211112	N.G.P.L.C.O.A. STN. 302	TX	-95.15083	30.12028		LATLON
MQ0064U	1321	211112	NATURAL GASPIPELINE CO OF AMERICA	TX	-95.25138	30.20271	15	LATLON
CZ0024D	1321	211112	NELEH GAS SYSTEMS	TX	-102.2207	31.03878	13	LATLON
HW0035P	1321	211112	NORTHERN NATURAL GAS CO	TX	-101.5136	36.02208	14	LATLON
HP0005E	1321	211112	OCCIDENTAL PERMIAN LTD	TX	-102.5589	33.4678	13	LATLON
TC0002Q	1321	211112	OCCIDENTAL PERMIAN LTD	TX	-101.8435	30.37381	14	LATLON
GH0001U	1321	211112	ONEOK FIELDSERVICES CO	TX	-101.0346	35.52066	14	LATLON
MR0023A	1321	211112	ONEOK FIELDSERVICES CO	TX	-101.6964	35.78764	14	LATLON
38108	1321	211112	ORYX ENERGYCOMPANY	TX	-98.06	27.3285	14	LATLON
38517	1321	211112	PANENERGY FIELDS SERVICES INC	TX	-98.1532	27.2766	14	LATLON
PG0035M	1321	211112	PIONEER NATRESOURCES CO	TX	-101.8941	35.53807	14	LATLON
BE0013Q	1321	211112	PIONEER NATURAL RESOURCES USA INC	TX	-97.99291	28.62278	14	LATLON
481690006	1321	211112	PLEASANT VALLEY PLANT	TX	-101.0214	33.23444		LATLON
AG0024G	1321	211112	PUEBLO MIDSTREAM GAS CORP	TX	-98.18026	28.79523	14	LATLON
MF0001W	1321	211112	RAPTOR FACILITIES INC	TX	-101.9322	32.21152	14	LATLON
39833	1321	211112	ROCKLAND PIPELINE COMPANY	TX	-100.693	31.5918	14	LATLON
482630002	1321	211112	SALT CREEK FIELD GAS PLT	TX	-100.5208	33.13972		LATLON
482490006	1321	211112	SEELIGSON GAS PLANT	TX	-98.08278	27.24139		LATLON
PE0009M	1321	211112	SID RICHARDSON GASOLINE CO	TX	-102.888	31.23951	13	LATLON
PE0042O	1321	211112	SID RICHARDSON GASOLINE COMPANY	TX	-102.9862	31.18636	13	LATLON
484510011	1321	211112	STRAWN GAS PLANT	TX	-100.689	31.3958		LATLON
CG0012C	1321	211112	SULPHUR RIVER GATHERING LP	TX	-94.45978	33.2238	15	LATLON
GJ0005S	1321	211112	SULPHUR RIVER GATHERING LP	TX	-94.82991	32.53675	15	LATLON
HM0014N	1321	211112	SULPHUR RIVER GATHERING LP	TX	-96.03903	32.26805	14	LATLON
VB0004M	1321	211112	SULPHUR RIVER GATHERING LP	TX	-95.8981	32.62733	15	LATLON
484510008	1321	211112	SUSAN PEAK GAS PLANT	TX	-100.689	31.3958		LATLON
RG0054U	1321	211112	TC OIL COMPANY	TX	-97.04596	28.50943	14	LATLON
RG0053W	1321	211112	T-C OIL COMPANY	TX	-97.0589	28.40712	14	LATLON
PF0049M	1321	211112	TECO GAS PROCESSING CO	TX	-94.70117	30.75699	15	LATLON
SD0072L	1321	211112	TEJAS CORPUS CHRISTI PROCESSING LP	TX	-97.41038	27.88751	14	LATLON
CZ0027U	1321	211112	TEXACO E &P INC	TX	-101.0706	30.63449	14	LATLON
ML0048E	1321	211112	TEXACO EXPLORATION & PRDCTN INC	TX	-102.0159	31.84817	13	LATLON
CZ0014G	1321	211112	TEXACO EXPLORATION & PRODUCTION	TX	-101.2058	30.67269	14	LATLON
SO0003G	1321	211112	TEXACO EXPLORATION & PRODUCTION INC	TX	-101.1956	31.74186	14	LATLON
EB0069R	1321	211112	TEXACO EXPLORATION AND PRODUCTION IN	TX	-102.313	31.86012	13	LATLON
NE0062T	1321	211112	TEXAS CRUDEENERGY INC	TX	-97.27911	27.65474	14	LATLON
44263	1321	211112	THE WISER OIL COMPANY	TX	-103.5085	31.8293	13	LATLON
482490007	1321	211112	TIJERINA, CANALES,BLUCHER	TX	-97.47139	28.03194		LATLON
44278	1321	211112	TONKAWA GASPROCESSING	TX	-95.5285	31.5084	15	LATLON
LK0027R	1321	211112	TONKAWA GASPROCESSING CO	TX	-98.1351	28.40499	14	LATLON
BL0004O	1321	211112	TRI-UNION DEVELOPMENT CORP	TX	-95.24388	29.50191	15	LATLON
HM0011T	1321	211112	TXU PROCESSING CO	TX	-96.08541	32.12701	14	LATLON
483390020	1321	211112	U.P. RESOURCES CONROE	TX	-95.4633	30.33665		LATLON
VB0011P	1321	211112	UNION OIL COMPANY OF CALIFORNIA	TX	-95.64252	32.59353	15	LATLON
PB0003L	1321	211112	UNION PACIFIC RESOURCES	TX	-94.40084	32.16103	15	LATLON
MQ0002T	1321	211112	UNION PACIFIC RESOURCES CO	TX	-95.36587	30.27968	15	LATLON
HR0018T	1321	211112	VALENCE OPERATING CO	TX	-95.49708	32.98774	15	LATLON

strStateFacilit	strSIC	strNAICS	strFacilityName	srtState	dblXCoord	dblYCoord	intUTMZo	strXYCoor
OC0151B	1321	211112	VASTAR RESOURCES INC	TX	-94.0024	30.19632	15	LATLON
484510004	1321	211112	Veribest Gas Plant	TX	-100.689	31.3958		LATLON
SG0031P	1321	211112	WEST TEXAS GAS PROCESSING LP	TX	-100.9308	32.85534	14	LATLON
RC0018W	1321	211112	WESTERN GASRESOURCES INC	TX	-101.6471	31.48897	14	LATLON
UB0009T	1321	211112	WESTERN GASRESOURCES INC	TX	-101.7967	31.3399	14	LATLON
481590003	1321	211112	WESTLAND OIL DEVELOPMENT	TX	-95.21683	33.1757		LATLON
WI0016D	1321	211112	WG OPERATING INC	TX	-98.96862	34.0436	14	LATLON
HL0076C	1321	211112	WILLIAMS FIELD SERVICES CO	TX	-100.3887	35.7466	14	LATLON
10679	1321	211112	Bridger Lake Plant	UT	-110.82	40.91557		LATLON
490131003	1321	211112	KOCH HYDROCARBONS - CEDAR RIM PLANT	UT	-110.3653	40.20028		LATLON
10683	1321	211112	Pineview Gas Plant	UT	-111.1629	40.94026		LATLON
10268	1321	211112	San Arroyo Plant	UT	-109.6337	39.0414		LATLON
5603700036	1321	211112	DUKE ENERGY FLD SVCS _ PATRICK DRAW	WY	-108.5023	41.5899	12	LATLON
5604100015	1321	211112	DUKE ENERGY FLD SVCS_EMIGRANT TRAIL	WY	-110.0909	41.3991	12	LATLON
5604300003	1321	48621	HILAND PARTNERS, LLC_HILAND GAS PLANT	WY	-107.8515	44.0302	13	LATLON
5602500020	1321	211112	KINDER MORGAN, INC _ CASPER EXTRACTION	WY	-106.3223	42.84456		LATLON
5600900015	1321	211112	KN GAS GATHERING_DOUGLAS GAS PLANT	WY	-105.3595	42.7902	13	LATLON
5602900007	1321	211112	MARATHON OIL CO _ OREGON BASIN GAS PLANT	WY	-108.9034	44.3524	12	LATLON
5603700006	1321	211112	MOUNTAIN GAS RESOURCES_GRANGER GAS PLANT	WY	-109.9535	41.5385	12	LATLON
560430004	1321	211112	UNION OIL COMPANY-WORLAND PLANT #60	WY	-107.9061	44.13222		LATLON
560370008	1321	211112	UNION PAC BRADY	WY	-108.7456	41.38806		LATLON
560410015	1321	211112	UNION PAC EMIGRANT	WY	-110.0908	41.39944		LATLON
560370026	1321	211112	UNION PAC RESCRS - NORTH BAXTER COMP STN	WY	-108.7785	41.634		LATLON
5603700008	1321	211112	UNION PAC_BRADY	WY	-108.7457	41.388	12	LATLON
560410018	1321	211112	UPRC - LUCKY DITCH GAS PLANT	WY	-110.2708	41.01944		LATLON
560370006	1321	211112	WESTERN GAS PROCESSORS-GRANGER GAS PLNT	WY	-109.9531	41.53861		LATLON
560370011	1321	211112	WESTERN GAS RESOURCES - FONTENELLE	WY	-109.9753	42.05417		LATLON
560050006	1321	211112	WESTERN GAS RESOURCES - KITTY PLANT	WY	-105.5462	44.24773		LATLON
560090036	1321	211112	WESTERN GAS RESOURCES - SAND DUNES	WY	-105.9006	43.09083		LATLON
5600500006	1321	211112	WESTERN GAS RESOURCES _ KITTY PLANT	WY	-105.4858	44.29511		LATLON
5600500003	1321	211112	WESTERN GAS RESOURCES_AMOS DRAW PLANT	WY	-105.8998	44.3558	13	LATLON
5600500049	1321	211112	WESTERN GAS_HILIGHT (MD_124)	WY	-105.357	43.8411	13	LATLON
560050049	1321	211112	WESTERN GAS-HILIGHT (MD-124)	WY	-105.5462	44.24773		LATLON
560070005	1321	211112	WILLIAMS FIELD SERVICES - ECHO SPRINGS	WY	-106.9999	41.71695		LATLON
560230014	1321	211112	WILLIAMS FIELD SVCS-OPAL PLANT	WY	-110.3417	41.76778		LATLON
490390007	1411	212311	BENTONITE PRODUCTION	UT	-111.8667	39.055		LATLON
00034	1422	212312	ALLEN COUNTY PUBLIC WORKS	KS	-95.29785	37.91552		LATLON
00045	1422	212312	APAC KANSAS, INC., SHEARS DIV DODGE CITY	KS	-100.0207	37.75704		LATLON
00009	1422	212312	APAC-KANSAS, INC., RENO CONST DIVISION	KS	-94.66778	38.82556		LATLON
00130	1422	212312	APAC-KANSAS, INC., RENO CONST DIVISION	KS	-94.65286	38.79999		LATLON
00131	1422	212312	APAC-KANSAS, INC., RENO CONST DIVISION	KS	-94.92956	38.81565		LATLON
00023	1422	212312	APAC-KANSAS, INC., RENO CONST. DIVISION	KS	-94.68745	38.67893		LATLON
00016	1422	212312	APAC-KANSAS, INC., SHEARS DIVISION	KS	-98.2089	39.0451		LATLON
00016	1422	212312	APAC-KANSAS, INC., SHEARS DIVISION	KS	-96.02793	37.60846		LATLON
00030	1422	212312	APAC-KANSAS, INC., SHEARS DIVISION	KS	-95.97929	38.27441		LATLON
00019	1422	212312	ASH GROVE AGGREGATES, INC.	KS	-94.73301	38.40049		LATLON
00019	1422	212312	ASH GROVE AGGREGATES, INC.	KS	-94.85085	37.8554		LATLON
00120	1422	212312	ASH GROVE AGGREGATES, INC.	KS	-94.83175	38.8978		LATLON

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00020	1422	212312	BAYER CONSTRUCTION CO., INC.	KS	-96.75208	39.29102		LATLON
00022	1422	212312	BAYER CONSTRUCTION CO., INC.	KS	-96.36603	39.3463		LATLON
00024	1422	212312	BAYER CONSTRUCTION CO., INC.	KS	-97.13476	39.37493		LATLON
00030	1422	212312	BAYER CONSTRUCTION CO., INC.	KS	-96.41752	39.8704		LATLON
00007	1422	212312	BYERS & SONS, INC. (HARRY)	KS	-95.47056	37.68913		LATLON
00043	1422	212312	HARSHMAN CONSTRUCTION L.L.C.	KS	-96.97079	37.67964		LATLON
00121	1422	212312	HOLLAND CORPORATION, INC.	KS	-94.8608	38.83988		LATLON
00011	1422	212312	HUNT MIDWEST MINING, INC.	KS	-96.47571	37.12088		LATLON
00020	1422	212312	HUNT MIDWEST MINING, INC.	KS	-94.80322	38.60663		LATLON
00020	1422	212312	HUNT MIDWEST MINING, INC.	KS	-95.37099	38.07939		LATLON
00021	1422	212312	HUNT MIDWEST MINING, INC.	KS	-95.12696	38.36686		LATLON
00022	1422	212312	HUNT MIDWEST MINING, INC.	KS	-95.35272	38.1768		LATLON
00023	1422	212312	HUNT MIDWEST MINING, INC.	KS	-94.81396	38.14271		LATLON
00024	1422	212312	HUNT MIDWEST MINING, INC.	KS	-94.70152	37.83246		LATLON
00025	1422	212312	HUNT MIDWEST MINING, INC.	KS	-95.67518	38.61903		LATLON
00025	1422	212312	HUNT MIDWEST MINING, INC.	KS	-94.70152	37.83246		LATLON
00029	1422	212312	HUNT MIDWEST MINING, INC.	KS	-95.26768	38.48788		LATLON
00039	1422	212312	HUNT MIDWEST MINING, INC.	KS	-95.37209	38.9446		LATLON
00040	1422	212312	HUNT MIDWEST MINING, INC.	KS	-95.39895	38.75095		LATLON
00123	1422	212312	HUNT MIDWEST MINING, INC.	KS	-94.9804	38.95647		LATLON
00124	1422	212312	JOHNSON COUNTY AGGREGATES	KS	-94.86205	38.85451		LATLON
00011	1422	212312	LABETTE COUNTY HIGHWAY DEPT.	KS	-95.11569	37.17144		LATLON
00017	1422	212312	MARTIN MARIETTA MATERIALS, INC	KS	-95.63743	38.51323		LATLON
00032	1422	212312	MARTIN MARIETTA MATERIALS, INC	KS	-97.01424	38.34863		LATLON
00017	1422	212312	MARTIN MARIETTA MATERIALS, INC.	KS	-96.22739	37.62547		LATLON
00023	1422	212312	MARTIN MARIETTA MATERIALS, INC.	KS	-96.42787	39.1195		LATLON
00023	1422	212312	MARTIN MARIETTA MATERIALS, INC.	KS	-95.2825	38.56432		LATLON
00031	1422	212312	MARTIN MARIETTA MATERIALS, INC.	KS	-95.48214	38.98573		LATLON
00044	1422	212312	MARTIN MARIETTA MATERIALS, INC.	KS	-96.83875	37.23763		LATLON
00061	1422	212312	MARTIN MARIETTA MATERIALS, INC.	KS	-96.96398	38.84736		LATLON
00029	1422	212312	MIDWEST MINERALS, INC.	KS	-95.59026	37.55881		LATLON
00037	1422	212312	MIDWEST MINERALS, INC.	KS	-94.70107	37.40638		LATLON
00049	1422	212312	MIDWEST MINERALS, INC.	KS	-95.26893	37.34054		LATLON
00071	1422	212312	MIDWEST MINERALS, INC.	KS	-95.62528	37.03866		LATLON
00073	1422	212312	MIDWEST MINERALS, INC.	KS	-95.74103	37.19285		LATLON
00042	1422	212312	MULBERRY LIMESTONE QUARRY CO.	KS	-94.64191	37.55744		LATLON
00043	1422	212312	MULBERRY LIMESTONE QUARRY CO.	KS	-94.85248	37.5065		LATLON
00014	1422	212312	N.R. HAMM QUARRY, INC.	KS	-95.73137	39.4627		LATLON
00020	1422	212312	N.R. HAMM QUARRY, INC.	KS	-95.3884	39.2321		LATLON
00022	1422	212312	N.R. HAMM QUARRY, INC.	KS	-95.3884	39.2321		LATLON
00024	1422	212312	N.R. HAMM QUARRY, INC.	KS	-96.18241	39.47825		LATLON
00027	1422	212312	N.R. HAMM QUARRY, INC.	KS	-96.06495	39.83569		LATLON
00028	1422	212312	N.R. HAMM QUARRY, INC.	KS	-96.0703	39.65311		LATLON
00037	1422	212312	N.R. HAMM QUARRY, INC.	KS	-95.08509	38.92783		LATLON
00065	1422	212312	N.R. HAMM QUARRY, INC.	KS	-97.0164	38.96732		LATLON
00034	1422	212312	NELSON QUARRIES, INC.	KS	-95.74676	38.19927		LATLON
00041	1422	212312	NELSON QUARRIES, INC.	KS	-94.85248	37.5065		LATLON
00078	1422	212312	NELSON QUARRIES, INC.	KS	-95.54378	37.26724		LATLON

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00044	1422	212312	NEOSHO COUNTY PUBLIC WORKS DEPT.	KS	-95.30663	37.55883		LATLON
00033	1422	212312	SCOTT ROCK COMPANY	KS	-95.7325	37.33		LATLON
00114	1422	212312	SHAWNEE ROCK COMPANY (PLANT #1)	KS	-94.82972	38.89127		LATLON
00231	1422	212312	SHAWNEE ROCK COMPANY (PLANT #3)	KS	-94.9075	39.07226		LATLON
00115	1422	212312	SHAWNEE ROCK COMPANY (PLANT #4)	KS	-94.70771	39.02012		LATLON
00020	1422	212312	WADE QUARRIES	KS	-94.73301	38.40049		LATLON
00021	1422	212312	WADE QUARRIES	KS	-94.67612	38.60332		LATLON
00021	1422	212312	WADE QUARRIES	KS	-94.86305	38.41787		LATLON
490270005	1422	212312	CONTINENTAL LIME	UT	-112.8169	38.93972		LATLON
10313	1422	212312	Cricket Mountain Plant	UT	-112.5857	39.36197		LATLON
0118	1474	212391	AMERICAN SODA LLP - PICEANCE FACILITY	CO	-107.8557	40.03395	13	LATLON
58196	1474	212391	FMC TRONA	WY	-109.8241	41.6013	12	LATLON
5603700010	1474	212391	FMC WYOMING CORP _ SODA ASH PLANT	WY	-109.8987	41.6744	12	LATLON
5603700049	1474	212391	FMC WYOMING CORPORATION-WESTVACO TRONA	WY	-109.4661	41.51425		LATLON
5603700002	1474	212391	GENERAL CHEMICAL	WY	-109.7534	41.5933	12	LATLON
5603700001	1474	212391	OCI (RHONE_POULENC) WYOMING	WY	-109.6898	41.7141	12	LATLON
5603700005	1474	212391	SOLVAY MINERALS, INC.	WY	-109.7524	41.531	12	LATLON
490470003	1475	212392	S.F. PHOSPHATES	UT	-109.4831	40.59972		LATLON
490570032	1479	212393	GREAT SALT LAKE MINERAL	UT	-112.2289	41.23333		LATLON
040250698	1499	2123	CHEMICAL LIME, NELSON PLANT	AZ	-113.3108	35.51639		LATLON
0209	2813	325120	DUKE ENERGY - LADDER CREEK HELIUM PLANT	CO	-102.3921	38.7943	13	LATLON
00031	2813	325120	ATOFINA CHEMICALS, INC.	KS	-97.42516	37.58492		LATLON
201650004	2813	325120	KANSAS REFINED HELIUM COMPANY	KS	-99.10667	38.56917		LATLON
200670008	2813	325120	MOBIL EXPLORATION & PRODUCING U.S. INC	KS	-101.1867	37.57194		LATLON
200670050	2813	325120	PRAXAIR, INC.	KS	-101.0889	37.64056		LATLON
T$11640	2813	325120	AIR LIQUIDE AMERICA CORP.	TX	-95.05	29.62111		LATLON
T$11721	2813	325120	AIR LIQUIDE AMERICA CORP.	TX	-95.33334	28.99167		LATLON
HG0010N	2813	325120	AIR PRODUCTS INC	TX	-95.06703	29.70155	15	LATLON
MONC4	2813	325120	AIR PRODUCTS, INCORPORATED/HARRIS/HG0011L	TX	-95.44	29.83	0	LATLON
HG1223K	2813	325120	BOC GASES	TX	-94.99216	29.74134	15	LATLON
JE0052V	2813	325120	HUNTSMAN CORPORATION	TX	-93.95389	29.84996	15	LATLON
HX2302N	2813	325120	LA PORTE MENTHANOL	TX	-95.06194	29.70682	15	LATLON
HX2334A	2813	325120	LINDE GAS INC.	TX	-95.05745	29.70675	15	LATLON
T$11739	2813	325120	MATHESON TRI-GAS	TX	-95.03806	29.65333		LATLON
238	2873	325311	KERLEY AG INC.	AZ	-112.1069	33.4228	12	LATLON
T$10213	2873	325311	FARMLAND INDS. INC. - LAWRENCE NITROGEN PLANT	KS	-95.19972	38.95583		LATLON
T$10374	2873	325311	FARMLAND INDS. INC. DODGE CITY NITROGEN PLANT	KS	-99.92917	37.77667		LATLON
00003	2873	325311	FARMLAND INDUSTRIES, INC. (FERTILIZER)	KS	-99.92722	37.74111		LATLON
350430021	2873	325311	AGRONICS, INC/HUMATES PLANT_______1127M1	NM	-106.9475	35.89806		LATLON
T$11018	2873	325311	FARMLAND INDS. INC.	OK	-97.76278	36.37972		LATLON
1635	2873	325311	Farmland Industries, Inc.-Enid Nitrogen Plant	OK	-97.7657	36.3751	14	LATLON
401310704	2873	325311	TERRA NITROGEN	OK	-95.71972	36.21972		LATLON
T$11021	2873	325311	TERRA NITROGEN CORP. WOODWARD COMPLEX	OK	-99.46889	36.43528		LATLON
2495	2873	325311	Terra Nitrogen, Limited Partnership Verdigris Plant	OK	-95.7201	36.2203	15	LATLON
HW0004D	2873	325311	AGRIUM US INC	TX	-101.4249	35.64532	14	LATLON
T$11681	2873	325311	EL DORADO NITROGEN CO.	TX	-94.92528	29.75583		LATLON
T$12138	2873	325311	COASTAL CHEM INC.	WY	-104.9042	41.09583		LATLON
560210002	2873	325311	COASTAL CHEMICAL	WY	-104.9128	41.09306		LATLON

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HG0534U	2874	325312	AGRIFOS FERTILIZER LP	TX	-95.25713	29.73725	15	LATLON
T$12154	2874	325312	SF PHOSPHATES LTD. CO.	WY	-109.2354	41.59491		LATLON
5603700022	2874	325312	SF PHOSPHATES, INC	WY	-109.1275	41.538	12	LATLON
0032	2911	324110	BARTKUS OIL CO	CO	-105.2461	40.0243	13	LATLON
0520	2911	324110	CHIEF PETROLEUM	CO	-104.8422	38.8332	13	LATLON
23-E	2911	324110	Colorado Refining Company	CO	-104.9422	39.80481	0	LATLON
55	2911	324110	Conoco Denver Products Terminal	CO	-104.9456	39.80333	0	LATLON
ESD035	2911	324110	Conoco Inc.	CO	-104.9411	39.80384	13	LATLON
080770001	2911	324110	LANDMARK PETROLEUM INC	CO	-108.7575	39.16833		LATLON
0063	2911	324110	REX OIL CO	CO	-105.021	39.7308	13	LATLON
0035	2911	324110	REX OIL CO INC	CO	-105.2484	40.0234	13	LATLON
0065	2911	324110	SIEGEL OIL CO	CO	-105.0152	39.7371	13	LATLON
ESD036	2911	324110	Ultramar Diamond Shamrock (formerly Total Petroleu	CO	-104.946	39.80495	13	LATLON
201730020	2911	324110	COASTAL DERBY REFINING CO.	KS	-97.31472	37.72556		LATLON
200150001	2911	324110	COASTAL DERBY REFINING CO.	KS	-96.85917	37.8325		LATLON
ESD050	2911	324110	Cooperative Refining (formerly Farmland Industries	KS	-95.60525	37.04822	15	LATLON
ESD051	2911	324110	Cooperative Refining (formerly National Cooperativ	KS	-97.66704	38.34928	14	LATLON
201470001	2911	324110	FARMLAND INDUSTRIES, INC.-REFINERY DIV.	KS	-99.37139	39.78694		LATLON
ESD052	2911	324110	Frontier Oil Corp. (formerly El Dorado Refining, f	KS	-96.87958	37.79681	14	LATLON
200150004	2911	324110	TEXACO REFINING & MARKETING, INC.	KS	-96.86667	37.79917		LATLON
200350004	2911	324110	TOTAL PETROLEUM, INC.	KS	-97.13139	37.075		LATLON
0008	2911	324110	Ciniza Refinery	NM	-108.425	35.4887	12	LATLON
ESD091	2911	324110	Giant Refining Co.	NM	-107.9755	36.70039	13	LATLON
ESD092	2911	324110	Giant Refining Co.	NM	-108.425	35.50724	12	LATLON
T$12478	2911	324110	LEA REFINING CO.	NM	-103.3003	32.87944		LATLON
T$12476	2911	324110	NAVAJO REFINING CO.	NM	-104.3961	32.85139		LATLON
T$12459	2911	324110	SAN JUAN REFINING CO.	NM	-107.9722	36.69722		LATLON
T$12490	2911	324110	FORELAND REFINING- TONOPAH REFY.	NV	-117.1	38.06667		LATLON
400810001	2911	324110	ALLIED MATLS-REFINER	OK	-97.0725	35.635		LATLON
T$11123	2911	324110	CONOCO INC. - PONCA CITY REFY.	OK	-97.08694	36.69305		LATLON
2477	2911	324110	Sun Company Inc.	OK	-96.0249	36.14	14	LATLON
23-D	2911	324110	TRI Petroleum, Inc. Ardmore Refinery	OK	-97.13592	34.17472	0	LATLON
ESD103	2911	324110	Ultramar/Diamond Shamrock (formerly Total Petroleu	OK	-97.10337	34.20234	14	LATLON
2782	2911	324110	Wynnewood Refining Company	OK	-97.1673	34.635	14	LATLON
ESD110	2911	324110	AGE Refining & Manufacturing	TX	-98.46007	29.34916	14	LATLON
ESD111	2911	324110	Alon Israel (formerly Fina Oil & Chemical Co.)	TX	-101.47	32.24	14	LATLON
HT0011Q	2911	324110	ALON USA LP	TX	-101.4237	32.27038	14	LATLON
JE0005H	2911	324110	ATOFINA PETROCHEMICALS INC	TX	-93.8954	29.95857	15	LATLON
HG0130C	2911	324110	BASIS PETROLEUM INC	TX	-95.26208	29.72616	15	LATLON
481670050	2911	324110	BASIS PETROLEUM, INC.	TX	-94.54389	29.22083		LATLON
10-C	2911	324110	Big Spring Refinery	TX	-101.4147	32.28444	0	LATLON
T$11755	2911	324110	BP AMOCO TEXAS CITY BUSINESS UNIT	TX	-94.925	29.37444		LATLON
27-H	2911	324110	Chevron El Paso Refinery (North Facility)	TX	-106.4024	31.77099	0	LATLON
ESD115	2911	324110	Citgo	TX	-97.48822	27.81323	14	LATLON
T$11904	2911	324110	CITGO REFINING & CHEMICALS CO. L.P. - EAST PLANT	TX	-97.42778	27.80917		LATLON
ESD116	2911	324110	Coastal Refining & Marketing Inc.	TX	-97.44322	27.81263	14	LATLON
24-C	2911	324110	Corpus Christi East Refinery	TX	-97.42223	27.80611	0	LATLON
24-B	2911	324110	Corpus Christi West Refinery	TX	-97.52778	27.83055	0	LATLON

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ESD117	2911	324110	Crown Central Petroleum Corp.	TX	-95.20725	29.72599	15	LATLON
T$11702	2911	324110	DEER PARK REFINING L.P.	TX	-95.12917	29.72139		LATLON
MR0008T	2911	324110	DIAMOND SHAMROCK REFINING CO LP	TX	-101.8905	35.95423	14	LATLON
LK0009T	2911	324110	DIAMOND SHAMROCK REFINING CO LP	TX	-98.18428	28.45563	14	LATLON
20-A	2911	324110	Exxon Baytown Refinery	TX	-94.99269	29.75505	0	LATLON
ESD119	2911	324110	ExxonMobil Corp. (formerly Mobil)	TX	-94.0716	30.07583	15	LATLON
26-A	2911	324110	Houston Refinery	TX	-95.25305	29.72333	0	LATLON
NE0122D	2911	324110	KOCH PETROLEUM GROUP LP	TX	-97.44185	27.80693	14	LATLON
SK0022A	2911	324110	LA GLORIA OIL AND GAS CO	TX	-95.26928	32.36675	15	LATLON
ESD121	2911	324110	LaGloria Oil & Gas Co.	TX	-95.27276	32.36735	15	LATLON
HG0048L	2911	324110	LYONDELL-CITGO REFINING LP	TX	-95.25121	29.70939	15	LATLON
ESD123	2911	324110	Marathon Ashland Petrol. LCC	TX	-94.90659	29.37657	15	LATLON
23-F	2911	324110	McKee Plants	TX	-101.8733	35.95167	0	LATLON
12-D	2911	324110	Mobil Beaumont Refinery	TX	-94.07027	30.06389	0	LATLON
ESD124	2911	324110	Motiva Enterprises (formerly Star)	TX	-93.95823	29.87322	15	LATLON
JE0095D	2911	324110	MOTIVA ENTERPRISES LLC	TX	-93.95268	29.88934	15	LATLON
BL0042G	2911	324110	PHILLIPS 66CO	TX	-95.76373	29.07126	15	LATLON
16-D	2911	324110	Phillips Borger Refinery & NGL Center	TX	-101.3678	35.69722	0	LATLON
JE0042B	2911	324110	PREMCOR REFINING GROUP	TX	-93.95519	29.85866	15	LATLON
ESD127.5	2911	324110	Pride Refining Inc.	TX	-99.76712	32.54485	14	LATLON
27-G	2911	324110	Refinery Holding Co. Refinery (South Facility)	TX	-106.4019	31.7703	0	LATLON
ESD128	2911	324110	Shell -Deer Park Refining Limited Partnership	TX	-95.11635	29.72406	15	LATLON
HG0659W	2911	324110	SHELL OIL CO	TX	-95.11546	29.72356	15	LATLON
ESD128.5	2911	324110	Specified Fuels & Chemicals (formerly Howell Hydro	TX	-95.09996	29.76851	15	LATLON
16-A	2911	324110	Sweeny Refinery and Petrochemical Complex	TX	-95.74667	29.06889	0	LATLON
21-G	2911	324110	Texas City Refinery	TX	-94.91142	29.40593	0	LATLON
T$11850	2911	324110	THREE RIVERS REFY.	TX	-98.19028	28.45667		LATLON
ESD129	2911	324110	Trifinery Petrol. Srvc. (formerly Neste Trifinery)	TX	-97.49272	27.81925	14	LATLON
ESD131	2911	324110	Ultramar/Diamond Shamrock Corp.	TX	-101.8825	35.96259	14	LATLON
ESD130	2911	324110	Ultramar/Diamond Shamrock Corp.	TX	-98.18844	28.45739	14	LATLON
ESD133	2911	324110	Valero (formerly Basis Petroleum, Inc.)	TX	-95.23721	29.57851	15	LATLON
GB0073P	2911	324110	VALERO REFINING CO - TEXAS	TX	-94.89437	29.3733	15	LATLON
ESD132	2911	324110	Valero Refining Co.	TX	-97.52651	27.89656	14	LATLON
T$12204	2911	324110	BIGWEST OIL L.L.C.	UT	-111.9056	40.86667		LATLON
ESD135	2911	324110	BP (formerly Amoco Oil Co.)	UT	-111.9032	40.79073	12	LATLON
ESD136	2911	324110	Chevron USA	UT	-111.9244	40.82801	12	LATLON
490470053	2911	324110	CHEVRON USA PRODUCING CO	UT	-109.3019	40.20306		LATLON
490470007	2911	324110	CITATION OIL AND GAS (PREV. EXXON)	UT	-109.3714	40.30417		LATLON
10122	2911	324110	Flying J Refinery (Big West Oil Co.)	UT	-111.9239	40.84199		LATLON
490130100	2911	324110	GARY REFINERY	UT	-110.22	40.36056		LATLON
490430004	2911	324110	NGC ENERGY RESOURCES	UT	-111.3681	40.90889		LATLON
490470017	2911	324110	NORTHWEST PIPELINE	UT	-109.3331	40.56889		LATLON
490130027	2911	324110	PENNZOIL	UT	-110.0183	40.28		LATLON
490130053	2911	324110	PG & E RESOURCES COMPANY	UT	-110.0197	40.04472		LATLON
490110013	2911	324110	PHILLIPS PETROLEUM	UT	-111.9081	40.8925		LATLON
ESD139	2911	324110	Phillips Petroleum Co.	UT	-111.9006	40.88746	12	LATLON
490439078	2911	324110	PINEVIEW FIELD	UT	-110.82	40.91557		LATLON
490430010	2911	324110	PINEVIEW GAS PLANT	UT	-110.82	40.91557		LATLON

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10335	2911	324110	Salt Lake City Refinery	UT	-111.9038	40.78906		LATLON
10119	2911	324110	Salt Lake Refinery	UT	-111.921	40.81955		LATLON
ESD137	2911	324110	Silver Eagle Refining Inc. (formerly Inland Refini	UT	-111.9102	40.86698	12	LATLON
490431001	2911	324110	UNION PACIFIC RESOURCES-YELLOW CREEK	UT	-111.1542	40.94528		LATLON
490070034	2911	324110	US FUEL CO	UT	-111.0106	39.49139		LATLON
5602100001	2911	324110	FRONTIER REFINING, INC.	WY	-104.7868	41.128	13	LATLON
ESD150	2911	324110	Little America Refining Co.	WY	-106.2645	42.85974	13	LATLON
T$12156	2911	324110	SILVER EAGLE REFINING	WY	-110.8069	41.26056		LATLON
60-C	2911	324110	Sinclair, Little America Refinery	WY	-106.2799	42.83902	0	LATLON
60-A	2911	324110	Sinclair, Wyoming Refinery	WY	-107.056	41.78889	0	LATLON
T$12150	2911	324110	WYOMING REFINING CO.	WY	-104.2158	43.84972		LATLON
080011182	3211	327211	CAPITOL GLASS & ALUMINUM CORP	CO	-104.8483	39.76389		LATLON
0008	3221	327213	ROCKY MOUNTAIN BOTTLE CO	CO	-105.1156	39.7857	13	LATLON
0326	3229	327212	FIBERON INC	CO	-105.083	40.603	13	LATLON
080311259	3229	327212	ROCKY MOUNTAIN SCIENTIFIC GLASS BLOWING	CO	-104.9286	39.68028		LATLON
0401900310	3241	32731	ARIZONA PORTLAND CEMENT COMPANY	AZ	-111.1492	32.40915	12	LATLON
0003	3241	327310	CEMEX, INC. - LYONS CEMENT PLANT	CO	-105.2291	40.209	13	LATLON
0001	3241	327310	HOLNAM INC PORTLAND PLANT	CO	-105.0172	38.3872	13	LATLON
0002	3241	327310	HOLNAM INC_FORT COLLINS PLANT	CO	-105.1407	40.6524	13	LATLON
T$10266	3241	327310	ASH GROVE CEMENT CO.	KS	-95.46306	37.69778		LATLON
T$10268	3241	327310	LAFARGE CORP. (INCLD SYSTECH ENVIRONMENTAL)	KS	-95.82167	37.50945		LATLON
T$10273	3241	327310	MONARCH CEMENT CO.	KS	-95.44167	37.80056		LATLON
T$12442	3241	327310	RIO GRANDE PORTLAND CEMENT CORP.	NM	-106.3897	35.07222		LATLON
BG0259G	3241	327310	ALAMO CEMENT CO II LTD	TX	-98.37563	29.61184	14	LATLON
BG0045E	3241	327310	CAPITOL CEMENT DIV CAPITOL AGGREGATE	TX	-98.42069	29.54637	14	LATLON
T$11980	3241	327310	LONE STAR IND. INC. MARYNEAL PLANT	TX	-100.4583	32.25		LATLON
ND0014S	3241	327310	LONE STAR INDUSTRIES INC	TX	-100.4593	32.25113	14	LATLON
T$11385	3241	327310	NORTH TEXAS CEMENT CO. LLP.	TX	-97.00833	32.52083		LATLON
EB0121R	3241	327310	SOUTHDOWN INC	TX	-102.5445	31.74667	13	LATLON
T$12011	3241	327310	SOUTHWESTERN PORTLAND CEMENT	TX	-102.5406	31.75111		LATLON
CS0022K	3241	327310	SUNBELT CEMENT OF TEXAS LP	TX	-98.25237	29.69211	14	LATLON
318	3241	327310	Texas Industries, Inc.	TX	-97.02847	32.46378	0	LATLON
T$11924	3241	327310	TEXAS-LEHIGH CEMENT CO.	TX	-97.85333	30.07111		LATLON
ED0066B	3241	327310	TXI OPERATIONS LIMITED PARTNERSHIP	TX	-97.02549	32.46194	14	LATLON
CS0018B	3241	327310	TXI OPERATIONS LP	TX	-98.04115	29.80478	14	LATLON
5600100002	3241	327310	MOUNTAIN CEMENT CO	WY	-105.6028	41.2689	13	LATLON
BSCP20	3251	327121	Clinton-Campbell Contractor, Inc	AZ	-112.0839	33.42083		LATLON
0043	3251	327	DENVER BRICK CO	CO	-104.8665	39.3757	13	LATLON
T$12069	3251	327	ROBINSON BRICK CO.	CO	-105.0067	39.6625		LATLON
BSCP116	3251	327121	Summit Pressed Brick and Tile Co	CO	-104.595	38.28083		LATLON
BSCP39	3251	327121	Summit Pressed Brick and Tile Co	CO	-105.0644	39.7375		LATLON
BSCP155	3251	327121	The Denver Brick Co	CO	-104.8561	39.37889		LATLON
00004	3251	327	ACME BRICK COMPANY	KS	-98.14778	38.71083		LATLON
00009	3251	327	CLOUD CERAMICS (DIV. GENERAL FINANCE)	KS	-97.68417	39.59167		LATLON
BSCP158	3251	327121	General Finance, Inc	KS	-97.65803	39.56749		LATLON
BSCP92	3251	327121	Justin Industries	KS	-98.15056	38.71222		LATLON
BSCP93	3251	327121	Justin Industries	KS	-94.72861	37.28556		LATLON
BSCP175NR	3251	327121	Kansas Brick and Tile Co	KS	-98.78416	38.53603		LATLON

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BSCP2	3251	327121	American Eagle Brick Co	NM	-106.5417	31.78889		LATLON
BSCP38	3251	327121	Hoffman Enterprises, Inc	NM	-106.6594	35.01473		LATLON
PC0001E	3251	327	ACME BRICK COMPANY	TX	-98.05362	32.715	14	LATLON
T$11307	3251	327	BORAL BRICKS INC. HENDERSON PLANT	TX	-94.80333	32.18083		LATLON
T$11314	3251	327	BORAL BRICKS INC. MARSHALL PLANT	TX	-94.36777	32.555		LATLON
BSCP21	3251	327121	D'Hanis Clay Products, Inc	TX	-99.27944	29.33028		LATLON
BSCP153	3251	327121	Elgin-Butler Brick Co	TX	-97.28944	30.32167		LATLON
BSCP70	3251	327121	Hanson, PLC	TX	-98.12583	32.81556		LATLON
BSCP77	3251	327121	Hanson, PLC	TX	-97.33972	30.31643		LATLON
BSCP118	3251	327121	Justin Industries	TX	-96.02084	32.16555		LATLON
BSCP125	3251	327121	Justin Industries	TX	-97.77444	33.20945		LATLON
BSCP126	3251	327121	Justin Industries	TX	-94.50889	31.83917		LATLON
BSCP128	3251	327121	Justin Industries	TX	-96.13972	29.82889		LATLON
BSCP151	3251	327121	Justin Industries	TX	-98.05167	32.68333		LATLON
BSCP97	3251	327121	Justin Industries	TX	-97.13472	33.18639		LATLON
BSCP98	3251	327121	Justin Industries	TX	-97.29333	30.31917		LATLON
BSCP99	3251	327121	Justin Industries	TX	-98.03972	29.5725		LATLON
BSCP160NR	3251	327121	Snyder Brick and Tile	TX	-100.9062	32.71685		LATLON
BSCP121	3251	327121	Texas Industries	TX	-97.35018	32.61335		LATLON
HM0003S	3251	327	TEXAS INDUSTRIES INC	TX	-95.82237	32.20379	15	LATLON
46461	3251	327	WILLIAMSBURG BRICK COMPANY	TX	-95.1039	32.9806	15	LATLON
DB1073N	3253	327122	AMERICAN MARAZZI TILE INC	TX	-96.56251	32.76681	14	LATLON
CC48	3253	327122	Dal-Tile Corporation	TX	-95.46722	30.39083		LATLON
CC50	3253	327122	Dal-Tile Corporation	TX	-106.3553	31.95278		LATLON
DB0242V	3253	327122	DAL-TILE CORPORATION	TX	-96.68785	32.71733	14	LATLON
CC72	3253	327122	Huntington/Pacfic Ceramics, Inc.	TX	-97.2954	32.76771		LATLON
CC73	3253	327122	Huntington/Pacific Ceramics, Inc.	TX	-95.24333	33.18528		LATLON
CC205	3253	327122	Lone Star Ceramics Mfg. Co.	TX	-96.90916	32.93528		LATLON
9611	3255	327124	ADIENCE INC	CO	-105.2303	38.442	13	LATLON
0459	3255	327124	COORSTEK, INC	CO	-105.1775	39.7829	13	LATLON
0017	3255	327124	DFC CERAMICS	CO	-105.2314	38.4393	13	LATLON
0012	3255	327124	VESUVIUS USA	CO	-105.2303	38.442	13	LATLON
BSCP106	3259	327123	MCP Industries, Inc	AZ	-112.1631	33.43684		LATLON
BSCP108	3259	327123	MCP Industries, Inc	KS	-94.69167	37.35833		LATLON
BSCP109	3259	327123	MCP Industries, Inc	TX	-98.3	29.2375		LATLON
CC15	3261	327111	American Standard, Inc.	AZ	-111.9569	33.30245		LATLON
CC92	3261	327111	Falcon Building Products, Inc. (Mansfield)	TX	-94.84861	32.40333		LATLON
CC203	3261	327111	Kohler Co	TX	-98.99722	31.66389		LATLON
CC38	3262	327112	CR/PL, L.L.C.	TX	-96.59428	30.87724		LATLON
0007	3264	327113	COORS CERAMICS CO ELECTRONICS DIV	CO	-105.2008	39.7649	13	LATLON
0024	3264	327113	COORSTEK GRAND JUNCTION	CO	-108.5964	39.0852	12	LATLON
0437	3264	327113	COORSTEK, INC.	CO	-105.174	39.7694	13	LATLON
308	3271	327331	QUALITY BLOCK INC	AZ	-112.225	33.68333		LATLON
490350200	3271	327331	BRICK MANUFACTURING PLANT	UT	-112.0136	40.59389		LATLON
490439045	3271	327331	HENIFER MINE	UT	-111.4719	41.025		LATLON
490499046	3271	327331	POWELL MINE (UTAH SITE #1)	UT	-111.9272	40.33		LATLON
490459043	3271	327331	SMILE MINE	UT	-112.1914	40.08889		LATLON
T$12328	3272	327	MONIERLIFETILE L.L.C.	AZ	-112.1692	33.43528		LATLON

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0411	3272	327	DENVER ARCHITECHURAL PRECAST INC	CO	-104.8913	39.8704	13	LATLON
0053	3272	327	ROCKY MOUNTAIN PRESTRESS ARCHITECTURAL	CO	-104.9825	39.8047	13	LATLON
0081	3272	327	STRESSCON CORP	CO	-104.7721	38.7808	13	LATLON
00097	3272	327	RICH MIX PRODUCTS, INC.- KANSAS DIVISION	KS	-97.41805	37.72333		LATLON
DB0374D	3272	327	FRITZ INDUSTRIES INC	TX	-96.67501	32.75562	14	LATLON
T$11169	3272	327	GIFFORD-HILL AMERICAN	TX	-96.95583	32.76639		LATLON
490410012	3272	327	COX ROCK PRODUCTS - AURORA PLANT	UT	-111.9076	38.7739		LATLON
490390001	3272	327	COX ROCK PRODUCTS - MT PLEASANT CONCRETE	UT	-111.6307	39.42275		LATLON
490350088	3272	327	HOBUSCH PIT	UT	-111.8614	40.58111		LATLON
490110049	3272	327	WEBER SAND AND GRAVEL L-6	UT	-112.1154	40.9611		LATLON
400	3273	327320	CALMAT OF ARIZONA	AZ	-112.25	33.85556		LATLON
401	3273	327320	CALMAT OF ARIZONA	AZ	-112.0722	33.70833		LATLON
403	3273	327320	CALMAT OF AZ PLANT #3	AZ	-112.4472	33.78889		LATLON
404	3273	327320	CALMAT OF AZ/SUN CITY PLANT	AZ	-112.5167	34.02778		LATLON
411	3273	327320	CENTURY MATERIALS, INC.	AZ	-112.4917	33.725		LATLON
413	3273	327320	CHANDLER READY MIX	AZ	-112.3806	33.68611		LATLON
304	3273	327320	PHOENIX REDI MIX	AZ	-112.2528	33.69167		LATLON
339	3273	327320	SUNWARD MATERIALS	AZ	-112.5222	33.82222		LATLON
340	3273	327320	SUNWARD MATERIALS (BCW CEMENT CO.)	AZ	-112.4389	33.55556		LATLON
367	3273	327320	UNITED METRO (TANNER)	AZ	-112.6611	33.70833		LATLON
0672	3273	327320	KIEWIT WESTERN CO	CO	-104.7339	39.7521	13	LATLON
0103	3273	327320	QUIKRETE OF DENVER HOLDINGS INC	CO	-105.0187	39.811	13	LATLON
0010	3273	327320	TRANSIT MIX CONCRETE	CO	-104.8168	38.8278	13	LATLON
0400300176	3274	32741	CHEMICAL LINE COMPANY - DOUGLAS FACILITY	AZ	-109.7347	31.36357	12	LATLON
0261	3274	327410	PILOT PEAK	NV	-114.2202	40.82477	11	LATLON
BJ0001T	3274	327410	CHEMICAL LIME LTD	TX	-97.59734	31.70845	14	LATLON
490450005	3274	327410	GRANTSVILLE PLANT	UT	-112.55	40.685		LATLON
490350373	3274	327410	HERCULES COMPOSITE MATERIALS	UT	-111.906	40.6737		LATLON
490450035	3274	327410	USPCI - MERR	UT	-113.0903	40.93056		LATLON
080370029	3275	327420	EAGLE GYPSUM PRODUCTS WALLBOARD PLT	CO	-106.8994	39.64583		LATLON
00021	3275	327420	G-P GYPSUM CORPORATION	KS	-96.645	39.70444		LATLON
T$10977	3275	327420	UNITED DESIGN CORP. NOBLE FAC.	OK	-97.40556	35.15694		LATLON
10654	3275	327420	Sigurd Plant	UT	-111.9668	38.83921		LATLON
5600300001	3275	327420	GEORGIA PACIFIC_GYPSUM PLANT	WY	-108.0004	44.7529	13	LATLON
T$12314	3281	327991	AVONTI MFG. INC.	AZ	-112.1264	33.85083		LATLON
T$12342	3281	327991	MESA FULLY FORMED INC.	AZ	-111.8306	33.39389		LATLON
T$12434	3281	327991	MOUNTAIN MARBLE MFG. INC.	AZ	-112.3175	34.58556		LATLON
0131	3281	327991	MANSTONE	CO	-104.8236	38.8792	13	LATLON
0286	3281	327991	ROCKY MOUNTAIN CULTURED MARBLE INC	CO	-105.0555	40.5885	13	LATLON
T$11300	3281	327991	ALDON MARBLE MFG. CO.	TX	-94.75667	32.40417		LATLON
T$11438	3291		NORTON CO.	TX	-98.23611	32.20278		LATLON
T$11914	3291		NORTON CO.	TX	-97.4399	25.90414		LATLON
455	3295	2123	HARBORLITE CORP, SUPERIOR PLANT	AZ	-111.128	33.2833	12	LATLON
040271006	3295	2123	YUMA COUNTY DEPT PUBLIC WORKS C&S PLANT	AZ	-114.4942	32.75833		LATLON
0004	3295	2123	MWCA INC	CO	-105.5746	37.1907	13	LATLON
00015	3295	2123	MICRO-LITE, L.L.C.	KS	-95.6971	37.70861		LATLON
NB0037F	3295	2123	TXI OPERATIONS LP	TX	-96.3488	31.91539	14	LATLON
T$12365	3296	327993	OWENS-CORNING ELOY PLANT	AZ	-111.6283	32.66833		LATLON

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0168	3296	327993	MESA FIBERGLASS INC	CO	-104.9136	39.7857	13	LATLON
00001	3296	327993	CERTAIN TEED CORPORATION	KS	-94.61139	39.14305		LATLON
00036	3296	327993	JOHNS MANVILLE	KS	-97.61166	38.38583		LATLON
00010	3296	327993	OWENS CORNING	KS	-94.61555	39.14667		LATLON
34651	3296	327993	SCHULLER INTL. INC.	KS	-97.615	38.38639		LATLON
T$11455	3296	327993	AMERICAN ROCKWOOL INC.	TX	-97.56861	31.075		LATLON
JH0025O	3296	327993	JOHNS MANVILLE INTERNATIONAL INC	TX	-97.397	32.38778	14	LATLON
AA0044U	3296	327993	OWEN CORNING	TX	-95.76103	31.65535	15	LATLON
ED0051O	3296	327993	OWENS-CORNING	TX	-96.85005	32.43925	14	LATLON
T$11220	3296	327993	OWENS-CORNING	TX	-96.85	32.43917		LATLON
HG1766N	3296	327993	ROCK WOOL MANUFACTURING CO	TX	-95.31723	29.69829	15	LATLON
BF0107S	3296	327993	THERMAFIBER LLC	TX	-97.56948	31.07524	14	LATLON
0106	3299	327	VISICOM LABORATORIES DBA MICROLITHICS CO	CO	-105.1657	39.7316	13	LATLON
T$11847	3299	327	KAMAL INC. VENETIAN MARBLE (DBA)	TX	-98.66194	29.56556		LATLON
BM0026Q	3299	327	NORTON CHEMICAL PROCESS PRODUCTS COR	TX	-96.40858	30.66233	14	LATLON
MQ0106G	3299	327	SCAN-PAC MFG INC	TX	-95.46	30.34	15	LATLON
RL0086D	3299	327	TROY MFG TEXAS INC	TX	-94.81824	32.19677	15	LATLON
0401501232	3312	331111	NORTH STAR STEEL ARIZONA	AZ	-114.0914	35.13795	11	LATLON
0048	3312	331	CF&I STEEL L P DBA ROCKY MTN STEEL MILLS	CO	-104.6127	38.237	13	LATLON
1144	3312	331	CONSOLIDATED STEEL SVC	CO	-105.0023	39.6479	13	LATLON
T$11138	3312	331	ACKER INDS. INC.	OK	-96.49111	35.16028		LATLON
2453	3312	331	Sheffield Steel	OK	-96.1185	36.1324	14	LATLON
T$11048	3312	331	SHEFFIELD STEEL CORP.	OK	-96.11861	36.11861		LATLON
EE0011P	3312	331	BORDER STEEL INC	TX	-106.5841	31.96589	13	LATLON
T$11384	3312	331	CHAPARRAL STEEL MIDLOTHIAN L.P.	TX	-97.04166	32.46389		LATLON
ED0011D	3312	331	CHAPARRAL STEEL MIDLOTHIAN LP	TX	-97.0375	32.45792	14	LATLON
CI0170H	3312	331	JINDAL UNITED STEEL CORP	TX	-94.89564	29.68826	15	LATLON
MS0008I	3312	331	LONE STAR STEEL CO	TX	-94.74	33.12	15	LATLON
T$11311	3312	331	LONE STAR STEEL CO.	TX	-94.71667	32.9		LATLON
55404	3312	331	LONE STAR STEEL COMPANY	TX	-94.718	32.9142	15	LATLON
OC0011S	3312	331	NORTH STAR STEEL OF TEXAS	TX	-94.0786	30.08556	15	LATLON
GL0028H	3312	331	STRUCTURAL METALS INC	TX	-98.03277	29.57685	14	LATLON
T$12209	3312	331	GENEVA STEEL	UT	-111.7403	40.29639		LATLON
T$12268	3312	331	NUCOR STEEL - A DIV. OF NUCOR CORP.	UT	-112.1894	41.87695		LATLON
5603700003	3312	331	P4 PRODUCTION_ROCK SPRINGS FACILITY	WY	-109.2204	41.5241	12	LATLON
T$12467	3331	331411	PHELPS DODGE HIDALGO INC.	NM	-108.5425	31.77111		LATLON
350230003	3331	331411	PHELPS DODGE/HIDALGO SMELTER________59M1	NM	-108.5292	31.77528		LATLON
T$11966	3331	331411	ASARCO INC. AMARILLO COPPER REFY.	TX	-101.7342	35.28528		LATLON
EE0007G	3331	331411	ASARCO INCORPORATED	TX	-106.5232	31.78263	13	LATLON
PG0005V	3331	331411	ASARCO INCORPORATED	TX	-101.733	35.28257	14	LATLON
EE0067L	3331	331411	PHELPS DODGE EL PASO OPERATIONS	TX	-106.3923	31.76683	13	LATLON
15076	3331	331411	KENNECOTT - UTAH POWER PLANT AND	UT	-112.1167	40.7		LATLON
T$12197	3331	331411	KENNECOTT UTAH COPPER SMELTER & REFY.	UT	-112.1969	40.72167		LATLON
10346	3331	331411	Smelter, Refinery	UT	-112.0833	40.70026		LATLON
T$11456	3334	331312	ALCOA	TX	-97.08861	30.63417		LATLON
MM0001T	3334	331312	ALUMINUM COMPANY OF AMERICA	TX	-97.07285	30.56841	14	LATLON
00002	3341	331	TOWER METAL PRODUCTS	KS	-94.69882	37.8389		LATLON
T$11049	3341	331	IMCO RECYCLING INC.	OK	-96.13167	36.01694		LATLON

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T$11114	3341	331	WABASH ALLOYS L.L.C.	OK	-95.54166	35.4		LATLON
T$11028	3341	331	ZINC CORP. OF AMERICA	OK	-95.99361	36.74167		LATLON
T$11852	3341	331	ALCOA INC. SAN ANTONIO WORKS	TX	-98.37889	29.2775		LATLON
T$11283	3341	331	ALUMAX MILL PRODS. INC.	TX	-94.14222	33.45139		LATLON
47835	3341	331	COLUMBIA ALUMINUM PROCESSORS	TX	-96.4494	32.925	14	LATLON
T$11212	3341	331	ECS REFINING TEXAS L.L.C.	TX	-96.31332	32.72585		LATLON
CP0029G	3341	331	EXIDE CORPORATION	TX	-96.83353	33.13477	14	LATLON
T$11520	3341	331	FABRICATED PRODS./LONE STAR	TX	-95.26367	29.76901		LATLON
BL0029V	3341	331	GULF CHEMICAL & METALLURGICAL CORP	TX	-95.33824	28.95808	15	LATLON
T$11469	3341	331	GULF REDUCTION CORP. - ESPERSON DIV. OF U.S. ZINC	TX	-95.3125	29.74333		LATLON
T$11478	3341	331	GULF REDUCTION CORP. - GREENWOOD METAL DIV. OF	TX	-95.3125	29.74694		LATLON
490350006	3341	331	UTAH METAL WORKS	UT	-111.7694	40.79944		LATLON
13374	4911	2211	AGUA FRIA	AZ	-112.2175	33.55667		LATLON
13068-A	4911	2211	Apache Station	AZ	-109.9265	32.03034		LATLON
040131025	4911	2211	APS-CC PLANT PHOENIX	AZ	-112.1572	33.44444		LATLON
040131507	4911	2211	APS-OCOTILLO POWER PLANT	AZ	-111.9119	33.42222		LATLON
313	4911	2211	APS-OCOTILLO POWER PLANT	AZ	-111.9119	33.4225	12	LATLON
324	4911	2211	APS-WEST PHOENIX POWER PLANT	AZ	-112.1579	33.4447	12	LATLON
T$12400	4911	2211	ARIZONA ELECTRIC POWER COOPERATIVE INC.	AZ	-109.8917	32.06167		LATLON
040030037	4911	2211	ARIZONA ELECTRIC POWER COOPERATIVE, INC.	AZ	-109.8931	32.06167		LATLON
040131009	4911	2211	ARIZONA NUCLEAR POWER PROJECT	AZ	-113.4333	33.65		LATLON
040030123	4911	2211	ARIZONA PUBLIC SERVICE COMPANY (APS)	AZ	-109.5519	31.36333		LATLON
040270331	4911	2211	ARIZONA PUBLIC SERVICE COMPANY (APS)	AZ	-114.7094	32.72139		LATLON
040210033	4911	2211	ARIZONA PUBLIC SERVICE, SAGUARO PLANT	AZ	-111.2997	32.55167		LATLON
0400300037	4911	221112	AZ ELECTRIC POWER COOPERATIVE INC	AZ	-109.8896	32.06176	12	LATLON
13700-A	4911	2211	Cholla Power Plant	AZ	-110.3638	35.1869		LATLON
13712	4911	2211	CORONADO	AZ	-109.2717	34.57778		LATLON
13712-A	4911	2211	Coronado	AZ	-109.377	34.50642		LATLON
040131007	4911	2211	GROVE COGENERATION PROJECT	AZ	-112.1158	33.58389		LATLON
13135	4911	2211	IRVINGTON	AZ	-110.9042	32.15972		LATLON
13135-A	4911	2211	Irvington	AZ	-110.9065	32.16294		LATLON
13160	4911	2211	KYRENE	AZ	-111.9364	33.35444		LATLON
13568	4911	2211	NAVAJO	AZ	-111.3917	37.52361		LATLON
13568-A	4911	2211	Navajo	AZ	-111.4602	36.91629		LATLON
13248	4911	2211	OCOTILLO	AZ	-111.9417	33.44667		LATLON
98	4911	221113	PALO VERDE NUCLEAR GENERATING STATION	AZ	-112.8749	33.39567	12	LATLON
040190076	4911	2211	PIMA CO. WASTE WATER	AZ	-110.8694	32.15111		LATLON
13308	4911	2211	SAGUARO	AZ	-111.2992	32.55194		LATLON
040131500	4911	2211	SANTAN GENERATING PLANT_(SRP)	AZ	-111.7478	33.33028		LATLON
318	4911	2211	SANTAN GENERATING PLANT_(SRP)	AZ	-111.748	33.3306	12	LATLON
040131006	4911	2211	SCOTTSDALE PRINCESS RESORT HOTEL	AZ	-111.9083	33.64806		LATLON
322	4911	2211	SCOTTSDALE PRINCESS RESORT HOTEL	AZ	-112.5222	34.08889		LATLON
13638	4911	2211	SPRINGERVILLE	AZ	-109.1633	34.31833		LATLON
13638-A	4911	2211	Springerville	AZ	-109.5223	35.24095		LATLON
3316	4911	221112	SRP AGUA FRIA	AZ	-112.216	33.55593	12	LATLON
040131215	4911	2211	SRP-AGUA FRIA PWR PL	AZ	-112.2158	33.55389		LATLON
0400100060	4911	22111	TUCSON ELECTRIC POWER CO-SPRINGERVILLE	AZ	-109.1636	34.31857	12	LATLON
13387	4911	2211	YUMA AXIS	AZ	-113.9397	33.21972		LATLON

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080450057	4911	2211	AMERICAN ATLAS NO 1	CO	-107.7083	39.51917		LATLON
13079	4911	2211	Arapahoe	CO	-105.0007	39.66833		LATLON
13391	4911	2211	Cameo	CO	-108.3167	39.13306		LATLON
13400	4911	2211	CHEROKEE	CO	-105.9664	39.80806		LATLON
080410030	4911	2211	COLORADO SPRINGS NIXON	CO	-104.7092	38.63306		LATLON
0030	4911	2211	COLORADO SPRINGS UTILITIES - NIXON PLT	CO	-104.7059	38.6329	13	LATLON
0004	4911	2211	COLORADO SPRINGS UTILITIES-DRAKE PLT	CO	-104.8307	38.8242	13	LATLON
13410	4911	2211	Comanche	CO	-104.5744	38.20806		LATLON
13418-A	4911	2211	Craig	CO	-107.7723	40.6362		LATLON
13091	4911	2211	GEORGE BIRDSALL	CO	-104.5197	38.82972		LATLON
13112	4911	2211	Hayden	CO	-107.2582	40.49484		LATLON
1238	4911	2211	KN SERVICES - LAKEWOOD GENERATION FACILI	CO	-105.1327	39.7154	13	LATLON
13168	4911	2211	LAMAR	CO	-102.4006	37.95028		LATLON
080990006	4911	2211	LAMAR UTILITIES BOARD	CO	-102.6147	38.09028		LATLON
13194	4911	2211	Martin Drake	CO	-104.8331	38.82417		LATLON
11589-A	4911	2211	Nucla	CO	-108.5064	38.24238		LATLON
13259	4911	2211	Pawnee	CO	-103.6931	40.26917		LATLON
081230321	4911	2211	PHOENIX POWER PARTNERS	CO	-104.6864	40.40972		LATLON
11170	4911	2211	PLATTE RIVER POWER AUTH RAWHIDE	CO	-105.0474	40.8408	13	LATLON
0053	4911	2211	PLATTE RIVER POWER AUTHORITY - RAWHIDE	CO	-105.0474	40.8408	13	LATLON
0008	4911	2211	PUBLIC SERVICE CO - ARAPAHOE	CO	-105	39.6695	13	LATLON
0001	4911	2211	PUBLIC SERVICE CO - VALMONT	CO	-105.2062	40.0162	13	LATLON
0007	4911	2211	PUBLIC SERVICE CO ALAMOSA PLT	CO	-105.8831	37.4655	13	LATLON
080030007	4911	2211	PUBLIC SERVICE CO ALAMOSA STA	CO	-105.8831	37.46556		LATLON
080310008	4911	2211	PUBLIC SERVICE CO ARAPAHOE	CO	-104.9992	39.66972		LATLON
080770002	4911	2211	PUBLIC SERVICE CO CAMEO	CO	-108.315	39.14861		LATLON
0002	4911	2211	PUBLIC SERVICE CO CAMEO PLT	CO	-108.3154	39.1484	12	LATLON
8653	4911	2211	PUBLIC SERVICE CO CHEROKEE PLANT	CO	-104.9685	39.8056	13	LATLON
0001	4911	2211	PUBLIC SERVICE CO CHEROKEE PLT	CO	-104.9685	39.8056	13	LATLON
081010003	4911	2211	PUBLIC SERVICE CO COMANCHE	CO	-104.5706	38.21111		LATLON
0003	4911	2211	PUBLIC SERVICE CO COMANCHE PLT	CO	-104.5706	38.2107	13	LATLON
0023	4911	2211	PUBLIC SERVICE CO FORT SAINT VRAIN PLT	CO	-104.8742	40.2434	13	LATLON
080770035	4911	2211	PUBLIC SERVICE CO FRUITA	CO	-108.7325	39.15972		LATLON
0035	4911	2211	PUBLIC SERVICE CO FRUITA STA	CO	-108.7328	39.16	12	LATLON
081230014	4911	2211	PUBLIC SERVICE CO FT LUPTON	CO	-104.7722	40.10028		LATLON
0014	4911	2211	PUBLIC SERVICE CO FT LUPTON STATION	CO	-104.7724	40.1	13	LATLON
081230023	4911	2211	PUBLIC SERVICE CO FT ST VRAIN	CO	-104.8742	40.24333		LATLON
11193	4911	2211	PUBLIC SERVICE CO HAYDEN	CO	-107.185	40.4858	13	LATLON
0001	4911	2211	PUBLIC SERVICE CO HAYDEN PLT	CO	-107.185	40.4858	13	LATLON
080590059	4911	2211	PUBLIC SERVICE CO LOOKOUT CTR	CO	-105.2017	39.73361		LATLON
080870011	4911	2211	PUBLIC SERVICE CO PAWNEE	CO	-103.6833	40.21889		LATLON
0011	4911	2211	PUBLIC SERVICE CO PAWNEE PLT	CO	-103.6838	40.2189	13	LATLON
8661	4911	2211	PUBLIC SERVICE CO VALMONT	CO	-105.2062	40.0162	13	LATLON
8662	4911	2211	PUBLIC SERVICE CO ZUNI	CO	-105.0152	39.7362	13	LATLON
T$12092	4911	2211	RAWHIDE ENERGY STATION	CO	-105.0239	40.85944		LATLON
9748-A	4911	2211	Ray D. Nixon	CO	-104.6908	38.64485		LATLON
0250	4911	2211	THERMO COGEN PARTNERSHIP FT LUPTON	CO	-104.7724	40.1063	13	LATLON
0412	4911	2211	THERMO GREELEY INC	CO	-104.6864	40.443	13	LATLON

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0126	4911	2211	THERMO POWER & ELEC INC	CO	-104.6865	40.4097	13	LATLON
081250001	4911	2211	TRI STATE GENERATION & TRANSMISSION ASSN	CO	-102.2417	40.07917		LATLON
0003	4911	2211	TRI STATE GENERATION BURLINGTON	CO	-102.2412	39.3286	13	LATLON
0018	4911	2211	TRI STATE GENERATION CRAIG	CO	-107.5912	40.4639	13	LATLON
0001	4911	2211	TRI STATE GENERATION NUCLA	CO	-108.5169	38.2474	12	LATLON
T$12135	4911	2211	TRI-STATE GENERATION & TRANSMISSION - CRAIG	CO	-107.5903	40.46444		LATLON
T$12125	4911	2211	TRI-STATE GENERATION & TRANSMISSION - NUCLA	CO	-108.5064	38.24238		LATLON
13363	4911	2211	Valmont	CO	-105.206	40.01735		LATLON
081010008	4911	2211	WEST PLAINS ENERGY PUEBLO	CO	-104.6139	38.26528		LATLON
0003	4911	2211	WEST PLAINS ENERGY - W.N. CLARK STATION	CO	-105.2383	38.4393	13	LATLON
080890004	4911	2211	WEST PLAINS ENERGY ROCKY FORD PLT	CO	-103.7133	38.04917		LATLON
13388	4911	2211	ZUNI	CO	-105.0181	39.73722		LATLON
200330001	4911	2211	ANR PIPELINE CO.	KS	-99.37722	37.47806		LATLON
200770002	4911	2211	ANTHONY-MUNICIPAL POWER PLANT	KS	-98.08944	37.17306		LATLON
13110	4911	2211	ARTHUR MULLERGREN	KS	-98.86917	38.40528		LATLON
200250001	4911	2211	ASHLAND-MUNICIPAL POWER PLANT	KS	-99.81139	37.21722		LATLON
200770013	4911	2211	ATTICA-MUNICIPAL POWER PLANT	KS	-98.28806	37.27667		LATLON
200150009	4911	2211	AUGUSTA-MUNICIPAL POWER PLANT (#1)	KS	-97.04194	37.69694		LATLON
200150010	4911	2211	AUGUSTA-MUNICIPAL POWER PLANT (#2)	KS	-97.04194	37.69667		LATLON
200450011	4911	2211	BALDWIN-MUNICIPAL POWER PLANT	KS	-95.17833	38.79556		LATLON
201570016	4911	2211	BELLEVILLE-MUNICIPAL POWER PLANT	KS	-97.66028	39.85167		LATLON
201230012	4911	2211	BELOIT-MUNICIPAL POWER PLANT	KS	-98.15306	39.49444		LATLON
00008	4911	2211	BOARD OF PUBLIC UTILITIES - NEARMAN	KS	-94.70556	39.15639		LATLON
00048	4911	2211	BOARD OF PUBLIC UTILITIES - QUINDARO	KS	-94.64139	39.14833		LATLON
202090048	4911	2211	BOARD OF PUBLIC UTILITIES - QUINDARO	KS	-94.64056	39.14972		LATLON
201390012	4911	2211	BURLINGAME-MUNICIPAL POWER PLANT	KS	-95.80639	38.75222		LATLON
200310006	4911	2211	BURLINGTON-MUNICIPAL POWER PLANT	KS	-95.71167	38.18972		LATLON
13404	4911	2211	CIMARRON RIVER	KS	-100.9319	37.05917		LATLON
201330030	4911	2211	CITY OF CHANUTE ELEC. DEPT.- N. GARFIELD	KS	-95.45083	37.67389		LATLON
201330028	4911	2211	CITY OF CHANUTE ELEC. DEPT.- S. PLUMMER	KS	-95.40056	37.68833		LATLON
201330002	4911	2211	CITY OF CHANUTE ELEC. DEPT.-S. SANTA FE	KS	-95.40056	37.68833		LATLON
200930019	4911	2211	CITY OF LAKIN	KS	-101.2853	37.95222		LATLON
201910055	4911	2211	CITY OF OXFORD, MUNICIPAL POWER PLANT	KS	-97.17306	37.26806		LATLON
200270007	4911	2211	CLAY CENTER-MUNICIPAL POWER PLANT	KS	-97.14556	39.39556		LATLON
13406	4911	2211	COFFEYVILLE	KS	-95.54333	37.04722		LATLON
201930007	4911	2211	COLBY-MUNICIPAL POWER PLANT	KS	-101.1267	39.40583		LATLON
13446	4911	2211	EAST 12TH STREET PLA	KS	-97.07167	37.26306		LATLON
200090025	4911	2211	ELLINWOOD-MUNICIPAL POWER PLANT	KS	-98.62778	38.39528		LATLON
00002	4911	2211	EMPIRE DISTRICT ELECTRIC COMPANY (THE)	KS	-94.69861	37.07167		LATLON
202050018	4911	2211	FREDONIA-MUNICIPAL POWER PLANT	KS	-95.76	37.53556		LATLON
200910065	4911	2211	GARDNER ENERGY CENTER	KS	-94.92556	38.80833		LATLON
200030001	4911	2211	GARNETT-MUNICIPAL POWER PLANT	KS	-95.24806	38.26917		LATLON
200370006	4911	2211	GIRARD-MUNICIPAL POWER PLANT	KS	-94.79472	37.52528		LATLON
201810005	4911	2211	GOODLAND-MUNICIPAL POWER PLANT	KS	-101.7967	39.34778		LATLON
13098	4911	2211	GORDON EVANS	KS	-97.52167	37.79028		LATLON
200970007	4911	2211	GREENSBURG-MUNICIPAL POWER PLANT	KS	-99.32417	37.64056		LATLON
200410034	4911	2211	HERINGTON-MUNICIPAL POWER PLANT	KS	-96.99694	38.68306		LATLON
201530011	4911	2211	HERNDON-MUNICIPAL POWER PLANT	KS	-100.8708	39.91667		LATLON

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200650009	4911	2211	HILL CITY-MUNICIPAL POWER PLANT	KS	-99.91167	39.39194		LATLON
200090026	4911	2211	HOISINGTON-MUNICIPAL POWER PLANT	KS	-98.77639	38.51528		LATLON
13121	4911	2211	HOLCOMB	KS	-100.9717	37.93167		LATLON
13121-A	4911	2211	Holcomb	KS	-100.9921	37.92702		LATLON
200850011	4911	2211	HOLTON-MUNICIPAL POWER PLANT	KS	-95.74167	39.465		LATLON
201890020	4911	2211	HUGOTON-MUNICIPAL POWER PLANT (#1)	KS	-101.3519	37.18194		LATLON
201890021	4911	2211	HUGOTON-MUNICIPAL POWER PLANT (#2)	KS	-101.3519	37.18194		LATLON
13132	4911	2211	HUTCHINSON	KS	-97.86944	38.09417		LATLON
13134	4911	2211	IOLA	KS	-95.35417	37.93667		LATLON
200010011	4911	2211	IOLA-MUNICIPAL POWER PLANT (#1)	KS	-95.35417	37.93639		LATLON
200010019	4911	2211	IOLA-MUNICIPAL POWER PLANT (#2)	KS	-95.4225	37.93056		LATLON
13509	4911	2211	JEFFREY ENERGY CENTE	KS	-96.10833	39.28528		LATLON
13509-A	4911	2211	Jeffrey Energy Center	KS	-96.11281	39.28223		LATLON
200830005	4911	2211	JETMORE-MUNICIPAL POWER PLANT	KS	-99.93167	38.11583		LATLON
201870009	4911	2211	JOHNSON CITY MUN. POWER PLANT	KS	-101.7644	37.56556		LATLON
13153	4911	2211	JUDSON LARGE	KS	-99.94917	37.73278		LATLON
201070005	4911	2211	KANSAS CITY POWER & LIGHT CO.	KS	-94.64306	38.34667		LATLON
201730079	4911	2211	KANSAS GAS AND ELECTRIC CO.-WICHITA STA.	KS	-97.28083	37.66389		LATLON
00007	4911	2211	KANSAS STATE UNIVERSITY	KS	-96.5825	39.19417		LATLON
13154	4911	2211	KAW	KS	-94.65167	39.08639		LATLON
200950004	4911	2211	KINGMAN-MUNICIPAL POWER PLANT	KS	-98.17417	37.68139		LATLON
200410017	4911	2211	KPL GAS SERVICE (AEC)	KS	-97.24944	38.93306		LATLON
201550033	4911	2211	KPL GAS SERVICE (HEC)	KS	-97.86944	38.09417		LATLON
201770030	4911	2211	KPL GAS SERVICE (TEC)	KS	-95.56889	39.05444		LATLON
13526	4911	2211	LA CYGNE	KS	-94.64556	38.34806		LATLON
13526-A	4911	2211	La Cygne	KS	-94.84505	38.2133		LATLON
201650001	4911	2211	LACROSSE MUNICIPAL POWER PLANT	KS	-99.36472	38.56889		LATLON
13172	4911	2211	LARNED	KS	-99.14278	38.20694		LATLON
201450010	4911	2211	LARNED-MUNICIPAL POWER PLANT	KS	-99.14278	38.20694		LATLON
13174	4911	2211	LAWRENCE	KS	-95.26806	39.00778		LATLON
13174-A	4911	2211	Lawrence	KS	-95.27081	39.00079		LATLON
201050013	4911	2211	LINCOLN-MUNICIPAL POWER PLANT	KS	-98.19528	39.07417		LATLON
13198	4911	2211	MCPHERSON 2	KS	-97.68667	38.37167		LATLON
201130014	4911	2211	MCPHERSON BOARD OF PUBLIC UTILITIES #2	KS	-97.68667	38.37167		LATLON
201190013	4911	2211	MEADE-MUNICIPAL POWER PLANT	KS	-100.3589	37.38639		LATLON
200090001	4911	2211	MIDWEST ENERGY, INC.	KS	-98.81083	38.39556		LATLON
200230008	4911	2211	MIDWEST ENERGY, INC.	KS	-101.6439	39.75722		LATLON
200510012	4911	2211	MIDWEST ENERGY, INC.	KS	-99.31806	38.86694		LATLON
201930001	4911	2211	MIDWEST ENERGY, INC.	KS	-101.1267	39.40583		LATLON
201430013	4911	2211	MINNEAPOLIS-MUNICIPAL POWER PLANT	KS	-97.74778	39.1575		LATLON
201910025	4911	2211	MULVANE-MUNICIPAL POWER PLANT	KS	-97.23694	37.45917		LATLON
13563	4911	2211	MURRAY GILL	KS	-97.41333	37.42806		LATLON
23422-A	4911	2211	Nearman Creek	KS	-94.70565	39.15488		LATLON
202050014	4911	2211	NEODESHA-MUNICIPAL POWER PLANT	KS	-95.61028	37.42333		LATLON
201370005	4911	2211	NORTON-MUNICIPAL POWER PLANT	KS	-99.955	39.85556		LATLON
201090009	4911	2211	OAKLEY-MUNICIPAL POWER PLANT	KS	-100.9422	39.11917		LATLON
200390009	4911	2211	OBERLIN-MUNICIPAL POWER PLANT	KS	-100.6125	39.83417		LATLON
201390014	4911	2211	OSAGE CITY-MUNICIPAL POWER PLANT	KS	-95.80194	38.6375		LATLON

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201210001	4911	2211	OSAWATOMIE-MUNICIPAL POWER PLANT	KS	-94.91167	38.52444		LATLON
201410009	4911	2211	OSBORNE-MUNICIPAL POWER PLANT	KS	-98.7525	39.46833		LATLON
200590006	4911	2211	OTTAWA-MUNICIPAL POWER PLANT	KS	-95.24806	38.63833		LATLON
13276	4911	2211	PRATT	KS	-98.79444	37.68417		LATLON
201510005	4911	2211	PRATT-MUNICIPAL POWER PLANT	KS	-98.79444	37.68417		LATLON
13278-A	4911	2211	Quindaro	KS	-94.64111	39.14855		LATLON
201730128	4911	2211	RITCHIE SAND, INC.	KS	-97.46139	37.77528		LATLON
13299	4911	2211	RIVERTON	KS	-94.69833	37.07167		LATLON
13299-A	4911	2211	Riverton	KS	-94.73527	37.02401		LATLON
201670005	4911	2211	RUSSELL-MUNICIPAL POWER PLANT	KS	-98.90306	38.91722		LATLON
201310009	4911	2211	SABETHA-MUNICIPAL POWER PLANT	KS	-95.83417	39.89778		LATLON
201990005	4911	2211	SHARON SPRINGS-MUNICIPAL POWER PLANT	KS	-101.8153	38.88306		LATLON
200230009	4911	2211	ST. FRANCIS-MUNICIPAL POWER PLANT	KS	-101.9081	39.76556		LATLON
201850015	4911	2211	ST. JOHN-MUNICIPAL POWER PLANT	KS	-98.81167	38.03194		LATLON
201850017	4911	2211	STAFFORD-MUNICIPAL POWER PLANT	KS	-98.64667	38.00306		LATLON
201590024	4911	2211	STERLING MUNICIPAL POWER PLANT	KS	-98.25917	38.24806		LATLON
201630014	4911	2211	STOCKTON-MUNICIPAL POWER PLANT	KS	-99.33222	39.46806		LATLON
200550026	4911	2211	SUNFLOWER ELECTRIC POWER CORPORATION	KS	-100.8942	37.96917		LATLON
13347	4911	2211	TECUMSEH	KS	-95.56889	39.05444		LATLON
13347-A	4911	2211	Tecumseh	KS	-95.5663	39.0516		LATLON
201490012	4911	2211	WAMEGO-MUNICIPAL POWER PLANT	KS	-96.30694	39.19722		LATLON
202010024	4911	2211	WASHINGTON-MUNICIPAL POWER PLANT	KS	-97.07778	39.82917		LATLON
13376	4911	2211	WELLINGTON	KS	-97.47028	37.28306		LATLON
201910056	4911	2211	WELLINGTON CITY POWER PLANT, GAS TURBINE	KS	-97.36444	37.27139		LATLON
201910019	4911	2211	WELLINGTON-MUNICIPAL POWER PLANT	KS	-97.47028	37.28306		LATLON
201750001	4911	2211	WEST PLAINS ENERGY	KS	-100.9319	37.05917		LATLON
202010012	4911	2211	WEST PLAINS ENERGY	KS	-97.30917	39.58694		LATLON
23413	4911	2211	WEST PLAINS ENERGY	KS	-98.8694	38.4052	14	LATLON
00014	4911	2211	WESTERN RESOURCES, INC.	KS	-95.28361	39.00056		LATLON
00033	4911	2211	WESTERN RESOURCES, INC. (HEC)	KS	-97.87639	38.08639		LATLON
200350006	4911	2211	WINFIELD MUNICIPAL POWER PLANT (OLD)	KS	-97.07167	37.26306		LATLON
13438	4911	2211	ANIMAS	NM	-108.3297	36.50972		LATLON
350450029	4911	2211	CITY OF FARMINGTON/ANIMAS PLANT___1061R1	NM	-108.1928	36.72806		LATLON
13423	4911	2211	CUNNINGHAM	NM	-103.3531	32.71306		LATLON
0032	4911	2211	Escalante	NM	-108.0815	35.416	12	LATLON
13086	4911	2211	FOUR CORNERS	NM	-108.4819	36.69056		LATLON
13086-A	4911	2211	Four Corners	NM	-108.4362	36.75341		LATLON
T$12460	4911	2211	FOUR CORNERS STEAM ELECTRIC STATION	NM	-108.4819	36.69139		LATLON
350250028	4911	2211	LEA COUNTY ELEC COOP/CUNNINGHAM_______GF	NM	-103.3197	32.97833		LATLON
350230001	4911	2211	LORDSBURG LTD/REPOWERING PRJCT___PSD90M1	NM	-108.6942	32.33778		LATLON
13189	4911	2211	MADDOX	NM	-103.3017	32.71306		LATLON
350310027	4911	2211	MERRION OIL & GAS/PAPERS WASH ELEC_949M1	NM	-107.3253	35.85333		LATLON
350130025	4911	2211	NMSU/PHYSICAL PLANT BOILERS_________1640	NM	-106.7531	32.27944		LATLON
0025	4911	2211	Physical Plant Boilers	NM	-106.753	32.2798	13	LATLON
350470004	4911	2211	PUBLIC SERV CO NM/LAS VEGAS GEN STA___GF	NM	-105.2317	35.60528		LATLON
12917	4911	2211	RATON	NM	-104.6506	36.60139		LATLON
13288	4911	2211	REEVES	NM	-106.5	36.33306		LATLON
13603	4911	2211	RIO GRANDE	NM	-106.5469	31.80444		LATLON

strStateFacilit	strSIC	strNAICS	strFacilityName	srtState	dblXCoord	dblYCoord	intUTMZo	strXYCoor
0002	4911	2211	Rio Grande Generating Station	NM	-106.5464	31.8017	13	LATLON
13618	4911	2211	SAN JUAN	NM	-108.4831	36.88306		LATLON
13618-A	4911	2211	San Juan	NM	-108.4821	36.7616		LATLON
350490017	4911	2211	SANTA FE COGEN ASSOC________________620	NM	-106.0481	35.55583		LATLON
350250054	4911	2211	SOUTHWESTERN PUBL SERV/CUNNINGH PSD622M1	NM	-103.3564	32.7175		LATLON
350250034	4911	2211	SOUTHWESTERN PUBL SERV/MADDOX STN____747	NM	-103.3031	32.71694		LATLON
350370002	4911	2211	SOUTHWESTERN PUBL SERV/TUCUMCARI___586M1	NM	-103.7369	35.175		LATLON
1011	4911	2211	AES Shady Point, Inc.	OK	-94.6466	35.1972	15	LATLON
13427	4911	2211	ANADARKO	OK	-98.22556	35.08417		LATLON
13313	4911	2211	BOOMER LAKE	OK	-96.98722	36.09389		LATLON
400310703	4911	2211	CENTRAL AND SOUTH WEST SERVICES, IN	OK	-98.32417	34.54306		LATLON
1211	4911	2211	Central and South West Services, Inc. - Comanche Power	OK	-98.3246	34.5435	14	LATLON
1212	4911	2211	Central and South West Services, Inc. - Northeastern Power	OK	-95.6992	36.426	15	LATLON
1213	4911	2211	Central and South West Services, Inc. - Riverside/Jenks Power	OK	-95.9566	35.9995	15	LATLON
1214	4911	2211	Central and South West Services, Inc. - Southwestern Power	OK	-98.3523	35.1009	14	LATLON
1215	4911	2211	Central and South West Services, Inc. - Tulsa Power Station	OK	-95.9903	36.1159	15	LATLON
1216	4911	2211	Central and South West Services, Inc. - Weleetka Power	OK	-96.1357	35.3261	14	LATLON
13411	4911	2211	COMANCHE	OK	-98.32417	34.54306		LATLON
1799	4911	2211	Grand River Dam Authority	OK	-95.2898	36.1913	15	LATLON
13103	4911	2211	GRDA	OK	-95.28917	36.18889		LATLON
13103-A	4911	2211	GRDA	OK	-95.33031	36.19272		LATLON
13488	4911	2211	HORSESHOE LAKE	OK	-97.17944	35.50222		LATLON
13492-A	4911	2211	Hugo	OK	-95.3167	34.0292		LATLON
13213	4911	2211	MOORELAND	OK	-99.22056	36.7375		LATLON
13224	4911	2211	MUSKOGEE	OK	-95.29528	35.76722		LATLON
13566-A	4911	2211	Muskogee	OK	-95.29613	35.7713		LATLON
13225	4911	2211	MUSTANG	OK	-97.67472	35.48139		LATLON
13241	4911	2211	NORTHEASTERN	OK	-95.69806	36.43194		LATLON
13241-A	4911	2211	Northeastern	OK	-95.71181	36.43913		LATLON
T$11045	4911	2211	NORTHEASTERN STATION	OK	-95.70084	36.43167		LATLON
401090052	4911	2211	OG & E TINKER	OK	-97.90056	35.24		LATLON
400470702	4911	2211	OG&E	OK	-97.87417	36.36917		LATLON
401090010	4911	2211	OG&E-HORSESHOE PLANT	OK	-97.17917	35.50833		LATLON
401330702	4911	2211	OG&E-SEMINOLE POWER PLANT	OK	-96.72472	34.96556		LATLON
2209	4911	2211	Oklahoma Gas & Electric	OK	-95.2869	35.7619	15	LATLON
2211	4911	2211	Oklahoma Gas & Electric	OK	-97.0517	36.4542	14	LATLON
13269	4911	2211	PONCA	OK	-97.15056	36.82		LATLON
401070700	4911	2211	PUBLIC SERVICE CO.	OK	-96.13083	35.32583		LATLON
13297	4911	2211	RIVERSIDE	OK	-95.95167	35.98556		LATLON
13624	4911	2211	SEMINOLE	OK	-96.72556	34.96639		LATLON
13637	4911	2211	SOONER	OK	-97.04972	36.45417		LATLON
13637-A	4911	2211	Sooner	OK	-97.12142	36.46992		LATLON
13331	4911	2211	SOUTHWESTERN	OK	-98.35306	35.10139		LATLON
13356	4911	2211	TULSA	OK	-95.99056	36.11639		LATLON
2700	4911	2211	Western Farmers Electric Coop Hugo	OK	-95.3197	34.0136	15	LATLON
13244-A	4911	2211	Big Brown	TX	-96.14939	31.72349		LATLON
481610004	4911	2211	BIG BROWN STATION	TX	-96.1418	31.712		LATLON
T$11331	4911	2211	BIG BROWN STEAM ELECTRIC STATION & LIGNITE MINE	TX	-96.05611	31.82056		LATLON

strStateFacilit	strSIC	strNAICS	strFacilityName	srtState	dblXCoord	dblYCoord	intUTMZo	strXYCoor
PA0003W	4911	2211	BRAZOS ELECTRIC POWER COOPERATIVE IN	TX	-98.30854	32.65814	14	LATLON
HG1169O	4911	2211	CALPINE CORPORATION	TX	-95.06532	29.62571	15	LATLON
GF0002R	4911	2211	CENTRAL SOUTH WEST SERVICES INC	TX	-97.21423	28.7129	14	LATLON
480830002	4911	2211	CITY OF COLEMAN	TX	-99.4588	31.76063		LATLON
BG0057U	4911	2211	CITY PUBLICSERVICE	TX	-98.32026	29.30802	14	LATLON
13705	4911	2211	COLETO CREEK	TX	-97.21417	28.71278		LATLON
13705-A	4911	2211	Coleto Creek	TX	-97.21632	28.73652		LATLON
484250001	4911	2211	COMANCHE PEAK POWER PLANT	TX	-97.47139	32.17528		LATLON
13456	4911	2211	GIBBONS CREEK	TX	-96.1375	30.61667		LATLON
13456-A	4911	2211	Gibbons Creek	TX	-96.0778	30.6167		LATLON
T$11304	4911	2211	H.W. PIRKEY POWER PLANT	TX	-94.48278	32.4625		LATLON
13157	4911	2211	KNOX LEE	TX	-94.64306	32.37417		LATLON
T$11951	4911	2211	L.C.R.A. FAYETTE POWER PROJECT	TX	-96.75306	29.91917		LATLON
13178	4911	2211	LIMESTONE	TX	-96.25528	31.42306		LATLON
T$11333	4911	2211	LIMESTONE ELECTRIC GENERATING STATION	TX	-96.26167	31.41083		LATLON
55505	4911	2211	LOWER COLORADO RIVER AUTHORITY	TX	-97.2723	30.0616	14	LATLON
FC0018G	4911	2211	LOWER COLORADO RIVER AUTHORITY	TX	-96.75057	29.91745	14	LATLON
T$11320	4911	2211	MARTIN LAKE STEAM ELECTRIC STATION & LIGNITE	TX	-94.57584	32.26111		LATLON
484490004	4911	2211	MONTICELLO STATION	TX	-95.02	33.05444		LATLON
T$11277	4911	2211	MONTICELLO STEAM ELECTRIC STATION & LIGNITE MINE	TX	-95.04166	33.09167		LATLON
13232	4911	2211	NEWMAN	TX	-106.4314	31.98306		LATLON
T$12027	4911	2211	NEWMAN POWER STATION	TX	-106.395	31.93399		LATLON
481410028	4911	2211	NEWMAN STATION	TX	-106.2228	31.45306		LATLON
T$11892	4911	2211	O.W. SOMMERS/J.T. DEELY/J.K. SPRUCE GENERATING	TX	-98.33583	29.32028		LATLON
13580	4911	2211	OKLAUNION	TX	-99.17528	34.14028		LATLON
13580-A	4911	2211	Oklaunion	TX	-99.30041	34.15378		LATLON
T$11436	4911	2211	OKLAUNION POWER STATION	TX	-99.17694	34.08333		LATLON
13257	4911	2211	PAINT CREEK	TX	-99.57778	33.08083		LATLON
13265	4911	2211	PIRKEY	TX	-94.46778	32.44556		LATLON
13265-A	4911	2211	Pirkey	TX	-94.58171	32.53524		LATLON
HT0065Q	4911	2211	POWER RESOURCES LTD	TX	-101.4222	32.27277	14	LATLON
FG0020V	4911	2211	RELIANT ENERGY INC	TX	-95.63411	29.47652	15	LATLON
LI0027L	4911	2211	RELIANT ENERGY INC	TX	-96.25341	31.42341	14	LATLON
13616	4911	2211	SAM SEYMOUR	TX	-96.75417	29.925		LATLON
13616-A	4911	2211	Sam Seymour	TX	-96.87554	29.91007		LATLON
13617	4911	2211	SAN ANGELO	TX	-100.4919	31.39306		LATLON
484510007	4911	2211	SAN ANGELO POWER STATION	TX	-100.0644	31.42167		LATLON
13619	4911	2211	SAN MIGUEL	TX	-98.47194	28.70889		LATLON
13619-A	4911	2211	San Miguel	TX	-98.4722	28.7089		LATLON
AG0007G	4911	2211	SAN MIGUEL ELCTRC COOPERATIVE INC	TX	-98.47229	28.70915	14	LATLON
483310002	4911	2211	SANDOW STATION	TX	-96.96548	30.78385		LATLON
T$11457	4911	2211	SANDOW STEAM ELECTRIC STATION	TX	-97.01197	30.65274		LATLON
13325	4911	2211	SIM GIDEON	TX	-97.27083	30.06056		LATLON
VC0026O	4911	2211	SOUTH TEXASELECTRIC COOPERATIVE INC	TX	-97.13592	28.89386	14	LATLON
GJ0043K	4911	2211	SOUTHWESTERN ELECTRIC POWER CO	TX	-94.64216	32.37419	15	LATLON
HH0037F	4911	2211	SOUTHWESTERN ELECTRIC POWER CO	TX	-94.46794	32.44564	15	LATLON
ME0006A	4911	2211	SOUTHWESTERN ELECTRIC POWER CO	TX	-94.54684	32.84868	15	LATLON
TF0012D	4911	2211	SOUTHWESTERN ELECTRIC POWER CO	TX	-94.84575	33.05838	15	LATLON

strStateFacilit	strSIC	strNAICS	strFacilityName	srtState	dblXCoord	dblYCoord	intUTMZo	strXYCoor
LB0047N	4911	2211	SOUTHWESTERN PUBLIC SERVICE CO	TX	-102.575	34.18164	13	LATLON
PG0041R	4911	2211	SOUTHWESTERN PUBLIC SERVICE CO	TX	-101.7462	35.29962	14	LATLON
T$11964	4911	2211	SOUTHWESTERN PUBLIC SERVICE CO. HARRINGTON	TX	-101.7467	35.29944		LATLON
T$11974	4911	2211	SOUTHWESTERN PUBLIC SERVICE CO. - TOLK STATION	TX	-102.5686	34.18472		LATLON
13343	4911	2211	T C FERGUSON	TX	-98.36917	30.55639		LATLON
GB0153Q	4911	2211	TEXAS CITY COGENERATION LP	TX	-94.9416	29.37886	15	LATLON
RI0035C	4911	2211	TEXAS NEW MEXICO POWER CO	TX	-96.69556	31.09322	14	LATLON
13351	4911	2211	TOLK STATION	TX	-102.5744	34.18139		LATLON
FB0025U	4911	2211	TX UTILITIES ELECTRIC CO	TX	-96.36733	33.63033	14	LATLON
HQ0012T	4911	2211	TXU ELECTRIC CO	TX	-97.68801	32.40537	14	LATLON
CP0065C	4911	2211	TXU ELECTRIC CO	TX	-96.81328	33.19956	14	LATLON
DB0249H	4911	2211	TXU ELECTRIC CO	TX	-96.54544	32.83763	14	LATLON
HM0017H	4911	2211	TXU ELECTRIC CO	TX	-96.10114	32.12639	14	LATLON
DB0251U	4911	2211	TXU ELECTRIC CO	TX	-96.97458	32.95025	14	LATLON
DB0252S	4911	2211	TXU ELECTRIC CO	TX	-96.93597	32.72499	14	LATLON
DB0253Q	4911	2211	TXU ELECTRIC CO	TX	-96.72273	32.77844	14	LATLON
CJ0026J	4911	2211	TXU ELECTRIC CO	TX	-94.98954	31.94187	15	LATLON
RE0012M	4911	2211	TXU ELECTRIC CO	TX	-95.15492	33.40181	15	LATLON
TF0013B	4911	2211	TXU ELECTRIC CO	TX	-95.03736	33.09243	15	LATLON
RL0020K	4911	2211	TXU ELECTRIC CO	TX	-94.57022	32.26071	15	LATLON
FI0020W	4911	2211	TXU ELECTRIC CO	TX	-96.0549	31.82158	14	LATLON
TA0352I	4911	2211	TXU ELECTRIC CO	TX	-97.47945	32.90547	14	LATLON
TA0354E	4911	2211	TXU ELECTRIC CO	TX	-97.33653	32.76111	14	LATLON
TA0353G	4911	2211	TXU ELECTRIC CO	TX	-97.22197	32.72918	14	LATLON
YB0017V	4911	2211	TXU ELECTRIC CO	TX	-98.61226	33.13643	14	LATLON
MM0023J	4911	2211	TXU ELECTRIC CO	TX	-97.05813	30.5681	14	LATLON
MB0117A	4911	2211	TXU ELECTRIC CO	TX	-96.98526	31.46673	14	LATLON
MO0014L	4911	2211	TXU ELECTRIC CO	TX	-100.916	32.3346	14	LATLON
WC0028Q	4911	2211	TXU ELECTRIC CO	TX	-102.9574	31.58346	13	LATLON
13368	4911	2211	W A PARISH	TX	-95.63167	29.48389		LATLON
13368-A	4911	2211	W A Parish	TX	-95.7641	29.5695		LATLON
481570011	4911	2211	W. A. PARISH STATION	TX	-95.25139	29.47167		LATLON
T$11617	4911	2211	W.A. PARISH ELECTRIC GENERATING STATION	TX	-95.63417	29.47528		LATLON
13675	4911	2211	WELSH	TX	-94.84556	33.05806		LATLON
WI0025C	4911	2211	WEST TEXAS UTILITIES CO	TX	-99.18023	34.083	14	LATLON
13379	4911	2211	WILKES	TX	-94.54667	32.84833		LATLON
12922	4911	2211	Bonanza	UT	-109.2831	40.08306		LATLON
T$12223	4911	2211	BONANZA POWER PLANT	UT	-109.2844	40.08639		LATLON
12997	4911	2211	Carbon	UT	-110.8639	39.72639		LATLON
10081	4911	2211	Carbon Power Plant	UT	-110.8524	39.66883		LATLON
490470001	4911	2211	DESERET - BONANZA	UT	-109.3173	40.1177	0	LATLON
490350044	4911	2211	ELECTRICAL GENERATION PLANT	UT	-111.906	40.6737		LATLON
10355	4911	2211	Gadsby Power Plant	UT	-111.93	40.77138		LATLON
11539	4911	2211	Hildale City Cogeneration Facility	UT	-113.1402	37.2278		LATLON
12799	4911	2211	Hunter	UT	-111.0188	39.21085		LATLON
10237	4911	2211	Hunter Power Plant	UT	-111.0188	39.21085		LATLON
12800	4911	2211	Huntington	UT	-111.075	39.37917		LATLON
10238	4911	2211	Huntington Power Plant	UT	-110.963	39.32856		LATLON

strStateFacilit	strSIC	strNAICS	strFacilityName	srtState	dblXCoord	dblYCoord	intUTMZo	strXYCoor
10327	4911	2211	Intermountain Generation Station	UT	-112.5681	39.49323		LATLON
490579088	4911	2211	LITTLE MOUNTAIN COGENERATION FACILITY	UT	-111.9563	41.24985		LATLON
13088	4911	2211	PACIFCORP GADSBY	UT	-111.9292	40.76667		LATLON
10120	4911	2211	Power Plant	UT	-111.8847	40.88658		LATLON
490490018	4911	2211	PROVO CITY POWER CO.	UT	-111.6664	40.2625		LATLON
490530011	4911	2211	ST GEORGE POWER	UT	-113.66	37.12861		LATLON
10892	4911	2211	St. George City Power Plant	UT	-113.5655	37.11274		LATLON
T$12281	4911	2211	SUNNYSIDE COGENERATION ASSOCIATES	UT	-110.3917	39.54722		LATLON
490490072	4911	2211	WHITEHEAD POWER PLANT	UT	-111.6186	40.17611		LATLON
5603100001	4911	2211	BASIN ELECTRIC_LARAMIE RIVER STATION	WY	-104.8768	42.1119	13	LATLON
T$12151	4911	2211	BHPL-OSAGE POWER PLANT	WY	-104.4097	43.97167		LATLON
5604500005	4911	2211	BLACK HILLS OSAGE	WY	-104.4081	43.9672	13	LATLON
5600500002	4911	2211	BLACK HILLS POWER & LGHT SIMPSON 1	WY	-105.387	44.2867	13	LATLON
58184-A	4911	2211	BLACK HILLS POWER & LGT-SIMPSON 2	WY	-105.4991	44.25329		LATLON
13722	4911	2211	DAVE JOHNSTON	WY	-105.7667	42.83306		LATLON
13722-A	4911	2211	Dave Johnston	WY	-105.8477	42.87368		LATLON
T$12140	4911	2211	LARAMIE RIVER STATION	WY	-104.8806	42.10833		LATLON
58145-A	4911	2211	Laramie River Station	WY	-104.8819	42.10436		LATLON
13228	4911	2211	Naughton	WY	-110.5425	41.79367		LATLON
T$12159	4911	2211	PACIFICORP, NAUGHTON POWER PLANT	WY	-110.5986	41.75722		LATLON
5600900001	4911	2211	PACIFICORP_DAVE JOHNSTON	WY	-105.7747	42.843	13	LATLON
5603701002	4911	2211	PACIFICORP_JIM BRIDGER	WY	-108.7948	41.7375	12	LATLON
5602300004	4911	221112	PACIFICORP_NAUGHTON POWER PLANT	WY	-110.5961	42.8489	12	LATLON
5600500046	4911	2211	PACIFICORP_WYODAK	WY	-105.3862	44.2903	13	LATLON
58233-A	4911	2211	PACIFICORP-JIM BRIDGER	WY	-108.9567	41.6029	12	LATLON
58137-A	4911	2211	Wyodak	WY	-105.3848	44.28926		LATLON
T$12153	4911	2211	WYODAK PLANT	WY	-105.3848	44.28926		LATLON
1639	3211	327211	Visteon	OK	-95.8318	36.0835	15	LATLON
1057	3221	327213	Anchor Glass Container Corporation	OK	-95.9694	35.4476	15	LATLON
1144	3221	327213	Bartlett-Collins Glass Company	OK	-96.1037	35.9929	14	LATLON
1826	3241	327310	Holnam, Inc.	OK	-96.6933	34.773	14	LATLON
401310703	3241	327310	BLUE CIRCLE CEMENT (LaFarge?)	OK	-95.81306	36.19417		LATLON
T$11100	3241	327310	LONE STAR IND. INC. PRYOR CEMENT PLANT	OK	-95.22166	36.27194		LATLON
BSCP134	3251	327121	Commercial Brick Corp	OK	-96.54583	35.175		LATLON
BSCP76	3251	327121	Scott Jewett Truck Line, Inc	OK	-99.5	34.9		LATLON
BSCP95	3251	327121	Justin Industries	OK	-97.63361	35.6025		LATLON
BSCP96	3251	327121	Justin Industries	OK	-95.93	36.18		LATLON
T$11108	3251	327	BORAL BRICKS INC. - MUSKOGEE PLANT	OK	-95.4	35.69167		LATLON
CC87	3253	327122	Laufen International	OK	-95.92182	36.24933		LATLON
T$10977	3275	327420	UNITED DESIGN CORP. NOBLE FAC.	OK	-97.40556	35.15694		LATLON
1219	3295	2123	Chandler Materials Co.	OK	-95.8206	36.1853	15	LATLON
10303	3241	327310	Ash Grove Leamington Cement Plant	UT	-112.8154	39.6627		LATLON
490290001	3241	327310	HOLNAM INC.-Devil Slide Plant	UT	-111.5142	41.06778		LATLON
BSCP154	3251	327121	Pacific Coast Building Products	UT	-112.0611	40.59444		LATLON
BSCP71	3251	327121	Interpace Industries Inc	UT	-111.9942	41.28388		LATLON
490450051	3255	327124	A.P.GREEN REFRACTORIES - SILICA STONE QU	UT	-113.1058	40.49005		LATLON
490490007	3255	327124	A.P.GREEN REFRACTORIES - LEHI PLANT	UT	-111.5237	40.1895		LATLON

U.S. GAS TREATING PLANTS (By State & Operator)

Prepared by GTI

Operator	State	Plantname	EPA ID	Lat	Long	IXCoordina	IYCoordina	Installed Capacity MMcf/d	Design Inlet CO2 Mol%	Inlet CO2 Mol%	Design Inlet H2S Mol%	Inlet H2S Mol%
AMOCO PROD. CO.	CO	WATTENBERG	http://maps.epa.go	39.7453	104.6781	-104.678	39.7448	175	Unknown	2.99	Unknown	0
AMOCO PROD. CO.	CO	FLORIDA RIVER COMPRESSION	http://maps.epa.go	37.1564	107.7792			250	3.50	3	0.00	0
CHEVRON USA	CO	RANGELY	http://maps.epa.go	40.1044	108.9286	-108.928	40.1042	6				
CONOCO	CO	DRAGON TAIL	http://maps.epa.go	39.8297	108.7903			20	0.60	0.72	0.00	0
GRACE PETROLEUM CORP.	CO	COLORADO						5				
KOCH HYDROCARBON CO.	CO	COLORADO						0				
NORTHWEST PIPELINE CO	CO	PICEANCE CREEK	http://maps.epa.go	40.0408	108.2664	-108.266	40.0406	15	Unknown	Unknown	Unknown	Unknown
NORTHWEST PIPELINE CORP.	CO	IGNACIO	http://maps.epa.go	37.1456	107.7839	-107.784	37.1449	347	1.57	Unknown	0.00	Unknown
NORTHWEST PIPELINE CORP.	CO	NORTH DOUGLAS CREEK	http://maps.epa.go	39.9606	108.7742	-108.676	40.1336	20	Unknown	0.42	Unknown	Unknown
NORTHWEST PIPELINE CORP.	CO	FOUNDATION CREEK				-108.803	39.6731	20	6.98	2.733	Unknown	Unknown
POLUMBUS	CO	UNKNOWN (KLINE)							Unknown		Unknown	
QUESTAR PIPELINE	CO	SKULL CREEK						40	Unknown		Unknown	
RKY. MT. NATURAL GAS	CO	SLICK ROCK				-108.893	38.0206	25				
UNION PACIFIC RESOURCES	CO	BLEDSOE RANCH	http://maps.epa.go	38.9544	103.0589	-103.059	38.9541	2	Unknown	1.25	Unknown	0
UNION PACIFIC RESOURCES	CO	MT. PEARL	http://maps.epa.go	38.8739	102.7522	-102.752	38.8738	2	0.87	0.93	0.00	0
UNION PACIFIC RESOURCES	CO	ARAPAHOE	http://maps.epa.go	38.8300	102.6100	-102.795	38.7664	8	3.75	Unknown	0.00	Unknown
UNKNOWN	CO	HANCOCK						40				
AMOCO PROD. CO.	KS	ULYSSES				-101.351	37.5792	400	Unknown	0.02	Unknown	0
ANADARKO PETROLEUM CORP.	KS	CIMARRON RIVER				-100.932	37.0592	15	0.18	0.12	0.00	0
ANADARKO PETROLEUM CORP.	KS	WOODS						10	0.08	0.15	0.00	0
COLORADO INTERST. GAS CO.	KS	LAKIN						216	0.02	0.02	0.00	0
COLORADO INTERST. GAS CO.	KS	MORTON COUNTY						25	0.60	0.15	0.00	0
INTERNORTH	KS	BUSHTON						130				
KAN-NEB NAT. GAS	KS	PAWNEE						20				
MESA LIMITED PARTNERSHIP	KS	ULYSSES				-101.351	37.5792	251	0.01	0.025	0.00	0
NATIIONAL HELIUM	KS	NATIONAL HELIUM PLANT						850	0.60	0.31	Unknown	Unknown
TEXACO INC.	KS	MINNEOLA						25	0.20	0.2	0.00	0
AMOCO PROD. CO.	NM	EMPIRE ABO				-104.263	32.7717	20	Unknown	0.8	Unknown	2.09
CHEVRON USA (WARREN)	NM	VADA				-103.544	33.4342	40				
CHEVRON USA (WARREN)	NM	EUNICE				-103.144	32.4258	70	Unknown	Unknown	Unknown	Unknown
CHEVRON USA (WARREN)	NM	MONUMENT				-103.144	32.4258	77	Unknown		Unknown	
CHEVRON USA (WARREN)	NM	SAUNDERS				-103.308	32.6106	26				
CITIES SERVICE OIL & GAS CO.	NM	EMPIRE ABO				-103.61	33.0569	4				
CONOCO	NM	MALJAMAR				-103.768	32.8125	200	0.49	1.64	0.00	0.1
CONOCO	NM	SAN JUAN				-107.959	36.7317	500	1.13	1.5	0.00	0
EL PASO NATURAL GAS CO.	NM	EUNICE				-103.454	32.2996	152				
EL PASO NATURAL GAS CO.	NM	JAL				-103.21	32.0661	76				
EL PASO NATURAL GAS CO.	NM	JAL 1				-103.21	32.0661	120				
EL PASO NATURAL GAS CO.	NM	JAL 3				-103.176	32.1742	100				
EL PASO NATURAL GAS CO.	NM	JAL 4				-103.195	32.2553	185				
EL PASO NATURAL GAS CO.	NM	MONUMENT				-103.308	32.6106	180				
GAS CO. OF NEW MEXICO	NM	AVALON				-104.209	32.5025	30	1.00	Unknown	0.00	Unknown
GAS CO. OF NEW MEXICO (SUNTERRA)	NM	LYBROOK PLANT				-107.545	36.2319	70	0.71	0.65	0.00	Unknown
GAS CO. OF NEW MEXICO (SUNTERRA)	NM	KUTZ II PLANT				-107.954	36.6683	80	1.16	1.24	0.00	Unknown
GETTY OIL	NM	NEW MEXICO						100				
GMP GAS CORP.	NM	ARTESIA				-104.231	32.7625	54	Unknown	Unknown	Unknown	Unknown
GPM GAS CORP.	NM	EUNICE				-103.299	32.5206	100	Unknown	Unknown	Unknown	Unknown

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GPM GAS CORP.	NM	LEE				-103.514	32.8053	42	Unknown	Unknown	Unknown	Unknown
INTERNORTH	NM	HOBBS				-103.358	32.7131	220	Unknown		Unknown	
MARATHON OIL CO.	NM	INDIAN BASIN				-104.574	32.4664	130	Unknown		Unknown	
NORTHWEST PIPELINE CO. (WILLIAMS)	NM	MILAGRO						320	10.00	10	Unknown	Unknown
OXY NGL, INC.	NM	BLUITT				-103.238	33.6206	37	Unknown	Unknown	Unknown	Unknown
PERRY GAS	NM	ANTELOPE RIDGE				-103.454	32.2996	20				
RICHARDSON, SID CARBON & GASOLINE	NM	JAL #3				-103.176	32.1742	200	Unknown	1.57	Unknown	0.56
SO. UNION	NM	KUTZ CANYON				-107.954	36.6683	82				
SO. UNION	NM	LYBROOK				-107.545	36.2319	72				
SUNTERRA GAS PROCESSING CO.	NM	KUTZ CANYON				-107.954	36.6683	70	0.36	1.41	0.00	Unknown
TEXACO INC.	NM	EUNICE COMPLEX				-103.158	32.3614	140	Unknown	1.5	Unknown	0.34
TEXACO, MIDLAND	NM	BUCKEYE				-103.508	32.7844	23	Unknown	3.4	Unknown	1.4
TRANSWESTERN	NM	BELL LAKE						30				
TRANSWESTERN	NM	YATES				-104.198	33.4286	10				
AMOCO PROD. CO.	OK	HITCHCOCK						55	0.45	Unknown	0.00	0
AMOCO PROD. CO.	OK	WILBURTON TREATING						24	3.95	Unknown	0.00	Unknown
AMOCO PROD. CO.	OK	MOORELAND				-99.1574	36.4408	130	Unknown	0.6	Unknown	0
ANADARKO PETROLEUM CORP.	OK	PANTHER CREEK				-97.4716	34.7079	15	0.23	0.36	0.00	0
ANADARKO PETROLEUM CORP.	OK	NORTH RICHLAND CTR						25	Unknown	0.22	Unknown	0
ANDARKO GATHERING SYSTEM	OK	BURNS FLAT						15	0.49	1.18	Unknown	Unknown
AQUILLA ENERGY CORP	OK	ELK CITY						100	0.50	0.85	0.00	0
CENTANA ENERGY CORP.	OK	SEILING GAS PLANT						75	0.60	0.92	Unknown	Unknown
CHEVRON USA (WARREN)	OK	MOCANE				-100.396	36.8989	175				
CHEVRON USA (WARREN)	OK	KINGFISHER				-97.7328	35.7908	15				
CHEVRON USA (WARREN)	OK	KNOX						50				
CHEVRON USA (WARREN)	OK	LEEDEY				-99.4659	35.8092	50				
COASTAL OIL & GAS CO.	OK	STURGIS						30	0.01	1.2	0.00	0
COASTAL OIL & GAS CO.	OK	CUSTER				-98.8918	35.6496	200	Unknown	Unknown	Unknown	Unknown
CONOCO	OK	MUSTANG				-97.6747	35.4814	30	0.35	0.61	0.00	0
CONOCO	OK	CASHION						30	0.35	0.48	0.00	0
CONOCO	OK	HENNESSEY				-97.9028	36.0719	30	0.21	0.32	0.00	0
DELHI GAS PIPELINE CORP.	OK	BEAVER				-100.147	36.5718	55	Unknown	Unknown	Unknown	Unknown
DELHI GAS PIPELINE CORP.	OK	EL RENO				-97.9522	35.6302	75	Unknown	Unknown	Unknown	Unknown
DELHI GAS PIPELINE CORP.	OK	CUSTER				-98.8918	35.6496	25	Unknown	Unknown	Unknown	Unknown
DELHI GAS PIPELINE CORP.	OK	ANTELOPE HILLS				-99.7841	35.8307	20	Unknown	Unknown	Unknown	Unknown
DELHI GAS PIPELINE CORP.	OK	WOODWARD						45	Unknown	Unknown	Unknown	Unknown
DIAMOND SHAMROCK R&M CO.	OK	ROGER MILLS						50				
EXXON COMPANY, U.S.A.	OK	DOVER-HENNESSEY				-97.904	36.0729	80				
FREEPORT-MCMORAN INC	OK	TYRONE				-101.088	36.9947	36				
GETTY OIL	OK	OKLAHOMA						100				
GETTY OIL	OK	OKLAHOMA UNIT 1						5				
GETTY OIL	OK	OKLAHOMA UNIT 4						5				
GETTY OIL	OK	OKLAHOMA UNIT 5						5				
GETTY OIL	OK	OKLAHOMA UNIT 2						5				
GETTY OIL	OK	OKLAHOMA UNIT 3						5				
GPM GAS CORP.	OK	KINGFISHER				-97.7328	35.7908	165	Unknown	Unknown	Unknown	Unknown
GPM GAS CORP.	OK	OKARCHE				-98.0856	35.7364	142	Unknown	Unknown	Unknown	Unknown

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GPM GAS CORP.	OK	LUCIEN						10	Unknown	Unknown	Unknown	Unknown
GPM GAS CORP.	OK	CIMARRON				-98.5417	36.0247	56	Unknown	Unknown	Unknown	Unknown
LIBERTY ENERGY	OK	OKLAHOMA						0				
MAXUS EXPLORATION CO.	OK	ROGER MILLS						50				
MOBIL	OK	BRADLEY						140				
MOBIL E & P U.S.	OK	CHITWOOD						50	0.50	0.46	0.00	0
MOBIL E & P U.S.	OK	SHOLEM ALECHEM				-97.605	34.4225	60	Unknown	0.75	Unknown	0
MOBIL E & P U.S.	OK	POSTLE HOUGH				-101.641	36.9014	20	Unknown	0.1	Unknown	Unknown
NGC ENERGY, INC	OK	BINGER						15	0.74	0.09	Unknown	Unknown
NGC ENERGY, INC	OK	RINGWOOD				-98.2417	36.3656	65	Unknown	0.3	Unknown	Unknown
NGC ENERGY, INC	OK	MADILL				-96.5903	34.0858	25	Unknown	0.68	Unknown	Unknown
ORYX ENERGY	OK	LAVERNE				-99.9263	36.7117	200	Unknown	0.5	Unknown	0
ORYX ENERGY	OK	CARNEY				-97.5067	35.1017	15	Unknown	Unknown	Unknown	Unknown
ORYX ENERGY	OK	GOLDSBY						40	0.47	0.44	0.00	0
PG&E RESOURCES COMPANY	OK	ELMORE CITY						24	0.02	0.02	0.00	0
TEXACO E & P INC	OK	CAMRICK						35	0.45	0.46	0.00	0
TEXACO E & P INC	OK	MAYSVILLE				-97.4456	34.815	500	0.50	Unknown	0.00	Unknown
TEXACO E & P INC	OK	ENVILLE						15	Unknown	Unknown	Unknown	Unknown
TEXACO E & P INC	OK	VELMA				-97.6781	34.4608	100	0.07	0.7	0.00	0.23
TONKAWA GAS PROCESSING CO.	OK	CIMARRON				-98.5417	36.0247	90	Unknown	Unknown	Unknown	Unknown
TONKAWA GAS PROCESSING CO.	OK	WATONGA						30	Unknown	Unknown	Unknown	Unknown
TRANSOK, INC.	OK	THOMAS						150	0.77	0.91	0.00	0
TRANSOK, INC.	OK	CLINTON						75	0.70	0.87	0.00	0
TRANSOK, INC.	OK	LINE CREEK						27	0.50	0.5	0.00	0
TRANSOK, INC.	OK	COMANCHE TAP				-98.3246	34.5435	30	0.50	0.5	0.00	0
TRANSOK, INC.	OK	GREASY CREEK						30	0.40	Unknown	0.00	Unknown
TRANSOK, INC.	OK	CRESCENT						45	0.28	0.28	0.00	0
TRANSOK, INC.	OK	CRYSTAL LAKE						7	Unknown	Unknown	Unknown	Unknown
TRANSOK, INC.	OK	RED FORK						30	1.28	1.34	0.00	0
UNION PACIFIC RESOURCES	OK	ENID				-97.8188	36.4263	36	0.50	0.5	0.00	0
VICKERS PETROLEUM	OK	UNKNOWN							Unknown		Unknown	
WARREN PETROLEUM COMPANY	OK	WAYSVILLE						40				
ADOBE RESOURCES CORP.	TX	APPLE CREEK						28	0.51	0.7	0.00	0
ADOBE RESOURCES CORP.	TX	SALE RANCH						16	0.29	0.28	0.00	0.004
AMERADA HESS CORP.	TX	VIDOR				-94.0024	30.1963					
AMERICAN CENTRAL	TX	SAND HILLS						15				
AMERICAN CENTRAL GAS COMPANIES	TX	LIVE OAK				-98.0132	28.4842	18				
AMOCO PROD. CO.	TX	MIDLAND FARMS						30	Unknown	1.69	Unknown	2.58
AMOCO PROD. CO.	TX	OLD OCEAN				-95.7467	29.0689	175	Unknown	1.73	Unknown	0
AMOCO PROD. CO.	TX	NORTH COWDEN						25	Unknown	3.5	Unknown	4.55
AMOCO PROD. CO.	TX	CEDAR LAKE						3	Unknown	5.71	Unknown	8.34
AMOCO PROD. CO.	TX	TEXAS CITY				-94.925	29.3744	70	Unknown	0.81	Unknown	0
AMOCO PROD. CO.	TX	ANTON IRISH						4	Unknown	9.3	Unknown	2.87
AMOCO PROD. CO.	TX	LEVELLAND						40	Unknown	Unknown	Unknown	Unknown
AMOCO PROD. CO.	TX	SLAUGHTER						62	Unknown	9.29	Unknown	3.01
AMOCO PROD. CO.	TX	MALLET CO2 REMOVAL PLANT						100	82.00	84	0.50	0.6
AMOCO PROD. CO.	TX	SOLD->BURNELL-N. PETTUS						35	Unknown	Unknown	Unknown	Unknown

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AMOCO PROD. CO.	TX	WEST YANTIS						45	Unknown	Unknown	Unknown	Unknown
AMOCO PROD. CO.	TX	WASSON CO2						80	Unknown	78.28	Unknown	0.35
ANADARKO PETROLEUM CORP.	TX	SNEED						150	0.27	0.56	0.00	0
ARCO OIL & GAS CO.	TX	BLOCK 31						75				
ARCO OIL & GAS CO.	TX	FREER						0				
ARCO OIL & GAS CO.	TX	GORMAN						100				
ARCO OIL & GAS CO.	TX	GORMAN						200				
ARCO OIL & GAS CO.	TX	GORMAN						40				
ARCO OIL & GAS CO.	TX	LONGVIEW						27				
ARCO OIL & GAS CO.	TX	ELDORADO				-100.683	30.9914	15				
ARCO OIL & GAS CO.	TX	FASHING				-98.1803	28.7952	20				
ARKLA	TX	WASKOM				-94.0723	32.4693	32	1.25	1.25	0.00	0
ARKLA	TX	WILLOW SPRINGS						10	1.29	Unknown	0.00	Unknown
ARKLA	TX	JEFFERSON						2	Unknown	1.04	Unknown	0
ARKLA	TX	GILMER						15	2.64	Unknown	0.26	Unknown
CABOT CORP.	TX	ESTES						13				
CABOT CORP.	TX	BRYAN						2				
CABOT CORP.	TX	YAKE-MERCHANT						7				
CABOT CORP.	TX	WALTON						25				
CHEVRON USA	TX	TAFT ONE						16				
CHEVRON USA	TX	THREE P.						12				
CHEVRON USA	TX	KSBHUGU #3						330				
CHEVRON USA	TX	N. WARD ESTES						63				
CHEVRON/WARREN	TX	PUCKETT						40				
CITIES SERVICE OIL & GAS CO.	TX	MONT BELVIEU				-94.9188	29.8518	57				
CITIES SERVICE OIL & GAS CO.	TX	WELCH						3				
CITIES SERVICE OIL & GAS CO.	TX	EAST TEXAS						19				
CITIES SERVICE OIL & GAS CO.	TX	DUNBAR						11				
CITIES SERVICE OIL & GAS CO.	TX	ROBERTS RANCH						85				
CITIES SERVICE OIL & GAS CO.	TX	PANTHER CREEK						15				
CITIES SERVICE OIL & GAS CO.	TX	CANTON						5				
CLAJON GAS CO., L.P.	TX	LAGRANGE						200				
CONOCO	TX	HAMLIN						20	1.19	1.26	0.03	0.06
CONOCO	TX	MC ALLEN RANCH						21	0.23	0.11	0.00	0
CONOCO	TX	BAILY						15	0.17	0.52	0.00	0
CONOCO	TX	MERTZON						25	0.40	0.62	0.00	0
CONOCO	TX	RAMSEY						5	0.27	0.52	0.00	0.01
CONOCO	TX	CHITTIM RANCH						3	0.29	0.25	0.00	0
CONOCO	TX	ELDORADO						30	0.17	0.71	0.00	0
CONOCO	TX	STERLING						60	0.50	0.5	0.00	0
CRYSTAL OIL	TX	UNKNOWN						0				
DELHI	TX	AKER						16	Unknown	Unknown	Unknown	Unknown
DELHI	TX	TEAS						12	Unknown	Unknown	Unknown	Unknown
DELHI GAS PIPELINE CORP.	TX	DENTON						30	Unknown	Unknown	Unknown	Unknown
DELHI GAS PIPELINE CORP.	TX	GRAPELAND						165	Unknown	Unknown	Unknown	Unknown
DELHI GAS PIPELINE CORP.	TX	THREE RIVERS						25	Unknown	Unknown	Unknown	Unknown
DELHI GAS PIPELINE CORP.	TX	EAST TEXAS						90	Unknown	Unknown	Unknown	Unknown

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DELHI GAS PIPELINE CORP.	TX	COYANOSA						100	Unknown	Unknown	Unknown	Unknown
DELHI GAS PIPELINE CORP.	TX	LAREDO						25	Unknown	Unknown	Unknown	Unknown
DIAMOND SHAMROCK R&M CO.	TX	MCKEE						300	Unknown		Unknown	
EL PASO NATURAL GAS CO.	TX	MCELROY CRANE						54				
EL PASO NATURAL GAS CO.	TX	GOLDSMITH						211				
EL PASO NATURAL GAS CO.	TX	WASSON						145				
EL PASO NATURAL GAS CO.	TX	PUCKETT						80				
EL PASO NATURAL GAS CO.	TX	TERRELL						271				
EL PASO NATURAL GAS CO.	TX	KEYSTONE						187				
EL PASO NATURAL GAS CO.	TX	MIDWAY LANE						90				
EL PASO NATURAL GAS CO.	TX	PANOMA						176				
EL PASO NATURAL GAS CO.	TX	WAHA						285				
EL PASO NATURAL GAS CO.	TX	UPTON CO.						18				
EL PASO NATURAL GAS CO.	TX	DENVER CITY						168				
ENSERCH PROCESSING, INC.	TX	NOVICE						5	Unknown	Unknown	Unknown	Unknown
ENSERCH PROCESSING, INC.	TX	SANTA ANNA						5	Unknown	Unknown	Unknown	Unknown
ENSERCH PROCESSING, INC.	TX	RANGER						10	Unknown	Unknown	Unknown	Unknown
ENSERCH PROCESSING, INC.	TX	PUEBLO						20	0.26	Unknown	Unknown	Unknown
ENSERCH PROCESSING, INC.	TX	REPRIEVE						3	Unknown	Unknown	Unknown	Unknown
ENSERCH PROCESSING, INC.	TX	TRINIDAD						65	1.45	1.45	Unknown	Unknown
ENSERCH PROCESSING, INC.	TX	CHICO						30	38.00	Unknown	Unknown	Unknown
ENSERCH PROCESSING, INC.	TX	GILLILAND						12	Unknown	Unknown	Unknown	Unknown
ENSERCH PROCESSING, INC.	TX	GORDON						48	0.43	Unknown	Unknown	Unknown
ENSERCH PROCESSING, INC.	TX	SPRINGTOWN						65	0.57	Unknown	Unknown	Unknown
EXXON COMPANY, U.S.A.	TX	CORDONA LAKE RYAN HOLMES						8	78.00	40	0.04	0.03
EXXON COMPANY, U.S.A.	TX	FT. STOCKTON						100				
EXXON COMPANY, U.S.A.	TX	TEXAS						125				
EXXON COMPANY, U.S.A.	TX	PYOTE						100	Unknown	0.175	Unknown	Unknown
FORMOSA HYDROCARBONS CO.	TX	POINT COMFORT						100	0.98	1.23	0.00	0
FOUR STAR OIL & GAS CO.	TX	HEADLEE DEVONIAN						200	0.74	0.526	0.01	0.004
GENERAL CRUDE	TX	SALT CREEK						28				
GETTY OIL	TX	TEXAS PANHANDLE						30				
GETTY OIL	TX	NEW HOPE						50	Unknown		Unknown	
GETTY OIL	TX	REVCO						50				
GPM	TX	SHERMAN						340				
GPM GAS CORP.	TX	FULLERTON						65	Unknown	Unknown	Unknown	Unknown
GPM GAS CORP.	TX	GIDDINGS						90	Unknown	Unknown	Unknown	Unknown
GPM GAS CORP.	TX	GRAY						70	Unknown	Unknown	Unknown	Unknown
GPM GAS CORP.	TX	ROCK CREEK						180	Unknown	Unknown	Unknown	Unknown
GPM GAS CORP.	TX	SPRAYBERRY TIDEWATER						12	Unknown	Unknown	Unknown	Unknown
GPM GAS CORP.	TX	SPRABERRY						41	Unknown	Unknown	Unknown	Unknown
GPM GAS CORP.	TX	DUMAS	http://maps.epa.g	35.8275	101.6308			120	Unknown	Unknown	Unknown	Unknown
GULF ENERGY	TX	CRANE						60				
HNG	TX	GOMEZ						280				
HNG	TX	DUBOSE						30				
HNG	TX	MI VIDA						400	Unknown		Unknown	
HUNT PETROLEUM	TX	NORDHEIM						10				

Prepared by GTI

Operator	State	Plantname	EPA ID	Lat	Long	IXCoordinaIYCoordina	Installed Capacity MMcf/d	Design Inlet CO2 Mol%	Inlet CO2 Mol%	Design Inlet H2S Mol%	Inlet H2S Mol%
HUNT PETROLEUM	TX	NORTH PUCKETT					10				
HUNT PETROLEUM	TX	YUCCA BUTTE					20				
INTERNORTH	TX	JASPER					10				
INTERNORTH	TX	MITCHELL					140				
INTERNORTH	TX	LOCKRIDGE					25				
INTERNORTH	TX	DATES					130				
INTERNORTH	TX	NORTH HUTCH					10				
INTERNORTH	TX	PIKES PEAK					75				
INTERNORTH	TX	KERMIT					60				
KERR-MCGEE CORP.	TX	PAMPA					11				
LIQUID ENERGY CORP.	TX	LIVE OAK COUNTY					15				
LIQUID ENERGY CORP.	TX	BRENT RANCH					20				
LIQUID ENERGY CORP.	TX	CANADIAN RIVER					20				
LIQUID ENERGY CORP.	TX	WHITE RANCH					6				
LONE STAR	TX	TEAGUE					15				
LONE STAR	TX	TEAGUE					25				
LONE STAR	TX	BOX CHURCH					15				
LONE STAR	TX	PIKES PEAK (A)					75				
LONE STAR	TX	PIKES PEAK (B)					75				
LONE STAR	TX	WARWINK					100				
MAPCO GAS PRODUCTS, INC.	TX	WESTPAN 950					52	0.18	0.54	0.00	0.0003
MAPCO WESTPAN, INC.	TX	BIVINS					120	0.07	0.41	Unknown	0.004
MAPLE GAS CORP, THE	TX	GRAY COUNTY					20				
MARATHON OIL CO.	TX	YATES					40	Unknown		Unknown	
MARATHON OIL CO.	TX	IRAAN					10				
MARATHON OIL CO.	TX	SUSAN PEAK					3				
MARATHON OIL CO.	TX	SCIPIO					30				
MEPUS	TX	NORTH WORD					33	Unknown	Unknown	Unknown	Unknown
MERIDIAN OIL	TX	VANDERBILT GAS PLANT					120	1.20	Unknown	Unknown	Unknown
MESA LIMITED PARTNERSHIP	TX	FAIN					80		0.5		0.004
MOBIL E & P U.S.	TX	FELDMAN					3	0.68	Unknown	0.00	Unknown
MOBIL E & P U.S.	TX	LA GLORIA					265	0.15	0.526	0.00	0
MOBIL E & P U.S.	TX	SALT CREEK					26	0.58	0.89	0.01	0.5
MOBIL E & P U.S.	TX	PEGASUS					60	2.00	2	0.00	0.003
MOBIL E & P U.S.	TX	LAKE CREEK					6	Unknown	Unknown	Unknown	Unknown
MOBIL E & P U.S.	TX	COYANOSA					50	0.16	0.1714	0.00	0
MOBIL E & P U.S.	TX	WAHA					125	Unknown	1	0.00	0.03
MOBIL E & P U.S.	TX	EAST WHITE POINT					25	1.00	Unknown	0.00	Unknown
MOBIL E & P U.S.	TX	PORTILLA					15	Unknown	0.391	Unknown	Unknown
MOBIL E & P U.S.	TX	WILL-O-MILLS					28	15.00	14	0.02	0.02
MONSANTO	TX	CHOCOLATE BAYOU					110				
MOORE-MCCORMACK	TX	GEORGEWEST					2				
NATURAL GAS P/L CO. AMERICA	TX	KERMIT					30				
OCCIDENTAL PETROLEUM CORP	TX	EUSTACE					51				
ODESSA NATURAL	TX	FOSTER					15				
ORYX ENERGY	TX	DIAMOND M-SHARON RDG					50				
ORYX ENERGY	TX	SNYDER					75				

U.S. GAS TREATING PLANTS (By State & Operator)

Prepared by GTI

Operator	State	Plantname	EPA ID	Lat	Long	IXCoordina	IYCoordina	Installed Capacity MMcf/d	Design Inlet CO2 Mol%	Inlet CO2 Mol%	Design Inlet H2S Mol%	Inlet H2S Mol%
OXY NGL, INC.	TX	WELCH						3				
OXY NGL, INC.	TX	WEST SEMINOLE						35				
OXY NGL, INC.	TX	MYRTLE SPRINGS						48				
OXY, USA	TX	WELCH PLANT						2				
PANHANDLE EASTERN	TX	CABOT						10				
PARKER & PARSLEY	TX	KARNES						10				
PENNZOIL PRODUCING CO.	TX	MCFADDIN EAST						5	Unknown	0.523	Unknown	0
PERRY GAS	TX	DEWITT						10				
PERRY GAS	TX	ROSITA						20				
PERRY GAS	TX	LA GRANGE						90				
PERRY GAS	TX	ROSITA						20				
PERRY GAS	TX	ROSITA						20				
PERRY GAS	TX	PYOTE FIELD						300				
PHILLIPS 66 NATURAL GAS CO.	TX	LULING						12				
PHILLIPS 66 NATURAL GAS CO.	TX	GOLDSMITH						120	Unknown	Unknown	Unknown	Unknown
PHILLIPS 66 NATURAL GAS CO.	TX	SHERMAN						250	Unknown	Unknown	Unknown	Unknown
PHILLIPS 66 NATURAL GAS CO.	TX	BURGER						52				
PHILLIPS 66 NATURAL GAS CO.	TX	BURGER						52				
PHILLIPS 66 NATURAL GAS CO.	TX	SNEED						250				
PHILLIPS 66 NATURAL GAS CO.	TX	SPRABERRY						25				
PHILLIPS 66 NATURAL GAS CO.	TX	FULLERTON						59				
POGO PRODUCING	TX	TEXAS						0				
REEF CORP.	TX	BIG SPRING						30				
RICHARDSON, SID CARBON & GASOLINE	TX	CHALK						15	Unknown	2.37	Unknown	0
RICHARDSON, SID CARBON & GASOLINE	TX	ESKOTA						12	Unknown	1.11	Unknown	0
RICHARDSON, SID CARBON & GASOLINE	TX	HALLEY						60	Unknown	0	Unknown	0
RICHARDSON, SID CARBON & GASOLINE	TX	KEYSTONE						120	Unknown	1.07	Unknown	0.32
SHELL WESTERN E & P, INC.	TX	PAWNEE						45				
SHELL WESTERN E & P, INC.	TX	BRYANS MILL						66	Unknown	Unknown	Unknown	Unknown
SHELL WESTERN E & P, INC.	TX	HOUSTON CENTRAL						550	Unknown	Unknown	Unknown	Unknown
SHELL WESTERN E & P, INC.	TX	PERSONS						38				
SOUTH TEXAS GAS TREATERS	TX	LIVE OAK						50	8.00	Unknown	0.12	Unknown
SUN GAS	TX	BIG WELLS						8				
SUN GAS	TX	CARRIZO SPRINGS						5				
SUN GAS	TX	JAMESON						50				
SUN GAS	TX	STRAIGHT GAS UNIT						8				
SUN GAS	TX	SACROC CO2 REMOVAL FAC.						110				
SUN GAS	TX	ROCKY FIELD						5				
SUPERIOR OIL	TX	SWEET HOME						28				
TENNECO OIL CO.	TX	TEXAS						0				
TEXACO E & P INC	TX	CHOCOLATE BAYOU GAS PLANT						20	Unknown	Unknown	Unknown	Unknown
TEXACO E & P INC	TX	BROOKELAND GAS PLANT						30	Unknown	Unknown	Unknown	Unknown
TEXACO INC.	TX	OZONA						25	Unknown	0.6	Unknown	0
TEXACO INC.	TX	STREETMAN						15	Unknown	Unknown	Unknown	Unknown
TEXACO INC.	TX	MCLEAN						25	Unknown	0.04	Unknown	0
TEXACO INC.	TX	EAST VEALMOOR						50	Unknown	1.03	Unknown	0.16
TEXACO INC.	TX	GEORGE WEST						20	0.00	Unknown	0.00	Unknown

U.S. GAS TREATING PLANTS (By State & Operator)

Prepared by GTI

Operator	State	Plantname	EPA ID	Lat	Long	IXCoordina	IYCoordina	Installed Capacity MMcf/d	Design Inlet CO2 Mol%	Inlet CO2 Mol%	Design Inlet H2S Mol%	Inlet H2S Mol%
TEXACO INC.	TX	GAS TREATING						10	Unknown	Unknown	Unknown	Unknown
TEXACO INC.	TX	BRADFORD RANCH						12	Unknown	0.5	Unknown	0.0015
TEXACO INC.	TX	PECOS						30				
TEXACO INC.	TX	FULLER						5	Unknown	1.2	Unknown	0.4
TEXACO INC.	TX	SOUTH KERMIT COMPLEX						24	Unknown	0.9	Unknown	0.2
TEXACO, MIDLAND	TX	REEVES						50				
TEXACO, MIDLAND	TX	MABEE						6	Unknown	Unknown	Unknown	Unknown
TEXACO, MIDLAND	TX	KNIGHT						90				
TEXACO, MIDLAND	TX	KERMIT						7				
TEXAS OIL & GAS CO	TX	TEAGUE						100	Unknown	Unknown	Unknown	Unknown
TEXAS OIL & GAS CO	TX	GILMER B						80	Unknown	Unknown	Unknown	Unknown
TONKAWA GAS PROCESSING CO.	TX	LONGVIEW						100	Unknown	Unknown	Unknown	Unknown
TONKAWA GAS PROCESSING CO.	TX	BOOKER						6	Unknown	Unknown	Unknown	Unknown
TRANSCO	TX	MCMULLEN						106	Unknown		Unknown	
TRANSCO	TX	TILDEN						96				
TRANSWESTERN	TX	ESTES						18				
TRANSWESTERN	TX	CHENOT PUTNAM						18				
TRANSWESTERN	TX	HALLEY						135				
TRANSWESTERN	TX	HUBER						3				
TRANSWESTERN	TX	KEYSTONE						78				
TRANSWESTERN	TX	WALTON						33				
TRANSWESTERN	TX	PYOTE						450				
TRANSWESTERN	TX	KERMIT						35				
UNION PACIFIC RESOURCES	TX	BRYAN						35	2.60	2.599	0.00	0
UNION PACIFIC RESOURCES	TX	A & M						50	Unknown	3.399	Unknown	0
UNION PACIFIC RESOURCES	TX	CONROE						70	1.57	1.242	Unknown	Unknown
UNION PACIFIC RESOURCES	TX	GULF PLAINS						135	0.37	0.275	Unknown	Unknown
UNION PACIFIC RESOURCES	TX	EAST TEXAS						220	1.41	Unknown	0.00	Unknown
UNION TEXAS	TX	BRAYSON						10				
UNITED TRANS.	TX	FANDANGO						20				
USAGAS PIPELINE CO.	TX	MCLEOD I						15	Unknown	Unknown	Unknown	Unknown
USAGAS PIPELINE CO.	TX	MCLEOD II						10	Unknown	Unknown	Unknown	Unknown
VALERO HYDROCARBONS CO.	TX	ARMSTRONG						50				
VALERO HYDROCARBONS CO.	TX	GOMEZ						250				
VALERO HYDROCARBONS CO.	TX	WEST GOMEZ						180				
VALERO HYDROCARBONS CO.	TX	BLOCK 21						100				
VALERO HYDROCARBONS CO.	TX	GREASEWOOD						100				
VALERO HYDROCARBONS CO.	TX	HOLESON						30				
VALERO HYDROCARBONS CO.	TX	MI VIDA						80				
VALERO HYDROCARBONS CO.	TX	GREY RANCH						275				
VALERO HYDROCARBONS CO.	TX	PYOTE						100				
VENTECH	TX	CARRIZO SPRINGS						17				
VENTECH	TX	POST						2				
WARREN PETROLEUM COMPANY	TX	FASHING						100	Unknown		Unknown	
WARREN PETROLEUM COMPANY	TX	SAND HILLS						150	Unknown		Unknown	
WARREN PETROLEUM COMPANY	TX	MOORES ORCHARD						10				
WARREN PETROLEUM COMPANY	TX	SHERMAN NORTH						33				

Operator	State	Plantname	EPA ID	Lat	Long	IXCoordina	IYCoordina	Installed Capacity MMcf/d	Design Inlet CO2 Mol%	Inlet CO2 Mol%	Design Inlet H2S Mol%	Inlet H2S Mol%
WARREN PETROLEUM COMPANY	TX	CANADIAN						25				
WARREN PETROLEUM COMPANY	TX	TONKAWA						4				
WARREN PETROLEUM COMPANY	TX	COMO						21	Unknown		Unknown	
WARREN PETROLEUM COMPANY	TX	FANNETT						33				
WARREN PETROLEUM COMPANY	TX	WORSHAM						30				
WARREN PETROLEUM COMPANY	TX	MONAHANS						45				
WESTERN GAS PROC., LTD.	TX	EDGEWOOD						60	Unknown	Unknown	Unknown	Unknown
CHEVRON USA	UT	RED WASH						22				
COASTAL OIL & GAS CO.	UT	ALTAMONT						40	Unknown	Unknown	Unknown	Unknown
ELKHORN OPERATING CO.	UT	ANETH						14	Unknown	Unknown	Unknown	Unknown
MOBIL E & P U.S.	UT	MCELMD CREEK						20	Unknown	65.66	Unknown	0.06
UNION PACIFIC RESOURCES	UT	YELLOW CREEK						80	0.03	0.3	0.00	0
UNION PACIFIC RESOURCES	UT	PINEVIEW						10	Unknown	2.04	Unknown	0.0025
AMOCO PROD. CO.	WY	BAIROIL CO2						150	Unknown	96.65	Unknown	0.34
AMOCO PROD. CO.	WY	BEAVER CREEK - J.I.						30	Unknown	0.34	Unknown	0
AMOCO PROD. CO.	WY	BEAVER CRK PHOSPHORIA						17	Unknown	1.26	Unknown	8.62
AMOCO PROD. CO.	WY	SALT CREEK						2	Unknown	9.75	Unknown	0.58
AMOCO PROD. CO.	WY	ELK BASIN						21	Unknown	8.63	Unknown	14.73
AMOCO PROD. CO.	WY	ANSCHUTZ RANCH EAST						700	Unknown	0.2	Unknown	0
AMOCO PROD. CO.	WY	WHITNEY CANYON						275	Unknown	4.67	Unknown	15.2
AMOCO PROD. CO.	WY	PAINTER COMPLEX						240	Unknown	0.1	Unknown	0
ARCO OIL & GAS CO.	WY	RIVERTON DOME						16				
CHEVRON USA (WARREN)	WY	CARTER CREEK						155	Unknown		Unknown	
COLORADO INTERST. GAS CO.	WY	RAWLINS						220	1.50	1.3	0.00	0
COLORADO INTERST. GAS CO.	WY	TABLE ROCK						60	17.51	11.5	3.75	4.5
EXXON COMPANY, U.S.A.	WY	SHUTE CREEK						480	65.00	65	5.00	5
GULF ENERGY	WY	POWELL						12				
KERR-MCGEE CORP.	WY	BOXCAR-BUTTE						5				
KN GAS GATHERING	WY	DOUGLAS						25	0.00	2.3	0.00	0
MARATHON OIL CO.	WY	OREGON BASIN						7	Unknown		Unknown	
MONTANA DAKOTA	WY	RIVERTON						20				
NORTHWEST PIPELINE CORP.	WY	OPAL						250	0.20	0.5	0.00	0
UNION PACIFIC RESOURCES	WY	BRADY						65	29.34	38.24	1.25	1.4
UNION PACIFIC RESOURCES	WY	PATRICK DRAW						20	3.40	1.86	0.00	0
UNION PACIFIC RESOURCES	WY	EMIGRANT TRAIL						60	0.79	1.07	0.00	0
UNION PACIFIC RESOURCES	WY	SILO						2	2.49	Unknown	0.00	Unknown

U.S. NATURAL GAS FIELDS WITH GREATER THAN 5% HYDROGEN SULFIDE (Sorted by Basin Code)

H2S >5%

Prepared by GTI

High H2S (> 5%)

STATE	COUNTY	BASIN CODE	FIELD	WELL NAME/PLANT	LOCATION/PIPELINE	OWNER	H2S	CO2
TEXAS	FREESTONE	260	NEAL	GLAYDENE NEAL NO. 1	JOHN BRADLEY SUR. A-53	GETTY OIL CO.	44.4%	4.3%
TEXAS	FREESTONE	260	NEAL	GLAYDENE NEAL NO. 1	JOHN BRADLEY SUR. A-53	GETTY OIL CO.	28.9%	5.0%
TEXAS	VAN ZANDT	260	EDGEWOOD	PARKER G.U. A NO. 1	J. H. PARKER TRACT	PAN AMERICAN PETROLEUM CORP.	24.0%	3.0%
TEXAS	VAN ZANDT	260	EDGEWOOD NE	PARKER G.U. B NO. 1	I. R. CHISUM A-157 SUR.	PAN AMERICAN PETROLEUM CORP.	21.6%	2.7%
WYOMING	NIOBRARA	515	ANT HILLS N	FED. NO. 32-12	SEC. 12, T37N, R63W	MILESTONE PETROLEUM, INC.	6.3%	4.7%
WYOMING	BIG HORN	520	TORCHLIGHT W	TORCHLIGHT UNIT WELL NO. 2	SEC. 14, T51N, R93W	STANOLIND OIL & GAS CO.	9.3%	0.3%
WYOMING	PARK	520	SILVERTIP	NO. 31-33	SEC. 33, T58N, R100W	TEXACO INC.	16.2%	4.3%
WYOMING	PARK	520	ELK BASIN	UNIT NO. 153	SEC. 25, T58N, R100W	PAN AMERICAN PETROLEUM CORP.	11.7%	4.2%
WYOMING	WASHAKIE	520	WORLAND	NO. 5E	SEC. 21, T48N, R92W	PURE OIL CO.	6.4%	2.5%
WYOMING	FREMONT	530	RIVERTON E	TRIBAL 32 NO. 6	SEC. 32, T1N, R6E	CONTINENTAL OIL CO.	5.4%	0.5%
WYOMING	FREMONT	530	BEAVER CREEK	BEAVER CREEK NO. 10	SEC. 16, T33N, R96W	PAN AMERICAN PETROLEUM CORP.	5.1%	1.0%

U.S. NATURAL GAS FIELDS WITH GREATER THAN 20% ACID GAS (Sorted by Basin Code)

Prepared by GTI

HIGH ACID GAS (HIGH TOTAL H2S+CO2)

STATE	COUNTY	BASIN	FIELD	WELL NAME/PLANT	LOCATION/PIPELINE	OWNER	H2S	CO2	SUM
COLORADO	BACA	360	NOT GIVEN	BORE HOLE NO. F614	SEC. 20, T29S, R50W	SKELLY OIL CO.	0.0%	99.4%	99.4%
COLORADO	BACA	360	NOT GIVEN	INGLE NO. 1	SEC. 27, T29S, R50W	SHARPLES OIL CORP.	0.0%	97.3%	97.3%
COLORADO	BACA	360	NOT GIVEN	INGLE NO. 1	SEC. 27, T29S, R50W	J. M. HUBER CORP.	0.0%	91.0%	91.0%
COLORADO	BACA	360	NOT GIVEN	JACOBSON NO. 1	NOT GIVEN	SHARPLES OIL CORP.	0.0%	90.0%	90.0%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	KOSCOVE NO. 1	SEC. 15, T27S, R70W	ATLANTIC RICHFIELD CO.	0.0%	97.3%	97.3%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	METER STA.	GATHERING SYSTEM	ARCO OIL & GAS CO.	0.0%	96.5%	96.5%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	NO. 1-15-C	SEC. 15, T27S, R70W	ARCO OIL & GAS CO.	0.0%	97.0%	97.0%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	NO. 1-22-H	SEC. 22, T27S, R70W	ARCO OIL & GAS CO.	0.0%	96.6%	96.6%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	NO. 2-10-0	SEC. 15, T27S, R70W	ARCO OIL & GAS CO.	0.0%	96.7%	96.7%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	NO. 3-15-B	SEC. 15, T27S, R70W	ARCO OIL & GAS CO.	0.0%	96.6%	96.6%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	NO. 3-4-O	SEC. 9, T27S, R70W	ARCO OIL & GAS CO.	0.0%	96.8%	96.8%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	NO. 4-4-P	SEC. 9, T27S, R70W	ARCO OIL & GAS CO.	0.0%	96.6%	96.6%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	NO. 5-15-F	SEC. 15, T27S, R70W	ARCO OIL & GAS CO.	0.0%	97.0%	97.0%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	NO. 5-9-A	SEC. 9, T27S, R70W	ARCO OIL & GAS CO.	0.0%	96.9%	96.9%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	NO. 6-15-I	SEC. 15, T27S, R70W	ARCO OIL & GAS CO.	0.0%	96.9%	96.9%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	SHEEP MOUNTAIN NO. 12	SEC. 15, T27S, R70W	ATLANTIC RICHFIELD CO.	0.0%	97.7%	97.7%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	SHEEP MOUNTAIN NO. 7	SEC. 9, T27S, R70W	ATLANTIC RICHFIELD CO.	0.0%	95.0%	95.0%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	SHEEP MOUNTAIN NO. 7	SEC. 9, T27S, R70W	ATLANTIC RICHFIELD CO.	0.0%	91.1%	91.1%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	SHEEP MOUNTAIN UNIT NO. 7	SEC. 9, T27S, R70W	ATLANTIC RICHFIELD CO.	0.0%	74.8%	74.8%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	SHEEP MOUNTAIN UNIT NO. 7-9	SEC. 9, T27S, R70W	ATLANTIC RICHFIELD CO.	0.0%	62.9%	62.9%
COLORADO	LAS ANIMAS	455	NOT GIVEN	BRUMLEY NO. 1	SEC. 6, T29S, R51W	BRUMLEY, C. W.	0.0%	98.8%	98.8%
COLORADO	LAS ANIMAS	455	NOT GIVEN	KING NO. 1	SEC. 1, T28S, R53W	NOT GIVEN	0.0%	95.9%	95.9%
COLORADO	LAS ANIMAS	455	NINA VIEW	WELL NO. 2	SEC. 7, T28S, R52W	NELSON-MOORE DEVELOPMENT CO.	0.0%	96.6%	96.6%
COLORADO	LAS ANIMAS	455	NINA VIEW	WELL NO. 3	SEC. 7, T28S, R52W	NELSON-MOORE DEVELOPMENT CO.	0.0%	96.7%	96.7%
COLORADO	LAS ANIMAS	455	NINA VIEW	WELL NO. 4	SEC. 7, T28S, R52W	NELSON-MOORE DEVELOPMENT CO.	0.0%	97.6%	97.6%
COLORADO	MOFFAT	535	MOFFAT	WICK NO. 13	SEC. 10, T4N, R91W	TEXACO INC.	0.0%	98.4%	98.4%
COLORADO	JACKSON	545	NOT GIVEN	BALLINGER FED. NO. 1	SEC. 8, T9N, R78W	GULF OIL CORP.	0.0%	90.4%	90.4%
COLORADO	JACKSON	545	MCCALLUM S	CONOCO FED. 8-3 UNIT NO. 1	SEC. 8, T9N, R78W	CONOCO, INC.	0.0%	70.2%	70.2%
COLORADO	JACKSON	545	MCCALLUM S	CONOCO-FEDERAL NO. 21-6	SEC. 21, T9N, R78W	CONOCO, INC.	0.0%	91.8%	91.8%
COLORADO	JACKSON	545	MCCALLUM N	GLENWOOD SPRINGS NO. 1	SEC. 12, T9N, R79W	CONTINENTAL OIL CO.	0.0%	91.8%	91.8%
COLORADO	JACKSON	545	CANADIAN RIVER	GOVT. LANMON NO. 1-A	SEC. 7, T9N, R80W	TEXACO INC.	0.0%	96.3%	96.3%
COLORADO	JACKSON	545	MCCALLUM S	HOYE NO. 1	SEC. 34, T9N, R76S	CONTINENTAL OIL CO.	0.0%	97.5%	97.5%
COLORADO	JACKSON	545	MCCALLUM S	HOYE NO. 3	SEC. 34, T9N, R78W	CONTINENTAL OIL CO.	0.0%	91.3%	91.3%
COLORADO	JACKSON	545	MCCALLUM UNIT	SEPERATOR AT PLANT	DAKOTA-LAKOTA RESERVOIR	CONTINENTAL OIL CO.	0.0%	92.3%	92.3%
COLORADO	JACKSON	545	MCCALLUM	SEPERATOR AT PLANT	MORRISON POOL	CONTINENTAL OIL CO.	0.0%	91.7%	91.7%
COLORADO	JACKSON	545	MCCALLUM N	SHERMAN NO. 1	SEC. 12, T9N, R79W	CONTINENTAL OIL CO.	0.0%	92.1%	92.1%
COLORADO	DOLORES	585	DOE CANYON	DOE CANYON NO. 1	SEC. 13, T40N, R18W	HUMBLE OIL & REFINING CO.	0.0%	92.6%	92.6%
COLORADO	DOLORES	585	DOE CANYON	DOE CANYON NO. 1	SEC. 13, T40N, R18W	HUMBLE OIL & REFINING CO.	0.0%	90.4%	90.4%
COLORADO	DOLORES	585	GLADE CANYON	GLADE CANYON UNIT NO. 1	SEC. 13, T40N, R17W	SINCLAIR OIL & GAS CO.	0.0%	95.8%	95.8%
COLORADO	MONTEZUMA	585	MCELMO DOME UNIT	DEAN DUDLEY NO. 2	SEC. 13, T36N, R18W	DELHI-TAYLOR OIL CORP.	0.0%	96.2%	96.2%
COLORADO	MONTEZUMA	585	MCELMO DOME UNIT	DEAN DUDLEY NO. 3	SEC. 13, T36N, R28W	AMERIGAS, INC.	0.0%	97.5%	97.5%
COLORADO	MONTEZUMA	585	MCELMO DOME UNIT	DUDLEY NO. 2	SEC. 13, T36N, R18W	TENNECO OIL CO.	0.0%	96.0%	96.0%
COLORADO	MONTEZUMA	585	MCELMO DOME UNIT	HOVENWEEP FED. NO. 1	SEC. 19, T38N, R18W	MOBIL RESEARCH & DEVELOPMENT	0.0%	98.6%	98.6%
COLORADO	MONTEZUMA	585	MCELMO DOME UNIT	HOVENWEEP FED. NO. 1	SEC. 19, T38N, R18W	MOBIL OIL CORP.	0.0%	98.5%	98.5%
COLORADO	MONTEZUMA	585	MCELMO DOME UNIT	J. A. FULKS NO. 1	SEC. 27, T37N, R17W	GULF OIL CORP.	0.0%	97.8%	97.8%
COLORADO	MONTEZUMA	585	MCELMO DOME UNIT	J. A. FULKS NO. 1	SEC. 27, T37N, R17W	GULF OIL CORP.	0.0%	97.7%	97.7%
COLORADO	MONTEZUMA	585	MCELMO DOME UNIT	J. A. FULKS NO. 1	SEC. 27, T37N, R17W	GULF OIL CORP.	0.0%	97.5%	97.5%
COLORADO	MONTEZUMA	585	MCELMO DOME UNIT	J. A. FULKS NO. 1	SEC. 27, T37N, R17W	GULF OIL CORP.	0.0%	97.5%	97.5%
COLORADO	MONTEZUMA	585	MCELMO DOME UNIT	MOQUI UNIT NO. 2	SEC. 12, T37N, R19W	MOBIL OIL CORP.	0.0%	97.9%	97.9%

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COLORADO	MONTEZUMA	585	MCELMO	SCHMIDT NO. 1	SEC. 24, T36N, R18W	BYRD-FROST, INC.	0.0%	81.9%	81.9%
COLORADO	MONTEZUMA	585	MCELMO DOME UNIT	SCHMIDT NO. 2	SEC. 24, T36N, R18W	AMERIGAS, INC.	0.0%	97.6%	97.6%
COLORADO	DELTA	595	BLACK CANYON	NO. 1	SEC. 6, T15S, R94W	BILLSTROM BROTHERS	0.0%	82.3%	82.3%
COLORADO	GARFIELD	595	GARMESA	GARMESA NO. 1	SEC. 5, T8S, R102W	GYPSY OIL CO.	0.0%	61.1%	61.1%
COLORADO	GARFIELD	595	GARMESA	GARMESA NO. 1	SEC. 8, T8S, R102W	FULTON PETROLEUM CO.	0.0%	35.6%	35.6%
COLORADO	GARFIELD	595	GARMESA	GARMESA NO. 1	SEC. 8, T8S, R102W	KERR-MCGEE OIL IND., INC.	0.0%	20.8%	20.8%
COLORADO	GARFIELD	595	GARMESA	NATIONAL NO. 1	SEC. 6, T8S, R102W	KERR-MCGEE OIL IND., INC.	0.0%	57.6%	57.6%
COLORADO	GARFIELD	595	GARMESA	NOT GIVEN	SEC. 5, T8S, R102W	GYPSY OIL CO.	0.0%	20.0%	20.0%
COLORADO	MESA	595	GARMESA	GARMESA NO. 1	SEC. 8, T8S, R102W	KERR-MCGEE OIL IND., INC.	0.0%	20.4%	20.4%
COLORADO	MESA	595	BRONCO FLATS	U.S.A. NO. 1-14 HC	SEC. 14, T9S, R98W	COORS ENERGY CO.	0.0%	53.7%	53.7%
COLORADO	RIO BLANCO	595	WHITE RIVER DOME	NO. 1	SEC. 30, T2N, R96W	TEXAS PRODUCTION CO.	0.0%	21.8%	21.8%
COLORADO	RIO BLANCO	595	FOUNDATION CREEK	STEELE NO. 1-35	SEC. 35, T4S, R102W	SWEET PEA OIL & GAS CO.	0.0%	37.5%	37.5%
COLORADO	RIO BLANCO	595	DOUGLAS CREEK S	UNIT NO. 7	SEC. 6, T4S, R101W	CITIES SERVICE OIL CO.	0.0%	21.4%	21.4%
NEW MEXICO	HARDING	445	BACA	BACA NO. 1	SEC. 19, T20N, R31E	WADDELL & MCFANN, ET AL.	0.0%	99.4%	99.4%
NEW MEXICO	HARDING	445	NOT GIVEN	DE BACA WELL NO. 2YB	SEC. 31, T20N, R31E	AMERIGAS, INC.	0.0%	99.6%	99.6%
NEW MEXICO	HARDING	445	BRAVO DOME	HEIMANN NO. 1 (1933-031M)	SEC. 3, T19N, R33E	AMOCO PRODUCTION CO. (USA)	0.0%	98.8%	98.8%
NEW MEXICO	HARDING	445	BACA	KERLIN NO. 1	SEC. 34, T21N, R30E	KUMMBACA OIL & GAS CO.	0.0%	98.2%	98.2%
NEW MEXICO	HARDING	445	NOT GIVEN	LIBBY WELL NO. 4K	SEC. 16, T20N, R31E	AMERIGAS, INC.	0.0%	99.1%	99.1%
NEW MEXICO	HARDING	445	NOT GIVEN	MITCHELL LEASE NO. 20K	SEC. 5, T18N, R30E	AMERIGAS, INC.	0.0%	99.6%	99.6%
NEW MEXICO	HARDING	445	NOT GIVEN	MITCHELL LEASE NO. 6M	SEC. 8, T19N, R30E	AMERIGAS, INC.	0.0%	98.4%	98.4%
NEW MEXICO	HARDING	445	BUEYEROS	POWERS-MARSHELL NO. 1	SEC. 34, T21N, R30E	POWERS-MARSHALL CO.	0.0%	99.7%	99.7%
NEW MEXICO	UNION	445	BRAVO DOME	CAIN NO. E-1 (1935-221G)	SEC. 22, T22N, R16W	AMOCO PRODUCTION CO. (USA)	0.0%	99.0%	99.0%
NEW MEXICO	UNION	445	SIERRA GRANDE	ROGERS NO. 1	SEC. 4, T29N, R29E	SIERRA GRANDE OIL CORP.	0.0%	98.4%	98.4%
NEW MEXICO	COLFAX	455	NOT GIVEN	ROBERTS NO. 1	SEC. 7, T28N, R27E	ROBERTS, W. C.	0.0%	89.1%	89.1%
NEW MEXICO	MORA	455	WAGON MOUND	C. F. CRUSE NO. 1	SEC. 11, T19N, R21E	ARKANSAS FUEL OIL CO.	0.0%	92.2%	92.2%
NEW MEXICO	MORA	455	WAGON MOUND	C. F. CRUSE NO. 1	SEC. 11, T19N, R21E	ARKANSAS FUEL OIL CO.	0.0%	90.0%	90.0%
NEW MEXICO	BERNALILLO	460	NOT GIVEN	WATER WELL	SEC. 36, T11N, R6E	CROSBY, JIM & U.S.G.S.	0.0%	78.7%	78.7%
NEW MEXICO	TORRANCE	460	TORRANCE	J. B. WITT TEXT	SEC. 12, T7N, R7E	SINOCO OIL CO.	0.0%	97.4%	97.4%
NEW MEXICO	TORRANCE	460	ESTANCIA VALLEY	PACE NO. 1	SEC. 12, T6N, R7E	NOT GIVEN	0.0%	99.0%	99.0%
NEW MEXICO	TORRANCE	460	ESTANCIA VALLEY	PACE NO. 1	NOT GIVEN	PACE, E., HEIRS	0.0%	98.4%	98.4%
NEW MEXICO	RIO ARRIBA	580	ABIQUIN	MORTEN NO. 1	SEC. 24, T24N, R5E	LOWRY, ET AL.	0.0%	96.5%	96.5%
NEW MEXICO	RIO ARRIBA	580	HAYSTACK DOME	NAVAJO C NO. 1	SEC. 8, T23N, R5W	HUMBLE OIL & REFINING CO.	0.0%	88.1%	88.1%
NEW MEXICO	SAN JUAN	580	WILDCAT	NAVAJO C NO. 1	SEC. 1, T29N, R17W	PAN AMERICAN PETROLEUM CORP.	0.0%	38.2%	38.2%
NEW MEXICO	SAN JUAN	580	HOGBACK N	NAVAJO K NO. 2	SEC. 31, T30N, R16W	HUMBLE OIL & REFINING CO.	0.0%	88.5%	88.5%
NEW MEXICO	SAN JUAN	580	NAVAJO	NAVAJO TRACT 27 NO. 1	SEC. 32, T26N, R15W	PURE OIL CO.	0.0%	96.2%	96.2%
NEW MEXICO	SAN JUAN	580	NAVAJO	NAVAJO TRACT 27 NO. 1	SEC. 32, T26N, R15W	PURE OIL CO.	0.0%	95.3%	95.3%
NEW MEXICO	SAN JUAN	580	UTE DOME	NOT GIVEN	NOT GIVEN	PAN AMERICAN PETROLEUM CORP.	1.1%	23.1%	24.2%
NEW MEXICO	SAN JUAN	580	HOGBACK	U.S.G. NO. 13	SEC. 19, T29N, R16W	STANOLIND OIL & GAS CO.	0.0%	20.3%	20.3%
NEW MEXICO	SAN JUAN	580	HOGBACK	U.S.G. NO. 13	SEC. 19, T29N, R16W	STANOLIND OIL & GAS CO.	0.0%	20.0%	20.0%
NEW MEXICO	SAN JUAN	580	UTE DOME	UTE MOUNTAIN TRIBAL D NO. 1	SEC. 10, T31N, R14W	PAN AMERICAN PETROLEUM CORP.	0.0%	88.0%	88.0%
NEW MEXICO	SAN JUAN	580	UTE DOME	UTE MOUNTAIN TRIBAL D NO. 1	SEC. 10, T31N, R14W	PAN AMERICAN PETROLEUM CORP.	0.0%	88.0%	88.0%
NEW MEXICO	SAN JUAN	580	UTE DOME	UTE MOUNTAIN TRIBAL D NO. 1	SEC. 10, T31N, R14W	PAN AMERICAN PETROLEUM CORP.	1.3%	31.2%	32.5%
NEW MEXICO	SAN JUAN	580	UTE DOME	UTE MOUNTAIN TRIBAL D NO. 1	SEC. 10, T31N, R14W	PAN AMERICAN PETROLEUM CORP.	1.3%	30.9%	32.2%
NEW MEXICO	SAN JUAN	580	UTE DOME	UTE MOUNTAIN TRIBAL D NO. 1	SEC. 10, T31N, R14W	PAN AMERICAN PETROLEUM CORP.	1.5%	28.5%	30.0%
NEW MEXICO	SAN JUAN	580	UTE DOME	UTE MOUNTAIN TRIBAL-K NO. 1	SEC. 33, T32N, R14W	PAN AMERICAN PETROLEUM CORP.	0.1%	33.7%	33.8%
NEW MEXICO	SANDOVAL	580	NACIMIENTO	OIL TEST	SEC. 1, T16N, R1W	ZIA PUEBLOS	0.0%	86.4%	86.4%
NEW MEXICO	VALENCIA	580	WATER WELL	ARTESIAN WATER WELL IN SEC12	SEC. 12, T9N, R5W	U.S. BUREAU OF INDIAN AFFAIRS	0.0%	42.7%	42.7%
NEW MEXICO	VALENCIA	580	WATER WELL	INDIAN WATER WELL OF MESITA	SEC. 12, T9N, R5W	U.S. BUREAU OF INDIAN AFFAIRS	0.0%	52.1%	52.1%
NEW MEXICO	VALENCIA	580	WATER WELL	NOT GIVEN	SEC. 12, T9N, R5W	U.S. BUREAU OF INDIAN AFFAIRS	0.0%	21.4%	21.4%
NEW MEXICO	VALENCIA	580	COMANCHE DRAW	SPRING	SEC. 35, T6N, R3W	USGS, QUALITY OF WATER BRANCH	0.0%	98.4%	98.4%
NEW MEXICO	VALENCIA	580	SPRING N OF MESA LUCERO	SPRING	SEC. 15, T8N, R3W	USGS, QUALITY OF WATER BRANCH	0.0%	92.1%	92.1%
TEXAS	FRANKLIN	260	NEW HOPE	DEEP UNIT NO. 2-1-D	C. F. MCKENZIE SUR.	TIDEWATER OIL CO.	14.0%	6.3%	20.3%

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TEXAS	FREESTONE	260	NEAL	GLAYDENE NEAL NO. 1	JOHN BRADLEY SUR. A-53	GETTY OIL CO.	44.4%	4.3%	48.7%
TEXAS	FREESTONE	260	NEAL	GLAYDENE NEAL NO. 1	JOHN BRADLEY SUR. A-53	GETTY OIL CO.	28.9%	5.0%	33.9%
TEXAS	FREESTONE	260	CARTER-BLOXOM	M. D. BLOXOM NO. 1	J. MATTHEWS SUR. A-418	GETTY OIL CO.	17.2%	5.5%	22.7%
TEXAS	RAINS	260	GINGER	JENKINS "C" NO. 1	A. WOODRING SUR., A-272	TXO PRODUCTION CORP.	28.4%	6.6%	35.0%
TEXAS	VAN ZANDT	260	EDGEWOOD	PARKER G.U. A NO. 1	J. H. PARKER TRACT	PAN AMERICAN PETROLEUM CORP.	24.0%	3.0%	27.0%
TEXAS	VAN ZANDT	260	EDGEWOOD NE	PARKER G.U. B NO. 1	I. R. CHISUM A-157 SUR.	PAN AMERICAN PETROLEUM CORP.	21.6%	2.7%	24.3%
TEXAS	MEDINA	400	WILDCAT	CARL EST BUSHWACK RANCH NO.1	NOT GIVEN	MONO CORP.	0.0%	74.2%	74.2%
TEXAS	CROCKETT	430	WILDCAT	M. MITCHELL NO. 1	BLK. 1, I&GN RR SUR.	SUN OIL CO.	0.0%	40.9%	40.9%
TEXAS	CROCKETT	430	J M	MITCHELL NO. 1	SEC. 3, BLK. Q-6, TCRR SUR.	SHELL OIL CO.	0.0%	20.3%	20.3%
TEXAS	IRION	430	BURNT ROCK	SHEEN "3061" NO. 1	SEC.3061,BLK.28,H&TCRR SUR.	UNION TEXAS PETROLEUM CORP.	0.0%	45.4%	45.4%
TEXAS	PECOS	430	GMW	ALLISON RANCH 3-170 NO. 1	SEC. 3, BLK. 170, TTRRCO.SUR	CONTINENTAL OIL CO.	0.0%	42.5%	42.5%
TEXAS	PECOS	430	GREY RANCH W	BLACKSTONE-SLAUGHTER NO. 1	SEC. 1, BLK. 131, T&STL SUR.	CHEVRON OIL CO.	0.0%	47.7%	47.7%
TEXAS	PECOS	430	OATES NE	C. E. MCINTYRE NO. 1	SEC. 139, BLK 3, T&PRR SUR.	HUMBLE OIL & REFINING CO.	0.0%	38.3%	38.3%
TEXAS	PECOS	430	PIKES PEAK E	EISINORE CATTLE CO. NO. 1	SEC. 25 BLK. C, GC&SF SUR.	TEXAS PACIFIC OIL CO., INC.	0.0%	41.6%	41.6%
TEXAS	PECOS	430	PUCKETT	GLENNA NO. 1	SEC. 28, BLK. 101, TCRR SUR.	PHILLIPS PETROLEUM CO.	0.0%	28.0%	28.0%
TEXAS	PECOS	430	GOMEZ & GRAY RANCH	GRAY RANCH	30 IN. LINE	COASTAL STATES GAS PROD. CO.	0.0%	47.2%	47.2%
TEXAS	PECOS	430	PUCKETT	MITCHELL-THOMAS 1 NO. 1	SEC. 23, BLK. 100, ELRR SUR.	CHEVRON OIL CO.	0.0%	26.7%	26.7%
TEXAS	PECOS	430	ELSINORE	MONTGOMERY-FULK NO. 11	SEC. 9, BLK. 170, TTRR CO.	TEXAS PACIFIC OIL CO., INC.	0.0%	46.6%	46.6%
TEXAS	PECOS	430	PUCKETT	PUCKETT K-1	SEC. 39, BLK. 101, TCRR SUR.	PHILLIPS PETROLEUM CO.	0.0%	26.9%	26.9%
TEXAS	REEVES	430	MI VIDA	CAMP UNIT NO. 1	SEC. 3, BLK. 4, H&GN SUR.	SUPERIOR OIL CO.	0.5%	52.0%	52.5%
TEXAS	TERRELL	430	BROWN-BASSETT	ALMA H. POULTER NO. 1	SEC. 21, BLK. 1, TC&RR SUR.	SINCLAIR OIL & GAS CO.	0.0%	47.5%	47.5%
TEXAS	TERRELL	430	BROWN-BASSETT	BROWN-BASSETT NO. 1-LT	SEC. 227, BLK. Y, TCRR SUR.	CONTINENTAL OIL CO.	0.0%	53.2%	53.2%
TEXAS	TERRELL	430	BROWN-BASSETT	GOODE ESTATE NO. 2	SEC. 1, BLK. R, TCRY SUR.	MAGNOLIA PETROLEUM CO.	0.0%	38.4%	38.4%
TEXAS	WARD	430	QUITO	SABINE G.U. NO. 1	SEC. 196, BLK. 34, H&TC SUR.	AMERICAN QUASAR PET. CO.	0.4%	37.7%	38.1%
TEXAS	WINKLER	430	O'BRIEN	PIPELINE SAMPLE	SEC. 27, BLK. B-12, P.S.L.	CONTINENTAL OIL CO.	0.0%	30.3%	30.3%
TEXAS	OLDHAM	435	WILDCAT	OLD HIGH NO. 1	SEC. 76, BLK GM-5 WMD LEE SR	BAKER & TAYLOR DRILLING CO.	0.0%	24.9%	24.9%
UTAH	CARBON	575	SEEP 30MMI. E. OF PRICE	GAS SEEP	SEC.--, T14, R15	LUNDY, G. E.	0.0%	97.2%	97.2%
UTAH	CARBON	575	FARNHAM DOME	NO. 1	SEC. 12, T15S, R11E	CARBON DIOXIDE & CHEMICAL CO.	0.0%	98.9%	98.9%
UTAH	CARBON	575	FARNHAM DOME	NO. 4	SEC. 12, T15S, R11E	CALIFORNIA OIL CO.	0.0%	98.3%	98.3%
UTAH	CARBON	575	GORDON CREEK UNIT	R. BRYNER NO. 1	SEC. 24, T14S, R7E	SKELLY OIL CO.	0.0%	99.5%	99.5%
UTAH	CARBON	575	GORDON CREEK UNIT	R. BRYNER NO. 2	SEC. 25, T14S, R7E	SKELLY OIL CO.	0.0%	89.3%	89.3%
UTAH	EMERY	585	WOODSIDE	FED. 44-12	SEC. 12, T19S, R13E	HOLLY RESOURCES CORP.	0.0%	33.2%	33.2%
UTAH	EMERY	585	FEDERAL MOUNDS	FED. MOUNDS NO. 1	SEC. 11, T16S, R11E	PAN AMERICAN PETROLEUM CORP.	0.0%	27.3%	27.3%
UTAH	EMERY	585	FEDERAL MOUNDS	FED. MOUNDS NO. 1	SEC. 11, T16S, R11E	PAN AMERICAN PETROLEUM CORP.	0.0%	26.8%	26.8%
UTAH	EMERY	585	FEDERAL MOUNDS	FED. MOUNDS NO. 1	SEC. 11, T16S, R11E	PAN AMERICAN PETROLEUM CORP.	0.0%	24.2%	24.2%
UTAH	EMERY	585	WOODSIDE	FED. NO. 44-12	SEC. 12, T19S, R13E	HOLLY RESOURCES CORP.	0.0%	33.0%	33.0%
UTAH	EMERY	585	FERRON UNIT	FERRON UNIT NO. 3	SEC. 21, T20S, R7E	PAN AMERICAN PETROLEUM CORP.	0.3%	52.4%	52.7%
UTAH	EMERY	585	FERRON UNIT	FERRON UNIT NO. 3	SEC. 21, T20S, R7E	PAN AMERICAN PETROLEUM CORP.	0.2%	51.4%	51.6%
UTAH	EMERY	585	FERRON UNIT	FERRON UNIT NO. 4	SEC. 2, T20S, R7E	PAN AMERICAN PETROLEUM CORP.	0.0%	79.0%	79.0%
UTAH	EMERY	585	WILDCAT	GOVT.-WHEATLEY NO. 1	SEC. 27, T16S, R12E	CARTER OIL CO.	0.0%	91.2%	91.2%
UTAH	EMERY	585	WILDCAT	PACKSADDLE NO. 1	SEC. 12, T18S, R12E	EL PASO NATURAL GAS CO.	0.0%	94.7%	94.7%
UTAH	EMERY	585	WOODSIDE	WOODSIDE	NOT GIVEN	UTAH OIL REFINING CO.	0.0%	28.4%	28.4%
UTAH	EMERY	585	WOODSIDE	WOODSIDE NO. 1	SEC. 12, T19S, R13E	UTAH OIL REFINING CO.	0.0%	31.7%	31.7%
UTAH	GARFIELD	585	ESCALANTE ANTICLINE	CHARGER NO. 2	SEC. 33, T32S, R3E	MID-CONTINENT OIL CO.	0.0%	98.8%	98.8%
UTAH	GARFIELD	585	ESCALANTE ANTICLINE	CHARGER NO. 4	SEC. 13, T33S, R2E	MID-CONTINENT OIL CORP.	0.0%	97.6%	97.6%
UTAH	GARFIELD	585	ESCALANTE	ESCALANTE NO. 2	SEC. 29, T32S, R3E	PHILLIPS PETROLEUM CO.	0.0%	96.1%	96.1%
UTAH	GARFIELD	585	ESCALANTE	ESCALANTE NO. 2	SEC. 29, T32S, R3E	PHILLIPS PETROLEUM CO.	0.0%	93.1%	93.1%
UTAH	GRAND	585	BAR X	BAR X UNIT NO. 4	SEC. 18, T17S, R26E	AMERICAN CLIMAX PETROLEUM CO.	0.0%	24.3%	24.3%
UTAH	GRAND	585	SAN ARROYO	NO. 6	SEC. 21, T16S, R25E	SINCLAIR OIL & GAS CO.	0.0%	23.9%	23.9%
UTAH	GRAND	585	SAN ARROYO	SAN ARROYO GOVT. NO. 1	SEC. 26, T16S, R25E	SINCLAIR OIL & GAS CO.	0.0%	26.1%	26.1%
UTAH	GRAND	585	SAN ARROYO	SAN ARROYO GOVT. NO. 2	SEC. 22, T16S, R25E	SINCLAIR OIL & GAS CO.	0.0%	24.5%	24.5%
UTAH	GRAND	585	SAN ARROYO	SAN ARROYO GOVT. NO. 3	SEC. 23, T16S, R25E	SINCLAIR OIL & GAS CO.	0.0%	23.4%	23.4%

STATE	COUNTY	BASIN	FIELD	WELL NAME/PLANT	LOCATION/PIPELINE	OWNER	H2S	CO2	SUM
UTAH	GRAND	585	SAN ARROYO	SAN ARROYO GOVT. NO. 3	SEC. 23, T16S, R25E	SINCLAIR OIL & GAS CO.	0.0%	22.7%	22.7%
UTAH	SAN JUAN	585	LISBON	ARNOLD 21-15	SEC. 15, T30S, R24E	CALIFORNIA OIL CO.	0.0%	28.7%	28.7%
UTAH	SAN JUAN	585	LISBON	ARNOLD 21-15	SEC. 15, T30S, R24E	CALIFORNIA OIL CO.	0.3%	26.3%	26.6%
UTAH	SAN JUAN	585	LISBON	BELCO NO. 2	SEC. 16, T30S, R24E	BELCO PETROLEUM CORP.	0.0%	30.2%	30.2%
UTAH	SAN JUAN	585	BIG INDIAN	BIG INDIAN U.S.A. NO. 1	SEC. 33, T29S, R24E	PURE OIL CO.	0.7%	23.5%	24.2%
UTAH	SAN JUAN	585	BLUFF UNIT	BLUFF UNIT NO. 3	SEC. 4, T40S, R23E	SHELL OIL CO.	0.0%	86.6%	86.6%
UTAH	SAN JUAN	585	BLUFF UNIT	BLUFF UNIT NO. 3	SEC. 4, T40S, R23E	SHELL OIL CO.	0.0%	85.7%	85.7%
UTAH	SAN JUAN	585	BOUNDARY BUTTE N	BOUNDARY BUTTE N NO. 1	SEC. 33, T42S, R22E	SHELL OIL CO.	0.0%	56.8%	56.8%
UTAH	SAN JUAN	585	ANTICLINE E	CANYON NO. 1	SEC. 28, T14N, R19S	UTAH SOUTHERN OIL CO.	0.0%	97.3%	97.3%
UTAH	SAN JUAN	585	COALBED CANYON	COALBED CANYON UNIT NO. 2	SEC. 20, T35S, R26E	GULF OIL CORP.	0.0%	62.3%	62.3%
UTAH	SAN JUAN	585	NOT GIVEN	DEADMAN CANYON NO. 1	SEC. 20, T37S, R24E	PAN AMERICAN PETROLEUM CORP.	0.0%	93.6%	93.6%
UTAH	SAN JUAN	585	DESERT CREEK	DESERT CREEK NO. 1	SEC. 2, T42S, R23E	SHELL OIL CO.	0.0%	77.5%	77.5%
UTAH	SAN JUAN	585	ROLLING MESA	GOVT. FEHR-LYON NO. 1	SEC. 33, T40S, R21E	CARTER OIL CO.	0.0%	69.2%	69.2%
UTAH	SAN JUAN	585	LISBON	LISBON FED. NO. 1-12	SEC. 12, T30S, R24E	PUBCO PETROLEUM CORP.	0.0%	29.0%	29.0%
UTAH	SAN JUAN	585	LISBON	LISBON VALLEY NO. 1-C	SEC. 9, T30S, R24E	ELLIOTT PRODUCTION CO.	0.0%	31.3%	31.3%
UTAH	SAN JUAN	585	LISBON	N. W. E-1	SEC. 15, T30S, R24E	PURE OIL CO.	0.0%	27.5%	27.5%
UTAH	SAN JUAN	585	NOT GIVEN	NAVAJO "D" NO. 30	SEC. 20, T40S, R24E	TEXACO INC.	0.0%	69.9%	69.9%
UTAH	SAN JUAN	585	GOTHIC AREA	NAVAJO-GOTHIC NO. 2	SEC. 36, T40S, R21E	CARTER OIL CO.	0.0%	93.4%	93.4%
UTAH	SAN JUAN	585	LISBON	NO. 1-12	SEC. 12, T30S, R24E	PUBCO PETROLEUM CORP.	0.3%	27.9%	28.2%
UTAH	SAN JUAN	585	LISBON	NO. 1-C	SEC. 9, T30S, R24E	ELLIOTT PRODUCTION CO.	0.3%	31.9%	32.2%
UTAH	SAN JUAN	585	LISBON	NO. 1-C	SEC. 9, T30S, R24E	ELLIOTT PRODUCTION CO.	0.2%	29.6%	29.8%
UTAH	SAN JUAN	585	GOTHIC MESA	NO. 30-1	SEC. 7, T41S, R21E	CARTER OIL CO.	0.0%	73.2%	73.2%
UTAH	SAN JUAN	585	LISBON	NO. A-1	SEC. 10, T30S, R24E	PURE OIL CO.	0.2%	25.8%	26.0%
UTAH	SAN JUAN	585	LISBON	NO. C-1	SEC. 4, T30S, R24E	PURE OIL CO.	0.1%	28.3%	28.4%
UTAH	SAN JUAN	585	LISBON	NO. C-3	SEC. 3, T30S, R24E	PURE OIL CO.	0.3%	23.9%	24.2%
UTAH	SAN JUAN	585	LISBON	NW B-2	SEC. 14, T30S, R24E	PURE OIL CO.	0.1%	30.6%	30.7%
UTAH	SAN JUAN	585	LISBON	NW LISBON B NO. 1	SEC. 14, T30S, R24E	PURE OIL CO.	0.6%	32.2%	32.8%
UTAH	SAN JUAN	585	LISBON	NW LISBON B NO. 1	SEC. 14, T30S, R24E	PURE OIL CO.	0.0%	24.0%	24.0%
UTAH	SAN JUAN	585	LISBON	NW LISBON NO. 2	SEC. 14, T30S, R24E	PURE OIL CO.	0.0%	21.1%	21.1%
UTAH	SAN JUAN	585	LISBON	NW LISBON NO. 3	SEC. 3, T30S, R24E	PURE OIL CO.	0.0%	26.7%	26.7%
UTAH	SAN JUAN	585	LISBON	NW LISBON NO. B-1	SEC. 14, T30S, R24E	PURE OIL CO.	0.2%	25.5%	25.7%
UTAH	SAN JUAN	585	LISBON	NW LISBON NO. B-1	SEC. 14, T30S, R24E	PURE OIL CO.	0.0%	23.5%	23.5%
UTAH	SAN JUAN	585	LISBON	NW LISBON NO. B-1	SEC. 14, T30S, R24E	PURE OIL CO.	0.0%	22.3%	22.3%
UTAH	SAN JUAN	585	LISBON	NW LISBON NO. C-1	SEC. 4, T30S, R24E	PURE OIL CO.	0.6%	27.7%	28.3%
UTAH	SAN JUAN	585	LISBON	NW LISBON NO. C-1	SEC. 4, T30S, R24E	PURE OIL CO.	1.7%	24.9%	26.6%
UTAH	SAN JUAN	585	LISBON	NW LISBON U.S.A. NO. 1	SEC. 10, T30S, R24E	PURE OIL CO.	0.1%	23.0%	23.1%
UTAH	SAN JUAN	585	LISBON	NW LISBON U.S.A. NO. 1	SEC. 10, T30S, R24E	PURE OIL CO.	0.1%	22.9%	23.0%
UTAH	SAN JUAN	585	LISBON	NW LISBON U.S.A. NO. 1	SEC. 10, T30S, R24E	PURE OIL CO.	0.2%	22.5%	22.7%
UTAH	SAN JUAN	585	LISBON	NW LISBON U.S.A. NO. 1	SEC. 10, T30S, R24E	PURE OIL CO.	0.0%	21.6%	21.6%
UTAH	SAN JUAN	585	LISBON	PIPELINE SAMPLE	LISBON UNIT WELL NO. C-93	PURE OIL CO.	0.3%	27.8%	28.1%
UTAH	SAN JUAN	585	LISBON	PUBCO LISBON FED. NO. 1-12	SEC. 12, T30S, R24E	PUBCO PETROLEUM CORP.	0.0%	26.6%	26.6%
UTAH	SAN JUAN	585	BLUFF UNIT	SHELL BLUFF UNIT NO. 1	NOT GIVEN	SHELL OIL CO.	0.0%	92.5%	92.5%
UTAH	SAN JUAN	585	LISBON	STATE NO. 2	SEC. 16, T30S, R24E	BELCO PETROLEUM CORP.	0.1%	32.9%	33.0%
UTAH	SAN JUAN	585	LISBON	STATE NO. 2	SEC. 16, T30S, R24E	BELCO PETROLEUM CORP.	0.1%	29.9%	30.0%
UTAH	SAN JUAN	585	LIME RIDGE	U.S. LIME RIDGE NO. 1	SEC. 28, T40S, R20E	KINGWOOD OIL CO.	3.9%	17.9%	21.8%
UTAH	SAN JUAN	585	LISBON	U.S.A. A-1	SEC. 10, T30S, R24E	PURE OIL CO.	1.0%	35.6%	36.6%
UTAH	SAN JUAN	585	LISBON	U.S.A. A-1	SEC. 10, T30S, R24E	PURE OIL CO.	0.2%	26.6%	26.8%
UTAH	SAN JUAN	585	WILDCAT	U.S.A. B NO. 1	SEC. 9, T35S, R25E	TEXAS PACIFIC COAL & OIL CO.	0.0%	88.6%	88.6%
UTAH	WASHINGTON	625	VIRGIN	NO. 1	SEC. 31, T41S, R11W	BARR & CO.	0.0%	86.8%	86.8%
UTAH	SEVIER	630	EMERY UNIT	EMERY UNIT NO. 1	SEC. 34, T22S, R5E	SKELLY OIL CO.	0.0%	95.7%	95.7%
UTAH	SEVIER	630	EMERY UNIT	EMERY UNIT NO. 1	SEC. 34, T22S, R5E	SKELLY OIL CO.	0.0%	92.2%	92.2%
UTAH	SEVIER	630	EMERY UNIT	EMERY UNIT NO. 1	SEC. 34, T22S, R5E	SKELLY OIL CO.	0.0%	91.7%	91.7%

STATE	COUNTY	BASIN	FIELD	WELL NAME/PLANT	LOCATION/PIPELINE	OWNER	H2S	CO2	SUM
WYOMING	HOT SPRINGS	520	HAMILTON DOME	NOT GIVEN	SEC. 13&14, T44N, R98W	ATLANTIC REFINING CO.	0.2%	96.4%	96.6%
WYOMING	PARK	520	HORSE CENTER	NO. 1	NOT GIVEN	NOT GIVEN	0.0%	98.0%	98.0%
WYOMING	PARK	520	SILVERTIP	NO. 31-33	SEC. 33, T58N, R100W	TEXACO INC.	16.2%	4.3%	20.5%
WYOMING	CARBON	535	WERTZ	PIPELINE SAMPLE	NOT GIVEN	SINCLAIR OIL & GAS CO.	0.0%	32.9%	32.9%
WYOMING	LINCOLN	535	WILDCAT	BROAD CANYON NO. 1	SEC. 28, T32N, R116W	ARCO OIL & GAS CO.	2.5%	80.4%	82.9%
WYOMING	LINCOLN	535	WILDCAT	BROAD CANYON NO. 1	SEC. 28, T32N, R116W	ARCO OIL & GAS CO.	34.9%	19.5%	54.4%
WYOMING	LINCOLN	535	BRUFF UNIT	BRUFF UNIT NO. 1	SEC. 22, T19N, R112W	MOUNTAIN FUEL SUPPLY CO.	0.0%	92.1%	92.1%
WYOMING	LINCOLN	535	BRUFF UNIT	BRUFF UNIT NO. 1	SEC. 22, T19N, R112W	MOUNTAIN FUEL SUPPLY CO.	0.0%	74.2%	74.2%
WYOMING	LINCOLN	535	CARTER CREEK	FEDERAL 1-30M	SEC. 30, T19N,R119W	CHEVRON U.S.A., INC.	21.3%	7.3%	28.6%
WYOMING	LINCOLN	535	FONTENELLE	FONTENELLE FED. NO. 35-22	SEC. 35, T26N, R112W	AMERICAN QUASAR PET. CO.	0.0%	95.9%	95.9%
WYOMING	SUBLETTE	535	RILEY RIDGE	FOGARTY CREEK UNIT NO. 11-24	SEC. 24, T28N, R115W	EXXON CO., U.S.A.	1.6%	87.2%	88.8%
WYOMING	SUBLETTE	535	RILEY RIDGE	HOBACK II UNIT, NO. 2	SEC. 15, T28N, R115W	HUMBLE OIL & REFINING CO.	3.9%	60.4%	64.3%
WYOMING	SUBLETTE	535	RILEY RIDGE	RILEY RIDGE N FED. NO. 33-24	SEC. 33, T30N, R114W	AMERICAN QUASAR PET. CO.	2.2%	76.2%	78.4%
WYOMING	SUBLETTE	535	RILEY RIDGE	RILEY RIDGE-FED. NO. 12-43	SEC. 12, T29N, R115W	AMERICAN QUASAR PET. CO.	0.1%	72.8%	72.9%
WYOMING	SUBLETTE	535	RILEY RIDGE	RILEY RIDGE-FED. NO. 8-24	SEC. 08, T29N, R114W	AMERICAN QUASAR PET. CO.	3.7%	69.4%	73.1%
WYOMING	SUBLETTE	535	RILEY RIDGE	RILEY RIDGE-FED. NO. 8-24	SEC. 08, T29N, R114W	AMERICAN QUASAR PET. CO.	4.2%	68.4%	72.6%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP 22-19G	SEC. 19, T28N, R113W	MOBIL OIL CO.	0.0%	85.5%	85.5%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP 22-19G	SEC. 19, T28N, R113W	MOBIL OIL CO.	0.0%	64.2%	64.2%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP T54-2G	SEC. 02, T28N, R114W	MOBIL OIL CORP.	3.5%	69.7%	73.2%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	1.6%	82.2%	83.8%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	1.2%	76.6%	77.8%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	4.5%	67.3%	71.8%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	4.6%	67.2%	71.8%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	6.8%	63.5%	70.3%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	6.4%	63.4%	69.8%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	5.9%	63.3%	69.2%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	5.8%	63.3%	69.1%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	6.7%	62.2%	68.9%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	6.6%	62.2%	68.8%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	6.0%	62.7%	68.7%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	6.4%	62.1%	68.5%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	6.3%	61.9%	68.2%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	6.2%	61.6%	67.8%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	2.0%	65.7%	67.7%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	5.7%	62.0%	67.7%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	5.2%	62.4%	67.6%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	6.2%	61.3%	67.5%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	6.1%	60.2%	66.3%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	5.9%	59.2%	65.1%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	5.3%	64.5%	69.8%
WYOMING	SWEETWATER	535	BRADY DEEP UNIT	BRADY NO. 11W	NOT GIVEN	CHAMPLIN PETROLEUM CO.	1.1%	27.5%	28.6%
WYOMING	SWEETWATER	535	BRADY DEEP UNIT	BRADY NO. 13W	NOT GIVEN	CHAMPLIN PETROLEUM CO.	1.1%	24.7%	25.8%
WYOMING	SWEETWATER	535	BRADY DEEP UNIT	BRADY NO. 16W	NOT GIVEN	CHAMPLIN PETROLEUM CO.	0.5%	27.6%	28.1%
WYOMING	SWEETWATER	535	BRADY DEEP UNIT	BRADY NO. 1W	NOT GIVEN	CHAMPLIN PETROLEUM CO.	0.9%	25.8%	26.7%
WYOMING	SWEETWATER	535	BRADY DEEP UNIT	BRADY NO. 2W	NOT GIVEN	CHAMPLIN PETROLEUM CO.	1.5%	24.8%	26.3%
WYOMING	SWEETWATER	535	BRADY DEEP UNIT	BRADY NO. 31N	NOT GIVEN	CHAMPLIN PETROLEUM CO.	0.0%	69.6%	69.6%
WYOMING	SWEETWATER	535	BRADY DEEP UNIT	BRADY NO. 3W	NOT GIVEN	CHAMPLIN PETROLEUM CO.	0.0%	26.4%	26.4%
WYOMING	SWEETWATER	535	BRADY DEEP UNIT	BRADY NO. 5N	NOT GIVEN	CHAMPLIN PETROLEUM CO.	0.1%	73.9%	74.0%
WYOMING	SWEETWATER	535	BRADY DEEP UNIT	BRADY NO. 8N	NOT GIVEN	CHAMPLIN PETROLEUM CO.	0.1%	72.3%	72.4%
WYOMING	SWEETWATER	535	BRADY DEEP UNIT	BRADY NO. 9N	NOT GIVEN	CHAMPLIN PETROLEUM CO.	0.3%	74.2%	74.5%
WYOMING	SWEETWATER	535	PRETTY WATER CREEK	FED. NO. 1-2	SEC. 2, T15N, R104W	GREAT WESTERN DRILLING CO.	0.0%	28.2%	28.2%
WYOMING	SWEETWATER	535	LOST SOLDIER	PIPELINE SAMPLE	SEC. 7, T26N, R89W	SINCLAIR OIL & GAS CO.	0.0%	29.3%	29.3%

STATE	COUNTY	BASIN	FIELD	WELL NAME/PLANT	LOCATION/PIPELINE	OWNER	H2S	CO2	SUM
WYOMING	SWEETWATER	535	BAXTER BASIN N	UNION PACIFIC 11-19-104 NO.4	SEC. 11, T19N, R104W	MOUNTAIN FUEL SUPPLY CO.	0.2%	72.1%	72.3%
WYOMING	SWEETWATER	535	BAXTER BASIN N	UNION PACIFIC NO. 4	SEC. 11, T19N, R104W	MOUNTAIN FUEL SUPPLY CO.	0.7%	82.0%	82.7%
WYOMING	SWEETWATER	535	CHURCH BUTTES	UNIT NO. 31	SEC. 21, T16N, R112W	WEXPRO CO.	6.2%	29.3%	35.5%
WYOMING	SWEETWATER	535	LOST SOLDIER	WEST WERTZ NO. 2	SEC. 2, T26N, R90W	SINCLAIR OIL & GAS CO.	0.0%	31.7%	31.7%
WYOMING	UINTA	535	BUTCHER KNIFE SPRINGS	BUTCHER KNIFE SPRINGS NO. 1	SEC. 29, T15N, R112W	MOUNTAIN FUEL SUPPLY CO.	11.8%	20.2%	32.0%
WYOMING	UINTA	535	BUTCHER KNIFE SPRINGS	BUTCHER KNIFE SPRINGS NO. 1	SEC. 29, T15N, R112W	MOUNTAIN FUEL SUPPLY CO.	6.4%	23.1%	29.5%
WYOMING	UINTA	535	BUTCHER KNIFE SPRINGS	BUTCHER KNIFE SPRINGS NO. 1	SEC. 29, T15N, R112W	MOUNTAIN FUEL SUPPLY CO.	4.6%	23.8%	28.4%
WYOMING	UINTA	535	CHURCH BUTTES	CHURCH BUTTES NO. 31	SEC. 9, T17N, R112W	MT. FUEL SUPPLY & CHAMPLIN PET.	0.9%	85.5%	86.4%
WYOMING	UINTA	535	CHURCH BUTTES	CHURCH BUTTES UNIT NO. 19	SEC. 8, T16N, R112W	MOUNTAIN FUEL SUPPLY CO.	0.1%	86.6%	86.7%
WYOMING	UINTA	535	CHURCH BUTTES	CHURCH BUTTES UNIT NO. 19	SEC. 8, T16N, R112W	MOUNTAIN FUEL SUPPLY CO.	0.0%	20.4%	20.4%
WYOMING	UINTA	535	WHITNEY CANYON-CARTER C	FED. NO. 2-6E	SEC. 6, T17N, R119W	CHEVRON U.S.A., INC..	0.7%	93.3%	94.0%
WYOMING	UINTA	535	WHITNEY CANYON-CARTER C	FED. NO. 2-6E	SEC. 6, T17N, R119W	CHEVRON U.S.A., INC.	12.9%	23.3%	36.2%
WYOMING	UINTA	535	CHURCH BUTTES	UNIT NO. 19	SEC. 8, T16N, R112W	MOUNTAIN FUEL SUPPLY CO.	3.7%	22.9%	26.6%

ORIS_CODE	UNIT_ ID	YEAR	MONTH	CO2_ TONS	CO2_ CONCENTRATION	SO2_ TONS	NOX_ TONS	MERCURY_ LBS	HEAT_ INPUT	TOTAL_ OPERATING _HOURS	FUEL_ TYPE_ COMBUSTED
1233	4	1980	0			31			3025789		
1233	4	1985	0			1			1605856		
1233	4	1990	0			1			2672220		
1233	4	1995	0	82736		1	145		1392189		
1233	4	1996	0	280307		115.6	454		4615376		
1233	4	1997	1	17191.2	0.045	0.1	22.1		289273	680	15
1233	4	1997	2	14863.7	0.045	0.1	19		250108	672	15
1233	4	1997	3	19060.7	0.045	0.1	25.3		320745	744	15
1233	4	1997	4	17829.5	0.045	0.1	32.3		300013	455	15
1233	4	1997	5	2208.4	0.045		3.1		37153	107	15
1233	4	1997	6	27053.7	0.045	0.1	52.4		455226	720	15
1233	4	1997	7	35441.3	0.045	0.2	76.5		596344	744	15
1233	4	1997	8	27853	0.045	0.1	48.9		468663	744	15
1233	4	1997	9	22031.9	0.045	0.1	41.9		370738	644	15
1233	4	1997	10	27683.8	0.045	0.1	44.7		465842	744	15
1233	4	1997	11	29728.2	0.045	0.1	53		500225	720	15
1233	4	1997	12	24836	0.045	0.1	38.8		417914	744	15
1233	4	1998	1	20438.3	0.045	0.1	28.7		343930	744	15
1233	4	1998	2	17697.2	0.045	0.1	23.8		297795	672	15
1233	4	1998	3	12238.8	0.045	0.1	22.4		205950	288	15
1233	4	1998	4		0.045						15
1233	4	1998	5	9683.3	0.045		19.7		162944	294	15
1233	4	1998	6	30693.9	0.045	0.2	64		516488	720	15
1233	4	1998	7	35574.4	0.045	0.2	69.6		598588	744	15
1233	4	1998	8	36804.5	0.045	0.2	79.5		619272	744	15
1233	4	1998	9	40651	0.045	0.2	94.6		684017	720	15
1233	4	1998	10	14484.2	0.045	0.1	24.9		243735	450	15
1233	4	1998	11	26046.2	0.045	0.1	51.7		438288	720	15
1233	4	1998	12	20807	0.045	0.1	31.6		350105	744	15
1233	4	1999	1	21338.5	0.045	0.1	35.9		359072	744	15
1233	4	1999	2	21522.5	0.045	0.1	42.4		362181	672	15
1233	4	1999	3	16878.8	0.045	0.1	38.6		284021	421	15
1233	4	1999	4	31698.8	0.045	0.2	82.7		533394	665	15
1233	4	1999	5	26409.8	0.045	0.1	56.9		444398	744	15
1233	4	1999	6	25290.2	0.045	0.1	50.7		425539	720	15
1233	4	1999	7	41694.7	0.045	0.2	114.1		701594	744	15
1233	4	1999	8	36477.2	0.045	0.2	64.3		613802	744	15
1233	4	1999	9	17226.7	0.045	0.1	33.4		289874	562	15
1233	4	1999	10	15738	0.045	0.1	20.3		264819	600	15

ORIS_CODE	UNIT_ ID	YEAR	MONTH	CO2_ TONS	CO2_ CONCENTR ATION	SO2_ TONS	NOX_ TONS	MERCURY_ LBS	HEAT_ INPUT	TOTAL_ OPERATING _HOURS	FUEL_ TYPE_ COMBUSTED
1233	4	1999	11	20510.3	0.045	0.1	36.8		345126	720	15
1233	4	1999	12	23131.9	0.045	0.1	47.4		389203	744	15
1233	4	2000	1	23652.1	0.045	0.1	42.9		397988	744	15
1233	4	2000	2	23380.9	0.045	0.1	48.8		393433	696	15
1233	4	2000	3	13299	0.045	0.1	26.6		223776	479	15
1233	4	2000	4	25761.3	0.045	0.1	63.9		433491	715	15
1233	4	2000	5	30858.3	0.045	0.2	78.1		519254	744	15
1233	4	2000	6	24799.3	0.045	0.1	48.7		417286	720	15
1233	4	2000	7	30418.3	0.045	0.2	73.1		511820	744	15
1233	4	2000	8	36241.2	0.045	0.2	105.5		609833	744	15
1233	4	2000	9	23717.7	0.045	0.1	56.6		399090	705	15
1233	4	2000	10	15988.4	0.045	0.1	33		269019	513	15
1233	4	2000	11	21916	0.045	0.1	49		368774	720	15
1233	4	2000	12	28759.5	0.045	0.1	70.4		483942	744	15
1233	4	2001	1	18746.8	0.045	0.1	27.9		315468	744	15
1233	4	2001	2	17194.7	0.045	0.1	27.3		289322	672	15
1233	4	2001	3	20551.1	0.045	0.1	42.6		345797	744	15
1233	4	2001	4	9647.6	0.045		20.7		162333	300	15
1233	4	2001	5	18897.3	0.045	0.1	38.7		317993	657	15
1233	4	2001	6	18118.6	0.045	0.1	28.9		304892	720	15
1233	4	2001	7	27743.4	0.045	0.1	61.6		466829	744	15
1233	4	2001	8	32576.9	0.045	0.2	79.8		548173	743	15
1233	4	2001	9	20393.7	0.045	0.1	33.6		343177	720	15
1233	4	2001	10	8424.4	0.045		14.6		141754	304	15
1233	4	2001	11	18823.1	0.045	0.1	30.5		316747	720	15
1233	4	2001	12	18644	0.045	0.1	28.3		313711	743	15
1233	4	2002	1	19756.7	0.045	0.1	32.6		332450	744	15
1233	4	2002	2	18809.2	0.045	0.1	32.3		316519	672	15
1233	4	2002	3	23903.1	0.045	0.1	43.2		402216	744	15
1233	4	2002	4	3342.1	0.045		4.4		56222	120	15
1233	4	2002	5		0.045						15
1233	4	2002	6	10976.4	0.045	0.1	13.8		184695	446	15
1233	4	2002	7	33404.9	0.045	0.2	89.5		562084	744	15
1233	4	2002	8	31563.4	0.045	0.2	73.5		531108	744	15
1233	4	2002	9	24972.8	0.045	0.1	50.7		420208	720	15
1233	4	2002	10	10030.6	0.045		12.5		168779	408	15
1233	4	2002	11	18948.8	0.045	0.1	25.3		318853	720	15
1233	4	2002	12	20546	0.045	0.1	30		345717	744	15
1328	ALL	1996	0	1440		0.495	33				

ORIS_CODE	UNIT_ ID	YEAR	MONTH	CO2_ TONS	CO2_ CONCENTR ATION	SO2_ TONS	NOX_ TONS	MERCURY_ LBS	HEAT_ INPUT	TOTAL_ OPERATING _HOURS	FUEL_ TYPE_ COMBUSTED
1328	ALL	1997	0	3216.73		0.15	78.02				
1328	ALL	1998	0	4073.05	0.045	0.21	100.85				15
1328	ALL	1999	0	3735.93	0.045	0.79	88.8				15
1328	ALL	2000	0	3099.87	0.045	0.37	73.7				15
1319	ALL	1996	0	28220		7	660				
1319	ALL	1997	0	18895.98		1.18	459.76				
1319	ALL	1998	0	25219.07	0.045	1.68	626.94				15
1319	ALL	1999	0	33963.88	0.045	7.87	805.89				15
1319	ALL	2000	0	24137.59	0.045	3.37	571.56				15
1225	ALL	1998	0	516.24	0.045	0.35	2.04				15
1225	ALL	1999	0	1170.84	0.045	0.1	3.36				15
1225	ALL	2000	0	1326.33	0.045	0.04	3.68				15
1251	ALL	1996	0	2753		0.239	11				
1251	ALL	1997	0	2861.74		0.02	11.2				
1251	ALL	1998	0	7495.43	0.045	0.22	21.08				15
1251	ALL	1999	0	4981.66	0.045	0.15	13.84				15
1251	ALL	2000	0	5893.58	0.045	1.31	20				15
1267	ALL	1996	0	8							
1267	ALL	1997	0	40.75		0.02	1.07				
1267	ALL	1998	0	5.57	0		0.15				26
1270	ALL	1996	0	648382		4	1543				
1270	ALL	1997	0	572384.2		10.4	1381.86				
1270	ALL	1998	0	16886.41	0.045	0.4	113.62				15
1270	ALL	1999	0	17639.5	0.045	1.21	87.48				15
1270	ALL	2000	0	20396.87	0.045	1.16	152.76				15
1299	ALL	1996	0	11477		0.383	77				
1299	ALL	1997	0	11844.57		0.08	33.6				
1299	ALL	1998	0	13640.87	0.045	0.13	38.16				15
1299	ALL	1999	0	11970.64	0.045	0.27	43.52				15
1299	ALL	2000	0	8378.12	0.045	0.46	64.07				15
1316	ALL	1996	0	3263		1	54				
1316	ALL	1997	0	4189.32		0.52	96.74				
1316	ALL	1998	0	6993.23	0.045	0.78	128.39				15
1316	ALL	2000	0	10992.2	0.045	1.58	115.54				15
1330	ALL	1996	0	13986		0.072	64				
1330	ALL	1997	0	12384.53		0.06	29.15				

ID	EGRID_CODE	EPA_CODE	DESCRIPTION_SPECIFIC	DESCRIPTION_ GENERIC	CO2_ CONCENTRATION
1	AB		Agricultural Byproduct	Biomass	0
2	AC		Anthracite Coal	Coal	0.12
3	BFG	PRG	Blast Furnace Gas	Other Gas	0
4	BG		Bituminous Gob	Coal	0.12
5	BIOMASS		Biomass	Biomass	0
6	BIT		Bituminous Coal	Coal	0.12
7	BL		Black Liquor	Biomass	0
8	CB		Cell Burner	Coal	0.12
9	COL	C	Coal	Coal	0.12
10		CRF	Coal Refuse	Coal	0.12
11	DFO	DSL	Diesel Fuel Oil	Diesel Oil	0
12	DG		Digester Gas	Other Gas	0
13	DI		Diesel	Diesel Oil	0
14	FO1		Fuel Oil	Diesel Oil	0
15	GAS	PNG	Natural Gas	Natural Gas	0.045
16	GE		Geothermal	Geothermal	0
17	HY		Hydro	Hydro	0
18	KE		Kerosene	Other Oil	0.06
20	LF		Landfill Gas	Other Gas	0
21		LPG	Liquid Petroleum Gas	Other Gas	0
22	LW		Lignite Waste	Coal	0.12
23	MW	R	Municipal Waste	Other	0
24	NG	NNG	Natural Gas	Natural Gas	0.045
25	OG	OGS	Other Gas	Other Gas	0
26	OIL	OIL	Residual Oil	Other Oil	0
27		OSF	Other Solid Fuel	Other	0
28	OW	OOL	Oil Waste	Other Oil	0
29	PC		Petroleum Coke	Other Oil	0
30	PET		Petroleum	Diesel Oil	0
31		PRS	Process Sludge	Other	0
32	RT		Railroad Ties	Biomass	0
33	SL		Solar	Solar	0
34	SS		Spent Sulfite Liquor	Biomass	0
35	SU		Sulfur	Other	0
36	TI		Tires	Other Gas	0
37	UR		Uranium	Nuclear	0
38	WC		Waste Coal	Coal	0.12
39	WH		Waste Heat	Other	0
40		WL	Waste Liquid	Other	0
41	WT		Water	Hydro	0
42	WW	W	Waste Wood	Biomass	0

RBLCID	ORIS_CODE	FACILITY_NAME	FACILITY_TYPE	OWNER_NAME	OWNER_TYPE	OPERATOR_NAME	COMPANY_NAME	STREET_ADDRESS	CITY
	50805	ABITIBI CONSOLIDATED SNOWFLAKE DIVISION	NON-UTILITY	Abitibi Consolidated		Abitibi Consolidated			
	141	Agua Fria Generating Station							
	160	Apache Station							
	118	APS Saguaro Power Plant							
	54594	BIOSPHERE 2 CENTER INC	NON-UTILITY	Decisions Investments Corp		Biosphere 2 Center Inc			
	55780	Bowie Power Station							
	112	CHILDS	UTILITY	Arizona Public Service Co		Arizona Public Service Co	Pinnacle West Capital Corporation		
	113	Cholla							
	6177	Coronado Generating Station							
	143	Crosscut							
	152	DAVIS	UTILITY	USBR-Lower Colorado Region		USBR-Lower Colorado Region	US Bureau Of Reclamation		
	124	De Moss Petrie Generating Station							
AZ-0044	55129	Desert Basin Generating Station							
	114	DOUGLAS	UTILITY	Arizona Public Service Co		Arizona Public Service Co	Pinnacle West Capital Corporation		
AZ-0035	55282	Duke Energy Arlington Valley							
	923	Gila Bend							
AZ-0038	55507	Gila Bend Power Generation Station							
AZ-0037	55306	Gila River Power Station							
	153	GLEN CANYON	UTILITY	USBR-Upper Colorado Region		USBR-Upper Colorado Region	US Bureau Of Reclamation		
	54838	GOULD ELECTRONICS FOIL DIVISION	NON-UTILITY	Japan Energy Corp Ltd		Japan Energy Corp Ltd			
	55124	Griffith Energy LLC							
AZ-0034	55372	Harquahala Generating Project							
	8902	HOOVER	UTILITY	USBR-Lower Colorado Region		USBR-Lower Colorado Region	US Bureau Of Reclamation		
	145	HORSE MESA	UTILITY	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist			
	55257	INA ROAD WATER POLLUTION CONTROL FACILITY	NON-UTILITY	PIMA County Wastewater Manage		PIMA County Wastewater Manage			
	10564	INTERMOUNTAIN REFINING COMPANY, INC	NON-UTILITY	INTERMOUNTAIN REFINING CO (NM)		INTERMOUNTAIN REFINING CO	N/A		
	115	IRVING	UTILITY	Arizona Public Service Co		Arizona Public Service Co	Pinnacle West Capital Corporation		
	126	Irvington Generating Station							
AZ-0041	147	Kyrene Generating Station							
	55711	La Paz Generating Facility							
AZ-0033	55481	Mesquite Generating Station							
	148	MORMON FLAT	UTILITY	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist			
	4941	Navajo Generating Station							
	54245	NELSON PLANT GENERATORS	NON-UTILITY	Chemical Lime Co		Chemical Lime Co			
	50738	NEW CORNELIA BRANCH POWER PLANT	NON-UTILITY	Phelps Dodge Corp		Phelps Dodge Corp			

RBLCID	ORIS_CODE	FACILITY_NAME	FACILITY_TYPE	OWNER_NAME	OWNER_TYPE	OPERATOR_NAME	COMPANY_NAME	STREET_ADDRESS	CITY
	54949	NORDIC POWER OF SOUTH POINT I	NON-UTILITY	NORDIC POWER OF SOUTH POINT I (MI)		NORDIC POWER OF SOUTH POINT I	N/A		
	6088	NORTH LOOP	UTILITY	Tucson Electric Power Co		Tucson Electric Power Co	UniSource Energy Corporation		
	116	Ocotillo Power Plant							
	6008	PALO VERDE	UTILITY	Arizona Public Service Co		Arizona Public Service Co	Pinnacle West Capital Corporation		
AZ-0045	55522	PPL Sundance Energy, LLC							
AZ-0036	55455	Redhawk Generating Facility							
	149	ROOSEVELT	UTILITY	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist			
AZ-0039	8068	Santan							
	55692	Signal Peak Generating Facility							
	100	SOUTH CONSOLIDATED	UTILITY	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist			
	55177	South Point Energy Center, LLC							
	8223	Springerville Generating Station							
	50238	STARWOOD HOTELS RESORTS	NON-UTILITY	Starwood Hotels Resorts		Starwood Hotels Resorts			
	150	STEWART MTN	UTILITY	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist			
	6515	VALENCIA	UTILITY	Citizens Utilities Co-AZ		Citizens Utilities Co-AZ	Citizens Utilities Co		
AZ-0040	117	West Phoenix Power Plant							
	120	Yuma Axis							
	54694	YUMA COGENERATION ASSOCIATES	NON-UTILITY	Yuma Cogeneration Associates		Yuma Cogeneration Associates			
	464	Alamosa							
	10755	AMERICAN ATLAS 1 COGENERATION PLANT	NON-UTILITY	American Atlas #1 Ltd		American Atlas #1 Ltd			
	54630	AMERICAN GYPSUM COGENERATION	NON-UTILITY	Centex Eagle Gypsum Co LLC		Centex Eagle Gypsum Co LLC			
	6207	AMES	UTILITY	Public Service Co of Colorado	PRIVATELY OWNED	Public Service Co of Colorado	Xcel Energy Inc		
	465	Arapahoe							
CO-0049	55200	Arapahoe Combustion Turbine							
	54680	BETASSO HYDROELECTRIC PLANT	NON-UTILITY	City of Boulder		City of Boulder			
	515	BIG THOMPSON	UTILITY	USBR-Great Plains Region		USBR-Great Plains Region	US Bureau Of Reclamation		
	512	BLUE MESA	UTILITY	USBR-Upper Colorado Region		USBR-Upper Colorado Region	US Bureau Of Reclamation		
	55645	Blue Spruce Energy Center							
	466	BOULDER	NON-UTILITY	City of Boulder		City of Boulder			
	10682	Brush 3							
	55209	Brush 4							
CO-0027 & CO-0045	10683	BRUSH COGEN PROJECT PHASE 2 BCP	NON-UTILITY	Brush Power, LLC		Colorado Cogeneration Operator			
	6619	BURLINGTON	UTILITY	Tri-State G & T Assn Inc		Tri-State G & T Assn Inc			
	467	CABIN CREEK	UTILITY	Public Service Co of Colorado		Public Service Co of Colorado	Xcel Energy Inc		
	468	Cameo							

RBLCID	ORIS_CODE	FACILITY_NAME	FACILITY_ TYPE	OWNER_NAME	OWNER_ TYPE	OPERATOR_ NAME	COMPANY_ NAME	STREET_ ADDRESS	CITY
	469	Cherokee							
	54679	CITY OF BOULDER - LAKEWOOD HYDROELECTRIC PLT	NON-UTILITY	BOULDER CITY OF (CO)		BOULDER CITY OF	N/A		

ORIS_CODE	FACILITY_NAME	COUNTY_ NAME	COUNTY_ CODE_ FIPS	STATE	ZIP_PLUS_4	LATITUDE	LONGITUDE	LAT_ LONG_ DATUM	LAT_ LONG_ SOURCE	POWER_ CAPACITY_ MW
50805	ABITIBI CONSOLIDATED SNOWFLAKE DIVISION		17	AZ		35.2863	-110.2885		EGRID	70.55
141	Agua Fria Generating Station	Maricopa	13	AZ		33.5569	-112.22		EPA	
160	Apache Station	Cochise	3	AZ		32.0556	-109.89		EPA	
118	APS Saguaro Power Plant	Pinal	21	AZ		32.5522	-111.3		EPA	
54594	BIOSPHERE 2 CENTER INC		21	AZ		32.9836	-111.3255		EGRID	3.05
55780	Bowie Power Station			AZ					EPA	
112	CHILDS		25	AZ		34.7053	-112.4042		EGRID	5.4
113	Cholla	Navajo	17	AZ		34.9414	-110.3		EPA	
6177	Coronado Generating Station	Apache	1	AZ		34.5778	-109.27		EPA	
143	Crosscut	Maricopa	13	AZ					EPA	
152	DAVIS		15	AZ		35.6134	-113.6474		EGRID	240
124	De Moss Petrie Generating Station	Pima	19	AZ		32.25	-110.98		EPA	
55129	Desert Basin Generating Station	Pinal	21	AZ					EPA	
114	DOUGLAS		3	AZ		31.8799	-109.754		EGRID	21.4
55282	Duke Energy Arlington Valley	Maricopa	13	AZ					EPA	
923	Gila Bend	Maricopa	13	AZ		33.2765	-111.88		EPA	
55507	Gila Bend Power Generation Station	Maricopa	13	AZ					EPA	
55306	Gila River Power Station	Maricopa	13	AZ					EPA	
153	GLEN CANYON		5	AZ		35.6337	-112.0444		EGRID	1296
54838	GOULD ELECTRONICS FOIL DIVISION		13	AZ		33.35	-112.49		EGRID	1.05
55124	Griffith Energy LLC	Mohave	15	AZ					EPA	
55372	Harquahala Generating Project	Maricopa	13	AZ					EPA	
8902	HOOVER		15	AZ		35.6134	-113.6474		EGRID	1039.4
145	HORSE MESA		13	AZ		33.35	-112.49		EGRID	129.58
55257	INA ROAD WATER POLLUTION CONTROL FACILITY		19	AZ		31.9699	-111.8899		EGRID	4.54
10564	INTERMOUNTAIN REFINING COMPANY, INC		5	AZ		35.6337	-112.0444		EGRID	3
115	IRVING		25	AZ		34.7053	-112.4042		EGRID	1.6
126	Irvington Generating Station	Pima	19	AZ		32.16	-110.9		EPA	
147	Kyrene Generating Station	Maricopa	13	AZ		33.3547	-111.94		EPA	
55711	La Paz Generating Facility			AZ					EPA	
55481	Mesquite Generating Station	Maricopa	13	AZ					EPA	
148	MORMON FLAT		13	AZ		33.35	-112.49		EGRID	57.85
4941	Navajo Generating Station	Coconino	5	AZ		36.9125	-111.39		EPA	
54245	NELSON PLANT GENERATORS		15	AZ		35.6134	-113.6474		EGRID	2.27
50738	NEW CORNELIA BRANCH POWER PLANT		19	AZ		31.9699	-111.8899		EGRID	10.5

ORIS_CODE	FACILITY_NAME	COUNTY_ NAME	COUNTY_ CODE_ FIPS	STATE	ZIP_PLUS_4	LATITUDE	LONGITUDE	LAT_ LONG_ DATUM	LAT_ LONG_ SOURCE	POWER_ CAPACITY_ MW
54949	NORDIC POWER OF SOUTH POINT I		15	AZ		35.6134	-113.6474		EGRID	233.2
6088	NORTH LOOP		19	AZ		31.9699	-111.8899		EGRID	81
116	Ocotillo Power Plant	Maricopa	13	AZ		33.4467	-111.94		EPA	
6008	PALO VERDE		13	AZ		33.35	-112.49		EGRID	4209.57
55522	PPL Sundance Energy, LLC	Pinal	21	AZ					EPA	
55455	Redhawk Generating Facility	Maricopa	13	AZ					EPA	
149	ROOSEVELT		13	AZ		33.35	-112.49		EGRID	36.02
8068	Santan			AZ					EPA	
55692	Signal Peak Generating Facility			AZ					EPA	
100	SOUTH CONSOLIDATED		13	AZ		33.35	-112.49		EGRID	1.4
55177	South Point Energy Center, LLC	Mohave	15	AZ					EPA	
8223	Springerville Generating Station	Apache	1	AZ		34.3186	-109.16		EPA	
50238	STARWOOD HOTELS RESORTS		13	AZ		33.35	-112.49		EGRID	1.65
150	STEWART MTN		13	AZ		33.35	-112.49		EGRID	10.4
6515	VALENCIA		23	AZ		31.532	-110.909		EGRID	54.4
117	West Phoenix Power Plant	Maricopa	13	AZ		33.4428	-112.15		EPA	
120	Yuma Axis	Yuma	27	AZ		33.22	-113.94		EPA	
54694	YUMA COGENERATION ASSOCIATES		27	AZ		32.7504	-114.0678		EGRID	62.64
464	Alamosa	Alamosa	3	CO					EPA	
10755	AMERICAN ATLAS 1 COGENERATION PLANT		45	CO		39.7286	-107.5255		EGRID	85
54630	AMERICAN GYPSUM COGENERATION		37	CO		39.6415	-106.6443		EGRID	9.85
6207	AMES		113	CO		37.9645	-108.3899		EGRID	3.6
465	Arapahoe	Denver	31	CO		39.67	-105.003		EPA	
55200	Arapahoe Combustion Turbine	Denver	31	CO					EPA	
54680	BETASSO HYDROELECTRIC PLANT		13	CO		40.0884	-105.3453		EGRID	3
515	BIG THOMPSON		69	CO		40.6281	-105.5665		EGRID	4.5
512	BLUE MESA		51	CO		38.7019	-106.9407		EGRID	86.4
55645	Blue Spruce Energy Center	Adams	1	CO					EPA	
466	BOULDER		31	CO		39.7114	-104.9217		EGRID	20
10682	Brush 3	Morgan	87	CO		40.1506	103.3722		EPA	
55209	Brush 4	Morgan	87	CO		40.1506	103.3722		EPA	
10683	BRUSH COGEN PROJECT PHASE 2 BCP		87	CO		40.2627	-103.807		EGRID	74
6619	BURLINGTON		63	CO		39.3061	-102.6048		EGRID	129.4
467	CABIN CREEK		19	CO		39.7085	-105.6604		EGRID	300
468	Cameo	Mesa	77	CO		39.1333	-108.32		EPA	

ORIS_CODE	FACILITY_NAME	COUNTY_ NAME	COUNTY_ CODE_ FIPS	STATE	ZIP_PLUS_4	LATITUDE	LONGITUDE	LAT_ LONG_ DATUM	LAT_ LONG_ SOURCE	POWER_ CAPACITY_ MW
469	Cherokee	Denver	31	CO		39.8083	-105.97		EPA	
54679	CITY OF BOULDER - LAKEWOOD HYDROELECTRIC PLT		13	CO		40.0884	-105.3453		EGRID	1.5

RBLCID	FACILITY	COMPANY	COUNTY	CONTACT	ADDRESS	CITY	STATE	ZIP	PHONE	EMAIL	REGION	AGENCY CODE	AGENCYNAME	AGENCY CONTACT	AGENCY PHONE	AGENCY EMAIL	PERMITNUM	SIC	NAICS	AIRSID	EPAID	UTM ZONE	XCOORD	YCOORD	RCVD DATE	PERMIT DATE	STARTUP DATE	VERIFY DATE
UT-0059	ASH GROVE CEMENT COMPANY	ASH GROVE CEMENT COMPANY	JUAB	KEN WARE	PO BOX 51	NEPHI		84648	801-857-1202		8	UT001	UTAH BUREAU OF AIR QUALITY	TIM BLANCHARD	(801) 536-4057		DAQE-958-96	3241				12	390000	4377500		10/24/1996		
UT-0059	ASH GROVE CEMENT COMPANY	ASH GROVE CEMENT COMPANY	JUAB	KEN WARE	PO BOX 51	NEPHI		84648	801-857-1202		8	UT001	UTAH BUREAU OF AIR QUALITY	TIM BLANCHARD	(801) 536-4057		DAQE-958-96	3241				12	390000	4377500		10/24/1996		
UT-0059	ASH GROVE CEMENT COMPANY	ASH GROVE CEMENT COMPANY	JUAB	KEN WARE	PO BOX 51	NEPHI		84648	801-857-1202		8	UT001	UTAH BUREAU OF AIR QUALITY	TIM BLANCHARD	(801) 536-4057		DAQE-958-96	3241				12	390000	4377500		10/24/1996		
UT-0059	ASH GROVE CEMENT COMPANY	ASH GROVE CEMENT COMPANY	JUAB	KEN WARE	PO BOX 51	NEPHI		84648	801-857-1202		8	UT001	UTAH BUREAU OF AIR QUALITY	TIM BLANCHARD	(801) 536-4057		DAQE-958-96	3241				12	390000	4377500		10/24/1996		
UT-0059	ASH GROVE CEMENT COMPANY	ASH GROVE CEMENT COMPANY	JUAB	KEN WARE	PO BOX 51	NEPHI		84648	801-857-1202		8	UT001	UTAH BUREAU OF AIR QUALITY	TIM BLANCHARD	(801) 536-4057		DAQE-958-96	3241				12	390000	4377500		10/24/1996		
UT-0059	ASH GROVE CEMENT COMPANY	ASH GROVE CEMENT COMPANY	JUAB	KEN WARE	PO BOX 51	NEPHI		84648	801-857-1202		8	UT001	UTAH BUREAU OF AIR QUALITY	TIM BLANCHARD	(801) 536-4057		DAQE-958-96	3241				12	390000	4377500		10/24/1996		
UT-0059	ASH GROVE CEMENT COMPANY	ASH GROVE CEMENT COMPANY	JUAB	KEN WARE	PO BOX 51	NEPHI		84648	801-857-1202		8	UT001	UTAH BUREAU OF AIR QUALITY	TIM BLANCHARD	(801) 536-4057		DAQE-958-96	3241				12	390000	4377500		10/24/1996		
UT-0059	ASH GROVE CEMENT COMPANY	ASH GROVE CEMENT COMPANY	JUAB	KEN WARE	PO BOX 51	NEPHI		84648	801-857-1202		8	UT001	UTAH BUREAU OF AIR QUALITY	TIM BLANCHARD	(801) 536-4057		DAQE-958-96	3241				12	390000	4377500		10/24/1996		
UT-0059	ASH GROVE CEMENT COMPANY	ASH GROVE CEMENT COMPANY	JUAB	KEN WARE	PO BOX 51	NEPHI		84648	801-857-1202		8	UT001	UTAH BUREAU OF AIR QUALITY	TIM BLANCHARD	(801) 536-4057		DAQE-958-96	3241				12	390000	4377500		10/24/1996		
UT-0059	ASH GROVE CEMENT COMPANY	ASH GROVE CEMENT COMPANY	JUAB	KEN WARE	PO BOX 51	NEPHI		84648	801-857-1202		8	UT001	UTAH BUREAU OF AIR QUALITY	TIM BLANCHARD	(801) 536-4057		DAQE-958-96	3241				12	390000	4377500		10/24/1996		
UT-0059	ASH GROVE CEMENT COMPANY	ASH GROVE CEMENT COMPANY	JUAB	KEN WARE	PO BOX 51	NEPHI		84648	801-857-1202		8	UT001	UTAH BUREAU OF AIR QUALITY	TIM BLANCHARD	(801) 536-4057		DAQE-958-96	3241				12	390000	4377500		10/24/1996		
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	HOLNAM, DEVIL'S SLIDE PLANT	MORGAN	KEVIN OVARD	6055 EAST CROYDEN ROAD	MORGAN		84050	801-829-6821		8	UT001	UTAH BUREAU OF AIR QUALITY	JOHN JENKS	(801) 536-4000		DAQE-522-96	3241	32731			12	455.4	4545.8	3/29/1996	5/13/1996		
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	HOLNAM, DEVIL'S SLIDE PLANT	MORGAN	KEVIN OVARD	6055 EAST CROYDEN ROAD	MORGAN		84050	801-829-6821		8	UT001	UTAH BUREAU OF AIR QUALITY	JOHN JENKS	(801) 536-4000		DAQE-522-96	3241	32731			12	455.4	4545.8	3/29/1996	5/13/1996		
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	HOLNAM, DEVIL'S SLIDE PLANT	MORGAN	KEVIN OVARD	6055 EAST CROYDEN ROAD	MORGAN		84050	801-829-6821		8	UT001	UTAH BUREAU OF AIR QUALITY	JOHN JENKS	(801) 536-4000		DAQE-522-96	3241	32731			12	455.4	4545.8	3/29/1996	5/13/1996		
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	HOLNAM, DEVIL'S SLIDE PLANT	MORGAN	KEVIN OVARD	6055 EAST CROYDEN ROAD	MORGAN		84050	801-829-6821		8	UT001	UTAH BUREAU OF AIR QUALITY	JOHN JENKS	(801) 536-4000		DAQE-522-96	3241	32731			12	455.4	4545.8	3/29/1996	5/13/1996		
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	HOLNAM, DEVIL'S SLIDE PLANT	MORGAN	KEVIN OVARD	6055 EAST CROYDEN ROAD	MORGAN		84050	801-829-6821		8	UT001	UTAH BUREAU OF AIR QUALITY	JOHN JENKS	(801) 536-4000		DAQE-522-96	3241	32731			12	455.4	4545.8	3/29/1996	5/13/1996		
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	HOLNAM, DEVIL'S SLIDE PLANT	MORGAN	KEVIN OVARD	6055 EAST CROYDEN ROAD	MORGAN		84050	801-829-6821		8	UT001	UTAH BUREAU OF AIR QUALITY	JOHN JENKS	(801) 536-4000		DAQE-522-96	3241	32731			12	455.4	4545.8	3/29/1996	5/13/1996		

RBLCID	FACILITY	COMPANY	COUNTY	CONTACT	ADDRESS	CITY	STATE	ZIP	PHONE	EMAIL	REGION	AGENCY CODE	AGENCYNAME	AGENCY CONTACT	AGENCY PHONE	AGENCY EMAIL	PERMITNUM	SIC	NAICS	AIRSID	EPAID	UTM ZONE	XCOORD	YCOORD	RCVD DATE	PERMIT DATE	STARTUP DATE	VERIFY DATE
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	HOLNAM, DEVIL'S SLIDE PLANT	MORGAN	KEVIN OVARD	6055 EAST CROYDEN ROAD	MORGAN		84050	801-829-6821		8	UT001	UTAH BUREAU OF AIR QUALITY	JOHN JENKS	(801) 536-4000		DAQE-522-96	3241	32731			12	455.4	4545.8	3/29/1996	5/13/1996		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	CLARK		1714 W. BONANZA ROAD	LAS VEGAS		-89106			9	NV002	CLARK CO DEPT OF AIR QUALITY MANAGEMENT	DAVID C. LEE	(702) 383-1276		A139	3241							10/15/1993	10/24/1995		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	CLARK		1714 W. BONANZA ROAD	LAS VEGAS		-89106			9	NV002	CLARK CO DEPT OF AIR QUALITY MANAGEMENT	DAVID C. LEE	(702) 383-1276		A139	3241							10/15/1993	10/24/1995		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	CLARK		1714 W. BONANZA ROAD	LAS VEGAS		-89106			9	NV002	CLARK CO DEPT OF AIR QUALITY MANAGEMENT	DAVID C. LEE	(702) 383-1276		A139	3241							10/15/1993	10/24/1995		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	CLARK		1714 W. BONANZA ROAD	LAS VEGAS		-89106			9	NV002	CLARK CO DEPT OF AIR QUALITY MANAGEMENT	DAVID C. LEE	(702) 383-1276		A139	3241							10/15/1993	10/24/1995		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	CLARK		1714 W. BONANZA ROAD	LAS VEGAS		-89106			9	NV002	CLARK CO DEPT OF AIR QUALITY MANAGEMENT	DAVID C. LEE	(702) 383-1276		A139	3241							10/15/1993	10/24/1995		
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NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	CLARK		1714 W. BONANZA ROAD	LAS VEGAS		-89106			9	NV002	CLARK CO DEPT OF AIR QUALITY MANAGEMENT	DAVID C. LEE	(702) 383-1276		A139	3241							10/15/1993	10/24/1995		
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	ALBANY		5 SAND CREEK ROAD	LARAMIE		-82070			8	WY001	WYOMING AIR QUAL DIV, DEPT OF ENV QUAL	CHAD SCHLICHTMEIER-DISTRICT 1	(307) 777-7391		CT-1137	3241		56-001-00002					5/16/1994	3/6/1995	1/31/1996	4/24/1996
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	ALBANY		5 SAND CREEK ROAD	LARAMIE		-82070			8	WY001	WYOMING AIR QUAL DIV, DEPT OF ENV QUAL	CHAD SCHLICHTMEIER-DISTRICT 1	(307) 777-7391		CT-1137	3241		56-001-00002					5/16/1994	3/6/1995	1/31/1996	4/24/1996
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WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	ALBANY		5 SAND CREEK ROAD	LARAMIE		-82070			8	WY001	WYOMING AIR QUAL DIV, DEPT OF ENV QUAL	CHAD SCHLICHTMEIER-DISTRICT 1	(307) 777-7391		CT-1137	3241		56-001-00002					5/16/1994	3/6/1995	1/31/1996	4/24/1996
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	ALBANY		5 SAND CREEK ROAD	LARAMIE		-82070			8	WY001	WYOMING AIR QUAL DIV, DEPT OF ENV QUAL	CHAD SCHLICHTMEIER-DISTRICT 1	(307) 777-7391		CT-1137	3241		56-001-00002					5/16/1994	3/6/1995	1/31/1996	4/24/1996
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WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	ALBANY		5 SAND CREEK ROAD	LARAMIE		-82070			8	WY001	WYOMING AIR QUAL DIV, DEPT OF ENV QUAL	CHAD SCHLICHTMEIER-DISTRICT 1	(307) 777-7391		CT-1137	3241		56-001-00002					5/16/1994	3/6/1995	1/31/1996	4/24/1996
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	ALBANY		5 SAND CREEK ROAD	LARAMIE		-82070			8	WY001	WYOMING AIR QUAL DIV, DEPT OF ENV QUAL	CHAD SCHLICHTMEIER-DISTRICT 1	(307) 777-7391		CT-1137	3241		56-001-00002					5/16/1994	3/6/1995	1/31/1996	4/24/1996

RBLCID	FACILITY	ENTRY DATE	LASTUP DATE	NEW_MOD	PUBLIC HEAR	FUEL	EMISSSOURCES	ABATEMENT
UT-0059	ASH GROVE CEMENT COMPANY	10/16/2001	6/6/2002	M		COAL, TIRE DERIVED FUEL (TDF), DIESEL, NATURAL GAS, USED OIL FUEL	COMBUSTION FOR KILN, KILN, CLINKER COOLING PROCESS	BAGHOUSES, LOW NOX BURNER
UT-0059	ASH GROVE CEMENT COMPANY	10/16/2001	6/6/2002	M		COAL, TIRE DERIVED FUEL (TDF), DIESEL, NATURAL GAS, USED OIL FUEL	COMBUSTION FOR KILN, KILN, CLINKER COOLING PROCESS	BAGHOUSES, LOW NOX BURNER
UT-0059	ASH GROVE CEMENT COMPANY	10/16/2001	6/6/2002	M		COAL, TIRE DERIVED FUEL (TDF), DIESEL, NATURAL GAS, USED OIL FUEL	COMBUSTION FOR KILN, KILN, CLINKER COOLING PROCESS	BAGHOUSES, LOW NOX BURNER
UT-0059	ASH GROVE CEMENT COMPANY	10/16/2001	6/6/2002	M		COAL, TIRE DERIVED FUEL (TDF), DIESEL, NATURAL GAS, USED OIL FUEL	COMBUSTION FOR KILN, KILN, CLINKER COOLING PROCESS	BAGHOUSES, LOW NOX BURNER
UT-0059	ASH GROVE CEMENT COMPANY	10/16/2001	6/6/2002	M		COAL, TIRE DERIVED FUEL (TDF), DIESEL, NATURAL GAS, USED OIL FUEL	COMBUSTION FOR KILN, KILN, CLINKER COOLING PROCESS	BAGHOUSES, LOW NOX BURNER
UT-0059	ASH GROVE CEMENT COMPANY	10/16/2001	6/6/2002	M		COAL, TIRE DERIVED FUEL (TDF), DIESEL, NATURAL GAS, USED OIL FUEL	COMBUSTION FOR KILN, KILN, CLINKER COOLING PROCESS	BAGHOUSES, LOW NOX BURNER
UT-0059	ASH GROVE CEMENT COMPANY	10/16/2001	6/6/2002	M		COAL, TIRE DERIVED FUEL (TDF), DIESEL, NATURAL GAS, USED OIL FUEL	COMBUSTION FOR KILN, KILN, CLINKER COOLING PROCESS	BAGHOUSES, LOW NOX BURNER
UT-0059	ASH GROVE CEMENT COMPANY	10/16/2001	6/6/2002	M		COAL, TIRE DERIVED FUEL (TDF), DIESEL, NATURAL GAS, USED OIL FUEL	COMBUSTION FOR KILN, KILN, CLINKER COOLING PROCESS	BAGHOUSES, LOW NOX BURNER
UT-0059	ASH GROVE CEMENT COMPANY	10/16/2001	6/6/2002	M		COAL, TIRE DERIVED FUEL (TDF), DIESEL, NATURAL GAS, USED OIL FUEL	COMBUSTION FOR KILN, KILN, CLINKER COOLING PROCESS	BAGHOUSES, LOW NOX BURNER
UT-0059	ASH GROVE CEMENT COMPANY	10/16/2001	6/6/2002	M		COAL, TIRE DERIVED FUEL (TDF), DIESEL, NATURAL GAS, USED OIL FUEL	COMBUSTION FOR KILN, KILN, CLINKER COOLING PROCESS	BAGHOUSES, LOW NOX BURNER
UT-0059	ASH GROVE CEMENT COMPANY	10/16/2001	6/6/2002	M		COAL, TIRE DERIVED FUEL (TDF), DIESEL, NATURAL GAS, USED OIL FUEL	COMBUSTION FOR KILN, KILN, CLINKER COOLING PROCESS	BAGHOUSES, LOW NOX BURNER
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	10/18/2001	3/3/2004	M		COAL, NATURAL GAS, COKE, FUEL OIL, TIRE DERIVED FUEL (TDF), DIAPER DERIVED FUEL (DDF)	KILN EXHAUST, FUGITIVES	BAGHOUSES, LOW NOX BURNER (COMPUTER CONTROLLED)
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	10/18/2001	3/3/2004	M		COAL, NATURAL GAS, COKE, FUEL OIL, TIRE DERIVED FUEL (TDF), DIAPER DERIVED FUEL (DDF)	KILN EXHAUST, FUGITIVES	BAGHOUSES, LOW NOX BURNER (COMPUTER CONTROLLED)
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	10/18/2001	3/3/2004	M		COAL, NATURAL GAS, COKE, FUEL OIL, TIRE DERIVED FUEL (TDF), DIAPER DERIVED FUEL (DDF)	KILN EXHAUST, FUGITIVES	BAGHOUSES, LOW NOX BURNER (COMPUTER CONTROLLED)
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	10/18/2001	3/3/2004	M		COAL, NATURAL GAS, COKE, FUEL OIL, TIRE DERIVED FUEL (TDF), DIAPER DERIVED FUEL (DDF)	KILN EXHAUST, FUGITIVES	BAGHOUSES, LOW NOX BURNER (COMPUTER CONTROLLED)
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	10/18/2001	3/3/2004	M		COAL, NATURAL GAS, COKE, FUEL OIL, TIRE DERIVED FUEL (TDF), DIAPER DERIVED FUEL (DDF)	KILN EXHAUST, FUGITIVES	BAGHOUSES, LOW NOX BURNER (COMPUTER CONTROLLED)
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	10/18/2001	3/3/2004	M		COAL, NATURAL GAS, COKE, FUEL OIL, TIRE DERIVED FUEL (TDF), DIAPER DERIVED FUEL (DDF)	KILN EXHAUST, FUGITIVES	BAGHOUSES, LOW NOX BURNER (COMPUTER CONTROLLED)

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UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	10/18/2001	3/3/2004	M		COAL, NATURAL GAS, COKE, FUEL OIL, TIRE DERIVED FUEL (TDF), DIAPER DERIVED FUEL (DDF)	KILN EXHAUST, FUGITIVES	BAGHOUSES, LOW NOX BURNER (COMPUTER CONTROLLED)
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	2/26/1996	12/18/2001					
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	2/26/1996	12/18/2001					
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	2/26/1996	12/18/2001					
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	2/26/1996	12/18/2001					
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	2/26/1996	12/18/2001					
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	2/26/1996	12/18/2001					
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	2/26/1996	12/18/2001					
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NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	2/26/1996	12/18/2001					
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	2/26/1996	12/18/2001					
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	4/13/1999	12/18/2001					
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	4/13/1999	12/18/2001					
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	4/13/1999	12/18/2001					
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	4/13/1999	12/18/2001					
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	4/13/1999	12/18/2001					
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	4/13/1999	12/18/2001					
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	4/13/1999	12/18/2001					
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	4/13/1999	12/18/2001					
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	4/13/1999	12/18/2001					
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	4/13/1999	12/18/2001					
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	4/13/1999	12/18/2001					

RBLCID	FACILITY	NARRATIVE	NOTES	PROCESS	PROCT YPE	SCC	FUEL	THRUPUT	THRUPUT UNIT	COMP VERIFY	STACK TEST	INSPECTION	CALCULATED	OTHER TEST	OTHER METHD
UT-0059	ASH GROVE CEMENT COMPANY	CEMENT PLANT	PHYSICAL PLANT - LEAMINGTON, UT. ALSO REFER TO TITLE V PERMIT 1/05/2000 DAQO-795067-99. LIMITS NOT TO BE EXCEEDED WITHOUT PRIOR APPROVAL WITH R307-1-3.1 UAC. A)QUARRY ORE AND WASTE PRODUCTION HANDLER BY CRUSHING/ CONVEXING SYSTEM 1.549 E 6 T/12 MO PERIOD. B) ANNUAL COAL CONSUMPTION-113,000 T/12 MO PERIOD. C) ANNUAL USED ORE CONSUMPTION-85,724 T/12 MO PERIOD. PLANTWIDE EMISSIONS - LEAD - 0.5	FUGITIVES - PLANTWIDE	90.028	30500699				N	N	N	N	N	
UT-0059	ASH GROVE CEMENT COMPANY	CEMENT PLANT	PHYSICAL PLANT - LEAMINGTON, UT. ALSO REFER TO TITLE V PERMIT 1/05/2000 DAQO-795067-99. LIMITS NOT TO BE EXCEEDED WITHOUT PRIOR APPROVAL WITH R307-1-3.1 UAC. A)QUARRY ORE AND WASTE PRODUCTION HANDLER BY CRUSHING/ CONVEXING SYSTEM 1.549 E 6 T/12 MO PERIOD. B) ANNUAL COAL CONSUMPTION-113,000 T/12 MO PERIOD. C) ANNUAL USED ORE CONSUMPTION-85,724 T/12 MO PERIOD. PLANTWIDE EMISSIONS - LEAD - 0.5	KILN	90.028	30500606	COAL	170	T/H	N	N	N	N	N	
UT-0059	ASH GROVE CEMENT COMPANY	CEMENT PLANT	PHYSICAL PLANT - LEAMINGTON, UT. ALSO REFER TO TITLE V PERMIT 1/05/2000 DAQO-795067-99. LIMITS NOT TO BE EXCEEDED WITHOUT PRIOR APPROVAL WITH R307-1-3.1 UAC. A)QUARRY ORE AND WASTE PRODUCTION HANDLER BY CRUSHING/ CONVEXING SYSTEM 1.549 E 6 T/12 MO PERIOD. B) ANNUAL COAL CONSUMPTION-113,000 T/12 MO PERIOD. C) ANNUAL USED ORE CONSUMPTION-85,724 T/12 MO PERIOD. PLANTWIDE EMISSIONS - LEAD - 0.5	KILN	90.028	30500606	COAL	170	T/H	N	N	N	N	N	
UT-0059	ASH GROVE CEMENT COMPANY	CEMENT PLANT	PHYSICAL PLANT - LEAMINGTON, UT. ALSO REFER TO TITLE V PERMIT 1/05/2000 DAQO-795067-99. LIMITS NOT TO BE EXCEEDED WITHOUT PRIOR APPROVAL WITH R307-1-3.1 UAC. A)QUARRY ORE AND WASTE PRODUCTION HANDLER BY CRUSHING/ CONVEXING SYSTEM 1.549 E 6 T/12 MO PERIOD. B) ANNUAL COAL CONSUMPTION-113,000 T/12 MO PERIOD. C) ANNUAL USED ORE CONSUMPTION-85,724 T/12 MO PERIOD. PLANTWIDE EMISSIONS - LEAD - 0.5	KILN	90.028	30500606	COAL	170	T/H	N	N	N	N	N	
UT-0059	ASH GROVE CEMENT COMPANY	CEMENT PLANT	PHYSICAL PLANT - LEAMINGTON, UT. ALSO REFER TO TITLE V PERMIT 1/05/2000 DAQO-795067-99. LIMITS NOT TO BE EXCEEDED WITHOUT PRIOR APPROVAL WITH R307-1-3.1 UAC. A)QUARRY ORE AND WASTE PRODUCTION HANDLER BY CRUSHING/ CONVEXING SYSTEM 1.549 E 6 T/12 MO PERIOD. B) ANNUAL COAL CONSUMPTION-113,000 T/12 MO PERIOD. C) ANNUAL USED ORE CONSUMPTION-85,724 T/12 MO PERIOD. PLANTWIDE EMISSIONS - LEAD - 0.5	KILN	90.028	30500606	COAL	170	T/H	N	N	N	N	N	
UT-0059	ASH GROVE CEMENT COMPANY	CEMENT PLANT	PHYSICAL PLANT - LEAMINGTON, UT. ALSO REFER TO TITLE V PERMIT 1/05/2000 DAQO-795067-99. LIMITS NOT TO BE EXCEEDED WITHOUT PRIOR APPROVAL WITH R307-1-3.1 UAC. A)QUARRY ORE AND WASTE PRODUCTION HANDLER BY CRUSHING/ CONVEXING SYSTEM 1.549 E 6 T/12 MO PERIOD. B) ANNUAL COAL CONSUMPTION-113,000 T/12 MO PERIOD. C) ANNUAL USED ORE CONSUMPTION-85,724 T/12 MO PERIOD. PLANTWIDE EMISSIONS - LEAD - 0.5	KILN	90.028	30500606	COAL	170	T/H	N	N	N	N	N	
UT-0059	ASH GROVE CEMENT COMPANY	CEMENT PLANT	PHYSICAL PLANT - LEAMINGTON, UT. ALSO REFER TO TITLE V PERMIT 1/05/2000 DAQO-795067-99. LIMITS NOT TO BE EXCEEDED WITHOUT PRIOR APPROVAL WITH R307-1-3.1 UAC. A)QUARRY ORE AND WASTE PRODUCTION HANDLER BY CRUSHING/ CONVEXING SYSTEM 1.549 E 6 T/12 MO PERIOD. B) ANNUAL COAL CONSUMPTION-113,000 T/12 MO PERIOD. C) ANNUAL USED ORE CONSUMPTION-85,724 T/12 MO PERIOD. PLANTWIDE EMISSIONS - LEAD - 0.5	CLINKER COOLER	90.028	30500614				N	N	N	N	N	
UT-0059	ASH GROVE CEMENT COMPANY	CEMENT PLANT	PHYSICAL PLANT - LEAMINGTON, UT. ALSO REFER TO TITLE V PERMIT 1/05/2000 DAQO-795067-99. LIMITS NOT TO BE EXCEEDED WITHOUT PRIOR APPROVAL WITH R307-1-3.1 UAC. A)QUARRY ORE AND WASTE PRODUCTION HANDLER BY CRUSHING/ CONVEXING SYSTEM 1.549 E 6 T/12 MO PERIOD. B) ANNUAL COAL CONSUMPTION-113,000 T/12 MO PERIOD. C) ANNUAL USED ORE CONSUMPTION-85,724 T/12 MO PERIOD. PLANTWIDE EMISSIONS - LEAD - 0.5	CLINKER COOLER	90.028	30500614				N	N	N	N	N	
UT-0059	ASH GROVE CEMENT COMPANY	CEMENT PLANT	PHYSICAL PLANT - LEAMINGTON, UT. ALSO REFER TO TITLE V PERMIT 1/05/2000 DAQO-795067-99. LIMITS NOT TO BE EXCEEDED WITHOUT PRIOR APPROVAL WITH R307-1-3.1 UAC. A)QUARRY ORE AND WASTE PRODUCTION HANDLER BY CRUSHING/ CONVEXING SYSTEM 1.549 E 6 T/12 MO PERIOD. B) ANNUAL COAL CONSUMPTION-113,000 T/12 MO PERIOD. C) ANNUAL USED ORE CONSUMPTION-85,724 T/12 MO PERIOD. PLANTWIDE EMISSIONS - LEAD - 0.5	CLINKER COOLER	90.028	30500614				N	N	N	N	N	
UT-0059	ASH GROVE CEMENT COMPANY	CEMENT PLANT	PHYSICAL PLANT - LEAMINGTON, UT. ALSO REFER TO TITLE V PERMIT 1/05/2000 DAQO-795067-99. LIMITS NOT TO BE EXCEEDED WITHOUT PRIOR APPROVAL WITH R307-1-3.1 UAC. A)QUARRY ORE AND WASTE PRODUCTION HANDLER BY CRUSHING/ CONVEXING SYSTEM 1.549 E 6 T/12 MO PERIOD. B) ANNUAL COAL CONSUMPTION-113,000 T/12 MO PERIOD. C) ANNUAL USED ORE CONSUMPTION-85,724 T/12 MO PERIOD. PLANTWIDE EMISSIONS - LEAD - 0.5	COAL DELIVERY SYSTEM	90.011	30501017				N	N	N	N	N	
UT-0059	ASH GROVE CEMENT COMPANY	CEMENT PLANT	PHYSICAL PLANT - LEAMINGTON, UT. ALSO REFER TO TITLE V PERMIT 1/05/2000 DAQO-795067-99. LIMITS NOT TO BE EXCEEDED WITHOUT PRIOR APPROVAL WITH R307-1-3.1 UAC. A)QUARRY ORE AND WASTE PRODUCTION HANDLER BY CRUSHING/ CONVEXING SYSTEM 1.549 E 6 T/12 MO PERIOD. B) ANNUAL COAL CONSUMPTION-113,000 T/12 MO PERIOD. C) ANNUAL USED ORE CONSUMPTION-85,724 T/12 MO PERIOD. PLANTWIDE EMISSIONS - LEAD - 0.5	COAL DELIVERY SYSTEM	90.011	30501017				N	N	N	N	N	
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	PORTLAND CEMENT TERMINAL	Facility now named Holcim. THIS A.O.REPLACES A.O. DATED 12/23/1993 (DAQE-1127-93), 8/31/1988(BAQE-741-88), 11/20/1987 (BAQE-043-87), 8/26/1985 START UP. FILE INCLUDED 10/20/1999 APPROVAL ORDER FOR ADDITION OF FINISH MILL AND CEMENT STORAGE SILOS, WHICH WAS A MINOR MODIFICATION WITH RESPECT TO PSD - WAS USED FOR CONTACT INFORMATION ETC. FILE ALSO INCLUDES A.O.'S FROM 6/15/1992 (DAQE-558-92), 11/20/1987 (BAQE-043-87). 8/8/96 APPROVAL ORDER MODIFICATION FOR SYNTHETIC MINOR STATUS LIMITING ANNUAL EMISSIONS TO 1) TSP - 6.0 T/YR 2) PM10 - 4.8 T/YR. ADDITIONAL PLANTWIDE EMISSIONS (T/YR): TSP = 804.29 TOTAL (659.18 CHANGE); PM10 = 377.26 TOTAL (-312.94 CHANGE); SO2 = 15 CHANGE; NOX =25.06 CHANGE; CO = 1655.46 CHANGE; VOC = 30 CHANGE. {SO2, NOX, CO, AND VOC TOTALS IN PLANTWIDE EMISSIONS FIELDS}	ROADS AND FUGITIVE DUST	99.19	2294015000				N	N	N	N	N	
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	PORTLAND CEMENT TERMINAL	Facility now named Holcim. THIS A.O.REPLACES A.O. DATED 12/23/1993 (DAQE-1127-93), 8/31/1988(BAQE-741-88), 11/20/1987 (BAQE-043-87), 8/26/1985 START UP. FILE INCLUDED 10/20/1999 APPROVAL ORDER FOR ADDITION OF FINISH MILL AND CEMENT STORAGE SILOS, WHICH WAS A MINOR MODIFICATION WITH RESPECT TO PSD - WAS USED FOR CONTACT INFORMATION ETC. FILE ALSO INCLUDES A.O.'S FROM 6/15/1992 (DAQE-558-92), 11/20/1987 (BAQE-043-87). 8/8/96 APPROVAL ORDER MODIFICATION FOR SYNTHETIC MINOR STATUS LIMITING ANNUAL EMISSIONS TO 1) TSP - 6.0 T/YR 2) PM10 - 4.8 T/YR. ADDITIONAL PLANTWIDE EMISSIONS (T/YR): TSP = 804.29 TOTAL (659.18 CHANGE); PM10 = 377.26 TOTAL (-312.94 CHANGE); SO2 = 15 CHANGE; NOX =25.06 CHANGE; CO = 1655.46 CHANGE; VOC = 30 CHANGE. {SO2, NOX, CO, AND VOC TOTALS IN PLANTWIDE EMISSIONS FIELDS}	KILN	90.028	30500606	COAL			N	N	N	N	N	
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	PORTLAND CEMENT TERMINAL	Facility now named Holcim. THIS A.O.REPLACES A.O. DATED 12/23/1993 (DAQE-1127-93), 8/31/1988(BAQE-741-88), 11/20/1987 (BAQE-043-87), 8/26/1985 START UP. FILE INCLUDED 10/20/1999 APPROVAL ORDER FOR ADDITION OF FINISH MILL AND CEMENT STORAGE SILOS, WHICH WAS A MINOR MODIFICATION WITH RESPECT TO PSD - WAS USED FOR CONTACT INFORMATION ETC. FILE ALSO INCLUDES A.O.'S FROM 6/15/1992 (DAQE-558-92), 11/20/1987 (BAQE-043-87). 8/8/96 APPROVAL ORDER MODIFICATION FOR SYNTHETIC MINOR STATUS LIMITING ANNUAL EMISSIONS TO 1) TSP - 6.0 T/YR 2) PM10 - 4.8 T/YR. ADDITIONAL PLANTWIDE EMISSIONS (T/YR): TSP = 804.29 TOTAL (659.18 CHANGE); PM10 = 377.26 TOTAL (-312.94 CHANGE); SO2 = 15 CHANGE; NOX =25.06 CHANGE; CO = 1655.46 CHANGE; VOC = 30 CHANGE. {SO2, NOX, CO, AND VOC TOTALS IN PLANTWIDE EMISSIONS FIELDS}	KILN	90.028	30500606	COAL			N	N	N	N	N	
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	PORTLAND CEMENT TERMINAL	Facility now named Holcim. THIS A.O.REPLACES A.O. DATED 12/23/1993 (DAQE-1127-93), 8/31/1988(BAQE-741-88), 11/20/1987 (BAQE-043-87), 8/26/1985 START UP. FILE INCLUDED 10/20/1999 APPROVAL ORDER FOR ADDITION OF FINISH MILL AND CEMENT STORAGE SILOS, WHICH WAS A MINOR MODIFICATION WITH RESPECT TO PSD - WAS USED FOR CONTACT INFORMATION ETC. FILE ALSO INCLUDES A.O.'S FROM 6/15/1992 (DAQE-558-92), 11/20/1987 (BAQE-043-87). 8/8/96 APPROVAL ORDER MODIFICATION FOR SYNTHETIC MINOR STATUS LIMITING ANNUAL EMISSIONS TO 1) TSP - 6.0 T/YR 2) PM10 - 4.8 T/YR. ADDITIONAL PLANTWIDE EMISSIONS (T/YR): TSP = 804.29 TOTAL (659.18 CHANGE); PM10 = 377.26 TOTAL (-312.94 CHANGE); SO2 = 15 CHANGE; NOX =25.06 CHANGE; CO = 1655.46 CHANGE; VOC = 30 CHANGE. {SO2, NOX, CO, AND VOC TOTALS IN PLANTWIDE EMISSIONS FIELDS}	KILN	90.028	30500606	COAL			N	N	N	N	N	
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	PORTLAND CEMENT TERMINAL	Facility now named Holcim. THIS A.O.REPLACES A.O. DATED 12/23/1993 (DAQE-1127-93), 8/31/1988(BAQE-741-88), 11/20/1987 (BAQE-043-87), 8/26/1985 START UP. FILE INCLUDED 10/20/1999 APPROVAL ORDER FOR ADDITION OF FINISH MILL AND CEMENT STORAGE SILOS, WHICH WAS A MINOR MODIFICATION WITH RESPECT TO PSD - WAS USED FOR CONTACT INFORMATION ETC. FILE ALSO INCLUDES A.O.'S FROM 6/15/1992 (DAQE-558-92), 11/20/1987 (BAQE-043-87). 8/8/96 APPROVAL ORDER MODIFICATION FOR SYNTHETIC MINOR STATUS LIMITING ANNUAL EMISSIONS TO 1) TSP - 6.0 T/YR 2) PM10 - 4.8 T/YR. ADDITIONAL PLANTWIDE EMISSIONS (T/YR): TSP = 804.29 TOTAL (659.18 CHANGE); PM10 = 377.26 TOTAL (-312.94 CHANGE); SO2 = 15 CHANGE; NOX =25.06 CHANGE; CO = 1655.46 CHANGE; VOC = 30 CHANGE. {SO2, NOX, CO, AND VOC TOTALS IN PLANTWIDE EMISSIONS FIELDS}	KILN	90.028	30500606	COAL			N	N	N	N	N	
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	PORTLAND CEMENT TERMINAL	Facility now named Holcim. THIS A.O.REPLACES A.O. DATED 12/23/1993 (DAQE-1127-93), 8/31/1988(BAQE-741-88), 11/20/1987 (BAQE-043-87), 8/26/1985 START UP. FILE INCLUDED 10/20/1999 APPROVAL ORDER FOR ADDITION OF FINISH MILL AND CEMENT STORAGE SILOS, WHICH WAS A MINOR MODIFICATION WITH RESPECT TO PSD - WAS USED FOR CONTACT INFORMATION ETC. FILE ALSO INCLUDES A.O.'S FROM 6/15/1992 (DAQE-558-92), 11/20/1987 (BAQE-043-87). 8/8/96 APPROVAL ORDER MODIFICATION FOR SYNTHETIC MINOR STATUS LIMITING ANNUAL EMISSIONS TO 1) TSP - 6.0 T/YR 2) PM10 - 4.8 T/YR. ADDITIONAL PLANTWIDE EMISSIONS (T/YR): TSP = 804.29 TOTAL (659.18 CHANGE); PM10 = 377.26 TOTAL (-312.94 CHANGE); SO2 = 15 CHANGE; NOX =25.06 CHANGE; CO = 1655.46 CHANGE; VOC = 30 CHANGE. {SO2, NOX, CO, AND VOC TOTALS IN PLANTWIDE EMISSIONS FIELDS}	KILN	90.028	30500606	COAL			N	N	N	N	N	

RBLCID	FACILITY	NARRATIVE	NOTES	PROCESS	PROCT YPE	SCC	FUEL	THRUPUT	THRUPUT UNIT	COMP VERIFY	STACK TEST	INSPECTION	CALCULATED	OTHER TEST	OTHER METHD
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	PORTLAND CEMENT TERMINAL	Facility now named Holcim. THIS A.O.REPLACES A.O. DATED 12/23/1993 (DAQE-1127-93), 8/31/1988(BAQE-741-88), 11/20/1987 (BAQE-043-87), 8/26/1985 START UP. FILE INCLUDED 10/20/1999 APPROVAL ORDER FOR ADDITION OF FINISH MILL AND CEMENT STORAGE SILOS, WHICH WAS A MINOR MODIFICATION WITH RESPECT TO PSD - WAS USED FOR CONTACT INFORMATION ETC. FILE ALSO INCLUDES A.O.'S FROM 6/15/1992 (DAQE-558-92), 11/20/1987 (BAQE-043-87). 8/8/96 APPROVAL ORDER MODIFICATION FOR SYNTHETIC MINOR STATUS LIMITING ANNUAL EMISSIONS TO 1) TSP - 6.0 T/YR 2) PM10 - 4.8 T/YR. ADDITIONAL PLANTWIDE EMISSIONS (T/YR): TSP = 804.29 TOTAL (659.18 CHANGE); PM10 = 377.26 TOTAL (-312.94 CHANGE); SO2 = 15 CHANGE; NOX =25.06 CHANGE; CO = 1655.46 CHANGE; VOC = 30 CHANGE. {SO2, NOX, CO, AND VOC TOTALS IN PLANTWIDE EMISSIONS FIELDS}	KILN	90.028	30500606	COAL			N	N	N	N	N	
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		ONE QUARRY WITH ANNUAL MINING CAPACITY OF FOUR MILLION TONS WILL PROVIDE RAW MATERIALS FOR PORTLAND CEMENT MANUFACTURING AND SAND AND GRAVEL PROCESSING WITHIN ONE CONTIGUOUS PROPERTY. THE ANNUAL PRODUCTION CAPACITY FOR CLINKER IS ONE MILLION TONS. THE CEMENT PLANT WILL USE LOW-SULFUR WESTERN COAL ONLY.	CEMENT STORAGE SILO W/VENT	90.024	3-05-006-18		0		F	F	F	F	F	
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		ONE QUARRY WITH ANNUAL MINING CAPACITY OF FOUR MILLION TONS WILL PROVIDE RAW MATERIALS FOR PORTLAND CEMENT MANUFACTURING AND SAND AND GRAVEL PROCESSING WITHIN ONE CONTIGUOUS PROPERTY. THE ANNUAL PRODUCTION CAPACITY FOR CLINKER IS ONE MILLION TONS. THE CEMENT PLANT WILL USE LOW-SULFUR WESTERN COAL ONLY.	MATL TRANSFER, SAND/GRAVEL LOADERS & CONVEYORS	90.024	3-05-025-04, -06		0		F	F	F	F	F	
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		ONE QUARRY WITH ANNUAL MINING CAPACITY OF FOUR MILLION TONS WILL PROVIDE RAW MATERIALS FOR PORTLAND CEMENT MANUFACTURING AND SAND AND GRAVEL PROCESSING WITHIN ONE CONTIGUOUS PROPERTY. THE ANNUAL PRODUCTION CAPACITY FOR CLINKER IS ONE MILLION TONS. THE CEMENT PLANT WILL USE LOW-SULFUR WESTERN COAL ONLY.	CEMENT KILN/CLINKER COOLER FACILITY	90.028	3-05-006		0		F	F	F	F	F	
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		ONE QUARRY WITH ANNUAL MINING CAPACITY OF FOUR MILLION TONS WILL PROVIDE RAW MATERIALS FOR PORTLAND CEMENT MANUFACTURING AND SAND AND GRAVEL PROCESSING WITHIN ONE CONTIGUOUS PROPERTY. THE ANNUAL PRODUCTION CAPACITY FOR CLINKER IS ONE MILLION TONS. THE CEMENT PLANT WILL USE LOW-SULFUR WESTERN COAL ONLY.	CEMENT KILN/CLINKER COOLER FACILITY	90.028	3-05-006		0		F	F	F	F	F	
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		ONE QUARRY WITH ANNUAL MINING CAPACITY OF FOUR MILLION TONS WILL PROVIDE RAW MATERIALS FOR PORTLAND CEMENT MANUFACTURING AND SAND AND GRAVEL PROCESSING WITHIN ONE CONTIGUOUS PROPERTY. THE ANNUAL PRODUCTION CAPACITY FOR CLINKER IS ONE MILLION TONS. THE CEMENT PLANT WILL USE LOW-SULFUR WESTERN COAL ONLY.	CEMENT KILN/CLINKER COOLER FACILITY	90.028	3-05-006		0		F	F	F	F	F	
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		ONE QUARRY WITH ANNUAL MINING CAPACITY OF FOUR MILLION TONS WILL PROVIDE RAW MATERIALS FOR PORTLAND CEMENT MANUFACTURING AND SAND AND GRAVEL PROCESSING WITHIN ONE CONTIGUOUS PROPERTY. THE ANNUAL PRODUCTION CAPACITY FOR CLINKER IS ONE MILLION TONS. THE CEMENT PLANT WILL USE LOW-SULFUR WESTERN COAL ONLY.	CEMENT KILN CALCINING	90.028	3-05-006-06		1.6	MILLION TONS	F	F	F	F	F	
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		ONE QUARRY WITH ANNUAL MINING CAPACITY OF FOUR MILLION TONS WILL PROVIDE RAW MATERIALS FOR PORTLAND CEMENT MANUFACTURING AND SAND AND GRAVEL PROCESSING WITHIN ONE CONTIGUOUS PROPERTY. THE ANNUAL PRODUCTION CAPACITY FOR CLINKER IS ONE MILLION TONS. THE CEMENT PLANT WILL USE LOW-SULFUR WESTERN COAL ONLY.	CLINKER COOLER	90.028	3-05-006-14		0		F	F	F	F	F	
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		ONE QUARRY WITH ANNUAL MINING CAPACITY OF FOUR MILLION TONS WILL PROVIDE RAW MATERIALS FOR PORTLAND CEMENT MANUFACTURING AND SAND AND GRAVEL PROCESSING WITHIN ONE CONTIGUOUS PROPERTY. THE ANNUAL PRODUCTION CAPACITY FOR CLINKER IS ONE MILLION TONS. THE CEMENT PLANT WILL USE LOW-SULFUR WESTERN COAL ONLY.	MATL HANDLING, SEPARATOR VENT	90.024	3-05-006-99		0		F	F	F	F	F	
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		ONE QUARRY WITH ANNUAL MINING CAPACITY OF FOUR MILLION TONS WILL PROVIDE RAW MATERIALS FOR PORTLAND CEMENT MANUFACTURING AND SAND AND GRAVEL PROCESSING WITHIN ONE CONTIGUOUS PROPERTY. THE ANNUAL PRODUCTION CAPACITY FOR CLINKER IS ONE MILLION TONS. THE CEMENT PLANT WILL USE LOW-SULFUR WESTERN COAL ONLY.	QUARRYING	90.024	3-05-020		0		F	F	F	F	F	
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		ONE QUARRY WITH ANNUAL MINING CAPACITY OF FOUR MILLION TONS WILL PROVIDE RAW MATERIALS FOR PORTLAND CEMENT MANUFACTURING AND SAND AND GRAVEL PROCESSING WITHIN ONE CONTIGUOUS PROPERTY. THE ANNUAL PRODUCTION CAPACITY FOR CLINKER IS ONE MILLION TONS. THE CEMENT PLANT WILL USE LOW-SULFUR WESTERN COAL ONLY.	LIMESTONE CRUSHING	90.024	3-05-020-01		0		F	F	F	F	F	
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		ONE QUARRY WITH ANNUAL MINING CAPACITY OF FOUR MILLION TONS WILL PROVIDE RAW MATERIALS FOR PORTLAND CEMENT MANUFACTURING AND SAND AND GRAVEL PROCESSING WITHIN ONE CONTIGUOUS PROPERTY. THE ANNUAL PRODUCTION CAPACITY FOR CLINKER IS ONE MILLION TONS. THE CEMENT PLANT WILL USE LOW-SULFUR WESTERN COAL ONLY.	SAND AND GRAVEL SCREENING	90.024	3-05-025-11		0		F	F	F	F	F	
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		ONE QUARRY WITH ANNUAL MINING CAPACITY OF FOUR MILLION TONS WILL PROVIDE RAW MATERIALS FOR PORTLAND CEMENT MANUFACTURING AND SAND AND GRAVEL PROCESSING WITHIN ONE CONTIGUOUS PROPERTY. THE ANNUAL PRODUCTION CAPACITY FOR CLINKER IS ONE MILLION TONS. THE CEMENT PLANT WILL USE LOW-SULFUR WESTERN COAL ONLY.	MATL HANDLING, RAW MATERIALS BLENDING	90.024	3-05-006-13		0		F	F	F	F	F	
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		ONE QUARRY WITH ANNUAL MINING CAPACITY OF FOUR MILLION TONS WILL PROVIDE RAW MATERIALS FOR PORTLAND CEMENT MANUFACTURING AND SAND AND GRAVEL PROCESSING WITHIN ONE CONTIGUOUS PROPERTY. THE ANNUAL PRODUCTION CAPACITY FOR CLINKER IS ONE MILLION TONS. THE CEMENT PLANT WILL USE LOW-SULFUR WESTERN COAL ONLY.	MATL HANDLING, COLLECTING AT FINISH MILL	90.024	3-05-006-19		0		F	F	F	F	F	
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		MODIFY AND REACTIVATE #1 KILN, CLINKER COOLER AND ASSOCIATED EQUIPMENT	KILN, COAL FIRED	90.028	30500606		45.3	T/H COAL	T	T	F	F	F	
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		MODIFY AND REACTIVATE #1 KILN, CLINKER COOLER AND ASSOCIATED EQUIPMENT	KILN, COAL FIRED	90.028	30500606		45.3	T/H COAL	T	T	F	F	F	
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		MODIFY AND REACTIVATE #1 KILN, CLINKER COOLER AND ASSOCIATED EQUIPMENT	KILN, COAL FIRED	90.028	30500606		45.3	T/H COAL	T	T	F	F	F	
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		MODIFY AND REACTIVATE #1 KILN, CLINKER COOLER AND ASSOCIATED EQUIPMENT	KILN, COAL FIRED	90.028	30500606		45.3	T/H COAL	T	T	F	F	F	
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		MODIFY AND REACTIVATE #1 KILN, CLINKER COOLER AND ASSOCIATED EQUIPMENT	KILN, COAL FIRED	90.028	30500606		45.3	T/H COAL	T	T	F	F	F	
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		MODIFY AND REACTIVATE #1 KILN, CLINKER COOLER AND ASSOCIATED EQUIPMENT	KILN, COAL FIRED	90.028	30500606		45.3	T/H COAL	T	T	F	F	F	
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		MODIFY AND REACTIVATE #1 KILN, CLINKER COOLER AND ASSOCIATED EQUIPMENT	CONVEYOR, CLINKER	90.028	30500616		0		F	F	F	F	F	
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		MODIFY AND REACTIVATE #1 KILN, CLINKER COOLER AND ASSOCIATED EQUIPMENT	CONVEYOR, CLINKER	90.028	30500616		0		F	F	F	F	F	
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		MODIFY AND REACTIVATE #1 KILN, CLINKER COOLER AND ASSOCIATED EQUIPMENT	DUST RETURN ELEVATOR SYSTEM	90.028	30500699		0		F	F	F	F	F	
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		MODIFY AND REACTIVATE #1 KILN, CLINKER COOLER AND ASSOCIATED EQUIPMENT	DUST RETURN ELEVATOR SYSTEM	90.028	30500699		0		F	F	F	F	F	
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		MODIFY AND REACTIVATE #1 KILN, CLINKER COOLER AND ASSOCIATED EQUIPMENT	MILL, FINISH	90.028	30500699		0		F	F	F	F	F	

RBLCID	FACILITY	PRNOTES	POLLUTANT	CAS	CONTROL COD	CTRLDESC	RANKOPTS	RANK SEL	EMIS LIMIT1	EMISLIMIT1 UNIT	EMISLIMIT1 CONDITION	BASIS	PCTE FFIC	EMISL IMIT2	EMISLI MIT2U NIT	EMISLI MIT2C ONDITI ON	STDEMISS	STDUNIT	STOTHER CONDITIONS	EMISSTYPE	CAPCOST	ANNUAL COST	OMCOST
UT-0059	ASH GROVE CEMENT COMPANY	FUGITIVES PLANTWIDE: PAVED ROADS TO BE SWEPT/WATER SPRAYED AS DAY CONDITIONS WARRANT - VISIBLE EMISSIONS NOT TO EXCEED 20% OPACITY. WATER OR COMMERCIAL DUST SURPRESSANTS SPRAYS AT 1) ALL CRUSHERS EXCEPT THE NEW ONE FEEDING THE FINISH MILL 2) ALL SCREENS 3) ALL FUGITIVE EMISSIONS POINTS ASSOCIATED WITH WASTE HANDLING. WATER TO BE ADDED TO MINED MATERIAL - MINED MATERIAL PASSED THROUGH PORTABLE CRUSHER TO HAVE NO LESS THAN 4.0% BY WEIGHT MOISTURE CONTENT.	VE	VE	P	SEE PROCESS NOTES.			20	% OPACITY		BACT-PSD					20	% OPACITY		P			
UT-0059	ASH GROVE CEMENT COMPANY	THROUGHPUT IS KILN FEES RATE LIMIT. ALSO USES TIRE DERIVED FUEL, NOT TO EXCEED 15% OF COMBINED ENERGY INPUT (AS PER DAQE -958-96) OTHER FUELS INCLUDE USED OIL, DIESEL AND NATURAL GAS. USED OIL CONTENTS NOT TO EXCEED: ARSENIC 5 PPM BY WT, BARIUM 100 PPM BY WT, CADIUM 2 PPM BY WT, CHROMIUM 10 PPM BY WT, LEAD 100 PPM BY WT, SULFER .5% BY WT, TOTAL HALOGENS 1000 PPM BY WT, FLASH POINT 100F (MINIMUM). CO LIMIT TO BE ESTABLISHED AFTER COMPLIANCE TEST. EMISSIONS FROM SOURCE HAVE BEEN ESTIMATED AT 501 LB CO/H.	TSP	PM	A	BAGHOUSE. EMISSION LIMITS 23.45 LB/H @170 T/H KILN FEED RATE.			23.45	LB/H	@170 T/H	BACT-PSD					0.14	LB/T		P			
UT-0059	ASH GROVE CEMENT COMPANY	THROUGHPUT IS KILN FEES RATE LIMIT. ALSO USES TIRE DERIVED FUEL, NOT TO EXCEED 15% OF COMBINED ENERGY INPUT (AS PER DAQE -958-96) OTHER FUELS INCLUDE USED OIL, DIESEL AND NATURAL GAS. USED OIL CONTENTS NOT TO EXCEED: ARSENIC 5 PPM BY WT, BARIUM 100 PPM BY WT, CADIUM 2 PPM BY WT, CHROMIUM 10 PPM BY WT, LEAD 100 PPM BY WT, SULFER .5% BY WT, TOTAL HALOGENS 1000 PPM BY WT, FLASH POINT 100F (MINIMUM). CO LIMIT TO BE ESTABLISHED AFTER COMPLIANCE TEST. EMISSIONS FROM SOURCE HAVE BEEN ESTIMATED AT 501 LB CO/H.	PM10	PM	A	BAGHOUSE. EMISSION LIMIT: 21.11 LB/H @ 170 T/H KILN FEED.			21.11	LB/H	@ 170 T/H	BACT-PSD					0.12	LB/T		P			
UT-0059	ASH GROVE CEMENT COMPANY	THROUGHPUT IS KILN FEES RATE LIMIT. ALSO USES TIRE DERIVED FUEL, NOT TO EXCEED 15% OF COMBINED ENERGY INPUT (AS PER DAQE -958-96) OTHER FUELS INCLUDE USED OIL, DIESEL AND NATURAL GAS. USED OIL CONTENTS NOT TO EXCEED: ARSENIC 5 PPM BY WT, BARIUM 100 PPM BY WT, CADIUM 2 PPM BY WT, CHROMIUM 10 PPM BY WT, LEAD 100 PPM BY WT, SULFER .5% BY WT, TOTAL HALOGENS 1000 PPM BY WT, FLASH POINT 100F (MINIMUM). CO LIMIT TO BE ESTABLISHED AFTER COMPLIANCE TEST. EMISSIONS FROM SOURCE HAVE BEEN ESTIMATED AT 501 LB CO/H.	SO2	9/5/7446	P	LOW SULFER FUEL REQUIREMENT. SULFER CONTENT OF FUEL NO GREATER THAN 1.0 LB/MMBTU FOR COAL, 0.5% BY WEIGHT FOR USED OIL.			1	LB/MMBTU		BACT-PSD								P			
UT-0059	ASH GROVE CEMENT COMPANY	THROUGHPUT IS KILN FEES RATE LIMIT. ALSO USES TIRE DERIVED FUEL, NOT TO EXCEED 15% OF COMBINED ENERGY INPUT (AS PER DAQE -958-96) OTHER FUELS INCLUDE USED OIL, DIESEL AND NATURAL GAS. USED OIL CONTENTS NOT TO EXCEED: ARSENIC 5 PPM BY WT, BARIUM 100 PPM BY WT, CADIUM 2 PPM BY WT, CHROMIUM 10 PPM BY WT, LEAD 100 PPM BY WT, SULFER .5% BY WT, TOTAL HALOGENS 1000 PPM BY WT, FLASH POINT 100F (MINIMUM). CO LIMIT TO BE ESTABLISHED AFTER COMPLIANCE TEST. EMISSIONS FROM SOURCE HAVE BEEN ESTIMATED AT 501 LB CO/H.	NOX	10102	P	LOW NOX BURNER. PRIMARY EMISSION LIMIT: 400 LB/H AT 90% OF MAX PRODUCTION CAPACITY. NOTE: TITLE V PERMIT DOES NOT INCLUDE				400	LB/H		BACT-PSD								P		
UT-0059	ASH GROVE CEMENT COMPANY	THROUGHPUT IS KILN FEES RATE LIMIT. ALSO USES TIRE DERIVED FUEL, NOT TO EXCEED 15% OF COMBINED ENERGY INPUT (AS PER DAQE -958-96) OTHER FUELS INCLUDE USED OIL, DIESEL AND NATURAL GAS. USED OIL CONTENTS NOT TO EXCEED: ARSENIC 5 PPM BY WT, BARIUM 100 PPM BY WT, CADIUM 2 PPM BY WT, CHROMIUM 10 PPM BY WT, LEAD 100 PPM BY WT, SULFER .5% BY WT, TOTAL HALOGENS 1000 PPM BY WT, FLASH POINT 100F (MINIMUM). CO LIMIT TO BE ESTABLISHED AFTER COMPLIANCE TEST. EMISSIONS FROM SOURCE HAVE BEEN ESTIMATED AT 501 LB CO/H.	VE	VE	A	BAGHOUSE			20	% OPACITY		BACT-PSD					20	% OPACITY		P			
UT-0059	ASH GROVE CEMENT COMPANY	TITLE V PERMIT:		TSP	PM	A	BAGHOUSE. EMISSION LIMIT 2 AS PER TITLE V PERMIT. NO EMISSION LIMIT IN LB/T.			10.69	LB/H		BACT-PSD		0.01	GR/DSCF					P		
UT-0059	ASH GROVE CEMENT COMPANY	TITLE V PERMIT:		PM10	PM	A	BAGHOUSE. EMISSION LIMIT 2: .009 GR/DSCF AS PER TITLE V. NO EMISSION LIMIT AS LB/T.			9.63	LB/H		BACT-PSD		0.009	GR/SCF					P		
UT-0059	ASH GROVE CEMENT COMPANY	TITLE V PERMIT:		VE	VE	A	BAGHOUSE			10	% OPACITY		BACT-PSD					10	% OPACITY		P		
UT-0059	ASH GROVE CEMENT COMPANY	EMISSION LIMITS ARE FOR COAL SYSTEM BAGHOUSE. TITLE V PERMIT LISTS AS (R140) COAL GRINDING SYSTEM AND SAYS	,	,	,	,	,	,	,	,	,	,	,	,	,	,	,	,	,	,	,	,	,
UT-0059	ASH GROVE CEMENT COMPANY	EMISSION LIMITS ARE FOR COAL SYSTEM BAGHOUSE. TITLE V PERMIT LISTS AS (R140) COAL GRINDING SYSTEM AND SAYS	,	,	,	,	,	,	,	,	,	,	,	,	,	,	,	,	,	,	,	,	,
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	1)UNPAVED ROADS AND OPERATIONAL AREAS WATER SPRAYED OR CHEMICALLY TREATED TO CONTROL FUGITIVE DUST. OPACITY NOT TO EXCEED 20%. 2)HAUL ROAD SPEED LIMITS: 25 MPH FOR HAULERS, 15 MPH FOR LOADERS. 3)DUST SUPRESSION SYSTEMS AT CRUSHER DUMP AND CONVEYOR TRANSFER POINTS.	VE	VE	P	WATER SPRAYS AND CHEMICAL TREATMENTS, PAVED ROADS, HAUL ROAD LIMITS, DUST SUPPRESSION SYSTEMS AT CRUSHER DUMP AND CONVEYOR TRANSFER POINTS			20	% OPACITY		BACT-OTHER					20	% OPACITY		F			
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	BASIS OF LIMITS IS UNCLEAR. APPROVAL ORDER REFERENCES NSPS AND TITLE V.	HALOGENS		P	LOW HALOGEN CONTENT IN FUELS					See POLLUTANT note.	OTHER								P			
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	BASIS OF LIMITS IS UNCLEAR. APPROVAL ORDER REFERENCES NSPS AND TITLE V.	PM10	PM	A	BAGHOUSE. NOTE: OPACITY LIMIT FOR KILN EXHAUST GASES IS 20%.			14	LB/H		NSPS							Not Available	P			
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	BASIS OF LIMITS IS UNCLEAR. APPROVAL ORDER REFERENCES NSPS AND TITLE V.	SO2	9/5/7446	P	LOW SULFUR FUELS			110	LB/H		NSPS								P			
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	BASIS OF LIMITS IS UNCLEAR. APPROVAL ORDER REFERENCES NSPS AND TITLE V.	NOX	10102	P	LOW NOX BURNER			251	LB/H		NSPS								P			
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	BASIS OF LIMITS IS UNCLEAR. APPROVAL ORDER REFERENCES NSPS AND TITLE V.	CO	630-08-0	P	COMBUSTION CONTROLS			438	LB/H		BACT-PSD								P			

RBLCID	FACILITY	PRNOTES	POLLUTANT	CAS	CONTROL COD	CTRLDESC	RANKOPTS	RANK SEL	EMIS LIMIT1	EMISLIMIT1 UNIT	EMISLIMIT1 CONDITION	BASIS	PCTE FFIC	EMISL IMIT2	EMISLI MIT2U NIT	EMISLI MIT2C ONDITI ON	STDEMISS	STDUNIT	STOTHER CONDITIONS	EMISSTYPE	CAPCOST	ANNUAL COST	OMCOST
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	BASIS OF LIMITS IS UNCLEAR. APPROVAL ORDER REFERENCES NSPS AND TITLE V.	VE	VE	A	FABRIC FILTER			20	% OPACITY		NSPS					20	% OPACITY		P			
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		PM10	PM	A	BAGHOUSE WITH A STACK	3	1	1.269	LB/HR & .010 GR/DSCF		BACT-PSD	99	4.72	TPY & 7% OPACITY		0			P	0	0	0
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		PM10	PM	P	WET SUPPRESSION	1	1	399.4	LB/HR		BACT-PSD	0	49.93	TPY		0			F	0	0	0
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		NOX	10102	B	SELECTIVE NON-CATALYTIC REDUCTION (SNCR) UREA INJECTION SYSTEM AT PREHEATER	3	1	3.1	LB/TON CLINKER PROD.		BACT-PSD	50	1548	TPY		0			P	0	0	0
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		CO	630-08-0	P	GOOD COMBUSTION PRACTICE. AIR/FUEL RATIO CONTROL SYSTEM	3	3	5.67	LB/TON CLINKER PROD.		BACT-PSD	0	2835	TPY		0			P	0	0	0
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		SO2	9/5/7446	P	FUEL SPEC: LIMIT FUEL TO COAL WITH 1% SULFUR (COAL SULFUR ANALYSIS)	3	2	0.416	LB/TON CLINKER PROD.		BACT-PSD	90	208	TPY		0			P	0	0	0
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	THROUGHPUT CAPACITY/SIZE: 1.6 MILLION TONS FOR THE CEMENT KILN	PM10	PM	A	BAGHOUSE WITH A STACK	3	1	23.7	LB/HR & .015 GR/DSCF		BACT-PSD	99	88	TPY & 10% OPACITY		0			P	0	0	0
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		PM10	PM	A	BAGHOUSE WITH A STACK	3	1	21	LB/HR & .015 GR/DSCF		BACT-PSD	99	78.2	TPY		0			P	0	0	0
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		PM10	PM	A	BAGHOUSE WITH A STACK	3	1	18.7	LB/HR & .010 GR/DSCF		BACT-PSD	99	69.5	TPY & 7% OPACITY		0			P	0	0	0
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		PM10	PM	P	WET SUPPRESSION	1	1	399.6	LB/HR		BACT-PSD	90	49.95	TPY		0			F	0	0	0
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		PM10	PM	A	BAGHOUSE WITH A STACK	3	1	0.05	LB/HR & .010 GR/DSCF		BACT-PSD	99	3.57	TPY & 7% OPACITY		0			P	0	0	0
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		PM10	PM	P	WET SUPPRESSION	1	1	274.9	LB/HR		BACT-PSD	82	34.37	TPY		0			F	0	0	0
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		PM10	PM	A	BAGHOUSE WITH A STACK	3	1	2.334	LB/HR & .010 GR/DSCF		BACT-PSD	99	8.682	TPY & 7% OPACITY		0			P	0	0	0
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		PM10	PM	A	BAGHOUSE WITH A STACK	3	1	3.32	LB/HR & .010 GR/DSCF		BACT-PSD	99	12.34	TPY & 7% OPACITY		0			P	0	0	0
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	KILN #1 FORMERLY WET PROCESS KILN MODIFIED TO A LONG DRY PROCESS KILN. 29 T/H CLINKER PRODUCTION. SPECIFIED COAL INPUT IS 7.3T/H.	VOC	VOC	P	PROPER COMBUSTION/BURNER DESIGN	0	0	7.3	LB/H		BACT-PSD	0	0			0			P	0	0	0
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	KILN #1 FORMERLY WET PROCESS KILN MODIFIED TO A LONG DRY PROCESS KILN. 29 T/H CLINKER PRODUCTION. SPECIFIED COAL INPUT IS 7.3T/H.	VE	VE	N		0	0	20	% OPACITY		NSPS	0	0			0			P	0	0	0
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	KILN #1 FORMERLY WET PROCESS KILN MODIFIED TO A LONG DRY PROCESS KILN. 29 T/H CLINKER PRODUCTION. SPECIFIED COAL INPUT IS 7.3T/H.	CO	630-08-0	P	PROPER COMBUSTION/BURNER DESIGN	0	0	3.2	LB/H		BACT-PSD	0	0			0			P	0	0	0
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	KILN #1 FORMERLY WET PROCESS KILN MODIFIED TO A LONG DRY PROCESS KILN. 29 T/H CLINKER PRODUCTION. SPECIFIED COAL INPUT IS 7.3T/H.	NOX	10102	P	COMBUSTION UNIT DESIGN (WELL DESIGNED PROCESS BURNER OPERATED IN DESIGN RANGE)	4	4	208.8	LB/H (30DAY ROLLING)		BACT-PSD	20	0			0			P	0	0	0
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	KILN #1 FORMERLY WET PROCESS KILN MODIFIED TO A LONG DRY PROCESS KILN. 29 T/H CLINKER PRODUCTION. SPECIFIED COAL INPUT IS 7.3T/H.	PM	PM	A	ELECTROSTATIC PRECIPITATOR (RECONSTRUCT EXISTING)	2	0	13.59	LB/H		BACT-PSD	99.9	0			0.3	LB/TON		P	0	0	0
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	KILN #1 FORMERLY WET PROCESS KILN MODIFIED TO A LONG DRY PROCESS KILN. 29 T/H CLINKER PRODUCTION. SPECIFIED COAL INPUT IS 7.3T/H.	SO2	9/5/7446	P	LOW SULFUR COAL AND ABSORPTION OF SO2 BY THE ALKA-LINE RAW MATERIAL	3	3	406	LB/H (3 H ROLLING)		BACT-PSD	50	0			0			P	0	0	0
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	CONVEYOR FROM KILN #1 8000 ACFM BAGHOUSE	PM	PM	A	BAGHOUSE	0	0	0.01	GR/ACF		BACT-PSD	99.9	0.69	LB/H		0			P	0	0	0
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	CONVEYOR FROM KILN #1 8000 ACFM BAGHOUSE	VE	VE	N		0	0	10	% OPACITY		NSPS	0	0			0			P	0	0	0
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	ASSOCIATED WITH KILN #1 2000 ACFM BAGHOUSE	VE	VE	N		0	0	10	% OPACITY		NSPS	0	0			0			P	0	0	0
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	ASSOCIATED WITH KILN #1 2000 ACFM BAGHOUSE	PM	PM	A	BAGHOUSE	0	0	0.01	GR/ACF		BACT-PSD	99.9	0.17	LB/H		0			P	0	0	0
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	FINISH MILL	EXISTING GRINDING MILL USED IN OLD WET PROCESS SYSTEM WHICH WILL BE CONVERTED TO PROCESS CLINKER. 2000 ACFM BAGHOUSE	PM	PM	A	BAGHOUSE	0	0	0.01 GR/ACF			BACT-PSD	99.9	1.89 LB/H			0		P	0	0

RBLCID	FACILITY	COST EFFECT	COST VERIFY	DOLLAR YEAR	POLNOTES
UT-0059	ASH GROVE CEMENT COMPANY		N		
UT-0059	ASH GROVE CEMENT COMPANY		N		
UT-0059	ASH GROVE CEMENT COMPANY		N		
UT-0059	ASH GROVE CEMENT COMPANY		N		
UT-0059	ASH GROVE CEMENT COMPANY			N	
UT-0059	ASH GROVE CEMENT COMPANY		N		
UT-0059	ASH GROVE CEMENT COMPANY			N	
UT-0059	ASH GROVE CEMENT COMPANY			N	
UT-0059	ASH GROVE CEMENT COMPANY			N	
UT-0059	ASH GROVE CEMENT COMPANY	,	,	,	,
UT-0059	ASH GROVE CEMENT COMPANY	,	,	,	,
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT		N		
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT		N		NO EMISSION LIMITS FOR POLLUTANTS:METALS AND HALOGENS. LIMITS INSTEAD FOR USED FUEL OIL NOT TO EXCEED: 1)ARSENIC-5 PPM BY WT. 2)CADIUM-2 PPM BY WEIGHT 3)CHROMIUM-10 PPM BY WT. 4)LEAD-100 PPM BY WT. 5)TOTAL HALOGENS 1000 PPM BY WT. FLASH POINT NOT LESS THAN 100 F.
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT		N		permitted limit is lb/h. Clinker production rate can vary so long as lb/h emission rate is achieved.
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT		N		FUELS NOT TO EXCEED 1.0 POUND SULFuR PER MMBTU HEAT INPUT FOR COAL. 2) USED OIL NOT TO EXCEED .5 PERCENT BY WEIGHT.
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT		N		
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT		N		

RBLCID	FACILITY	COST EFFECT	COST VERIFY	DOLLAR YEAR	POLNOTES
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT		N		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		N		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		N		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		N		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		N		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		N		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		N		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		N		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		N		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		N		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		N		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		N		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		N		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		N		
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		N		
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		N		
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		N		
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		N		
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		N		
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		N		
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		N		
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		N		
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		N		
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		N		
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	0		N	

RBLCID	FACILITY	COMPANY	COUNTY	CONTACT	ADDRESS	CITY	STATE	ZIP	PHONE	EMAIL	REGION	AGENCY CODE	AGENCYNAME	AGENCYCONTACT	AGENCY PHONE	AGENCY EMAIL	PERMITNUM	SIC	NAICS	AIRSID	EPAID	UTMZONE	XCOORD	YCOORD	RCVD DATE	PERMIT DATE	STARTUP DATE	EMISLIMIT2 UNIT	STOTHER CONDITIONS	CAP COST	OM COST	COST EFFECT	COST VERIFY	DOLLAR YEAR
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000		T/YR					N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000		T/YR					N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000		T/YR					N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000		T/YR					N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000		T/YR					N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000		T/YR					N	
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*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000		T/YR					N	
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*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000		T/YR					N	
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*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000		T/YR					N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000		T/YR					N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000							N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000							N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000							N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000							N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000							N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000							N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000							N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000							N	

RBLCID	FACILITY	COMPANY	COUNTY	CONTACT	ADDRESS	CITY	STATE	ZIP	PHONE	EMAIL	REGION	AGENCY CODE	AGENCYNAME	AGENCYCONTACT	AGENCY PHONE	AGENCY EMAIL	PERMITNUM	SIC	NAICS	AIRSID	EPAID	UTMZONE	XCOORD	YCOORD	RCVD DATE	PERMIT DATE	STARTUP DATE	EMISLIMIT2 UNIT	STOTHER CONDITIONS	CAP COST	OM COST	COST EFFECT	COST VERIFY	DOLLAR YEAR
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000							N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000							N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000							N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000							N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000							N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000							N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000							N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000							N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000							N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000							N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000							N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000							N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000							N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000							N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000							N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000							N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000							N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000							N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000							N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000		T/YR					N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000		T/YR					N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000		T/YR					N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000		T/YR					N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000		T/YR					N	
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*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000		T/YR					N	
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*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000		T/YR					N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000		T/YR					N	
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*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000		T/YR					N	
WY-0050	SF PHOSPHATES LIMITED CO - FERTILIZER COMPLEX	SF PHOSPHATES LIMITED CO - FERTILIZER COMPLEX	SWEETWATER		P.O. BOX 1789	ROCK SPRINGS		-82902			8	WY001	WYOMING AIR QUAL DIV, DEPT OF ENV QUAL	LEE GRIBOVICZ- DISTRICT 5 ENGIN	(307) 332-6755		MD-384	2874		3700022					4/28/1998	12/22/1998	1/31/2000			0	0		N	
WY-0050	SF PHOSPHATES LIMITED CO - FERTILIZER COMPLEX	SF PHOSPHATES LIMITED CO - FERTILIZER COMPLEX	SWEETWATER		P.O. BOX 1789	ROCK SPRINGS		-82902			8	WY001	WYOMING AIR QUAL DIV, DEPT OF ENV QUAL	LEE GRIBOVICZ- DISTRICT 5 ENGIN	(307) 332-6755		MD-384	2874		3700022					4/28/1998	12/22/1998	1/31/2000	LB/H (ANNUAL AVG)		0	0		N	

RBLCID	FACILITY	POLNOTES
*TX-0280	AGRIFIOS- OLIN FACILITY	
*TX-0280	AGRIFIOS- OLIN FACILITY	
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*TX-0280	AGRIFIOS- OLIN FACILITY	
*TX-0280	AGRIFIOS- OLIN FACILITY	
*TX-0280	AGRIFIOS- OLIN FACILITY	THE EMISSIONS FROM THIS SOURCE ARE INCLUDED IN EPN F-9BFD007 (FERTILIZER STORAGE AND LOADING).
*TX-0280	AGRIFIOS- OLIN FACILITY	
*TX-0280	AGRIFIOS- OLIN FACILITY	
*TX-0280	AGRIFIOS- OLIN FACILITY	
*TX-0280	AGRIFIOS- OLIN FACILITY	
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WY-0050	SF PHOSPHATES LIMITED CO - FERTILIZER COMPLEX	
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RBLCID	FACILITY	COMPANY	COUNTY	CONTACT	ADDRESS	CITY	STATE	ZIP	PHONE	EMAIL	REGION	AGENCYCODE	AGENCYNAME	AGENCY CONTACT	AGENCYPHONE	AGENCYEMAIL	PERMITNUM	SIC	NAICS	AIRSID	EPAID	UTMZONE	XCOORD	YCOORD
AZ-0022	INTEL CORPORATION	INTEL CORPORATION			OLD PRICE RD ALIGNMENT	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		93-0046	3674	334413					
AZ-0022	INTEL CORPORATION	INTEL CORPORATION			OLD PRICE RD ALIGNMENT	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		93-0046	3674	334413					
AZ-0022	INTEL CORPORATION	INTEL CORPORATION			OLD PRICE RD ALIGNMENT	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		93-0046	3674	334413					
AZ-0022	INTEL CORPORATION	INTEL CORPORATION			OLD PRICE RD ALIGNMENT	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		93-0046	3674	334413					
AZ-0022	INTEL CORPORATION	INTEL CORPORATION			OLD PRICE RD ALIGNMENT	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		93-0046	3674	334413					
AZ-0028	SITIX OF PHOENIX, INC.	SITIX OF PHOENIX, INC.	MARICOPA		1901 N. TATUM BLVD	PHOENIX	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	HARRY H. CHIU	(602) 506-6736		950460	3674	334413					
AZ-0028	SITIX OF PHOENIX, INC.	SITIX OF PHOENIX, INC.	MARICOPA		1901 N. TATUM BLVD	PHOENIX	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	HARRY H. CHIU	(602) 506-6736		950460	3674	334413					
AZ-0028	SITIX OF PHOENIX, INC.	SITIX OF PHOENIX, INC.	MARICOPA		1901 N. TATUM BLVD	PHOENIX	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	HARRY H. CHIU	(602) 506-6736		950460	3674	334413					
AZ-0032	INTEL CORPORATION	INTEL CORPORATION			4500 S. DOBSON RD	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE LIEB	(602) 506-6738		96-0743	3674	334413					
AZ-0032	INTEL CORPORATION	INTEL CORPORATION			4500 S. DOBSON RD	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE LIEB	(602) 506-6738		96-0743	3674	334413					
AZ-0032	INTEL CORPORATION	INTEL CORPORATION			4500 S. DOBSON RD	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE LIEB	(602) 506-6738		96-0743	3674	334413					
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	RIO GRANDE PORTLAND CEMENT CORP.	PUEBLO	BRIAN MCGILL	APPROX 6 MI SSE OF PUEBLO	PUEBLO	CO		505-281-3311	BMCGILL@GCC.COM	8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	RAM N. SEETHARAM	303-692-3198		98PB0893	3241		1010252		13	534.5	4220.1
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	RIO GRANDE PORTLAND CEMENT CORP.	PUEBLO	BRIAN MCGILL	APPROX 6 MI SSE OF PUEBLO	PUEBLO	CO		505-281-3311	BMCGILL@GCC.COM	8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	RAM N. SEETHARAM	303-692-3198		98PB0893	3241		1010252		13	534.5	4220.1
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	RIO GRANDE PORTLAND CEMENT CORP.	PUEBLO	BRIAN MCGILL	APPROX 6 MI SSE OF PUEBLO	PUEBLO	CO		505-281-3311	BMCGILL@GCC.COM	8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	RAM N. SEETHARAM	303-692-3198		98PB0893	3241		1010252		13	534.5	4220.1
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	RIO GRANDE PORTLAND CEMENT CORP.	PUEBLO	BRIAN MCGILL	APPROX 6 MI SSE OF PUEBLO	PUEBLO	CO		505-281-3311	BMCGILL@GCC.COM	8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	RAM N. SEETHARAM	303-692-3198		98PB0893	3241		1010252		13	534.5	4220.1
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	RIO GRANDE PORTLAND CEMENT CORP.	PUEBLO	BRIAN MCGILL	APPROX 6 MI SSE OF PUEBLO	PUEBLO	CO		505-281-3311	BMCGILL@GCC.COM	8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	RAM N. SEETHARAM	303-692-3198		98PB0893	3241		1010252		13	534.5	4220.1
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	RIO GRANDE PORTLAND CEMENT CORP.	PUEBLO	BRIAN MCGILL	APPROX 6 MI SSE OF PUEBLO	PUEBLO	CO		505-281-3311	BMCGILL@GCC.COM	8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	RAM N. SEETHARAM	303-692-3198		98PB0893	3241		1010252		13	534.5	4220.1
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	RIO GRANDE PORTLAND CEMENT CORP.	PUEBLO	BRIAN MCGILL	APPROX 6 MI SSE OF PUEBLO	PUEBLO	CO		505-281-3311	BMCGILL@GCC.COM	8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	RAM N. SEETHARAM	303-692-3198		98PB0893	3241		1010252		13	534.5	4220.1
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	RIO GRANDE PORTLAND CEMENT CORP.	PUEBLO	BRIAN MCGILL	APPROX 6 MI SSE OF PUEBLO	PUEBLO	CO		505-281-3311	BMCGILL@GCC.COM	8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	RAM N. SEETHARAM	303-692-3198		98PB0893	3241		1010252		13	534.5	4220.1
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	RIO GRANDE PORTLAND CEMENT CORP.	PUEBLO	BRIAN MCGILL	APPROX 6 MI SSE OF PUEBLO	PUEBLO	CO		505-281-3311	BMCGILL@GCC.COM	8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	RAM N. SEETHARAM	303-692-3198		98PB0893	3241		1010252		13	534.5	4220.1
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6

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CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6

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CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6

RBLCID	FACILITY	RCVDDATE	PERMITDATE	STARTUPDATE	VERIFYDATE	ENTRYDATE	LASTUPDATE	NEW_MOD	PUBLICHEAR	FUEL	EMISSSOURCES	ABATEMENT	NARRATIVE
AZ-0022	INTEL CORPORATION		4/10/1994	4/1/1995		5/16/1994	12/18/2001						
AZ-0022	INTEL CORPORATION		4/10/1994	4/1/1995		5/16/1994	12/18/2001						
AZ-0022	INTEL CORPORATION		4/10/1994	4/1/1995		5/16/1994	12/18/2001						
AZ-0022	INTEL CORPORATION		4/10/1994	4/1/1995		5/16/1994	12/18/2001						
AZ-0022	INTEL CORPORATION		4/10/1994	4/1/1995		5/16/1994	12/18/2001						
AZ-0028	SITIX OF PHOENIX, INC.		2/1/1996	1/1/1996		2/26/1996	12/18/2001						
AZ-0028	SITIX OF PHOENIX, INC.		2/1/1996	1/1/1996		2/26/1996	12/18/2001						
AZ-0028	SITIX OF PHOENIX, INC.		2/1/1996	1/1/1996		2/26/1996	12/18/2001						
AZ-0032	INTEL CORPORATION		9/1/1996			10/21/1996	12/18/2001						
AZ-0032	INTEL CORPORATION		9/1/1996			10/21/1996	12/18/2001						
AZ-0032	INTEL CORPORATION		9/1/1996			10/21/1996	12/18/2001						
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	12/30/1998	9/25/2000	3/1/2003	9/1/2003	11/9/2000	3/2/2004	N		PRIMARILY COAL, NATURAL GAS USED OCCASIONALLY.	5-STAGE PREHEATER/PRECALCINER/KILN, CLINKER COOLER, CEMENT MILL, RAW MATERIALS QUARRIES, MATERIAL HANDLING	HIGH TEMPERATURE FABRIC FILTER FOR KILN & CLINKER COOLER GASES, LOW TEMPERATURE MEMBRANE FILTERS FOR ALL OTHER PARTICULATE EMISSION, MULTI- STAGE COMBUSTION AND GOOD COMBUSTION MANAGEMENT PRACTICES, COUNTER-CURRENT DRY SCRUBBING (ABSORPTION) FOR SO2, VARIOUS FUGITIVE DUST CONTROLS	MANUFACTURE OF PORTLAND CEMENT (DRY PROCESS)
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	12/30/1998	9/25/2000	3/1/2003	9/1/2003	11/9/2000	3/2/2004	N		PRIMARILY COAL, NATURAL GAS USED OCCASIONALLY.	5-STAGE PREHEATER/PRECALCINER/KILN, CLINKER COOLER, CEMENT MILL, RAW MATERIALS QUARRIES, MATERIAL HANDLING	HIGH TEMPERATURE FABRIC FILTER FOR KILN & CLINKER COOLER GASES, LOW TEMPERATURE MEMBRANE FILTERS FOR ALL OTHER PARTICULATE EMISSION, MULTI- STAGE COMBUSTION AND GOOD COMBUSTION MANAGEMENT PRACTICES, COUNTER-CURRENT DRY SCRUBBING (ABSORPTION) FOR SO2, VARIOUS FUGITIVE DUST CONTROLS	MANUFACTURE OF PORTLAND CEMENT (DRY PROCESS)
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	12/30/1998	9/25/2000	3/1/2003	9/1/2003	11/9/2000	3/2/2004	N		PRIMARILY COAL, NATURAL GAS USED OCCASIONALLY.	5-STAGE PREHEATER/PRECALCINER/KILN, CLINKER COOLER, CEMENT MILL, RAW MATERIALS QUARRIES, MATERIAL HANDLING	HIGH TEMPERATURE FABRIC FILTER FOR KILN & CLINKER COOLER GASES, LOW TEMPERATURE MEMBRANE FILTERS FOR ALL OTHER PARTICULATE EMISSION, MULTI- STAGE COMBUSTION AND GOOD COMBUSTION MANAGEMENT PRACTICES, COUNTER-CURRENT DRY SCRUBBING (ABSORPTION) FOR SO2, VARIOUS FUGITIVE DUST CONTROLS	MANUFACTURE OF PORTLAND CEMENT (DRY PROCESS)
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	12/30/1998	9/25/2000	3/1/2003	9/1/2003	11/9/2000	3/2/2004	N		PRIMARILY COAL, NATURAL GAS USED OCCASIONALLY.	5-STAGE PREHEATER/PRECALCINER/KILN, CLINKER COOLER, CEMENT MILL, RAW MATERIALS QUARRIES, MATERIAL HANDLING	HIGH TEMPERATURE FABRIC FILTER FOR KILN & CLINKER COOLER GASES, LOW TEMPERATURE MEMBRANE FILTERS FOR ALL OTHER PARTICULATE EMISSION, MULTI- STAGE COMBUSTION AND GOOD COMBUSTION MANAGEMENT PRACTICES, COUNTER-CURRENT DRY SCRUBBING (ABSORPTION) FOR SO2, VARIOUS FUGITIVE DUST CONTROLS	MANUFACTURE OF PORTLAND CEMENT (DRY PROCESS)
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	12/30/1998	9/25/2000	3/1/2003	9/1/2003	11/9/2000	3/2/2004	N		PRIMARILY COAL, NATURAL GAS USED OCCASIONALLY.	5-STAGE PREHEATER/PRECALCINER/KILN, CLINKER COOLER, CEMENT MILL, RAW MATERIALS QUARRIES, MATERIAL HANDLING	HIGH TEMPERATURE FABRIC FILTER FOR KILN & CLINKER COOLER GASES, LOW TEMPERATURE MEMBRANE FILTERS FOR ALL OTHER PARTICULATE EMISSION, MULTI- STAGE COMBUSTION AND GOOD COMBUSTION MANAGEMENT PRACTICES, COUNTER-CURRENT DRY SCRUBBING (ABSORPTION) FOR SO2, VARIOUS FUGITIVE DUST CONTROLS	MANUFACTURE OF PORTLAND CEMENT (DRY PROCESS)
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	12/30/1998	9/25/2000	3/1/2003	9/1/2003	11/9/2000	3/2/2004	N		PRIMARILY COAL, NATURAL GAS USED OCCASIONALLY.	5-STAGE PREHEATER/PRECALCINER/KILN, CLINKER COOLER, CEMENT MILL, RAW MATERIALS QUARRIES, MATERIAL HANDLING	HIGH TEMPERATURE FABRIC FILTER FOR KILN & CLINKER COOLER GASES, LOW TEMPERATURE MEMBRANE FILTERS FOR ALL OTHER PARTICULATE EMISSION, MULTI- STAGE COMBUSTION AND GOOD COMBUSTION MANAGEMENT PRACTICES, COUNTER-CURRENT DRY SCRUBBING (ABSORPTION) FOR SO2, VARIOUS FUGITIVE DUST CONTROLS	MANUFACTURE OF PORTLAND CEMENT (DRY PROCESS)
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	12/30/1998	9/25/2000	3/1/2003	9/1/2003	11/9/2000	3/2/2004	N		PRIMARILY COAL, NATURAL GAS USED OCCASIONALLY.	5-STAGE PREHEATER/PRECALCINER/KILN, CLINKER COOLER, CEMENT MILL, RAW MATERIALS QUARRIES, MATERIAL HANDLING	HIGH TEMPERATURE FABRIC FILTER FOR KILN & CLINKER COOLER GASES, LOW TEMPERATURE MEMBRANE FILTERS FOR ALL OTHER PARTICULATE EMISSION, MULTI- STAGE COMBUSTION AND GOOD COMBUSTION MANAGEMENT PRACTICES, COUNTER-CURRENT DRY SCRUBBING (ABSORPTION) FOR SO2, VARIOUS FUGITIVE DUST CONTROLS	MANUFACTURE OF PORTLAND CEMENT (DRY PROCESS)
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	12/30/1998	9/25/2000	3/1/2003	9/1/2003	11/9/2000	3/2/2004	N		PRIMARILY COAL, NATURAL GAS USED OCCASIONALLY.	5-STAGE PREHEATER/PRECALCINER/KILN, CLINKER COOLER, CEMENT MILL, RAW MATERIALS QUARRIES, MATERIAL HANDLING	HIGH TEMPERATURE FABRIC FILTER FOR KILN & CLINKER COOLER GASES, LOW TEMPERATURE MEMBRANE FILTERS FOR ALL OTHER PARTICULATE EMISSION, MULTI- STAGE COMBUSTION AND GOOD COMBUSTION MANAGEMENT PRACTICES, COUNTER-CURRENT DRY SCRUBBING (ABSORPTION) FOR SO2, VARIOUS FUGITIVE DUST CONTROLS	MANUFACTURE OF PORTLAND CEMENT (DRY PROCESS)
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	12/30/1998	9/25/2000	3/1/2003	9/1/2003	11/9/2000	3/2/2004	N		PRIMARILY COAL, NATURAL GAS USED OCCASIONALLY.	5-STAGE PREHEATER/PRECALCINER/KILN, CLINKER COOLER, CEMENT MILL, RAW MATERIALS QUARRIES, MATERIAL HANDLING	HIGH TEMPERATURE FABRIC FILTER FOR KILN & CLINKER COOLER GASES, LOW TEMPERATURE MEMBRANE FILTERS FOR ALL OTHER PARTICULATE EMISSION, MULTI- STAGE COMBUSTION AND GOOD COMBUSTION MANAGEMENT PRACTICES, COUNTER-CURRENT DRY SCRUBBING (ABSORPTION) FOR SO2, VARIOUS FUGITIVE DUST CONTROLS	MANUFACTURE OF PORTLAND CEMENT (DRY PROCESS)
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.

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CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.

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CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.

RBLCID	FACILITY	NOTES	PROCESS	PROCTYPE	SCC	FUEL	THRUPUT	THRUPUTUNIT	COMPVERIFY	STACKTEST	INSPECTION	CALCULATED	OTHERTEST	OTHERMETHD	PRNOTES
AZ-0022	INTEL CORPORATION		BOILERS, 5	13.31	10200602	NATURAL GAS	50	MMBTU/HR	F	F	F	F	F		
AZ-0022	INTEL CORPORATION		BOILERS, 5	13.31	10200602	NATURAL GAS	50	MMBTU/HR	F	F	F	F	F		
AZ-0022	INTEL CORPORATION		PHOTORESIST OPERATIONS	99.011	40100399		0		F	F	F	F	F		
AZ-0022	INTEL CORPORATION		GENERATORS, BACKUP, 5	17.13	20200202	NATURAL GAS	2220	BHP	F	F	F	F	F		
AZ-0022	INTEL CORPORATION		GENERATORS, BACKUP, 5	17.13	20200202	NATURAL GAS	2220	BHP	F	F	F	F	F		
AZ-0028	SITIX OF PHOENIX, INC.		WAFER CLEANING	99.011	3-13-999-9		131	TPY	F	F	F	F	F		
AZ-0028	SITIX OF PHOENIX, INC.		WAFER POLISHING	99.011	3-13-999-9		240000	WAFERS/MO	F	F	F	F	F		
AZ-0028	SITIX OF PHOENIX, INC.		BOILER, GAS-FIRED	13.31	1-02-006-02	NATURAL GAS	42	MMBTU/HR	F	F	F	F	F		
AZ-0032	INTEL CORPORATION	PROJECT XL PERMIT	SEMICONDUCTOR MANUFACTURING	99.011	3-13-999-99		0		F	F	F	F	F		
AZ-0032	INTEL CORPORATION	PROJECT XL PERMIT	BOILERS, GENERATORS	16.11	1-02-005-02		0		F	F	F	F	F		
AZ-0032	INTEL CORPORATION	PROJECT XL PERMIT	BOILERS (10)	13.31	1-02-005-02		54	MMBTU	F	F	F	F	F		
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	CLINKER PRODUCTION: 950,000 T/YR; FINISHED CEMENT: 1,000,000 T/YR; COAL CONSUMED: 122,500 T/YR. RAW MATERIALS QUARRIES ADJACENT TO PLANT, CONTINUOUS EMISSION MONITOR FOR SO2, CO, NOX, CONTINUOUS OPACITY MONITORS, CEMENT KILN SUBJECT TO MACT. PLANTWIDE EMISSIONS (IN T/YR) INCLUDE: FILTERABLE PM = 155.4, PM10 FILT = 148, PM(ALL PM10) = 49.7, PM FUGITIVE = 42.7, PM10 FUGITIVE = 17.8, AND PB = 0.038. DIVISION DID NOT DETERMINE BACT EMISSION LIMIT BASED ON STANDARD UNITS. LIMITS IN STANDARD UNITS HAVE BEEN CALCULATED USING THROUGHPUT AND LB/H LIMITS.	RAW MATERIAL TRANSFER, ROAD DUST	99.19	2294015002		950000	T/YR	N	N	N	N	N		THROUGHPUT IS CEMENT CLINKER.
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	CLINKER PRODUCTION: 950,000 T/YR; FINISHED CEMENT: 1,000,000 T/YR; COAL CONSUMED: 122,500 T/YR. RAW MATERIALS QUARRIES ADJACENT TO PLANT, CONTINUOUS EMISSION MONITOR FOR SO2, CO, NOX, CONTINUOUS OPACITY MONITORS, CEMENT KILN SUBJECT TO MACT. PLANTWIDE EMISSIONS (IN T/YR) INCLUDE: FILTERABLE PM = 155.4, PM10 FILT = 148, PM(ALL PM10) = 49.7, PM FUGITIVE = 42.7, PM10 FUGITIVE = 17.8, AND PB = 0.038. DIVISION DID NOT DETERMINE BACT EMISSION LIMIT BASED ON STANDARD UNITS. LIMITS IN STANDARD UNITS HAVE BEEN CALCULATED USING THROUGHPUT AND LB/H LIMITS.	KILN, CLINKER COOLER	90.028	30500614		950000	T/YR	N	N	N	N	N		THROUGHPUT IS CEMENT CLINKER. ADDITIONAL SCC: 30500606, KILN.
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	CLINKER PRODUCTION: 950,000 T/YR; FINISHED CEMENT: 1,000,000 T/YR; COAL CONSUMED: 122,500 T/YR. RAW MATERIALS QUARRIES ADJACENT TO PLANT, CONTINUOUS EMISSION MONITOR FOR SO2, CO, NOX, CONTINUOUS OPACITY MONITORS, CEMENT KILN SUBJECT TO MACT. PLANTWIDE EMISSIONS (IN T/YR) INCLUDE: FILTERABLE PM = 155.4, PM10 FILT = 148, PM(ALL PM10) = 49.7, PM FUGITIVE = 42.7, PM10 FUGITIVE = 17.8, AND PB = 0.038. DIVISION DID NOT DETERMINE BACT EMISSION LIMIT BASED ON STANDARD UNITS. LIMITS IN STANDARD UNITS HAVE BEEN CALCULATED USING THROUGHPUT AND LB/H LIMITS.	MATERIAL MILLING	90.028	30500627		1000000	T/YR	N	N	N	N	N		FINISH MILLING OF CLINKER AND ADDITIVES TO PRODUCE PORTLAND CEMENT. PARTICULATE ROUTED THROUGH LOW TEMPERATURE BAGHOUSE. ADDITIONAL SCC NUMBERS: 30500628 AND 30500629.
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	CLINKER PRODUCTION: 950,000 T/YR; FINISHED CEMENT: 1,000,000 T/YR; COAL CONSUMED: 122,500 T/YR. RAW MATERIALS QUARRIES ADJACENT TO PLANT, CONTINUOUS EMISSION MONITOR FOR SO2, CO, NOX, CONTINUOUS OPACITY MONITORS, CEMENT KILN SUBJECT TO MACT. PLANTWIDE EMISSIONS (IN T/YR) INCLUDE: FILTERABLE PM = 155.4, PM10 FILT = 148, PM(ALL PM10) = 49.7, PM FUGITIVE = 42.7, PM10 FUGITIVE = 17.8, AND PB = 0.038. DIVISION DID NOT DETERMINE BACT EMISSION LIMIT BASED ON STANDARD UNITS. LIMITS IN STANDARD UNITS HAVE BEEN CALCULATED USING THROUGHPUT AND LB/H LIMITS.	MATERIAL HANDLING	90.028	30500616		950000	T/YR	N	N	N	N	N		MATERIAL HANDLING PARTICULATE, ROUTED THROUGH LOW TEMPERATURE BAGHOUSE
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	CLINKER PRODUCTION: 950,000 T/YR; FINISHED CEMENT: 1,000,000 T/YR; COAL CONSUMED: 122,500 T/YR. RAW MATERIALS QUARRIES ADJACENT TO PLANT, CONTINUOUS EMISSION MONITOR FOR SO2, CO, NOX, CONTINUOUS OPACITY MONITORS, CEMENT KILN SUBJECT TO MACT. PLANTWIDE EMISSIONS (IN T/YR) INCLUDE: FILTERABLE PM = 155.4, PM10 FILT = 148, PM(ALL PM10) = 49.7, PM FUGITIVE = 42.7, PM10 FUGITIVE = 17.8, AND PB = 0.038. DIVISION DID NOT DETERMINE BACT EMISSION LIMIT BASED ON STANDARD UNITS. LIMITS IN STANDARD UNITS HAVE BEEN CALCULATED USING THROUGHPUT AND LB/H LIMITS.	PREHEATER/PRECAL CINER, KILN	90.028	30500606		950000	T/YR	N	N	N	N	N		THROUGHPUT IS CEMENT CLINKER. PYROPROCESSING OF CRUDE IN A 5-STAGE PREHEATER/PRECALCINER AND CLINKERING ROTORY KILN TO PRODUCE CEMENT CLINKER. PM10 EMISSIONS ROUTED THROUGH THE KILN & CLINKER BAGHOUSE - THIS IS ENTERED AS A SEPARATE PROCESS IN THIS DETERMINATION. BACT DETERMINATIONS FOR CO, NOX, PM, PM10 AND SOX.
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	CLINKER PRODUCTION: 950,000 T/YR; FINISHED CEMENT: 1,000,000 T/YR; COAL CONSUMED: 122,500 T/YR. RAW MATERIALS QUARRIES ADJACENT TO PLANT, CONTINUOUS EMISSION MONITOR FOR SO2, CO, NOX, CONTINUOUS OPACITY MONITORS, CEMENT KILN SUBJECT TO MACT. PLANTWIDE EMISSIONS (IN T/YR) INCLUDE: FILTERABLE PM = 155.4, PM10 FILT = 148, PM(ALL PM10) = 49.7, PM FUGITIVE = 42.7, PM10 FUGITIVE = 17.8, AND PB = 0.038. DIVISION DID NOT DETERMINE BACT EMISSION LIMIT BASED ON STANDARD UNITS. LIMITS IN STANDARD UNITS HAVE BEEN CALCULATED USING THROUGHPUT AND LB/H LIMITS.	PREHEATER/PRECAL CINER, KILN	90.028	30500606		950000	T/YR	N	N	N	N	N		THROUGHPUT IS CEMENT CLINKER. PYROPROCESSING OF CRUDE IN A 5-STAGE PREHEATER/PRECALCINER AND CLINKERING ROTORY KILN TO PRODUCE CEMENT CLINKER. PM10 EMISSIONS ROUTED THROUGH THE KILN & CLINKER BAGHOUSE - THIS IS ENTERED AS A SEPARATE PROCESS IN THIS DETERMINATION. BACT DETERMINATIONS FOR CO, NOX, PM, PM10 AND SOX.
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	CLINKER PRODUCTION: 950,000 T/YR; FINISHED CEMENT: 1,000,000 T/YR; COAL CONSUMED: 122,500 T/YR. RAW MATERIALS QUARRIES ADJACENT TO PLANT, CONTINUOUS EMISSION MONITOR FOR SO2, CO, NOX, CONTINUOUS OPACITY MONITORS, CEMENT KILN SUBJECT TO MACT. PLANTWIDE EMISSIONS (IN T/YR) INCLUDE: FILTERABLE PM = 155.4, PM10 FILT = 148, PM(ALL PM10) = 49.7, PM FUGITIVE = 42.7, PM10 FUGITIVE = 17.8, AND PB = 0.038. DIVISION DID NOT DETERMINE BACT EMISSION LIMIT BASED ON STANDARD UNITS. LIMITS IN STANDARD UNITS HAVE BEEN CALCULATED USING THROUGHPUT AND LB/H LIMITS.	PREHEATER/PRECAL CINER, KILN	90.028	30500606		950000	T/YR	N	N	N	N	N		THROUGHPUT IS CEMENT CLINKER. PYROPROCESSING OF CRUDE IN A 5-STAGE PREHEATER/PRECALCINER AND CLINKERING ROTORY KILN TO PRODUCE CEMENT CLINKER. PM10 EMISSIONS ROUTED THROUGH THE KILN & CLINKER BAGHOUSE - THIS IS ENTERED AS A SEPARATE PROCESS IN THIS DETERMINATION. BACT DETERMINATIONS FOR CO, NOX, PM, PM10 AND SOX.
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	CLINKER PRODUCTION: 950,000 T/YR; FINISHED CEMENT: 1,000,000 T/YR; COAL CONSUMED: 122,500 T/YR. RAW MATERIALS QUARRIES ADJACENT TO PLANT, CONTINUOUS EMISSION MONITOR FOR SO2, CO, NOX, CONTINUOUS OPACITY MONITORS, CEMENT KILN SUBJECT TO MACT. PLANTWIDE EMISSIONS (IN T/YR) INCLUDE: FILTERABLE PM = 155.4, PM10 FILT = 148, PM(ALL PM10) = 49.7, PM FUGITIVE = 42.7, PM10 FUGITIVE = 17.8, AND PB = 0.038. DIVISION DID NOT DETERMINE BACT EMISSION LIMIT BASED ON STANDARD UNITS. LIMITS IN STANDARD UNITS HAVE BEEN CALCULATED USING THROUGHPUT AND LB/H LIMITS.	PREHEATER/PRECAL CINER, KILN	90.028	30500606		950000	T/YR	N	N	N	N	N		THROUGHPUT IS CEMENT CLINKER. PYROPROCESSING OF CRUDE IN A 5-STAGE PREHEATER/PRECALCINER AND CLINKERING ROTORY KILN TO PRODUCE CEMENT CLINKER. PM10 EMISSIONS ROUTED THROUGH THE KILN & CLINKER BAGHOUSE - THIS IS ENTERED AS A SEPARATE PROCESS IN THIS DETERMINATION. BACT DETERMINATIONS FOR CO, NOX, PM, PM10 AND SOX.
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	CLINKER PRODUCTION: 950,000 T/YR; FINISHED CEMENT: 1,000,000 T/YR; COAL CONSUMED: 122,500 T/YR. RAW MATERIALS QUARRIES ADJACENT TO PLANT, CONTINUOUS EMISSION MONITOR FOR SO2, CO, NOX, CONTINUOUS OPACITY MONITORS, CEMENT KILN SUBJECT TO MACT. PLANTWIDE EMISSIONS (IN T/YR) INCLUDE: FILTERABLE PM = 155.4, PM10 FILT = 148, PM(ALL PM10) = 49.7, PM FUGITIVE = 42.7, PM10 FUGITIVE = 17.8, AND PB = 0.038. DIVISION DID NOT DETERMINE BACT EMISSION LIMIT BASED ON STANDARD UNITS. LIMITS IN STANDARD UNITS HAVE BEEN CALCULATED USING THROUGHPUT AND LB/H LIMITS.	PREHEATER/PRECAL CINER, KILN	90.028	30500606		950000	T/YR	N	N	N	N	N		THROUGHPUT IS CEMENT CLINKER. PYROPROCESSING OF CRUDE IN A 5-STAGE PREHEATER/PRECALCINER AND CLINKERING ROTORY KILN TO PRODUCE CEMENT CLINKER. PM10 EMISSIONS ROUTED THROUGH THE KILN & CLINKER BAGHOUSE - THIS IS ENTERED AS A SEPARATE PROCESS IN THIS DETERMINATION. BACT DETERMINATIONS FOR CO, NOX, PM, PM10 AND SOX.
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	FINISH MILL SYSTEM	90.028	30500628				N	N	N	N	N		MILL #1 - AIRS ID 115 A. MILL #2 - AIRS ID 115 B. MILL #3 - AIRS ID 115 C: TO BE CONSTRUCTED
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	FINISH MILL SYSTEM	90.028	30500628				N	N	N	N	N		MILL #1 - AIRS ID 115 A. MILL #2 - AIRS ID 115 B. MILL #3 - AIRS ID 115 C: TO BE CONSTRUCTED
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	TRANSFER, CEMENT TO CEMENT SILOS	90.028	30500618				N	N	N	N	N		AIRS ID 116
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	TRANSFER, CEMENT TO CEMENT SILOS	90.028	30500618				N	N	N	N	N		AIRS ID 116
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	MATERIAL HANDLING, CEMENT PACKHOUSE	90.028	30500619				N	N	N	N	N		AIRS ID 117
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	MATERIAL HANDLING, CEMENT PACKHOUSE	90.028	30500619				N	N	N	N	N		AIRS ID 117

RBLCID	FACILITY	NOTES	PROCESS	PROCTYPE	SCC	FUEL	THRUPUT	THRUPUTUNIT	COMPVERIFY	STACKTEST	INSPECTION	CALCULATED	OTHERTEST	OTHERMETHD	PRNOTES
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	MATERIAL HANDLING, CEMENT BULK LOADOUTS	90.028	30500619				N	N	N	N	N		AIRS ID 118
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	MATERIAL HANDLING, CEMENT BULK LOADOUTS	90.028	30500619				N	N	N	N	N		AIRS ID 118
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	PAVED ROADS, CEMENT PRODUCT HAULOUT	99.14	2294015000				N	N	N	N	N		AIRS ID 119
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	PAVED ROADS, CEMENT PRODUCT HAULOUT	99.14	2294015000				N	N	N	N	N		AIRS ID 119
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	DRILLING AND BLASTING	90.023					N	N	N	N	N		AIRS ID 101B
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	DRILLING AND BLASTING	90.023					N	N	N	N	N		AIRS ID 101B
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	DRILLING AND BLASTING	90.023					N	N	N	N	N		AIRS ID 101B
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	DRILLING AND BLASTING	90.023					N	N	N	N	N		AIRS ID 101B
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	UNLOADING, TRANSFER, CONVEYING RAW MAT. & ADD.	90.028	30500607				N	N	N	N	N		UNLOADING, TRANSFER, CONVEYING RAW MATERIALS & ADDITIVES TO TRANSFER TOWER. AIRS ID 104
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	UNLOADING, TRANSFER, CONVEYING RAW MAT. & ADD.	90.028	30500607				N	N	N	N	N		UNLOADING, TRANSFER, CONVEYING RAW MATERIALS & ADDITIVES TO TRANSFER TOWER. AIRS ID 104
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	PRE-BLENDING	90.028	30500612				N	N	N	N	N		STACKER BELT, RECLAIMER, CONVEYORS, ALL ENCLOSED TO BE CONSTRUCTED AIRS ID 102 K
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	PRE-BLENDING	90.028	30500612				N	N	N	N	N		STACKER BELT, RECLAIMER, CONVEYORS, ALL ENCLOSED TO BE CONSTRUCTED AIRS ID 102 K
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	RAW MATERIALS CONVEYING, RAW MILL FEED BINS	90.028	30500612				N	N	N	N	N		RAW MATERIALS CONVEYING - RAW MILL FEED BINS TO TRANSFER TOWER. TRANSFER ACROSS THE RIVER. AIRS ID 102 L.
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	RAW MATERIALS CONVEYING, RAW MILL FEED BINS	90.028	30500612				N	N	N	N	N		RAW MATERIALS CONVEYING - RAW MILL FEED BINS TO TRANSFER TOWER. TRANSFER ACROSS THE RIVER. AIRS ID 102 L.
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	UNLOADING & CONVEYING, COAL TO STOCKPILE	90.011	30510103				N	N	N	N	N		AIRS ID 103 A. PM EMISSIONS NOT SUBJECT TO BACT ANALYSIS, STANDARD EMISSON UNITS NOT AVAILABLE.
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	UNLOADING & CONVEYING, COAL TO STOCKPILE	90.011	30510103				N	N	N	N	N		AIRS ID 103 A. PM EMISSIONS NOT SUBJECT TO BACT ANALYSIS, STANDARD EMISSON UNITS NOT AVAILABLE.
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	COAL STOCKPILE	90.011	30510303				N	N	N	N	N		
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	COAL STOCKPILE	90.011	30510303				N	N	N	N	N		
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	RECLAIMING, CONVEYING, & TRANS COAL TO COAL SCREEN	90.011	30510103				N	N	N	N	N		AIRS ID 103 C. PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	RECLAIMING, CONVEYING, & TRANS COAL TO COAL SCREEN	90.011	30510103				N	N	N	N	N		AIRS ID 103 C. PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.

RBLCID	FACILITY	NOTES	PROCESS	PROCTYPE	SCC	FUEL	THRUPUT	THRUPUTUNIT	COMPVERIFY	STACKTEST	INSPECTION	CALCULATED	OTHERTEST	OTHERMETHD	PRNOTES
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	SCREENING AND CRUSHING OVERSIZE COAL	90.011	30501017				N	N	N	N	N		PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	SCREENING AND CRUSHING OVERSIZE COAL	90.011	30501017				N	N	N	N	N		PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	TRANS & CONVEYING - CRUSHED COAL TO TRANSFER TOWER	90.011	30510103				N	N	N	N	N		AIRS ID 103 E. PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	TRANS & CONVEYING - CRUSHED COAL TO TRANSFER TOWER	90.011	30510103				N	N	N	N	N		AIRS ID 103 E. PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	TRANSFER, COAL, TRANSFER TOWER TO SILO	90.011	30510103				N	N	N	N	N		AIRS ID 105. PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	TRANSFER, COAL, TRANSFER TOWER TO SILO	90.011	30510103				N	N	N	N	N		AIRS ID 105. PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	RAW MATERIALS EXTRACTION	90.023	305040				N	N	N	N	N		AIRS ID 101 (A)
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	RAW MATERIALS EXTRACTION	90.023	305040				N	N	N	N	N		AIRS ID 101 (A)
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	OVERBURDEN AND WASTE ROCK REMOVAL	90.023	30504024				N	N	N	N	N		AIRS ID 101C
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	OVERBURDEN AND WASTE ROCK REMOVAL	90.023	30504024				N	N	N	N	N		AIRS ID 101C
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	RAW MATERIAL, REMOVAL AND HAULAGE	90.023	305040				N	N	N	N	N		AIRS ID 101D
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	RAW MATERIAL, REMOVAL AND HAULAGE	90.023	305040				N	N	N	N	N		AIRS ID 101D
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	CEMENT KILN DUST HAULING	90.028	30500699				N	N	N	N	N		AIRS ID 101E
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	CEMENT KILN DUST HAULING	90.028	30500699				N	N	N	N	N		AIRS ID 101E
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	DISTURBED AREAS IN QUARRY AND PLANT	90.999	30500699				N	N	N	N	N		MINIMIZATION OF AREAS EXPOSED TO EROSION. AIRS ID 101 F
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	DISTURBED AREAS IN QUARRY AND PLANT	90.999	30500699				N	N	N	N	N		MINIMIZATION OF AREAS EXPOSED TO EROSION. AIRS ID 101 F
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	MATERIAL TRANSFER, HAUL TRUCKS TO PRI CRUSH FEED	90.028	30500607				N	N	N	N	N		TRANSFER FROM HAUL TRUCK TO PRIMARY CRUSHER FEED HOPPER. (2)TO BE CONSTRUCTED. AIRS ID 102
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	MATERIAL TRANSFER, HAUL TRUCKS TO PRI CRUSH FEED	90.028	30500607				N	N	N	N	N		TRANSFER FROM HAUL TRUCK TO PRIMARY CRUSHER FEED HOPPER. (2)TO BE CONSTRUCTED. AIRS ID 102
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	ROCK CRUSHER	90.028	30500609				N	N	N	N	N		AIRS ID 102 C
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	ROCK CRUSHER	90.028	30500609				N	N	N	N	N		AIRS ID 102 C

RBLCID	FACILITY	POLLUTANT	CAS	CONTROLCOD	CTRLDESC	RANKOPTS	,	RANKSEL	EMISLIMIT1	EMISLIMIT1UNIT	EMISLIMIT1CONDITION	BASIS	PCTEFFIC	EMISLIMIT2	EMISLIMIT2UNIT	EMISLIMIT2CONDITION	STDEMISS	STDUNIT	STOTHERCONDITIONS	EMISSTYPE	CAPCOST	ANNUALCOST
AZ-0022	INTEL CORPORATION	NOX	10102	P	LOW NOX BURNERS	0	,	0	0			BACT	0	0			0			P	0	0
AZ-0022	INTEL CORPORATION	SOX/PM10	7446	P	FUEL SPEC: NATURAL GAS PRIMARY, .055 WT % S FUEL OIL BACKUP ONLY	0	,	0	0			BACT	0	0			0			P	0	0
AZ-0022	INTEL CORPORATION	VOC	VOC	A	AFTERBURNERS	0	,	0	0			BACT	90	0			0			P	0	0
AZ-0022	INTEL CORPORATION	NOX/PM10	10102	A	CYANURIC ACID INJECTION TAILPIPE CONTROL	0	,	0	0			BACT	80	0			0			P	0	0
AZ-0022	INTEL CORPORATION	SOX	7446	P	FUEL SPEC: .055 WT % S FUEL OIL	0	,	0	0			BACT	0	0			0			P	0	0
AZ-0028	SITIX OF PHOENIX, INC.	VOC	VOC	A	THERMAL OXIDIZER	0	,	0	49	TPY		BACT-PSD	90	0			0			P	0	0
AZ-0028	SITIX OF PHOENIX, INC.	PM10	PM	A	FILTERS	0	,	0	35	TPY		BACT-PSD	95	0			0			P	0	0
AZ-0028	SITIX OF PHOENIX, INC.	NOX	10102	A	FLUE GAS RECIRCULATION (FGR) NOX NOT TO EXCEED 30 PPM	0	,	0	49	TPY		BACT-PSD	0	0			0			P	0	0
AZ-0032	INTEL CORPORATION	VOC	VOC	A	CARBON ADSORPTION KREHA CONTINUOUSLY DESORBED WITH CHILLER	0	,	0	40	TPY		BACT-OTHER	90	0			0			P	0	0
AZ-0032	INTEL CORPORATION	SOX	7446	P	FUEL SPEC: 0.055 WT% S OIL	0	,	0	5	TPY		BACT-OTHER	0	0			0			P	0	0
AZ-0032	INTEL CORPORATION	NOX	10102	P	LOW NOX BURNERS < 50 PPM NOX	0	,	0	49	TPY		BACT-OTHER	0	0			0			P	0	0
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	PM10	PM	P	CE = 85-90%. TREATMENT OF UNPAVED HAUL SURFACES WITH CHEMICAL STABILIZERS AND REGULAR WATERING. REGULAR INSPECTION AND CLEANING OF PAVED HAUL SURFACES. USE OF SURFACTANTS IN SPRAY WATERS. NO LIMIT SET FOR FUGITIVE EMISSION		,		85	% REDUCTION		BACT-PSD	85							F		
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	PM10	PM	A	HIGH TEMPERATURE FABRIC FILTER BAGHOUSES FOR CLINKER COOLER.	4	,	2	0.01	GR/DSCF		BACT-PSD	99.9	46.08	T/YR		0.097	LB/T		P	2000000	212000
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	PM10	PM	A	LOW TEMPERATURE MEMBRANE TYPE FILTER BAGHOUSE	4	,	2	0.005	GR/DSCF		BACT-PSD	99.9				0.036	LB/T		P		
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	PM10	PM	A	LOW TEMPERATURE MEMBRANE TYPE FILTER BAGHOUSE; CE > 99.9%	4	,	2	0.005	GR/DSCF		BACT-PSD	99.9	10	T/YR		0.021	LB/T		P	2280000	122905
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	SO2	9/5/7446	P	RAW MATERIALS QUARRY WILL BE MANAGED FOR OPTIMUM SULFUR CONTENTS. SO2 WILL BE ABSORBED IN 5-STAGE PRECALCINER/PREHEATER/KILN AND RAW MILL. EMISSION LIMIT IN LB/T OF CLINKER, 12-MO ROLLING AVG.		,		1.99	LB/T		BACT-PSD	85				1.99	LB/T		P	7373600	437760
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	PM	PM	A	HIGH TEMPERATURE BAGHOUSE. EMISSION LIMITS SET IN GR/DSCF AND LB/T CLINKER.		,		0.01	GR/DSCF		BACT-PSD		94.7	T/YR		0.105	LB/T		P		
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	PM10	PM	A	HIGH TEMPERATURE FILTER BAGHOUSE		,		45.9	T/YR		BACT-PSD					0.097	LB/T		P		
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	CO	630-08-0	P	MULTI-STAGE COMBUSTION AND GOOD COMBUSTION MANAGEMENT PRACTICES. EMISSION LIMIT IN LB/T OF CLINKER. LB/T LIMIT IS 12-MO ROLLING AVG.	3	,	2	2.11	LB/T		BACT-PSD	90	1000	T/YR		2.11	LB/T		P	1734900	360650
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	NOX	10102	P	MULTI-STAGE COMBUSTION AND RECIRCULATION. EMISSION LIMIT IN LB/T OF CLINKER. LB/T LIMIT IS 12-MO ROLLING AVG.	3	,	2	2.32	LB/T		BACT-PSD	85	1100	T/YR		2.32	LB/T		P	3032100	294830
CO-0047	HOLNAM, FLORENCE	PM10	PM	A	BAGHOUSE		,		70.78	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM	PM	A	BAGHOUSE		,		70.78	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM	PM	A	BAGHOUSE		,		2.55	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM10	PM	A	BAGHOUSE		,		2.54	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM	PM	A	BAGHOUSE		,		0.13	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM10	PM	A	BAGHOUSE		,		0.13	T/YR		NSPS								P		

RBLCID	FACILITY	POLLUTANT	CAS	CONTROLCOD	CTRLDESC	RANKOPTS	,	RANKSEL	EMISLIMIT1	EMISLIMIT1UNIT	EMISLIMIT1CONDITION	BASIS	PCTEFFIC	EMISLIMIT2	EMISLIMIT2UNIT	EMISLIMIT2CONDITION	STDEMISS	STDUNIT	STOTHERCONDITIONS	EMISSTYPE	CAPCOST	ANNUALCOST
CO-0047	HOLNAM, FLORENCE	PM	PM	A	BAGHOUSE		,		2.58	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM10	PM	A	BAGHOUSE		,		2.46	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM	PM	P	CONTROL PLAN		,		1.6	T/YR		OTHER								F		
CO-0047	HOLNAM, FLORENCE	PM10	PM	A	CONTROL PLAN		,		1.2	T/YR		OTHER								F		
CO-0047	HOLNAM, FLORENCE	CO	630-08-0	N			,		70.6	T/YR		BACT-PSD								P		
CO-0047	HOLNAM, FLORENCE	NOX	10102	N			,		17.9	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM	PM	N			,		1.35	T/YR		NSPS								F		
CO-0047	HOLNAM, FLORENCE	PM10	PM	A			,		0.7	T/YR		NSPS								F		
CO-0047	HOLNAM, FLORENCE	PM10	PM	A	BAGHOUSE		,		0.16	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM	PM	A	BAGHOUSE		,		0.17	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM	PM	A	BAGHOUSE		,		0.25	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM10	PM	A	BAGHOUSE		,		0.25	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM	PM	A	BAGHOUSE		,		0.22	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM10	PM	A	BAGHOUSE		,		0.21	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM10	PM	A	NEG PRESSURE AND BAGHOUSE. STANDARD EMISSION UNITS NOT AVAILABLE.		,		1.85	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM	PM	A	NEG PRESSURE AND BAGHOUSE. STANDARD EMISSION UNITS NOT AVAILABLE.		,		1.94	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM	PM	P	SURFACE MOISTURE		,		0.45	T/YR		NSPS								F		
CO-0047	HOLNAM, FLORENCE	PM10	PM	P	SURFACE MOISTURE		,		0.33	T/YR		NSPS								F		
CO-0047	HOLNAM, FLORENCE	PM	PM	A	BAGHOUSE. PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.		,		0.19	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM10	PM	A	BAGHOUSE. PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.		,		0.19	T/YR		NSPS								P		

RBLCID	FACILITY	POLLUTANT	CAS	CONTROLCOD	CTRLDESC	RANKOPTS	,	RANKSEL	EMISLIMIT1	EMISLIMIT1UNIT	EMISLIMIT1CONDITION	BASIS	PCTEFFIC	EMISLIMIT2	EMISLIMIT2UNIT	EMISLIMIT2CONDITION	STDEMISS	STDUNIT	STOTHERCONDITIONS	EMISSTYPE	CAPCOST	ANNUALCOST
CO-0047	HOLNAM, FLORENCE	PM	PM	A	BAGHOUSE. PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.		,		0.19	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM10	PM	A	BAGHOUSE. PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.		,		0.19	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM	PM	A	BAGHOUSE. PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.		,		0.02	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM10	PM	A	BAGHOUSE. PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.		,		0.02	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM	PM	A	BAGHOUSE. PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.		,		0.02	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM10	PM	A	BAGHOUSE. PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.		,		0.02	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM	PM	P	MINIMIZE DISTANCE AREA, REVEGETATION, CHEMICAL STABILIZERS		,		2.63	T/YR		NSPS								F		
CO-0047	HOLNAM, FLORENCE	PM10	PM	P	MINIMIZE DISTANCE AREA, REVEGETATION, CHEMICAL STABILIZERS		,		1.32	T/YR		NSPS								F		
CO-0047	HOLNAM, FLORENCE	PM	PM	P	CONTROL PLAN		,		32.37	T/YR		OTHER								F		
CO-0047	HOLNAM, FLORENCE	PM10	PM	P	CONTROL PLAN		,		16.73	T/YR		OTHER								F		
CO-0047	HOLNAM, FLORENCE	PM	PM	P	CONTROL PLAN		,		62.47	T/YR		NSPS								F		
CO-0047	HOLNAM, FLORENCE	PM10	PM	P	CONTROL PLAN		,		37.27	T/YR		NSPS								F		
CO-0047	HOLNAM, FLORENCE	PM10	PM	P	WETTING MATERIAL PRIOR TO PLACEMENT.		,		1.34	T/YR		NSPS								F		
CO-0047	HOLNAM, FLORENCE	PM	PM	P	WETTING MATERIAL PRIOR TO PLACEMENT.		,		2.23	T/YR		NSPS								F		
CO-0047	HOLNAM, FLORENCE	PM	PM	P			,		167.21	T/YR		NSPS								F		
CO-0047	HOLNAM, FLORENCE	PM10	PM	P			,		83.61	T/YR		NSPS								F		
CO-0047	HOLNAM, FLORENCE	PM	PM	B	ENCLOSURE UNDER NEG PRESSURE, DUST CURTAINS, WATER SPRAY, BAGHOUSE		,		0.01	T/YR	transfer 1	OTHER		0.02	T/YR	transfer 2				P		
CO-0047	HOLNAM, FLORENCE	PM10	PM	B	ENCLOSURE UNDER NEG PRESSURE, DUST CURTAINS, WATER SPRAY, BAGHOUSE		,		0.01	T/YR	transfer 1	OTHER		0.02	T/YR	transfer 2				P		
CO-0047	HOLNAM, FLORENCE	PM	PM	A	BAGHOUSE		,		0.05	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM10	PM	A	BAGHOUSE		,		0.05	T/YR		NSPS								P		

RBLCID	FACILITY	OMCOST	COSTEFFECT	COSTVERIFY	DOLLARYEAR	POLNOTES
AZ-0022	INTEL CORPORATION	0		N		
AZ-0022	INTEL CORPORATION	0		N		
AZ-0022	INTEL CORPORATION	0		N		
AZ-0022	INTEL CORPORATION	0		N		
AZ-0022	INTEL CORPORATION	0		N		
AZ-0028	SITIX OF PHOENIX, INC.	0		N		
AZ-0028	SITIX OF PHOENIX, INC.	0		N		
AZ-0028	SITIX OF PHOENIX, INC.	0		N		
AZ-0032	INTEL CORPORATION	0		N		
AZ-0032	INTEL CORPORATION	0		N		
AZ-0032	INTEL CORPORATION	0		N		
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.			N		
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	112000	5.18	N	1998	
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.			N		
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	8905	21.25	N	1998	
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	66080	27.05	N	1998	
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.			N		
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.			N		
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	206000		N	1998	
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	75320		N	1998	
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		

RBLCID	FACILITY	OMCOST	COSTEFFECT	COSTVERIFY	DOLLARYEAR	POLNOTES
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		

RBLCID	FACILITY	OMCOST	COSTEFFECT	COSTVERIFY	DOLLARYEAR	POLNOTES
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		no regulatory basis provided.
CO-0047	HOLNAM, FLORENCE			N		no regulatory basis provided.
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		regulatory basis not provided.
CO-0047	HOLNAM, FLORENCE			N		regulatory basis not provided.
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		

HCMREG	BASCODE	BASIN	FORMATION	NRES	NCOMP	ULT_COMP	AVDEPTH	CO2AV	CO2MIN
G	221	Texas Gulf Coast	Wilcox	1358	15026	2.49245	10210	3.3	0.1
D	260	East Texas Basin	Cotton Valley	208	6137	1.83996	10813	2.2	0.8
FR	535	Green River Basin	Madison	8	26	300.15773	15994	65.6	65.2
G	221	Texas Gulf Coast	Austin Chalk	45	1463	1.75877	13303	4.7	4.7
JS	430	Permian Basin	Ellenburger	150	1014	17.86021	16920	18.1	0.1
FR	535	Green River Basin	Mesaverde	127	1470	2.60129	9099	2.4	0.1
TB	507	Overthrust	Madison	5	54	40.48403	14655	7.2	7.2
G	221	Texas Gulf Coast	Edwards Lime	85	874	4.10249	11736	6.8	3.8
JN	345	Arkoma Basin	Atoka	151	6618	1.78807	7167	1.6	0.0
FR	515	Powder River Basin	Fort Union Coal	2	2629	0.4	494	0.5	0.5
FR	575	Uinta Basin	Mesaverde Group Coal	6	455	1.69404	2487	4.3	3.1
D	260	East Texas Basin	Smackover	96	324	10.08857	12096	5.7	2.8
JN	360	Anadarko Basin	Hunton	128	1017	4.36172	17071	3.3	0.0
FR	530	Wind River Basin	Fort Union	25	270	3.84961	7263	2.0	0.3
JN	345	Arkoma Basin	Other	652	4670	0.99011	5694	0.9	0.0
JN	360	Anadarko Basin	Morrow	877	10817	2.23185	10706	1.0	0.0
FR	540	Denver Basin	Other	56	1754	0.5652	7622	2.0	2.0
FR	595	Piceance Basin	Mesaverde	43	958	1.1197	6520	2.9	0.8
FR	540	Denver Basin	J Sand	180	2447	0.55486	7885	2.5	0.3
D	260	East Texas Basin	Bossier	45	255	1.45852	12474	2.4	2.0
D	260	East Texas Basin	Haynesville	12	182	4.74496	11711	2.5	1.2
FR	530	Wind River Basin	Madison	1	3	102.75904	23877	19.0	19.0
JS	430	Permian Basin	Other	836	4458	1.49725	5760	0.3	0.0
FR	535	Green River Basin	Weber	9	29	21.41971	15007	19.7	10.6
JS	430	Permian Basin	Strawn	334	2254	1.12572	10066	1.9	0.1
JN	360	Anadarko Basin	Other	2221	12567	1.62904	8221	0.7	0.0
JS	430	Permian Basin	Fusselman	81	397	7.02808	16292	5.0	0.1
FR	535	Green River Basin	Frontier	113	2630	1.93548	9501	0.7	0.1
FR	535	Green River Basin	Other	162	397	1.24587	7465	0.4	0.1
FR	585	Paradox Basin	Mississippian	5	12	16.73878	8483	22.9	22.9
JN	360	Anadarko Basin	Douglas	72	830	1.5925	7233	3.6	0.1
FR	515	Powder River Basin	Muddy	37	134	1.45668	10802	1.9	0.4
G	221	Texas Gulf Coast	Vicksburg	507	5721	2.50623	11311	0.3	0.0
G	221	Texas Gulf Coast	Yegua	940	5410	2.0855	8835	1.0	0.1
FR	535	Green River Basin	Nugget	15	43	9.29993	15344	2.4	1.4
JN	345	Arkoma Basin	Arbuckle	4	20	19.55891	13891	2.0	1.7

HCMREG	BASCODE	BASIN	FORMATION	NRES	NCOMP	ULT_COMP	AVDEPTH	CO2AV	CO2MIN
D	260	East Texas Basin	Woodbine	83	622	2.03957	4651	1.9	0.5
FR	595	Piceance Basin	Dakota	47	321	0.81646	6571	4.1	0.1
FR	530	Wind River Basin	Cody	11	39	8.41204	16798	2.9	1.5
FR	530	Wind River Basin	Other	58	96	2.77003	10734	3.3	0.1
FR	530	Wind River Basin	Mesaverde	10	33	4.23784	14868	4.0	1.3
FR	540	Denver Basin	Niobrara	47	1484	0.37251	2265	0.9	0.2
FR	595	Piceance Basin	Wasatch	13	190	2.12091	3133	1.5	0.0
JN	360	Anadarko Basin	Viola	44	100	1.36674	11944	2.3	0.2
FR	535	Green River Basin	Lewis	65	461	2.10241	8707	0.7	0.0
JS	430	Permian Basin	Wolfcamp	287	1167	2.05626	9140	0.7	0.0
FR	595	Piceance Basin	Other	74	224	0.97037	5658	0.5	0.3
JN	360	Anadarko Basin	Skinner	63	644	1.55135	10955	1.1	0.1
FR	585	Paradox Basin	Other	86	183	0.99482	5783	1.3	0.0
FR	595	Piceance Basin	Mesaverde Group Coal	13	146	0.41521	6820	14.8	14.8
TB	507	Overthrust	Weber	3	10	6.93112	12817	5.3	5.3
JS	430	Permian Basin	Atoka	246	801	1.61476	13724	0.5	0.0
FR	575	Uinta Basin	Other	53	177	1.47338	6947	0.9	0.0
FR	540	Denver Basin	Dakota	5	74	0.37364	8177	2.3	2.3
JS	430	Permian Basin	San Andres	68	606	0.81152	4213	1.7	0.1
FR	535	Green River Basin	Phosphoria	2	8	2.32811	10009	28.2	28.2
FR	515	Powder River Basin	Other	78	176	0.28963	6155	0.9	0.1
D	260	East Texas Basin	Rodessa	192	1133	2.41318	8254	1.4	0.0
JN	360	Anadarko Basin	Red Fork	135	2480	2.0527	12305	1.2	0.1
D	260	East Texas Basin	Pettit	188	2109	4.27018	7046	1.0	0.5
JN	360	Anadarko Basin	Marmaton	114	254	0.57939	7821	0.8	0.1
FR	535	Green River Basin	Dakota	68	536	2.64748	11934	0.8	0.0
FR	585	Paradox Basin	Entrada	4	12	1.35918	5516	15.8	1.5
JS	430	Permian Basin	Tubb	26	299	1.66603	5675	0.8	0.1
TB	507	Overthrust	Other	12	14	1.33158	7667	0.0	0.0
JN	360	Anadarko Basin	Chester	243	2518	1.01939	7066	0.5	0.1
FR	535	Green River Basin	Mesaverde Group Coal	6	20	0.13585	6100	0.0	0.0
FR	535	Green River Basin	Fort Union	24	120	2.90528	5779	0.7	0.1
FR	540	Denver Basin	D Sand	129	259	0.64767	5927	1.3	0.9
JN	360	Anadarko Basin	Chase	95	15639	4.18928	2755	0.1	0.0
JS	430	Permian Basin	Queen	64	487	0.36983	3187	0.0	0.0
D	260	East Texas Basin	Glen Rose	32	260	1.45441	6347	0.6	0.2

HCMREG	BASCODE	BASIN	FORMATION	NRES	NCOMP	ULT_COMP	AVDEPTH	CO2AV	CO2MIN
D	260	East Texas Basin	Hill	37	306	1.78225	6132	0.7	0.4
D	260	East Texas Basin	James Lime	35	133	2.4993	8823	3.1	2.3
D	260	East Texas Basin	Jeter	2	37	8.1009	4944	1.3	1.3
D	260	East Texas Basin	Other	188	1154	1.08279	10334	0.7	0.1
D	260	East Texas Basin	Paluxy	27	192	1.99473	4797	0.3	0.2
D	260	East Texas Basin	Travis Peak	296	4393	1.49973	8113	0.9	0.4
D	415	Strawn Basin	Big Saline	8	138	0.40827	3808	0.6	0.3
D	415	Strawn Basin	Conglomerate	11	29	0.13508	3463	0.1	0.1
D	415	Strawn Basin	Marble Falls	26	419	0.46882	4165	0.4	0.1
D	415	Strawn Basin	Other	46	223	0.11282	4160	0.0	0.0
D	415	Strawn Basin	Strawn	32	345	0.11067	2892	0.1	0.1
D	420	Fort Worth Syncline	Atoka	133	984	0.29277	5565	0.4	0.2
D	420	Fort Worth Syncline	Barnett Shale	1	556	1.21501	7656	1.5	1.5
D	420	Fort Worth Syncline	Bend	65	3908	0.94008	5736	0.4	0.4
D	420	Fort Worth Syncline	Big Saline	14	124	0.31396	4770	1.5	1.5
D	420	Fort Worth Syncline	Caddo	115	683	0.31811	4666	0.3	0.2
D	420	Fort Worth Syncline	Conglomerate	176	1161	0.34608	5616	0.6	0.1
D	420	Fort Worth Syncline	Marble Falls	70	300	0.26676	5471	0.1	0.1
D	420	Fort Worth Syncline	Other	105	646	0.19196	4760	0.2	0.2
D	420	Fort Worth Syncline	Strawn	154	1168	0.18993	3293	0.3	0.1
D	425	Bend Arch	Bend	136	726	0.35291	4015	0.3	0.3
D	425	Bend Arch	Big Saline	28	243	0.4117	3765	0.3	0.2
D	425	Bend Arch	Caddo	244	787	0.25019	3532	0.3	0.0
D	425	Bend Arch	Conglomerate	275	1072	0.24836	3928	0.3	0.1
D	425	Bend Arch	Duffer	128	712	0.22313	3840	0.3	0.2
D	425	Bend Arch	Fry	60	1103	0.09271	2877	0.2	0.2
D	425	Bend Arch	Gardner	62	128	0.19579	3186	0.2	0.2
D	425	Bend Arch	Gray	51	111	0.20026	3116	0.1	0.1
D	425	Bend Arch	Jennings	36	129	0.30605	2986	0.1	0.1
D	425	Bend Arch	Marble Falls	250	2485	0.22606	3316	0.3	0.1
D	425	Bend Arch	Morris	59	142	0.22171	2862	0.1	0.1
D	425	Bend Arch	Other	673	4041	0.12572	3427	0.2	0.2
D	425	Bend Arch	Strawn	207	878	0.13245	2699	0.1	0.1
FR	450	Las Animas Arch	Morrow	49	145	1.25692	5178	0.8	0.2
FR	450	Las Animas Arch	Niobrara	6	125	0.16844	1291	1.5	0.0
FR	450	Las Animas Arch	Other	13	52	1.05401	4882	0.3	0.3

HCMREG	BASCODE	BASIN	FORMATION	NRES	NCOMP	ULT_COMP	AVDEPTH	CO2AV	CO2MIN
FR	455	Raton/Las Vegas Basins	Other	5	12	0.1695	5490	0.0	0.0
FR	455	Raton/Las Vegas Basins	Vermejo Coal	10	280	1.53359	1277	1.0	1.0
FR	515	Powder River Basin	Frontier	11	86	2.32626	12066	0.0	0.0
FR	515	Powder River Basin	Turner	5	58	0.89013	9535	0.9	0.9
FR	520	Big Horn Basin	Chugwater	4	31	4.24559	2933	0.1	0.1
FR	520	Big Horn Basin	Dakota	9	20	1.0014	2179	0.1	0.1
FR	520	Big Horn Basin	Frontier	36	162	1.67598	7664	0.6	0.1
FR	520	Big Horn Basin	Muddy	19	72	1.57204	8363	0.3	0.1
FR	520	Big Horn Basin	Other	43	98	0.68278	3389	0.0	0.0
FR	520	Big Horn Basin	Phosphoria	10	21	0.57955	4761	0.0	0.0
FR	530	Wind River Basin	Frontier	30	141	4.73159	7853	0.3	0.1
FR	530	Wind River Basin	Lance	19	111	6.2425	10055	0.1	0.1
FR	530	Wind River Basin	Muddy	21	55	4.30152	17088	0.3	0.0
FR	530	Wind River Basin	Phosphoria	6	35	2.87246	10556	0.7	0.7
FR	530	Wind River Basin	Tensleep	1	4	0.08597	1758	0.5	0.5
FR	530	Wind River Basin	Wind River	3	30	3.8462	3314	0.0	0.0
FR	535	Green River Basin	Almy	15	205	0.58244	2368	0.1	0.1
FR	535	Green River Basin	Bear River	28	314	1.13259	8532	0.3	0.1
FR	535	Green River Basin	Lance	24	218	5.32791	10905	0.7	0.6
FR	535	Green River Basin	Morgan	5	10	0.72865	18489	23.3	22.4
FR	535	Green River Basin	Wasatch	11	71	3.58078	3159	0.9	0.9
FR	540	Denver Basin	Codell	3	217	0.28554	7244	1.0	1.0
FR	540	Denver Basin	Sussex	6	169	0.47335	4493	0.2	0.2
FR	575	Uinta Basin	Dakota	13	43	0.73191	8567	1.0	0.9
FR	575	Uinta Basin	Frontier	1	17	11.57782	5547	0.1	0.1
FR	575	Uinta Basin	Green River	19	174	1.25994	5187	0.4	0.1
FR	575	Uinta Basin	Wasatch	31	1314	1.49993	6395	0.2	0.1
FR	585	Paradox Basin	Cedar Mountain	11	34	0.86599	6255	0.8	0.7
FR	585	Paradox Basin	Dakota	21	271	1.03999	4784	0.8	0.1
FR	585	Paradox Basin	Desert Creek	9	14	0.6991	6078	0.2	0.2
FR	585	Paradox Basin	Morrison	8	78	0.42631	4869	0.8	0.5
FR	590	Black Mesa	Other	0	0	0	3132	12.9	0.0
FR	595	Piceance Basin	Mancos	30	522	1.18108	2936	0.4	0.2
FR	595	Piceance Basin	Morrison	12	25	0.263	4985	2.7	1.4
G	221	Texas Gulf Coast	Catahoula	155	1373	0.62256	3136	0.2	0.2
G	221	Texas Gulf Coast	Cockfield	93	884	1.81167	5066	0.3	0.3

HCMREG	BASCODE	BASIN	FORMATION	NRES	NCOMP	ULT_COMP	AVDEPTH	CO2AV	CO2MIN
G	221	Texas Gulf Coast	Cook Mountain	112	397	1.49055	8594	0.3	0.1
G	221	Texas Gulf Coast	Frio	2586	38788	1.57339	8366	0.4	0.0
G	221	Texas Gulf Coast	Jackson	434	2170	0.59917	5939	0.2	0.1
G	221	Texas Gulf Coast	Marginulina	111	674	2.13413	7110	0.2	0.2
G	221	Texas Gulf Coast	Miocene	677	9791	0.83648	3631	0.1	0.1
G	221	Texas Gulf Coast	Oakville	44	275	0.33138	2674	0.1	0.0
G	221	Texas Gulf Coast	Olmos	188	2439	0.50746	8510	0.1	0.1
G	221	Texas Gulf Coast	Other	1369	5647	1.39514	10636	3.3	0.1
G	221	Texas Gulf Coast	Queen City	191	906	1.03463	7433	1.0	0.2
G	221	Texas Gulf Coast	San Miguel	106	484	0.52022	4290	0.0	0.0
JN	345	Arkoma Basin	Hartshorne Coal	16	201	0.29172	1828	0.9	0.9
JN	345	Arkoma Basin	Hunton	23	99	2.3968	6129	1.1	0.3
JN	345	Arkoma Basin	Morrow	2	2	0.32933	5346	2.1	0.3
JN	350	South Ok. Folded Belt	Cisco	21	96	1.61012	5430	0.2	0.1
JN	350	South Ok. Folded Belt	Deese	22	201	0.67602	8838	0.3	0.3
JN	350	South Ok. Folded Belt	Goddard	11	39	1.31367	12546	0.2	0.2
JN	350	South Ok. Folded Belt	Granite Wash	23	187	0.11177	7906	0.0	0.0
JN	350	South Ok. Folded Belt	Hart	5	364	1.00191	7802	0.0	0.0
JN	350	South Ok. Folded Belt	Hoxbar	35	172	0.91544	7918	0.2	0.0
JN	350	South Ok. Folded Belt	Hunton	11	78	1.52848	7631	0.6	0.2
JN	350	South Ok. Folded Belt	Other	269	1773	0.69937	9965	0.3	0.0
JN	350	South Ok. Folded Belt	Pontotoc	20	76	0.16303	2539	0.0	0.0
JN	350	South Ok. Folded Belt	Simpson	61	382	2.538	9691	0.2	0.1
JN	350	South Ok. Folded Belt	Springer	34	304	1.89864	9208	0.1	0.0
JN	350	South Ok. Folded Belt	Sycamore	13	165	2.25029	7630	0.5	0.2
JN	350	South Ok. Folded Belt	Viola	30	85	1.38258	11208	0.0	0.0
JN	350	South Ok. Folded Belt	Woodford	6	38	0.87132	4937	0.2	0.2
JN	355	Chautauqua Platform	Bartlesville	174	889	0.3711	2988	0.2	0.1
JN	355	Chautauqua Platform	Booch	95	807	0.32756	1926	0.2	0.1
JN	355	Chautauqua Platform	Burgess	42	190	0.06893	1491	0.1	0.1
JN	355	Chautauqua Platform	Cherokee Group Coal	20	176	0.14174	934	0.5	0.5
JN	355	Chautauqua Platform	Cleveland	77	375	0.34942	3959	0.1	0.1
JN	355	Chautauqua Platform	Cromwell	133	545	0.41113	3413	0.2	0.1
JN	355	Chautauqua Platform	Dutcher	111	1285	0.09471	2062	0.1	0.0
JN	355	Chautauqua Platform	Gilcrease	121	834	0.28456	2631	0.2	0.0
JN	355	Chautauqua Platform	Hart	35	224	0.43667	3445	0.1	0.0

HCMREG	BASCODE	BASIN	FORMATION	NRES	NCOMP	ULT_COMP	AVDEPTH	CO2AV	CO2MIN
JN	355	Chautauqua Platform	Hoover	25	68	0.31601	3027	0.1	0.1
JN	355	Chautauqua Platform	Hunton	96	295	0.59086	5731	0.1	0.0
JN	355	Chautauqua Platform	Layton	67	220	0.35468	4147	0.4	0.0
JN	355	Chautauqua Platform	Neva	9	381	0.01466	828	0.5	0.5
JN	355	Chautauqua Platform	Osborne	4	55	3.35092	9088	0.4	0.4
JN	355	Chautauqua Platform	Oswego	59	188	0.85408	4864	0.4	0.4
JN	355	Chautauqua Platform	Other	1168	6990	0.32423	4342	0.1	0.1
JN	355	Chautauqua Platform	Prue	90	378	0.55516	5062	0.2	0.0
JN	355	Chautauqua Platform	Red Fork	155	606	0.31484	3836	0.2	0.0
JN	355	Chautauqua Platform	Senora	39	126	0.16657	1624	0.3	0.3
JN	355	Chautauqua Platform	Skinner	163	450	0.38647	5891	0.1	0.0
JN	355	Chautauqua Platform	Tonkawa	32	56	0.21498	2912	0.1	0.0
JN	355	Chautauqua Platform	Viola	42	95	0.55676	9177	0.3	0.2
JN	355	Chautauqua Platform	Wilcox	51	97	0.26421	4900	0.3	0.3
JN	360	Anadarko Basin	Arbuckle	23	66	2.53792	17062	1.2	0.1
JN	360	Anadarko Basin	Cherokee	144	545	1.02124	10691	0.9	0.0
JN	360	Anadarko Basin	Cleveland	75	1375	0.89596	7502	0.5	0.1
JN	360	Anadarko Basin	Council Grove	73	2997	1.33942	2911	0.1	0.0
JN	360	Anadarko Basin	Granite Wash	94	1155	1.41488	10763	0.5	0.0
JN	360	Anadarko Basin	Hoxbar	14	80	1.16849	8330	0.2	0.2
JN	360	Anadarko Basin	Kansas City	37	76	0.38208	4807	0.1	0.1
JN	360	Anadarko Basin	Lansing	46	114	0.67458	4422	0.0	0.0
JN	360	Anadarko Basin	Manning	41	501	1.24747	6827	0.3	0.2
JN	360	Anadarko Basin	Oswego	86	734	1.18307	7660	0.4	0.1
JN	360	Anadarko Basin	Springer	115	1827	3.25034	13921	1.1	0.2
JN	360	Anadarko Basin	Tonkawa	104	1396	1.71522	6962	0.3	0.0
JN	360	Anadarko Basin	Topeka	47	578	2.36438	3252	0.1	0.0
JN	360	Anadarko Basin	Toronto	12	21	1.62976	4389	0.0	0.0
JN	360	Anadarko Basin	Wabaunsee	27	63	0.57183	3377	0.2	0.1
JN	365	Cherokee/Forest City	Cherokee Group Coal	11	39	0.08318	1047	1.4	1.2
JN	365	Cherokee/Forest City	Other	224	1283	0.083	1188	0.1	0.1
JN	370	Nemaha Anticline	Bartlesville	7	13	0.10939	3365	0.0	0.0
JN	370	Nemaha Anticline	Cleveland	12	32	0.22831	2473	0.0	0.0
JN	370	Nemaha Anticline	Oswego	1	1	0.35298	3082	0.2	0.2
JN	370	Nemaha Anticline	Other	156	566	0.10487	1518	0.1	0.1
JN	370	Nemaha Anticline	Wabaunsee	3	5	0.2499	591	0.0	0.0

HCMREG	BASCODE	BASIN	FORMATION	NRES	NCOMP	ULT_COMP	AVDEPTH	CO2AV	CO2MIN
JN	375	Sedgwick Basin	Douglas	36	132	0.84749	3390	0.2	0.1
JN	375	Sedgwick Basin	Kansas City	17	22	0.1713	3742	0.1	0.1
JN	375	Sedgwick Basin	Lansing	12	31	0.73438	3718	0.1	0.1
JN	375	Sedgwick Basin	Other	722	4327	0.62307	4216	0.2	0.0
JN	375	Sedgwick Basin	Topeka	6	18	0.30248	3593	0.1	0.1
JN	385	Central Kansas Uplift	Arbuckle	53	231	0.40623	3800	0.2	0.2
JN	385	Central Kansas Uplift	Chase	42	157	0.19628	1934	0.1	0.1
JN	385	Central Kansas Uplift	Cherokee	16	49	0.4864	4436	0.1	0.1
JN	385	Central Kansas Uplift	Kansas City	25	46	0.30289	3312	0.1	0.1
JN	385	Central Kansas Uplift	Lansing	35	53	0.22459	3671	0.3	0.1
JN	385	Central Kansas Uplift	Other	504	1395	0.22836	3652	0.2	0.0
JN	385	Central Kansas Uplift	Simpson	33	53	0.34785	3838	0.2	0.1
JN	385	Central Kansas Uplift	Topeka	9	47	0.37046	3044	0.2	0.2
JN	385	Central Kansas Uplift	Viola	39	87	0.28069	4066	0.2	0.2
JN	385	Central Kansas Uplift	Wabaunsee	45	87	0.28698	2895	0.1	0.1
JN	400	Ouachita Tectonic Belt	Anacacho	6	35	0.06635	973	0.0	0.0
JN	400	Ouachita Tectonic Belt	Bromide	2	10	1.70887	7467	0.2	0.2
JN	400	Ouachita Tectonic Belt	Mclish	1	6	3.50406	7736	0.5	0.5
JN	400	Ouachita Tectonic Belt	Olmos Navarro	8	75	0.03907	1111	0.0	0.0
JN	400	Ouachita Tectonic Belt	Other	40	125	0.88168	7296	0.3	0.3
JN	435	Palo Duro Basin	Atoka	2	8	0.58795	4291	0.1	0.1
JN	435	Palo Duro Basin	Cisco	4	41	0.48352	1763	0.1	0.1
JN	435	Palo Duro Basin	Keyes	4	195	2.66319	4654	0.6	0.2
JN	435	Palo Duro Basin	Morrow	7	92	1.39335	4596	0.2	0.1
JN	435	Palo Duro Basin	Other	46	716	1.81375	3053	0.4	0.0
JN	435	Palo Duro Basin	Topeka	5	41	0.6447	3533	0.4	0.4
JN	435	Palo Duro Basin	Wichita Falls	3	39	0.53127	978	0.1	0.1
JS	410	Llano Uplift	Other	19	54	0.03844	1024	0.4	0.2
JS	410	Llano Uplift	Strawn	13	105	0.08949	1184	0.1	0.1
JS	430	Permian Basin	Abo	29	1240	0.44464	4497	0.2	0.2
JS	430	Permian Basin	Canyon	242	8247	0.60827	6425	0.5	0.0
JS	430	Permian Basin	Cisco	42	318	0.59474	7054	0.5	0.1
JS	430	Permian Basin	Clear Fork	59	462	0.4774	4243	0.4	0.0
JS	430	Permian Basin	Delaware	89	396	0.92605	5109	0.1	0.0
JS	430	Permian Basin	Devonian	175	1649	6.63736	12409	1.0	0.7
JS	430	Permian Basin	Grayburg	44	280	1.14532	3151	0.1	0.0

HCMREG	BASCODE	BASIN	FORMATION	NRES	NCOMP	ULT_COMP	AVDEPTH	CO2AV	CO2MIN
JS	430	Permian Basin	Judkins	1	330	3.17719	2953	1.7	1.7
JS	430	Permian Basin	Mckee	24	172	1.57574	9703	0.1	0.1
JS	430	Permian Basin	Mcknight	1	117	1.34253	3260	1.7	1.7
JS	430	Permian Basin	Montoya	23	82	4.28962	14012	1.8	1.8
JS	430	Permian Basin	Morrow	245	2007	2.25048	11479	0.5	0.2
JS	430	Permian Basin	Pennsylvanian	189	2229	2.18633	8550	1.1	0.3
JS	430	Permian Basin	Silurian	14	75	14.32901	16842	0.0	0.0
JS	430	Permian Basin	Wichita Albany	33	162	1.11576	4786	0.4	0.1
JS	430	Permian Basin	Yates	92	1141	0.74697	2623	0.1	0.0
L	475	Southern Basin And Range	All	0	0	0	0	0.0	0.0
TB	507	Overthrust	Big Horn	4	21	6.6725	15516	0.9	0.7
TB	507	Overthrust	Nugget	9	76	43.03867	13866	0.3	0.0
TB	507	Overthrust	Phosphoria	3	9	8.7473	12176	1.3	1.3
TB	507	Overthrust	Sun River	1	4	1.751	1079	5.9	5.9
TB	507	Overthrust	Thaynes	3	4	2.23356	15780	0.1	0.1
TB	507	Overthrust	Twin Creek	5	22	3.3606	7467	0.1	0.1

BASIN	FORMATION	CO2MAX	CO2STD	RAW_RUR	R_SAMP	GASAN	CONVGROW	CONVNEWF
Texas Gulf Coast	Wilcox	17.9	2.03	6523	0.16	991	12064	14017
East Texas Basin	Cotton Valley	3.1	0.54	4642	0.37	464	10302	796
Green River Basin	Madison	65.7	0.23	5204	1.00	221	199	4688
Texas Gulf Coast	Austin Chalk	5.2	0.13	482	0.99	220	597	352
Permian Basin	Ellenburger	47.7	14.03	1660	0.96	220	858	3846
Green River Basin	Mesaverde	5.7	0.71	1900	0.86	132	6631	12368
Overthrust	Madison	7.2	0	741	1.00	85	746	2472
Texas Gulf Coast	Edwards Lime	9.9	0.87	455	0.95	68	1169	2082
Arkoma Basin	Atoka	4.5	1.13	2579	0.90	268	4590	1089
Powder River Basin	Fort Union Coal	0.5	0	1785	0.00	58	0	0
Uinta Basin	Mesaverde Group Coal	5.5	1.75	657	0.00	52	0	0
East Texas Basin	Smackover	9.0	1.12	373	0.95	40	364	351
Anadarko Basin	Hunton	8.4	2.38	490	0.81	50	1030	332
Wind River Basin	Fort Union	4.9	0.99	647	0.95	49	511	393
Arkoma Basin	Other	4.8	0.81	1155	0.44	121	1622	418
Anadarko Basin	Morrow	5.1	0.7	3682	0.79	375	17107	20271
Denver Basin	Other	2.0	0	652	0.00	51	48	317
Piceance Basin	Mesaverde	18.3	2.13	790	0.91	51	2275	1583
Denver Basin	J Sand	2.7	0.26	387	0.94	27	283	435
East Texas Basin	Bossier	2.4	0.09	259	0.77	26	37	118
East Texas Basin	Haynesville	2.9	0.66	239	1.00	26	169	542
Wind River Basin	Madison	19.0	0	2143	1.00	19	0	1510
Permian Basin	Other	7.2	0.24	511	0.52	81	720	2297
Green River Basin	Weber	22.4	4.99	248	0.99	18	59	1563
Permian Basin	Strawn	4.9	1.41	865	0.74	90	1022	376
Anadarko Basin	Other	2.9	0.44	2891	0.26	298	9474	11235
Permian Basin	Fusselman	21.3	4.39	89	0.89	13	107	656
Green River Basin	Frontier	4.2	0.85	2496	0.89	168	496	2786
Green River Basin	Other	0.7	0.17	266	0.08	19	7	122
Paradox Basin	Mississippian	22.9	0	192	0.90	8	3	306
Anadarko Basin	Douglas	10.9	4.93	260	0.67	24	832	989
Powder River Basin	Muddy	2.2	0.64	119	0.12	9	29	511
Texas Gulf Coast	Vicksburg	3.3	0.43	2814	0.40	413	3600	4069
Texas Gulf Coast	Yegua	3.0	0.72	605	0.12	118	1025	2249
Green River Basin	Nugget	3.0	0.62	122	0.79	9	21	377
Arkoma Basin	Arbuckle	2.0	0.01	48	1.00	5	724	555

BASIN	FORMATION	CO2MAX	CO2STD	RAW_RUR	R_SAMP	GASAN	CONVGROW	CONVNEWF
East Texas Basin	Woodbine	2.4	0.83	66	0.02	7	249	254
Piceance Basin	Dakota	27.9	3.48	107	0.62	7	139	69
Wind River Basin	Cody	3.0	0.34	61	0.99	5	138	599
Wind River Basin	Other	4.0	1.39	125	0.11	9	14	59
Wind River Basin	Mesaverde	5.1	1.61	72	0.98	5	261	735
Denver Basin	Niobrara	2.9	0.91	299	0.80	21	113	171
Piceance Basin	Wasatch	3.2	1.54	91	0.96	6	118	61
Anadarko Basin	Viola	2.7	0.86	32	0.55	3	96	115
Green River Basin	Lewis	2.0	0.52	412	0.65	29	133	459
Permian Basin	Wolfcamp	6.8	1.12	524	0.25	67	1090	2255
Piceance Basin	Other	37.5	1.49	66	0.02	5	75	60
Anadarko Basin	Skinner	3.5	0.7	268	0.77	30	395	471
Paradox Basin	Other	4.4	1.8	69	0.26	4	6	252
Piceance Basin	Mesaverde Group Coal	14.8	0	24	0.37	2	0	0
Overthrust	Weber	5.3	0	44	0.30	2	24	931
Permian Basin	Atoka	3.3	0.7	233	0.21	36	825	1560
Uinta Basin	Other	1.7	0.24	79	0.66	3	56	197
Denver Basin	Dakota	2.3	0	24	0.99	1	8	7
Permian Basin	San Andres	10.6	2.04	23	0.48	4	143	46
Green River Basin	Phosphoria	28.2	0	15	0.56	1	1	14
Powder River Basin	Other	14.3	1.73	13	0.43	1	17	748
East Texas Basin	Rodessa	2.4	0.39	128	0.40	14	208	191
Anadarko Basin	Red Fork	2.3	0.55	1345	0.86	144	5022	5199
East Texas Basin	Pettit	2.0	0.22	326	0.78	36	415	254
Anadarko Basin	Marmaton	4.1	1.3	40	0.08	4	120	136
Green River Basin	Dakota	3.2	0.33	487	0.73	34	366	2175
Paradox Basin	Entrada	22.5	9.74	5	1.00	0	0	13
Permian Basin	Tubb	2.4	0.65	22	0.55	3	23	72
Overthrust	Other	0.0	0	3	0.13	0	0	872
Anadarko Basin	Chester	14.6	0.62	516	0.76	55	2376	2826
Green River Basin	Mesaverde Group Coal	0.0	0	1	0.00	0	0	0
Green River Basin	Fort Union	2.6	0.52	69	0.83	5	391	165
Denver Basin	D Sand	2.2	0.28	10	0.08	1	8	54
Anadarko Basin	Chase	4.5	0.05	6550	0.80	555	6411	638
Permian Basin	Queen	3.2	0.23	36	0.18	5	35	233
East Texas Basin	Glen Rose	1.9	0.6	58	0.70	7	42	128

BASIN	FORMATION	CO2MAX	CO2STD	RAW_RUR	R_SAMP	GASAN	CONVGROW	CONVNEWF
East Texas Basin	Hill	1.4	0.22	17	0.20	2	7	49
East Texas Basin	James Lime	3.9	1.13	118	0.00	13	594	63
East Texas Basin	Jeter	1.3	0	6	0.99	1	1	14
East Texas Basin	Other	1.3	0.43	218	0.77	22	91	711
East Texas Basin	Paluxy	0.7	0.23	17	0.25	2	20	32
East Texas Basin	Travis Peak	1.6	0.31	1488	0.59	157	1216	574
Strawn Basin	Big Saline	0.6	0.06	8	0.88	1	158	112
Strawn Basin	Conglomerate	0.1	0	1	0.00	0	19	14
Strawn Basin	Marble Falls	0.4	0.07	10	0.46	2	39	27
Strawn Basin	Other	0.0	0	5	0.00	1	16	11
Strawn Basin	Strawn	0.1	0	4	0.00	1	59	38
Fort Worth Syncline	Atoka	0.5	0.12	49	0.26	5	126	91
Fort Worth Syncline	Barnett Shale	1.5	0	477	1.00	41	0	0
Fort Worth Syncline	Bend	0.4	0	476	0.94	42	1697	1223
Fort Worth Syncline	Big Saline	1.5	0	2	0.00	0	35	26
Fort Worth Syncline	Caddo	0.3	0.03	25	0.18	3	61	45
Fort Worth Syncline	Conglomerate	0.7	0.17	53	0.07	5	330	237
Fort Worth Syncline	Marble Falls	0.1	0	17	0.00	2	35	26
Fort Worth Syncline	Other	0.2	0	19	0.00	2	352	254
Fort Worth Syncline	Strawn	0.3	0.06	32	0.11	3	120	85
Bend Arch	Bend	0.4	0.03	24	0.09	4	73	52
Bend Arch	Big Saline	0.3	0.04	8	0.42	1	51	36
Bend Arch	Caddo	0.5	0.08	18	0.07	3	81	58
Bend Arch	Conglomerate	0.6	0.18	32	0.04	5	315	228
Bend Arch	Duffer	0.6	0.13	22	0.18	4	150	107
Bend Arch	Fry	0.2	0	12	0.00	2	7	6
Bend Arch	Gardner	0.3	0.05	1	0.18	0	42	30
Bend Arch	Gray	0.1	0	1	0.00	0	35	26
Bend Arch	Jennings	0.1	0	1	0.00	0	12	7
Bend Arch	Marble Falls	1.7	0.26	44	0.33	7	257	185
Bend Arch	Morris	0.1	0	1	0.00	0	19	14
Bend Arch	Other	0.3	0.04	48	0.05	7	646	465
Bend Arch	Strawn	0.1	0	15	0.00	2	59	41
Las Animas Arch	Morrow	1.6	0.35	117	0.58	8	10	60
Las Animas Arch	Niobrara	1.9	0.76	8	0.57	1	2	13
Las Animas Arch	Other	0.3	0	8	0.82	1	4	22

BASIN	FORMATION	CO2MAX	CO2STD	RAW_RUR	R_SAMP	GASAN	CONVGROW	CONVNEWF
Raton/Las Vegas Basins	Other	0.0	0	0	0.00	0	0	926
Raton/Las Vegas Basins	Vermejo Coal	1.0	0	816	0.00	28	0	0
Powder River Basin	Frontier	0.0	0	71	0.00	5	52	911
Powder River Basin	Turner	0.9	0	15	0.70	1	29	349
Big Horn Basin	Chugwater	0.1	0	58	0.15	4	2	10
Big Horn Basin	Dakota	0.1	0	5	0.15	0	1	4
Big Horn Basin	Frontier	0.7	0.21	73	0.71	5	42	218
Big Horn Basin	Muddy	0.6	0.15	43	0.41	3	15	78
Big Horn Basin	Other	0.0	0	30	0.28	2	15	934
Big Horn Basin	Phosphoria	0.0	0	7	0.91	1	0	1
Wind River Basin	Frontier	0.7	0.09	158	0.74	8	157	1096
Wind River Basin	Lance	0.3	0.01	579	0.56	42	436	67
Wind River Basin	Muddy	0.6	0.26	157	0.06	12	61	265
Wind River Basin	Phosphoria	0.7	0	8	1.00	1	22	94
Wind River Basin	Tensleep	0.5	0	0	0.00	0	0	302
Wind River Basin	Wind River	0.0	0	40	1.00	3	16	70
Green River Basin	Almy	0.1	0.01	44	0.06	3	6	110
Green River Basin	Bear River	1.4	0.19	129	0.62	10	29	418
Green River Basin	Lance	0.7	0.02	1051	0.02	78	4	71
Green River Basin	Morgan	24.2	1.3	0	0.00	0	1	0
Green River Basin	Wasatch	0.9	0	31	0.20	2	6	102
Denver Basin	Codell	1.0	0	28	0.97	2	28	189
Denver Basin	Sussex	0.2	0.01	18	0.47	1	16	17
Uinta Basin	Dakota	1.1	0.07	16	0.71	1	9	31
Uinta Basin	Frontier	0.1	0	32	1.00	1	6	100
Uinta Basin	Green River	0.6	0.2	72	0.91	3	24	79
Uinta Basin	Wasatch	0.2	0.02	1579	0.93	64	823	956
Paradox Basin	Cedar Mountain	0.8	0.05	11	0.27	0	1	40
Paradox Basin	Dakota	1.0	0.26	103	0.79	4	5	30
Paradox Basin	Desert Creek	0.2	0	2	0.40	0	0	61
Paradox Basin	Morrison	1.0	0.21	11	0.97	0	1	34
Black Mesa	Other	99.8	25.7	0	0.00	0	0	185
Piceance Basin	Mancos	1.1	0.31	173	0.95	12	210	125
Piceance Basin	Morrison	3.7	1.18	1	0.00	0	4	1
Texas Gulf Coast	Catahoula	0.2	0	14	0.04	2	46	100
Texas Gulf Coast	Cockfield	0.5	0.06	129	0.01	26	37	80

BASIN	FORMATION	CO2MAX	CO2STD	RAW_RUR	R_SAMP	GASAN	CONVGROW	CONVNEWF
Texas Gulf Coast	Cook Mountain	0.4	0.14	87	0.00	18	49	106
Texas Gulf Coast	Frio	1.9	0.47	2392	0.36	414	3515	6748
Texas Gulf Coast	Jackson	0.2	0.05	64	0.03	11	65	140
Texas Gulf Coast	Marginulina	0.2	0	28	0.01	6	35	75
Texas Gulf Coast	Miocene	0.4	0.06	151	0.06	28	316	691
Texas Gulf Coast	Oakville	0.2	0.14	5	0.00	1	12	24
Texas Gulf Coast	Olmos	0.6	0.03	331	0.09	38	1148	988
Texas Gulf Coast	Other	7.4	1.94	696	0.34	122	12936	27406
Texas Gulf Coast	Queen City	1.9	0.42	73	0.08	12	201	442
Texas Gulf Coast	San Miguel	0.0	0	31	0.11	3	83	180
Arkoma Basin	Hartshorne Coal	0.9	0	29	0.67	3	0	0
Arkoma Basin	Hunton	1.5	0.37	24	0.78	2	724	555
Arkoma Basin	Morrow	4.3	0.87	0	0.00	0	1176	306
South Ok. Folded Belt	Cisco	0.3	0.09	17	0.64	2	15	17
South Ok. Folded Belt	Deese	0.3	0.02	8	0.28	1	18	20
South Ok. Folded Belt	Goddard	0.2	0	10	0.04	1	6	6
South Ok. Folded Belt	Granite Wash	0.0	0	4	0.11	0	6	4
South Ok. Folded Belt	Hart	0.0	0	11	0.00	1	15	16
South Ok. Folded Belt	Hoxbar	0.3	0.06	33	0.58	4	56	59
South Ok. Folded Belt	Hunton	1.2	0.38	23	0.89	3	33	37
South Ok. Folded Belt	Other	0.8	0.18	257	0.03	28	187	205
South Ok. Folded Belt	Pontotoc	0.1	0.05	2	0.09	0	0	0
South Ok. Folded Belt	Simpson	0.4	0.04	37	0.76	4	63	72
South Ok. Folded Belt	Springer	0.2	0.04	191	0.17	21	175	190
South Ok. Folded Belt	Sycamore	0.8	0.3	100	0.64	11	135	144
South Ok. Folded Belt	Viola	0.0	0	22	0.01	2	27	31
South Ok. Folded Belt	Woodford	0.2	0	4	0.00	0	6	7
Chautauqua Platform	Bartlesville	0.5	0.11	23	0.23	3	81	86
Chautauqua Platform	Booch	0.3	0.05	15	0.20	2	9	10
Chautauqua Platform	Burgess	0.1	0	3	0.00	0	6	6
Chautauqua Platform	Cherokee Group Coal	0.5	0	20	0.06	2	0	0
Chautauqua Platform	Cleveland	0.1	0	10	0.05	1	43	42
Chautauqua Platform	Cromwell	0.9	0.28	13	0.06	1	90	96
Chautauqua Platform	Dutcher	0.8	0.22	10	0.35	1	84	90
Chautauqua Platform	Gilcrease	0.3	0.07	31	0.19	3	72	76
Chautauqua Platform	Hart	0.2	0.07	14	0.14	2	48	51

BASIN	FORMATION	CO2MAX	CO2STD	RAW_RUR	R_SAMP	GASAN	CONVGROW	CONVNEWF
Chautauqua Platform	Hoover	0.1	0	1	0.00	0	15	16
Chautauqua Platform	Hunton	0.3	0.1	21	0.06	2	157	167
Chautauqua Platform	Layton	0.4	0.1	5	0.17	1	12	14
Chautauqua Platform	Neva	0.5	0	0	0.00	0	3	3
Chautauqua Platform	Osborne	0.4	0	15	1.00	2	42	45
Chautauqua Platform	Oswego	0.4	0	9	0.19	1	27	26
Chautauqua Platform	Other	0.3	0.05	128	0.03	14	380	405
Chautauqua Platform	Prue	0.4	0.17	17	0.40	2	45	48
Chautauqua Platform	Red Fork	0.3	0.07	11	0.25	1	90	96
Chautauqua Platform	Senora	0.3	0	2	0.00	0	9	10
Chautauqua Platform	Skinner	0.4	0.16	22	0.18	2	51	56
Chautauqua Platform	Tonkawa	0.3	0.14	1	0.63	0	6	4
Chautauqua Platform	Viola	0.3	0.02	8	0.04	1	21	23
Chautauqua Platform	Wilcox	0.3	0	3	0.15	0	12	14
Anadarko Basin	Arbuckle	1.3	0.27	34	0.44	4	112	110
Anadarko Basin	Cherokee	1.6	0.46	166	0.44	18	1478	989
Anadarko Basin	Cleveland	1.3	0.17	340	0.92	30	2538	927
Anadarko Basin	Council Grove	0.1	0.01	1188	0.94	98	1113	222
Anadarko Basin	Granite Wash	0.8	0.16	445	0.76	43	3473	2244
Anadarko Basin	Hoxbar	0.5	0.06	17	0.32	2	383	455
Anadarko Basin	Kansas City	0.1	0	6	0.04	1	109	129
Anadarko Basin	Lansing	0.4	0.04	8	0.40	1	45	56
Anadarko Basin	Manning	0.5	0.11	62	0.27	7	235	279
Anadarko Basin	Oswego	0.6	0.22	92	0.76	10	645	766
Anadarko Basin	Springer	1.7	0.34	1135	0.75	127	4813	5717
Anadarko Basin	Tonkawa	0.9	0.11	252	0.83	27	1137	1350
Anadarko Basin	Topeka	1.0	0.11	153	0.81	12	401	474
Anadarko Basin	Toronto	0.0	0	29	0.00	3	27	33
Anadarko Basin	Wabaunsee	0.3	0.09	10	0.09	1	21	26
Cherokee/Forest City	Cherokee Group Coal	1.4	0.1	1	0.35	0	0	0
Cherokee/Forest City	Other	0.1	0	35	0.00	3	0	899
Nemaha Anticline	Bartlesville	0.0	0	0	0.00	0	0	0
Nemaha Anticline	Cleveland	0.0	0	0	0.00	0	6	1
Nemaha Anticline	Oswego	0.2	0	0	0.00	0	0	0
Nemaha Anticline	Other	0.1	0	3	0.00	0	39	20
Nemaha Anticline	Wabaunsee	0.0	0	0	0.00	0	0	0

BASIN	FORMATION	CO2MAX	CO2STD	RAW_RUR	R_SAMP	GASAN	CONVGROW	CONVNEWF
Sedgwick Basin	Douglas	0.2	0.05	4	0.50	0	15	1
Sedgwick Basin	Kansas City	0.1	0	0	0.00	0	6	0
Sedgwick Basin	Lansing	0.1	0	2	0.50	0	18	1
Sedgwick Basin	Other	0.4	0.13	298	0.01	24	633	51
Sedgwick Basin	Topeka	0.1	0	0	1.00	0	3	0
Central Kansas Uplift	Arbuckle	0.4	0.07	2	0.36	0	6	0
Central Kansas Uplift	Chase	0.1	0	8	0.00	1	18	1
Central Kansas Uplift	Cherokee	0.1	0	1	0.00	0	6	0
Central Kansas Uplift	Kansas City	0.1	0	1	1.00	0	6	0
Central Kansas Uplift	Lansing	0.4	0.13	1	0.19	0	6	0
Central Kansas Uplift	Other	0.3	0.06	43	0.09	3	127	10
Central Kansas Uplift	Simpson	0.3	0.1	5	0.00	0	3	0
Central Kansas Uplift	Topeka	0.2	0	1	1.00	0	3	0
Central Kansas Uplift	Viola	0.3	0.05	5	0.53	0	6	0
Central Kansas Uplift	Wabaunsee	0.1	0	4	0.03	0	6	0
Ouachita Tectonic Belt	Anacacho	0.0	0	0	0.00	0	0	0
Ouachita Tectonic Belt	Bromide	0.2	0	1	1.00	0	0	0
Ouachita Tectonic Belt	Mclish	0.5	0	1	1.00	0	0	0
Ouachita Tectonic Belt	Olmos Navarro	0.0	0	0	0.00	0	0	0
Ouachita Tectonic Belt	Other	0.3	0	24	0.05	3	0	899
Palo Duro Basin	Atoka	0.1	0	0	1.00	0	6	1
Palo Duro Basin	Cisco	0.1	0	1	0.00	0	0	0
Palo Duro Basin	Keyes	0.6	0.08	11	1.00	1	45	19
Palo Duro Basin	Morrow	0.3	0.1	8	1.00	1	45	19
Palo Duro Basin	Other	0.9	0.28	79	0.06	8	112	44
Palo Duro Basin	Topeka	0.4	0	3	0.24	0	9	3
Palo Duro Basin	Wichita Falls	0.1	0	14	1.00	1	3	0
Llano Uplift	Other	0.7	0.25	0	0.00	0	0	0
Llano Uplift	Strawn	0.1	0	0	0.36	0	0	0
Permian Basin	Abo	0.2	0	77	0.91	13	1542	938
Permian Basin	Canyon	0.9	0.1	1361	0.91	131	7460	6565
Permian Basin	Cisco	1.6	0.07	33	0.60	4	96	187
Permian Basin	Clear Fork	0.5	0.2	30	0.55	4	34	111
Permian Basin	Delaware	0.4	0.08	22	0.35	3	30	96
Permian Basin	Devonian	1.8	0.5	999	0.45	130	509	2063
Permian Basin	Grayburg	1.1	0.35	19	0.86	3	30	96

BASIN	FORMATION	CO2MAX	CO2STD	RAW_RUR	R_SAMP	GASAN	CONVGROW	CONVNEWF
Permian Basin	Judkins	1.7	0	43	1.00	6	185	592
Permian Basin	Mckee	0.1	0	29	0.93	4	24	77
Permian Basin	Mcknight	1.7	0	13	1.00	2	45	145
Permian Basin	Montoya	1.8	0	61	0.91	9	50	159
Permian Basin	Morrow	1.3	0.24	821	0.48	136	2381	3931
Permian Basin	Pennsylvanian	1.2	0.16	1044	0.22	140	1444	3150
Permian Basin	Silurian	0.0	0	67	0.85	9	447	1425
Permian Basin	Wichita Albany	1.4	0.56	32	0.82	5	95	303
Permian Basin	Yates	0.2	0.06	53	0.62	9	35	233
Southern Basin And Range	All	0.0	0	0	0.00	0	0	1171
Overthrust	Big Horn	1.2	0.22	27	0.74	3	37	1628
Overthrust	Nugget	0.5	0.06	509	0.88	118	60	582
Overthrust	Phosphoria	1.3	0	36	0.14	4	0	0
Overthrust	Sun River	5.9	0	0	0.00	0	2	1163
Overthrust	Thaynes	0.1	0.04	0	0.00	0	1	29
Overthrust	Twin Creek	0.1	0.02	4	1.00	0	5	58

BASIN	FORMATION	UNCONV	TYPUNCNV	PRD	RUR	UND
Texas Gulf Coast	Wilcox	15671	Tight	447	2939	18811
East Texas Basin	Cotton Valley	37561	Tight	407	4103	43005
Green River Basin	Madison	14689	Low Btu	221	5204	19576
Texas Gulf Coast	Austin Chalk	1015	Tight	220	482	1964
Permian Basin	Ellenburger	0		204	1547	4383
Green River Basin	Mesaverde	117288	Tight	86	1229	88212
Overthrust	Madison	0		85	741	3218
Texas Gulf Coast	Edwards Lime	1006	Tight	68	455	4257
Arkoma Basin	Atoka	2758	Tight	67	618	2022
Powder River Basin	Fort Union Coal	10036	Coal	58	1785	10036
Uinta Basin	Mesaverde Group Coal	3810	Coal	52	657	3810
East Texas Basin	Smackover	0		40	373	715
Anadarko Basin	Hunton	212	Tight	32	311	998
Wind River Basin	Fort Union	8280	Tight	32	414	5883
Arkoma Basin	Other	0		31	287	507
Anadarko Basin	Morrow	178	Tight	31	336	3429
Denver Basin	Other	0		29	384	215
Piceance Basin	Mesaverde	43843	Tight	28	427	25752
Denver Basin	J Sand	2426	Tight	27	377	3061
East Texas Basin	Bossier	73	Tight	24	245	216
East Texas Basin	Haynesville	332	Tight	20	187	815
Wind River Basin	Madison	0		19	2143	1510
Permian Basin	Other	0		18	113	670
Green River Basin	Weber	0		18	248	1622
Permian Basin	Strawn	1099	Tight	16	152	439
Anadarko Basin	Other	0		14	133	952
Permian Basin	Fusselman	0		11	80	682
Green River Basin	Frontier	7342	Tight	9	145	616
Green River Basin	Other	0		9	152	74
Paradox Basin	Mississippian	0		8	192	309
Anadarko Basin	Douglas	0		8	81	568
Powder River Basin	Muddy	0		7	100	451
Texas Gulf Coast	Vicksburg	4758	Tight	7	36	159
Texas Gulf Coast	Yegua	9417	CoProd	7	41	853
Green River Basin	Nugget	0		7	92	300
Arkoma Basin	Arbuckle	0		5	48	1278

BASIN	FORMATION	UNCONV	TYPUNCNV	PRD	RUR	UND
East Texas Basin	Woodbine	0		5	49	372
Piceance Basin	Dakota	1062	Tight	4	73	859
Wind River Basin	Cody	0		4	58	697
Wind River Basin	Other	540	Coal	4	86	423
Wind River Basin	Mesaverde	4541	Tight	4	54	4163
Denver Basin	Niobrara	982	Tight	3	49	208
Piceance Basin	Wasatch	821	Tight	3	41	445
Anadarko Basin	Viola	0		3	27	177
Green River Basin	Lewis	205	Tight	3	39	75
Permian Basin	Wolfcamp	1254	Tight	2	15	128
Piceance Basin	Other	0		2	31	64
Anadarko Basin	Skinner	0		2	20	64
Paradox Basin	Other	0		2	42	156
Piceance Basin	Mesaverde Group Coal	11550	Coal	2	24	11550
Overthrust	Weber	0		2	44	955
Permian Basin	Atoka	1099	Tight	2	11	169
Uinta Basin	Other	0		1	22	71
Denver Basin	Dakota	106	Tight	1	24	121
Permian Basin	San Andres	0		1	5	40
Green River Basin	Phosphoria	0		1	15	15
Powder River Basin	Other	0		1	12	725
East Texas Basin	Rodessa	0		1	8	24
Anadarko Basin	Red Fork	4726	Tight	1	6	70
East Texas Basin	Pettit	0		1	7	13
Anadarko Basin	Marmaton	36	Tight	0	5	38
Green River Basin	Dakota	1143	Tight	0	4	33
Paradox Basin	Entrada	0		0	3	9
Permian Basin	Tubb	0		0	1	4
Overthrust	Other	0		0	1	503
Anadarko Basin	Chester	0		0	1	9
Green River Basin	Mesaverde Group Coal	4660	Coal	0	1	4660
Green River Basin	Fort Union	7526	Tight	0	1	109
Denver Basin	D Sand	0		0	1	4
Anadarko Basin	Chase	0		0	0	0
Permian Basin	Queen	0		0	0	0
East Texas Basin	Glen Rose	0		0	0	0

BASIN	FORMATION	UNCONV	TYPUNCNV	PRD	RUR	UND
East Texas Basin	Hill	0		0	0	0
East Texas Basin	James Lime	1575	Tight	0	0	0
East Texas Basin	Jeter	0		0	0	0
East Texas Basin	Other	0		0	0	0
East Texas Basin	Paluxy	0		0	0	0
East Texas Basin	Travis Peak	2363	Tight	0	0	0
Strawn Basin	Big Saline	0		0	0	0
Strawn Basin	Conglomerate	0		0	0	0
Strawn Basin	Marble Falls	0	Tight	0	0	0
Strawn Basin	Other	0		0	0	0
Strawn Basin	Strawn	16	Tight	0	0	0
Fort Worth Syncline	Atoka	0		0	0	0
Fort Worth Syncline	Barnett Shale	7110	Shale	0	0	0
Fort Worth Syncline	Bend	0		0	0	0
Fort Worth Syncline	Big Saline	0		0	0	0
Fort Worth Syncline	Caddo	0		0	0	0
Fort Worth Syncline	Conglomerate	0		0	0	0
Fort Worth Syncline	Marble Falls	0		0	0	0
Fort Worth Syncline	Other	0		0	0	0
Fort Worth Syncline	Strawn	3	Tight	0	0	0
Bend Arch	Bend	0		0	0	0
Bend Arch	Big Saline	0		0	0	0
Bend Arch	Caddo	0		0	0	0
Bend Arch	Conglomerate	0		0	0	0
Bend Arch	Duffer	0		0	0	0
Bend Arch	Fry	0		0	0	0
Bend Arch	Gardner	0		0	0	0
Bend Arch	Gray	0		0	0	0
Bend Arch	Jennings	0		0	0	0
Bend Arch	Marble Falls	0		0	0	0
Bend Arch	Morris	0		0	0	0
Bend Arch	Other	0		0	0	0
Bend Arch	Strawn	3	Tight	0	0	0
Las Animas Arch	Morrow	0		0	0	0
Las Animas Arch	Niobrara	0		0	0	0
Las Animas Arch	Other	0		0	0	0

BASIN	FORMATION	UNCONV	TYPUNCNV	PRD	RUR	UND
Raton/Las Vegas Basins	Other	0		0	0	0
Raton/Las Vegas Basins	Vermejo Coal	1880	Coal	0	0	0
Powder River Basin	Frontier	0		0	0	0
Powder River Basin	Turner	176	Tight	0	0	0
Big Horn Basin	Chugwater	0		0	0	0
Big Horn Basin	Dakota	0		0	0	0
Big Horn Basin	Frontier	0		0	0	0
Big Horn Basin	Muddy	0		0	0	0
Big Horn Basin	Other	0		0	0	0
Big Horn Basin	Phosphoria	0		0	0	0
Wind River Basin	Frontier	861	Tight	0	0	0
Wind River Basin	Lance	8280	Tight	0	0	0
Wind River Basin	Muddy	0		0	0	0
Wind River Basin	Phosphoria	0		0	0	0
Wind River Basin	Tensleep	0		0	0	0
Wind River Basin	Wind River	0		0	0	0
Green River Basin	Almy	0		0	0	0
Green River Basin	Bear River	112	Tight	0	0	0
Green River Basin	Lance	0		0	0	0
Green River Basin	Morgan	0		0	0	0
Green River Basin	Wasatch	0		0	0	0
Denver Basin	Codell	218	Tight	0	0	0
Denver Basin	Sussex	202	Tight	0	0	0
Uinta Basin	Dakota	0		0	0	0
Uinta Basin	Frontier	0		0	0	0
Uinta Basin	Green River	0		0	0	0
Uinta Basin	Wasatch	10556	Tight	0	0	0
Paradox Basin	Cedar Mountain	0		0	0	0
Paradox Basin	Dakota	0	Tight	0	0	0
Paradox Basin	Desert Creek	0		0	0	0
Paradox Basin	Morrison	6	Tight	0	0	0
Black Mesa	Other	0		0	0	0
Piceance Basin	Mancos	1062	Tight	0	0	0
Piceance Basin	Morrison	48	Tight	0	0	0
Texas Gulf Coast	Catahoula	424	CoProd	0	0	0
Texas Gulf Coast	Cockfield	336	CoProd	0	0	0

BASIN	FORMATION	UNCONV	TYPUNCNV	PRD	RUR	UND
Texas Gulf Coast	Cook Mountain	439	CoProd	0	0	0
Texas Gulf Coast	Frio	2689	Tight	0	0	0
Texas Gulf Coast	Jackson	585	CoProd	0	0	0
Texas Gulf Coast	Marginulina	307	CoProd	0	0	0
Texas Gulf Coast	Miocene	2895	CoProd	0	0	0
Texas Gulf Coast	Oakville	102	CoProd	0	0	0
Texas Gulf Coast	Olmos	1736	Tight	0	0	0
Texas Gulf Coast	Other	8096	Tight	0	0	0
Texas Gulf Coast	Queen City	1857	CoProd	0	0	0
Texas Gulf Coast	San Miguel	760	CoProd	0	0	0
Arkoma Basin	Hartshorne Coal	3813	Coal	0	0	0
Arkoma Basin	Hunton	0		0	0	0
Arkoma Basin	Morrow	0		0	0	0
South Ok. Folded Belt	Cisco	0		0	0	0
South Ok. Folded Belt	Deese	0		0	0	0
South Ok. Folded Belt	Goddard	0		0	0	0
South Ok. Folded Belt	Granite Wash	0		0	0	0
South Ok. Folded Belt	Hart	0		0	0	0
South Ok. Folded Belt	Hoxbar	33	Tight	0	0	0
South Ok. Folded Belt	Hunton	0		0	0	0
South Ok. Folded Belt	Other	0		0	0	0
South Ok. Folded Belt	Pontotoc	0		0	0	0
South Ok. Folded Belt	Simpson	0		0	0	0
South Ok. Folded Belt	Springer	0		0	0	0
South Ok. Folded Belt	Sycamore	37	Tight	0	0	0
South Ok. Folded Belt	Viola	0		0	0	0
South Ok. Folded Belt	Woodford	0		0	0	0
Chautauqua Platform	Bartlesville	0		0	0	0
Chautauqua Platform	Booch	0		0	0	0
Chautauqua Platform	Burgess	0		0	0	0
Chautauqua Platform	Cherokee Group Coal	700	Coal	0	0	0
Chautauqua Platform	Cleveland	25	Tight	0	0	0
Chautauqua Platform	Cromwell	0		0	0	0
Chautauqua Platform	Dutcher	0		0	0	0
Chautauqua Platform	Gilcrease	0		0	0	0
Chautauqua Platform	Hart	0		0	0	0

BASIN	FORMATION	UNCONV	TYPUNCNV	PRD	RUR	UND
Chautauqua Platform	Hoover	0		0	0	0
Chautauqua Platform	Hunton	0		0	0	0
Chautauqua Platform	Layton	0		0	0	0
Chautauqua Platform	Neva	0		0	0	0
Chautauqua Platform	Osborne	0		0	0	0
Chautauqua Platform	Oswego	0		0	0	0
Chautauqua Platform	Other	0		0	0	0
Chautauqua Platform	Prue	0		0	0	0
Chautauqua Platform	Red Fork	0		0	0	0
Chautauqua Platform	Senora	0		0	0	0
Chautauqua Platform	Skinner	0		0	0	0
Chautauqua Platform	Tonkawa	0		0	0	0
Chautauqua Platform	Viola	0		0	0	0
Chautauqua Platform	Wilcox	0		0	0	0
Anadarko Basin	Arbuckle	0		0	0	0
Anadarko Basin	Cherokee	4726	Tight	0	0	0
Anadarko Basin	Cleveland	12808	Tight	0	0	0
Anadarko Basin	Council Grove	0		0	0	0
Anadarko Basin	Granite Wash	11595	Tight	0	0	0
Anadarko Basin	Hoxbar	0		0	0	0
Anadarko Basin	Kansas City	0		0	0	0
Anadarko Basin	Lansing	0		0	0	0
Anadarko Basin	Manning	0		0	0	0
Anadarko Basin	Oswego	0		0	0	0
Anadarko Basin	Springer	0		0	0	0
Anadarko Basin	Tonkawa	0		0	0	0
Anadarko Basin	Topeka	0		0	0	0
Anadarko Basin	Toronto	0		0	0	0
Anadarko Basin	Wabaunsee	0		0	0	0
Cherokee/Forest City	Cherokee Group Coal	2930	Coal	0	0	0
Cherokee/Forest City	Other	0		0	0	0
Nemaha Anticline	Bartlesville	0		0	0	0
Nemaha Anticline	Cleveland	0		0	0	0
Nemaha Anticline	Oswego	0		0	0	0
Nemaha Anticline	Other	0		0	0	0
Nemaha Anticline	Wabaunsee	0		0	0	0

BASIN	FORMATION	UNCONV	TYPUNCNV	PRD	RUR	UND
Sedgwick Basin	Douglas	0		0	0	0
Sedgwick Basin	Kansas City	0		0	0	0
Sedgwick Basin	Lansing	0		0	0	0
Sedgwick Basin	Other	0		0	0	0
Sedgwick Basin	Topeka	0		0	0	0
Central Kansas Uplift	Arbuckle	0		0	0	0
Central Kansas Uplift	Chase	0		0	0	0
Central Kansas Uplift	Cherokee	0		0	0	0
Central Kansas Uplift	Kansas City	0		0	0	0
Central Kansas Uplift	Lansing	0		0	0	0
Central Kansas Uplift	Other	0		0	0	0
Central Kansas Uplift	Simpson	0		0	0	0
Central Kansas Uplift	Topeka	0		0	0	0
Central Kansas Uplift	Viola	0		0	0	0
Central Kansas Uplift	Wabaunsee	0		0	0	0
Ouachita Tectonic Belt	Anacacho	0		0	0	0
Ouachita Tectonic Belt	Bromide	0		0	0	0
Ouachita Tectonic Belt	Mclish	0		0	0	0
Ouachita Tectonic Belt	Olmos Navarro	0		0	0	0
Ouachita Tectonic Belt	Other	0		0	0	0
Palo Duro Basin	Atoka	0		0	0	0
Palo Duro Basin	Cisco	0		0	0	0
Palo Duro Basin	Keyes	0		0	0	0
Palo Duro Basin	Morrow	0		0	0	0
Palo Duro Basin	Other	0		0	0	0
Palo Duro Basin	Topeka	0		0	0	0
Palo Duro Basin	Wichita Falls	0		0	0	0
Llano Uplift	Other	0		0	0	0
Llano Uplift	Strawn	0		0	0	0
Permian Basin	Abo	4068	Tight	0	0	0
Permian Basin	Canyon	17627	Tight	0	0	0
Permian Basin	Cisco	120	Tight	0	0	0
Permian Basin	Clear Fork	1	Tight	0	0	0
Permian Basin	Delaware	0		0	0	0
Permian Basin	Devonian	261	Tight	0	0	0
Permian Basin	Grayburg	0		0	0	0

BASIN	FORMATION	UNCONV	TYPUNCNV	PRD	RUR	UND
Permian Basin	Judkins	0		0	0	0
Permian Basin	Mckee	0		0	0	0
Permian Basin	Mcknight	0		0	0	0
Permian Basin	Montoya	0		0	0	0
Permian Basin	Morrow	3753	Tight	0	0	0
Permian Basin	Pennsylvanian	1490	Tight	0	0	0
Permian Basin	Silurian	0		0	0	0
Permian Basin	Wichita Albany	0		0	0	0
Permian Basin	Yates	0		0	0	0
Southern Basin And Range	All	0		0	0	0
Overthrust	Big Horn	0		0	0	0
Overthrust	Nugget	0		0	0	0
Overthrust	Phosphoria	0		0	0	0
Overthrust	Sun River	0		0	0	0
Overthrust	Thaynes	0		0	0	0
Overthrust	Twin Creek	0		0	0	0

HCMREG	Hydrocarbon Supply Model Region (see map)
BASCODE	AAPG Basin Code
BASIN	Basin name
FORMATION	Formation name
NRES	Number of reservoirs
NCOMP	Number of gas well completions
ULT_COMP	Average recovery per completion
AVDEPTH	Average depth
CO2AV	Carbon dioxide average
CO2MIN	Carbon dioxide minimum
CO2MAX	Carbon dioxide maximum
CO2STD	Carbon dioxide standard deviation
HEATAV	Average heating value
HEATMIN	Minimum heating value
HEATMAX	Maximum heating value
HEATSTD	Heating value standard deviation
RAW_RUR	Proven raw gas reserves as of 12/32/99
R_SAMP	Fraction of raw gas reserves sampled
GASAN	1999 raw gas production
CONVGROW	Reserve growth in existing conventional fields
CONVNEWF	Conventional new field potential
UNCONV	Undiscovered unconventional reserves
TYPUNCNV	Type of unconventional gas: TIGHT, COAL, SHALE, LOW_Btu, CoProduction
PRD	1999 production CO2>2%
RUR	1999 reserves of CO2>2%
UND	Undiscovered resources of CO2>2%

	CO2 Emissions*, MMTCE								
	AZ	CO	NM	OK	UT	KS	NV	TX	WY
Energy - Residential		1.6	0.5	1.1	0.7	1		3.5	
Energy - commercial		1.1	0.5	0.7	0.4	0.8		3.3	
Energy - Industrial		2.4	2.2	6.2	2.2	3.8		52.3	
Energy - Transport		5.2	4	6.5	2.8	5.2		42.1	
Energy- Utility		9.6	7.3	9.4	8.1	7.1		48.3	
Energy - Exported Electricity									
Energy - Other									
Total Energy	0	19.9	14.5	23.9	14.2	17.9	0	149.5	0
Waste				-0.2					
Agriculture				0					
Industry		0.2	0	0.3	0.4	0		0.9	
Land Use		-19.5	-1	-10.2	-0.003	0.1		4.8	
Total	0	0.6	13.5	13.8	14.597	18	0	155.2	0

* 1990 Data

Company	Plant Name	address	City	State	Zip	Phone	PhoneFree	Fax	NoKilms	K ton/y
Arizona Portland Cement Co (California Portland)	Rillito Cement Plant	11115 Casa Grande Hwy PO Box 338	Rillito	AZ	85654	520-682-2221			4	1045
Phoenix Cement Company	Clarkdale Plant	3000 W. Cement Plant Road PO Box 428	Clarkdale	AZ	86324	928-634-2261		928-634-3543	3	1618
CEMEX	Lyons Operation	5134 Ute Hwy	Lyons	CO	80503		800-492-9004		1	391
Holcim	Portland Plant	3500 Highway 120	Florence	CO	81226	719-784-6325		719-784-3470	3	761
Ash Grove	Chanute, KS Plant	1801 N. Santa Fe	Chanute	KS	66720	620-431-4500			2	440
Heartland Cement Company	Independence Plant	PO Box 428	Independence	KS	67301	316-331-0200		316-331-3890	4	272
LaFarge	Fredonia Cement Plant	1400 South Cement Road	Fredonia	KS		620-378-4458		620-378-2573	2	349
Monarch Cement Company	Humboldt Plant	449 1200 Street, PO Box 1000	Humboldt	KS	66748-1000	620-473-2222			3	611
GCC	Rio Grande Cement Plant	11783 State Highway 14 S	Tijeras	NM	87059	505-281-3311		505-281-9126	2	432
Holcim	Ada Plant	1100 West 18th St.	Ada	OK	74820	580-332-1512	800-890-9332	580-436-3273	2	554
LaFarge	Tulsa Cement Plant	2609 N. 145th East Avenue	Tulsa	OK		918-437-3902		918-234-7599	2	590
Lonestart	Pryor	PO Box 68	Pryor	OK	74362	918-825-1937			3	622
Lonestart	Maryneal	FM 608	Maryneal	TX	79556	915-228-4221			3	441
Ash Grove	Midlothian Plant	900 Gifco Road	Midlothian	TX	76065	972-723-2301			3	774
Holcim	Midlothian Plant	1800 Dove Lane	Midlothian	TX	76065	972-923-5800		972-923-5923	1	1015
TXI	Midlothian Plant	245 Ward Road	Midlothian	TX	76065	972-647-4985			4	1144
CEMEX	Balcones Plant	2580 Wald Road	New Braunfels	TX	78132		800-492-9004		1	891
TXI	Hunter Cement	7781 FM 1102	New Braunfels	TX	78132		800-292-7852		1	770
CEMEX	Odessa Operation	13 miles west of Odessa Exit 104 off Interstate 20	Odessa	TX	79776		800-492-9004		2	478
Alamo Cement	San Antonio	6055 West Green Mountain Road	San Antonio	TX	78265	210-208-1881		210-208-1990	1	769
Capitol Aggregates	San Antonio		San Antonio	TX	78265				2	763
Texas Lehigh Cement	Buda Plant	FM 2770 South	Buda	TX	78132	512-295-6111	800-252-5408	512-295-2440	1	1003
Lehigh Portland Cement	Waco Plant	PO Box 2576	Waco	TX	76720	254-776-7162			1	77
Ash Grove	Learnington, UT Plant	PO Box 51	Nephi	UT	84648	435-857-1212			1	717
Holcim	Devil's Slide Plant	6055 E. Croydon Rd.	Morgan	UT	84050	801-829-6821		801-829-2100	2	228
Mountain Cement Company	Laramie Plant	5 Sand Creek Road	Laramie	WY	82072	307-745-4879 ext 145		307-742-4534	2	585

FROM INTERCEM (cement distribution consultants)

Company	Website	US?
Aalborg Portland	Aalborg Portland	Denmark
Adelaide Brighton	Adelaide Brighton	Australian
Alsen	Alsen	Holcim Germany
Alsons Cement Corporation	Alsons Cement Corporation	Philippines
Anneliese	Anneliese	Germany
Apasco	Apasco	Holcim Mexico
Aso Cement	Aso Cement	
Australian Cement Holdings	Australian Cement Holdings	
Bacnotan Cement Corp	Bacnotan Cement Corp	
Blue Circle	Blue Circle	
Blue Circle N. America	Blue Circle N. America	
Blue Circle S. Africa	Blue Circle S. Africa	
California Portland	California Portland	AZ
Caribbean Cement	Caribbean Cement	Kingston
Castle Cement	Castle Cement	Lehigh Cement, USA
Cemento Melón	Cemento Melón	Italy
Cementos Caribe	Cementos Caribe	Holcim (Venezuela)
Cementos Catatumbo	Cementos Catatumbo	Columbia
Cementos Molins	Cementos Molins	South America
Cementos Valderrivas	Cementos Valderrivas	South America
Cemex Mexico	Cemex Mexico	Mexico
Cemroc	Cemroc	Holcim
Centex Dallas	Centex Dallas	?
Cimento Itambé	Cimento Itambé	
Ciments Calcia	Ciments Calcia	
Ciments Francais	Ciments Francais	
Ciments Nationale S.A.L.	Ciments Nationale S.A.L.	
Cimpor	Cimpor	Portugal
Cimsa Cimento Sanayi ve Ticaret A.S.	Cimsa Cimento Sanayi ve	
Civil and Marine Slag Cement Ltd	Civil and Marine Slag Cement	
CMS Cement	CMS Cement	
Cockburn Cement	Cockburn Cement	
Dyckerhoff	Dyckerhoff	
Ehdasse Sanat	Ehdasse Sanat	
ENCI	ENCI	
Galadari Cement	Galadari Cement	
Golden Bay Cement Co.	Golden Bay Cement Co.	
Gyproc	Gyproc	
Halla Group	Halla Group	
HCB	HCB	
HCB, Switzerland	HCB, Switzerland	
Heidelberger	Heidelberger	
Holcim South Africa (Pty) Limited	Holcim South Africa (Pty) Limited	
Holderbank	Holderbank	Holcim
Holdercim Brazil	Holdercim Brazil	
Holnam	Holnam	yes

Company	Website	US?
Hirocem	Hirocem	
Indocement	Indocement	
Italcementi Group	Italcementi Group	Italian
Kaiser Cement	Kaiser Cement	California
Kuwait Cement	Kuwait Cement	
Khuzestan Cement	Khuzestan Cement	
Lafarge	Lafarge	YES
Larsen & Toubro	Larsen & Toubro	India
Loma Negra	Loma Negra	
Lone Star	Lone Star	yes
Milburn Cement	Milburn Cement	
Norcem	Norcem	Noway
Origny Cement	Origny Cement	
Oskol Cement	Oskol Cement	
Oyak Group	Oyak Group	
Phinma Group	Phinma Group	
PPC	PPC	
PT Semen Andalas	PT Semen Andalas	
PT Semen Baturaja	PT Semen Baturaja	
PT Semen Cibinong	PT Semen Cibinong	
PT Indocement	PT Indocement	
PT Semen Kupang	PT Semen Kupang	
PT Semen Nusantara	PT Semen Nusantara	
PT Semen Padang	PT Semen Padang	
PT Semen Tonasa	PT Semen Tonasa	
Queensland Cement	Queensland Cement	
Quinn Group	Quinn Group	Ireland
RH Cement	RH Cement	
Riverside Cement	Riverside Cement	TXI
Rugby Group	Rugby Group	
Roanoke Cement	Roanoke Cement	
Sabanci Holding	Sabanci Holding	
Scancem	Scancem	North Europe
Siam Cement	Siam Cement	
Skanska	Skanska	
St.Lawrence	St.Lawrence	Holcim Canada
Southdown	Southdown	
Ssangyong Cement	Ssangyong Cement	
Suedwestzement	Suedwestzement	
Sumitomo	Sumitomo	
TBS Transportbeton	TBS Transportbeton	
Taiheiyo Cement Co.	Taiheiyo Cement Co.	
Taiwan Cement Corporation	Taiwan Cement Corporation	
Titan Cement	Titan Cement	Greek
Tong Yang Cement Corporation	Tong Yang Cement	Korean
TPI Cement	TPI Cement	
Turkish Factories	Turkish Factories	
TXI	TXI	Riverside

Company	Website	US?
FROM PORTLAND CEMENT ASSOCIATION		
Alamo Cement Company	Alamo Cement Company	
Arizona Portland Cement Company	Arizona Portland Cement	y
Ash Grove Cement Company	Ash Grove Cement Company	y
Ash Grove Texas, L.P.	Ash Grove Texas, L.P.	y
Buzzi Unicem USA Inc.	Buzzi Unicem USA Inc.	
California Portland Cement Company	California Portland Cement	y
Capitol Aggregates, Ltd.	Capitol Aggregates, Ltd.	
CEMEX	CEMEX	
Ciment Quebec, Inc	Ciment Quebec, Inc	
Coastal Cement Corporation	Coastal Cement Corporation	
CPC Terminals	CPC Terminals	
Dragon Products Company	Dragon Products Company	
Essroc Canada, Inc.	Essroc Canada, Inc.	
Essroc Cement Corporation	Essroc Cement Corporation	
Federal White Cement Ltd.	Federal White Cement Ltd.	
GCC America	GCC America	
Giant Cement Holding, Inc.	Giant Cement Holding, Inc.	
Glacier Northwest, Inc.	Glacier Northwest, Inc.	
Glens Falls Lehigh Cement Company	Glens Falls Lehigh Cement	
Hanson Permanente Cement, Inc.	Hanson Permanente Cement,	
Heartland Cement Company	Heartland Cement Company	
Hercules Cement Company	Hercules Cement Company	
Holcim (US) Inc.	Holcim (US) Inc.	
Illinois Cement Company	Illinois Cement Company	
Keystone Cement Company	Keystone Cement Company	
Lafarge Canada	Lafarge Canada	
Lafarge North America Inc.	Lafarge North America Inc.	
Lehigh Cement Company	Lehigh Cement Company	
Lehigh Inland Cement Limited	Lehigh Inland Cement Limited	
Lehigh Northwest Cement Company	Lehigh Northwest Cement	
Lehigh Northwest Cement Limited	Lehigh Northwest Cement	
Lehigh Southwest Cement Company	Lehigh Southwest Cement	
Mitsubishi Cement Corporation	Mitsubishi Cement Corporation	
Phoenix Cement Company	Phoenix Cement Company	
Rinker Materials Corporation	Rinker Materials Corporation	
River Cement Company	River Cement Company	
RMC Pacific Materials, Inc.	RMC Pacific Materials, Inc.	
Signal Mountain Cement Company	Signal Mountain Cement	
St. Lawrence Cement Company	St. Lawrence Cement Company	
St. Lawrence Cement, Inc.	St. Lawrence Cement, Inc.	
St. Marys Cement Inc.	St. Marys Cement Inc.	
Suwannee American Cement	Suwannee American Cement	
Texas Industries, Inc.	Texas Industries, Inc.	
Texas-Lehigh Cement Company	Texas-Lehigh Cement Company	
The Monarch Cement Company	The Monarch Cement Company	

Licensor/Construction	City	State	Tonnes/yea	Feedstock
Agrium Inc	Borger	TX	439	NG
Air Products	Pensacola	FL	46	NG
Allied Signal	Hopewell	WV	409	NG
Ampro	Donaldsonville	LA	386	NG
Arcadian	Geismar	LA	501	NG/RG
Arcadian	Clinton	IA	237	NG
Arcadian	Augusta	GA	576	NG
Arcadian	La Platte	NE	182	NG
Arcadian	Lima	OH	523	NG
Arcadian	Memphis	TN	340	NG
Arcadian	Woodstock	TN	356	NG
Avondale Ammonia	Fortier	LA	399	NG
Borden Chemical	Geismar	LA	363	NG
CF Industries	Donaldsonville	LA	1740	NG
Coastal St. Helens Chemical	St. Helens	OR	85	NG
Coastal Chem	Cheyenne	WY	172	NG
Cytec Industries	Avondale	LA	385	NG
Dakota Gasification Co.	Beulah ND	ND	91	N/A
Du Pont Beaumont	Beaumont	TX	364	NG
Farmland Industries	Beatrice	NE	255	NG
Farmland Industries	Dodge City	KS	255	NG
Farmland Industries	Enid	OK	919	NG
Farmland Industries	Fort Dodge	IO	241	NG
Farmland Industries	Lawrence	KS	409	NG
Farmland Industries	Pollock	LA	459	NG
Greenvalley Chemical	Creston	IA	33	NG
IMC Agrico	Donaldsonville LA 482,000 NG	LA	482	NG
IMC Nitrogen Co.	East Dubuque	IL	269	NG
J.R. Simplot Co.	Pocatello	ID	93	NG
Koch Industries	Sterlington	LA	1,110	NG
LaRoche Ind	Cherokee	AL	159	NG
Missippi Chemical Co.	Yazoo City	MS	364	NG
Missippi Chemical Co.	Donaldsonville	LA	409	NG
Missippi Chemical Co.	Donaldsonville	LA	500	NG
Monsanto	Luling	LA	446	NG
Nitromite Fertilizer	Dumas	TX	128	NG
Shoreline Chem	Gordon	GA	31	H2
Terra International	Blythville	AR	364	NG/FO
Terra International	Sergeant Bluff	IA	319	NG/FO
Terra International	Verdigris OK	OK	955	NG/FO
Terra International	Woodward City	OK	446	NG/FO
Union Chemical Co. (Unocal)	Finley	WA	150	NG/FO
Union Chemical Co. (Unocal)	Kenia	AK	1180	NG
Wil-Grow Fertilizer	Pryor	OK	86	NG
			17656	

Notes: Feedstock: Natural Gas (NG), Refinery Gas (RG), Fuel Oil (FO), Hydrogen (H2)
Energy Use and Energy Intensity of the US Chemical Industry, Worrell, E., et al. Lawrence Berkeley National Laboratory, LBNL-44314, April 2000
www.energystar.gov/ia/business/industry/LBNL-44314.pdf

Company	City	State	k METRIC TONS/YEAR
Farmland Industires	Dodge City	KS	255
Farmland Industires	Lawrence	KS	409
Farmland Industires	Enid	OK	919
Wil-Grow Fertilizer Co.	Pryor	OK	86
Terra International	Verdigris	OK	955
Terra International	Woodward	OK	446
E. I. du Pont de Nemours & Co. Inc.	Beaumont	TX	433
Agrium Inc.	Borger	TX	439
Nitromite Fertilizer Dumas	Dumas	TX	128
Coastal Chem, Inc.	Cheyenne	WY	172

Company	City	State	Capacity (Kt/year)[a]	Age of Process in 1994[*b]	Process[c]
Ashta Chemicals	Ashtabula	OH	36	31	KCl electrolysis; mercury cell; KOH by-product
BF Goodrich	Calvert City	KY	109	28	Salt; mercury cell; diaphragm
Dow	Freeport	TX	2,041	54	MgCl containing brines; diaphragm and by-product of magnesium metal production
Dow	Plaquemine	LA	1,075	36	Brine; diaphragm
DuPont	Niagara Falls	NY	77	96	Downs; By-product of metallic sodium production
Elf Atochem	Portland	OR	169	47	Salt; diaphragm
Formosa Plastics	Baton Rouge	LA	180	13	Brine; diaphragm (upgraded in 1981)
Formosa Plastics	Point Comfort	TX	505	0	Membrane
Fort Howard	Green Bay	WI	8	26	Rocksalt; diaphragm
Fort Howard	Muskogee	OK	5	9	Rocksalt; membrane (upgraded 1985)
Fort Howard	Rincon	GA	6	4	
GE	Burkville	AL	24	7	Membrane
GE	Mount Vernon	IN	50	18	Captive brine; diaphragm
Georgia Gulf Corp.	Plaquemine	LA	410	19	Captive brine; diaphragm
Georgia Gulf Corp.	Bellingham	WA	82	29	Salt; mercury cell
HoltraChem	Acme	NC	48	31	Salt; mercury cell
HoltraChem	Orrington	ME	73	27	Salt; mercury cell
La Roche Holdings Inc.	Gramercy	LA	181	36	Brine; diaphragm
Miles Inc.	Baytown	TX	82	22	By-Product HCl; HCl electrolysis
Niachlor Inc.	Niagara Falls	NY	218	7	Brine; membrane (upgraded 1987)
Occidental	Convent	LA	279	13	Captive salt dome; diaphragm
Occidental	Corpus Christi	TX	417	20	Brine; diaphragm
Occidental	Deer Park	TX	347	56	Captive salt dome; mercury cell; diaphragm
Occidental	Delaware City	DE	126	29	Salt mercury cell
Occidental	La Porte	TX	480	20	Captive salt dome; diaphragm
Occidental	Mobile	AL	41	3	Mercury cell; KOH is produced; membrane (upgraded 1991)
Occidental	Muscle Shoals	AL	132	42	Mercury cell; KOH is produced
Occidental	Niagara Falls	NY	293	20	Captive salt dome; diaphragm (upgraded 1974)
Occidental	Tacoma	WA	195	6	Rock salt; diaphragm; membrane (upgraded 1988)
Occidental	Taft	LA	581	19/8	Captive salt dome; diaphragm (upgraded 1975); membrane (upgraded in 1986)
Olin Corporation	Augusta	GA	102	29	Salt; mercury cell
Olin Corporation	Charleston	TN	230	32	Rock salt; mercury cell
Olin Corporation	McIntosh	AL	365	17	Brine diaphragm (upgraded 1977)
Olin Corporation	Niagara Falls	NY	82	34	Rock salt; mercury cell (upgraded 1960)
Oregon Metallugical Corp.	Albany	OR	2	23	Magnesium chloride; by-product of metallic magnesium
PioneerChlor Alkali Co.	Henderson	NV	104	18	Salt; diaphragm (upgraded 1976)
PioneerChlor Alkali Co.	St. Gabriel	LA	160	24	Salt; mercury cell
PPG Industries	Lake Charles	LA	1,126	25/17	Brine; mercury cell (upgraded 1969); diaphragm (upgraded 1977)
PPG Industries	Natrium	WV	356	36/10	Brine; mercury cell (upgraded 1958); diaphragm (upgraded 1984)
Renco Group (Magnesium Corp. of America)	Rowley	UT	14	17	Brine; by-product of magnesium metal production
Vicksburg Chemical Co.	Vicksburg	MS	33	32	By-product of production of potassium nitrate from KCl
Vulcan Materials Co.	Geismar	LA	243	18	Brine; diaphragm
Vulcan Materials Co.	Port Edwards	WI	65	27	Salt; mercury cell; KOH is also produced
Vulcan Materials Co.	Wichita	KS	239	19/11	Brine; diaphragm (upgraded 1975); membrane (upgraded 1983)
Weyerhaeuser	Longview	WA	136	19	Brine; diaphragm (upgraded 1975)
TOTAL			11,525	29[d]	
Total Production			10,973[e]		

a. Capacity numbers taken from Directory of Chemical Producers (DCP), SRI International FOR 1994
b. Cell type data and year of plant upgrade taken from Chlorine Institute Pamphlet 10 (1994)
c. Process data taken from DCP
d. Capacity weighted average age
e. Chemical Manufacturers Association
*Time since last major upgrade

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www.energystar.gov/ia/business/industry/LBNL-44314.pdf

Company	Location	State	Year of start up	Ethylene Capacity (ktonne/a)	Feedstock Mix (%)						Licensor, Remarks
					Ethane	Propane	Butane	Naphtha	Gas oil	Other	
Amoco	Chocolate Bayou	TX		1,451	36%	40%	0%	24%	0%		Braun ?
Chevron	Cedar Bayou	TX		681	25%	40%	5%	30%	0%		Stone & Webster
Chevron	Port Arthur	TX		784	80%	20%	0%	0%	0%		
Concea Vista	Lake Charles	LA	1968	430	100%	0%	0%	0%	0%		Lummus; Including expansion of 150kt in 1990; Formerly Vista Chemicals
Dow	Freeport	TX		1,224	50%	50%	0%	0%	0%		
Dow	Freeport	TX			50%	50%	0%	0%	0%		
Dow	Plaquemine	LA		1,102	50%	50%	0%	0%	0%		
Dow	Plaquemine	LA			25%	25%	25%	25%	0%		
DuPont	Orange	TX		590	50%	50%	0%	0%	0%		Lummus
Eastman	Long-view	TX		675	30%	50%	5%	15%	0%		Lummus/Kelloggg ?
Equistar	Channelview	TX		873	5%	5%	5%	40%	45%		Before 1997: Lyondell
Equistar	Channelview	TX		873	5%	5%	5%	40%	45%		Before 1997: Lyondell
Equistar	Clinton	IA	1968	435	95%	5%	0%	0%	0%		Kelloggg; Before 1997 Quantum; Expansion planned of 37kt in 1997
Equistar	LaPorte	TX	1991	789	80%	20%	0%	0%	0%		Before 1997: Quantum; Expansion planned of 182kt in 1996
Equistar	Morris	IL	1971	512	90%	10%	0%	0%	0%		Lummus; Before 1997: Quantum; Including expansion of 32kt in 1996
Exxon	Baton Rouge	LA	1973	882	0%	0%	0%	0%	0%		Kelloggg; Including expansion in 1993
Exxon	Baytown	TX		1,890	0%	0%	0%	0%	0%		Kelloggg; Including expansion of 700kt in 1997 by Lummus/Exxon
Formosa Plastics	Point Comfort	TX	1994	714	45%	25%	0%	15%	15%		Kelloggg Millisecond; Expansion planned of 204kt in 1997
Huntsman	Port Arthur	TX	1978	551	0%	0%	0%	60%	0%	40% LPG	Stone & Webster; Before 1994: Texaco
Huntsman	Port Neches	TX		136	50%	50%	0%	0%	0%	RG	Scientific Design
Javelina Co.	Corpus Christi	TX		108	0%	0%	0%	0%	0%	100% RG	
Mobil	Beaumont	TX	1975	566	70%	24%	6%	0%	0%		Stone & Webster; Expansion planned of 250kt in 1995
Mobil	Houston	TX		342	70%	30%	0%	0%	0%		Kelloggg
Occidental	Chocolate Bayou	TX	1980	500	0%	0%	0%	75%	25%		Brown & Root, Lummus
Occidental	Corpus Christi	TX	1980	773	15%	30%	0%	35%	20%		Stone & Webster
Occidental	Lake Charles	LA	1986	364	50%	50%	0%	0%	0%		Lummus Crest
Philips	Sweeny	TX		2,040	70%	30%	0%	0%	0%		
Philips	Sweeny	TX	1978		92%	8%	0%	0%	0%		
Philips	Sweeny	TX			75%	25%	0%	0%	0%		Selas, debottlenecking 1990
Philips	Sweeny	TX	1990		30%	60%	10%	0%	0%		1,000kt Braun, 1990; Including expansion of 227kt in 1996
Rexene Prod.	Odessa	TX		230	50%	50%	0%	0%	0%		Expansion planned of 188kt in 1998
Shell	Deer Park	TX		952	10%	0%	0%	60%	30%		Kellogg
Shell	Norco	LA	1976	793	0%	0%	0%	30%	70%		Kellogg
Shell	Norco	LA	1976	535	50%	0%	0%	50%	0%		Kellogg: Including expansion of 182kt in 1996
Sun	Brandenburg	KY		45	100%	0%	0%	0%	0%		Lummus
Sun Marcus	Hook	PA		102	0%	0%	0%	0%	0%		
Union Carbide	Seadrift	TX	1962	415	80%	20%	0%	0%	0%		
Union Carbide	Taft	LA	1978	680	30%	30%	0%	40%	0%		Wulff/Lummus, restarted in 1989; expansion planned of 318kt in 1997
Union Carbide	Texas City	TX		680	0%	60%	10%	30%	0%		
Union Texas	Geismar	LA	1968	545	82%	18%	0%	0%	0%		Lummus
Westlake Pol	Calvert City	KY	1964	170	0%	100%	0%	0%	0%		Braun; Before 1994: BF Goodrich
Westlake Pol	Lake Charles	LA	1992	1,043	80%	20%	0%	0%	0%		Kellogg Millisecond; Including 590kt expansion in 1997
Total				**25,475**							

Type	Operator	Field	State	County	Pay zone	Formation	Project Maturity
CO2 Immiscible	Chaparral Energy	Sho-Vel-Tum	OK	Stephens	Aldridge	Sandstone	
CO2 Misible	Amerada Hess	Adair San Andres Unit	TX	Gaines	San Andres	Dolomite	js
CO2 Misible	Amerada Hess	Seminole Unit-Main Pay Zone	TX	Gaines	San Andres	Dolomite	hf
CO2 Misible	Amerada Hess	Seminole Unit-ROZ Phase 1	TX	Gaines	San Andres	Dolomite	hf
CO2 Misible	Anadarko	Bradley Unit	OK	Garvin/Gardy	Springer	Sandstone	js
CO2 Misible	Anadarko	Northeast Prudy	OK	Garvin	Springer	Sandstone	hf
CO2 Misible	Anadarko	Patrick Draw Monell	WY	Sweetwater	Mesaverde Almond	Sandstone	js
CO2 Misible	Anadarko	Slaughter (HT Boyd lease)	TX	Cochran	San Andres	Dolomite	js
CO2 Misible	Chaparral Energy	Camrick	OK	Beaver	Morrow	Sandstone	js
CO2 Misible	Chaparral Energy	Sho-Vel-Tum	OK	Stephens	Sims	Sandstone	hf
CO2 Misible	ChevronTexaco	Goldsmith	TX	Ector	San Andres	Dolomite	js
CO2 Misible	ChevronTexaco	Greater Aneth	UT	San Juan	Desert Creek	Limestone	js
CO2 Misible	ChevronTexaco	Mabee	TX	Andrews-Martin	San Andres	Dolomite	nc
CO2 Misible	ChevronTexaco	Rangely Weber Sand	CO	Rio Blanco	Weber SS	Sandstone	js
CO2 Misible	ChevronTexaco	Slaughter Sundown	TX	Hockley Co	San Andres	Dolomite	hf
CO2 Misible	ChevronTexaco	Vacuum	NM	Lea Co.	San Andres	Dolomite	js
CO2 Misible	ExxonMobil	Cordona Lake	TX	Crane	Devonian	Tripolite	hf
CO2 Misible	ExxonMobil	GMK South	TX	Gaines	San Andres	Dolomite	js
CO2 Misible	ExxonMobil	Greater Aneth Area	UT	San Juan	Ismay Desert Creek	Limestone	js
CO2 Misible	ExxonMobil	Means (San Andres)	TX	Andrews-Martin	San Andres	Dolomite	
CO2 Misible	ExxonMobil	Postle	OK	Texas	Morrow	SS	
CO2 Misible	ExxonMobil	Salt Creek	TX	Kent	Canyon	Limestone	
CO2 Misible	ExxonMobil	Sharon Ridge	TX	Scurry	Canyon Reef	Limestone	
CO2 Misible	ExxonMobil	Slaughter	TX	Hockley & Terry	San Andres	Dolomite	
CO2 Misible	ExxonMobil	Slaughter	TX	Hockley & Cochran	San Andres	Dolomite	
CO2 Misible	ExxonMobil	Wasson	TX	Yoakum	San Andres	Dolomite	
CO2 Misible	ExxonMobil	Wasson (Cornell Unit)	TX	Yoakum	San Andres	Dolomite	
CO2 Misible	Fasken	Hanford	TX	Gaines	San Andres	Dolomite	
CO2 Misible	Fasken	Hanford East	TX	Gaines	San Andres	Dolomite	
CO2 Misible	First Permian	East Penwell (SA) Unit	TX	Ector	San Andres	Dolomite	
CO2 Misible	Great Western Drilling	Twofreds	TX	Loving, Ward, Reeves	Delawar, Ramsey	Sandstone	
CO2 Misible	Kinder Morgan	SACROC	TX	Scurry	Canyon Reef	Limestone	
CO2 Misible	Merit Energy	Lost Soldier	WY	Sweetwater	Tensleep	Sandstone	
CO2 Misible	Merit Energy	Lost Soldier	WY	Sweetwater	Darwin-Madiison	Sandstone	
CO2 Misible	Merit Energy	Lost Soldier	WY	Sweetwater	Cambrian	Sandstone	
CO2 Misible	Merit Energy	Wertz	WY	Carbon, Sweetwater	Tensleep	Sandstone	
CO2 Misible	Merit Energy	Wertz	WY	Carbon, Sweetwater	Darwin-Madiison	s/Limestone-Dolomite	
CO2 Misible	Murfin Drilling	Hall-Gurney	KS	Russell	LKC XC	Limestone	
CO2 Misible	Occidental Permian	Alex Slughter Estate	TX	Hockley	San Andres	Dolomite/Limestone	
CO2 Misible	Occidental Permian	Anton Irish	TX	Hale	Clearfork	Dolomite	

Type	Operator	Field	State	County	Pay zone	Formation	Project Maturity
CO2 Misible	Occidental Permian	Bennett Ranch Unit	TX	Yoakum	San Andres	Dolomite	
CO2 Misible	Occidental Permian	Cedar Lake	TX	Gaines	San Andres	Dolomite	
CO2 Misible	Occidental Permian	Cogdell	TX	Scurry/Kent	Canyon Reef	Limestone	
CO2 Misible	Occidental Permian	Mid Cross - Devonian Unit	TX	Crane, Upton & Crockett	Devonian	Tripolite	
CO2 Misible	Occidental Permian	N. Cross	TX	Crane & Upton	Devonian	Tripolite	
CO2 Misible	Occidental Permian	North Cowden	TX	Ector	Grayburg	Dolomite	
CO2 Misible	Occidental Permian	North Hobbs	NM	Lea Co.	San Andres	Dolomite	
CO2 Misible	Occidental Permian	S. Cross - Devonian Unit	TX	Crockett	Devonian	Tripolite	
CO2 Misible	Occidental Permian	Slaughter (Central Mallet)	TX	Hockley	San Andres	Dolomite/Limestone	
CO2 Misible	Occidental Permian	Slaughter Estate	TX	Hockley	San Andres	Dolomite/Limestone	
CO2 Misible	Occidental Permian	Slaughter Frazier	TX	Hockley	San Andres	Dolomite/Limestone	
CO2 Misible	Occidental Permian	T-Star (Slaughter Consolidated)	TX	Hockley	Abo	Dolomite	
CO2 Misible	Occidental Permian	Wasson (Denver)	TX	Yoakum & Gaines	San Andres	Dolomite	
CO2 Misible	Occidental Permian	Wasson ODC	TX	Yoakum	San Andres	Dolomite/Limestone	
CO2 Misible	Occidental Permian	Wasson-Willard	TX	Yoakum	San Andres	Dolomite	
CO2 Misible	Orla Petco	East Ford	TX	Reeves	Delaware, Ramsey	Sandstone	
CO2 Misible	Oxy USA	El-Mar	TX	Loving	Delaware	Sandstone	
CO2 Misible	Oxy USA	North dollarhide	TX	Andrews	Devonian	Tripolite	
CO2 Misible	Oxy USA	South Welch	TX	Dawson	San Andres	Dolomite	
CO2 Misible	Oxy USA	West Welch	TX	Gaines	San Andres	Dolomite	
CO2 Misible	Phillips	South Cowden	TX	Lea Co.	San Andres	Dolomite	
CO2 Misible	Phillips	Vacuum	NM	Lea Co.	San Andres	Dolomite	
CO2 Misible	Pioneer Natural Resources	Sprayberry	TX	Midland	Sprayberry	Sandstone	
CO2 Misible	Pure Resources	Dollarhide (Clearfork "A" Unit)	TX	Andrews	Clearfork	Dolomite	
CO2 Misible	Pure Resources	Dollarhide (Devonian) Unit	TX	Andrews	Devonian	Dolomite/Tripolite	
CO2 Misible	Pure Resources	Reinecke	TX	Borden	Cisco Canyon Reef	Dolomite/Limestone	
CO2 Misible	Stanberry Oil	Hansford Marmaton	TX	Hansford	Marmaton	Sandstone	
Hot Water	Carrizo	Camp Hill	TX	Anderson	Carrizo	Sandstone	hf
N2 Immiscible	ExxonMobil	Hawkins	TX	Woodbine-East FB	Woodbine	Sandstone	
N2 Immiscible	ExxonMobil	Hawkins	TX	Woodbine-West FB	Woodbine	Sandstone	
N2 Immiscible	Marthon Oil	Yates	TX	Pecos & Crockett	Grayburg/San Andres	Dolomite	
Polymer/Chemical	Ballard & Associates	Mitten Prong	WY	Crook	Minnelusa	Sandstone	
Polymer/Chemical	Continental Resources	Cottenwood Creek	WY	Washakie	Phosphoria	L	
Steam	Marathon	Yates	TX	Pecos & Crockett	Grayburg/San Andres	Dolomite	js

Operator	Field	Proj. Eval	Profit	Project Scope
Chaparral Energy	Sho-Vel-Tum			
Amerada Hess	Adair San Andres Unit	prom		p
Amerada Hess	Seminole Unit-Main Pay Zone	succ	y	fw
Amerada Hess	Seminole Unit-ROZ Phase 1	prom		p
Anadarko	Bradley Unit	prom		el
Anadarko	Northeast Prudy	succ		fw
Anadarko	Patrick Draw Monell	tett		lw
Anadarko	Slaughter (HT Boyd lease)	prom		lw
Chaparral Energy	Camrick	succ	y	Phase 1 (1/3 FW)
Chaparral Energy	Sho-Vel-Tum	succ	y	fw
ChevronTexaco	Goldsmith	tett		p
ChevronTexaco	Greater Aneth	prom	y	p
ChevronTexaco	Mabee	succ	n	fw
ChevronTexaco	Rangely Weber Sand	succ		fw
ChevronTexaco	Slaughter Sundown	succ	y	lw
ChevronTexaco	Vacuum	succ	y	lw
ExxonMobil	Cordona Lake	prom	y	lw
ExxonMobil	GMK South	succ	y	lw
ExxonMobil	Greater Aneth Area	succ	y	lw
ExxonMobil	Means (San Andres)			
ExxonMobil	Postle			
ExxonMobil	Salt Creek			
ExxonMobil	Sharon Ridge			
ExxonMobil	Slaughter			
ExxonMobil	Slaughter			
ExxonMobil	Wasson			
ExxonMobil	Wasson (Cornell Unit)			
Fasken	Hanford			
Fasken	Hanford East			
First Permian	East Penwell (SA) Unit			
Great Western Drilling	Twofreds			
Kinder Morgan	SACROC			
Merit Energy	Lost Soldier			
Merit Energy	Lost Soldier			
Merit Energy	Lost Soldier			
Merit Energy	Wertz			
Merit Energy	Wertz			
Murfin Drilling	Hall-Gurney			
Occidental Permian	Alex Slughter Estate			
Occidental Permian	Anton Irish			

Operator	Field	Proj. Eval	Profit	Project Scope
Occidental Permian	Bennett Ranch Unit			
Occidental Permian	Cedar Lake			
Occidental Permian	Cogdell			
Occidental Permian	Mid Cross - Devonian Unit			
Occidental Permian	N. Cross			
Occidental Permian	North Cowden			
Occidental Permian	North Hobbs			
Occidental Permian	S. Cross - Devonian Unit			
Occidental Permian	Slaughter (Central Mallet)			
Occidental Permian	Slaughter Estate			
Occidental Permian	Slaughter Frazier			
Occidental Permian	T-Star (Slaughter Consolidated)			
Occidental Permian	Wasson (Denver)			
Occidental Permian	Wasson ODC			
Occidental Permian	Wasson-Willard			
Orla Petco	East Ford			
Oxy USA	El-Mar			
Oxy USA	North dollarhide			
Oxy USA	South Welch			
Oxy USA	West Welch			
Phillips	South Cowden			
Phillips	Vacuum			
Pioneer Natural Resources	Sprayberry			
Pure Resources	Dollarhide (Clearfork "A" Unit)			
Pure Resources	Dollarhide (Devonian) Unit			
Pure Resources	Reinecke			
Stanberry Oil	Hansford Marmaton			
Carrizo	Camp Hill	succ		lw
ExxonMobil	Hawkins			
ExxonMobil	Hawkins			
Marthon Oil	Yates			
Ballard & Associates	Mitten Prong			
Continental Resources	Cottenwood Creek			
Marathon	Yates	prom		p

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AZ	141	Agua Fria Generating Station	1	2002	133741.8	2	307.8	2252797	2339	Natural Gas	Natural Gas	0.045
AZ	141	Agua Fria Generating Station	2	2002	47458.7	1.5	116.5	800198	1908	Natural Gas	Natural Gas	0.045
AZ	141	Agua Fria Generating Station	3	2002	241576	5.4	1154	4069773	3927	Natural Gas	Natural Gas	0.045
AZ	160	Apache Station	1	2002	165726.2	0.8	194.3	2788345	5262	Natural Gas	Natural Gas	0.045
AZ	160	Apache Station	2	2002	1514137.5	2720.9	3398.5	14869246	8554	Coal	Coal	0.12
AZ	160	Apache Station	3	2002	1383705	2445.2	2934.5	13532211	7843	Coal	Coal	0.12
AZ	160	Apache Station	4	2002	5278.9		0.7	88828	278	Natural Gas	Natural Gas	0.045
AZ	118	APS Saguaro Power Plant	1	2002	64080.3	0.4	79.5	1078270	1994	Natural Gas	Natural Gas	0.045
AZ	118	APS Saguaro Power Plant	2	2002	71897.6	0.4	80.4	1209839	2082	Natural Gas	Natural Gas	0.045
AZ	118	APS Saguaro Power Plant	CT3	2002	19261.2		4.8	324128	562	Natural Gas	Natural Gas	0.045
AZ	113	Cholla	1	2002	1039269.7	961.4	1857.3	10135096	8466	Coal	Coal	0.12
AZ	113	Cholla	2	2002	2174596.6	1420.3	3375.1	21208981	7430	Coal	Coal	0.12
AZ	113	Cholla	3	2002	2202917.5	8830.9	3393.3	21469660	8556	Coal	Coal	0.12
AZ	113	Cholla	4	2002	2933904.6	9557.3	4255.3	28625404	8019	Coal	Coal	0.12
AZ	6177	Coronado Generating Station	U1B	2002	2638379.3	7808.8	5236.9	25715201	7750	Coal	Coal	0.12
AZ	6177	Coronado Generating Station	U2B	2002	3066213	9918.5	6696	29885143	8336	Coal	Coal	0.12
AZ	124	De Moss Petrie Generating Station	GT1	2002	45909.6		8.8	772533	1426	Natural Gas	Natural Gas	0.045
AZ	55129	Desert Basin Generating Station	DBG1	2002	794992.2	4.2	68.2	13377300	7807	Natural Gas	Natural Gas	0.045
AZ	55129	Desert Basin Generating Station	DBG2	2002	769892.8	4.1	71.4	12954947	7527	Natural Gas	Natural Gas	0.045
AZ	55282	Duke Energy Arlington Valley	CTG1	2002	145238.7	0.6	15.3	2443933	1834	Natural Gas	Natural Gas	0.045
AZ	55282	Duke Energy Arlington Valley	CTG2	2002	159424.2	0.8	17.8	2682628	2028	Natural Gas	Natural Gas	0.045
AZ	55124	Griffith Energy LLC	P1	2002	313868.6	1.7	49.8	5281387	3912	Natural Gas	Natural Gas	0.045
AZ	55124	Griffith Energy LLC	P2	2002	381844.2	2	59.6	6425231	4757	Natural Gas	Natural Gas	0.045
AZ	126	Irvington Generating Station	1	2002	109272.8	0.5	190.3	1838717	5081	Natural Gas	Natural Gas	0.045
AZ	126	Irvington Generating Station	2	2002	102942.7	0.5	212	1732244	4396	Natural Gas	Natural Gas	0.045
AZ	126	Irvington Generating Station	3	2002	209219.1	1.1	394.9	3520437	7321	Natural Gas	Natural Gas	0.045
AZ	126	Irvington Generating Station	4	2002	805643.8	3116.5	1742.8	7895976	8607	Coal	Coal	0.12
AZ	147	Kyrene Generating Station	K-1	2002	7686.9	0.3	18.1	129682	443	Natural Gas	Natural Gas	0.045
AZ	147	Kyrene Generating Station	K-2	2002	40839.1	1.8	241	688822	1017	Diesel Fuel Oil	Diesel Oil	0
AZ	147	Kyrene Generating Station	K-7	2002	301357	1.5	31	5070942	3652	Natural Gas	Natural Gas	0.045
AZ	4941	Navajo Generating Station	1	2002	6684086.9	1272.9	11630.8	65147476	8524	Coal	Coal	0.12
AZ	4941	Navajo Generating Station	2	2002	6828039.5	1151.7	11677.8	66550066	8200	Coal	Coal	0.12
AZ	4941	Navajo Generating Station	3	2002	6946138.6	1582.7	12260.1	67701145	8551	Coal	Coal	0.12
AZ	116	Ocotillo Power Plant	1	2002	116851.4	0.6	107.5	1966274	4579	Natural Gas	Natural Gas	0.045
AZ	116	Ocotillo Power Plant	2	2002	71308.1	0.4	54.8	1199791	2832	Natural Gas	Natural Gas	0.045
AZ	55522	PPL Sundance Energy, LLC	CT01	2002	1684.1		0.5	28340	88	Natural Gas	Natural Gas	0.045
AZ	55522	PPL Sundance Energy, LLC	CT02	2002	1331.7		0.4	22407	67	Natural Gas	Natural Gas	0.045
AZ	55522	PPL Sundance Energy, LLC	CT03	2002	1884		0.8	31711	92	Natural Gas	Natural Gas	0.045
AZ	55522	PPL Sundance Energy, LLC	CT04	2002	2115.9		0.5	35604	108	Natural Gas	Natural Gas	0.045
AZ	55522	PPL Sundance Energy, LLC	CT05	2002	2490.4		1	41913	141	Natural Gas	Natural Gas	0.045
AZ	55522	PPL Sundance Energy, LLC	CT06	2002	1832.7		0.6	30839	99	Natural Gas	Natural Gas	0.045
AZ	55522	PPL Sundance Energy, LLC	CT07	2002	1646.9		0.9	27712	100	Natural Gas	Natural Gas	0.045
AZ	55522	PPL Sundance Energy, LLC	CT08	2002	1699.8		0.5	28598	94	Natural Gas	Natural Gas	0.045
AZ	55522	PPL Sundance Energy, LLC	CT09	2002	1090.2		0.4	18345	61	Natural Gas	Natural Gas	0.045
AZ	55522	PPL Sundance Energy, LLC	CT10	2002	1743.7		0.6	29340	100	Natural Gas	Natural Gas	0.045
AZ	55455	Redhawk Generating Facility	CC1A	2002	243260.7	1.3	20	4092393	2938	Natural Gas	Natural Gas	0.045
AZ	55455	Redhawk Generating Facility	CC1B	2002	237534.1	1.2	21.2	4018817	2900	Natural Gas	Natural Gas	0.045
AZ	55455	Redhawk Generating Facility	CC2A	2002	181829.7	1	16.8	3060963	2233	Natural Gas	Natural Gas	0.045
AZ	55455	Redhawk Generating Facility	CC2B	2002	158908.4	0.8	14.5	2675648	1944	Natural Gas	Natural Gas	0.045
AZ	55177	South Point Energy Center, LLC	A	2002	552496.5	2.8	42.8	9296828	6905	Natural Gas	Natural Gas	0.045
AZ	55177	South Point Energy Center, LLC	B	2002	679503.7	3.4	54	11433969	7767	Natural Gas	Natural Gas	0.045
AZ	8223	Springerville Generating Station	1	2002	3171808.8	9807.1	6342.5	30914350	7876	Coal	Coal	0.12
AZ	8223	Springerville Generating Station	2	2002	3279265	10055.1	6229.2	31961643	8692	Coal	Coal	0.12
AZ	117	West Phoenix Power Plant	CC4	2002	226569.2	1	58.8	3812454	5454	Natural Gas	Natural Gas	0.045
AZ	120	Yuma Axis	1	2002	204545.6	1.6	194.4	3441418	7980	Natural Gas	Natural Gas	0.045
CO	465	Arapahoe	1	2002	414718.5	1060.4	1412.4	4044321	7836	Coal	Coal	0.12
CO	465	Arapahoe	2	2002	312828.5	758.3	1095.8	3049897	6044	Coal	Coal	0.12
CO	465	Arapahoe	3	2002	501346.8	1344.8	1772	4890120	8274	Coal	Coal	0.12
CO	465	Arapahoe	4	2002	957691	1944	1062.8	9336380	8256	Coal	Coal	0.12
CO	55200	Arapahoe Combustion Turbine	CT5	2002	29847.8		15.2	502285	1834	Natural Gas	Natural Gas	0.045

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CO	55200	Arapahoe Combustion Turbine	CT6	2002	32566.8	0.1	16.3	548024	1921	Natural Gas	Natural Gas	0.045
CO	10682	Brush 3	GT2	2002	48454.8	0.1	35.5	815339	1559	Natural Gas	Natural Gas	0.045
CO	55209	Brush 4	GT4	2002	29278.8		20.5	492680	1231	Natural Gas	Natural Gas	0.045
CO	55209	Brush 4	GT5	2002	30093.7		20.8	506386	1180	Natural Gas	Natural Gas	0.045
CO	468	Cameo	2	2002	434629.2	2095.4	819.2	4239546	8641	Coal	Coal	0.12
CO	469	Cherokee	1	2002	918504.6	3082.4	1459.4	8970803	8148	Coal	Coal	0.12
CO	469	Cherokee	2	2002	629958	2526.5	2472.4	6203590	5837	Coal	Coal	0.12
CO	469	Cherokee	3	2002	995926.4	3082.8	1557.9	9797921	7240	Coal	Coal	0.12
CO	469	Cherokee	4	2002	2216333.6	7265.2	3985.6	21731931	7498	Coal	Coal	0.12
CO	470	Comanche (470)	1	2002	2893746.9	8023.9	4773.2	28241573	7662	Coal	Coal	0.12
CO	470	Comanche (470)	2	2002	2799628.5	8749.5	4036.5	27300712	8550	Coal	Coal	0.12
CO	6021	Craig	C1	2002	3640704.6	4261.1	6607.4	35484468	8484	Coal	Coal	0.12
CO	6021	Craig	C2	2002	3906720.9	4736.7	7428.1	38077168	8687	Coal	Coal	0.12
CO	6021	Craig	C3	2002	3117803.8	1393.1	5345.6	30387919	8248	Coal	Coal	0.12
CO	6112	Fort St. Vrain	2	2002	778987	4.1	236.5	13107969	8524	Natural Gas	Natural Gas	0.045
CO	6112	Fort St. Vrain	3	2002	751052.4	3.7	166.1	12637865	8147	Natural Gas	Natural Gas	0.045
CO	6112	Fort St. Vrain	4	2002	778000.8	4	90.8	13091422	8456	Natural Gas	Natural Gas	0.045
CO	55453	Fountain Valley Combustion Turbine	1	2002	63771.4		48	1073099	3564	Natural Gas	Natural Gas	0.045
CO	55453	Fountain Valley Combustion Turbine	2	2002	54535.8		41.3	917668	3168	Natural Gas	Natural Gas	0.045
CO	55453	Fountain Valley Combustion Turbine	3	2002	44622.2		34.7	750816	2656	Natural Gas	Natural Gas	0.045
CO	55453	Fountain Valley Combustion Turbine	4	2002	40160.7		29.4	675764	2413	Natural Gas	Natural Gas	0.045
CO	55453	Fountain Valley Combustion Turbine	5	2002	38041.9		30.9	640100	2343	Natural Gas	Natural Gas	0.045
CO	55453	Fountain Valley Combustion Turbine	6	2002	32341.9		24.1	544193	2039	Natural Gas	Natural Gas	0.045
CO	55505	Frank Knutson Station	BR1	2002	42783.3	0.2	9.4	719922	990	Natural Gas	Natural Gas	0.045
CO	55505	Frank Knutson Station	BR2	2002	33868.3	0.1	6.7	569905	791	Natural Gas	Natural Gas	0.045
CO	525	Hayden	H1	2002	1932554.4	1242.1	4139.2	18836044	8345	Coal	Coal	0.12
CO	525	Hayden	H2	2002	2500623	1625.7	4464	24378570	8498	Coal	Coal	0.12
CO	55504	Limon Generating Station	L1	2002	21022.5	0.1	6.1	352372	599	Natural Gas	Natural Gas	0.045
CO	55504	Limon Generating Station	L2	2002	16947.3	0.1	4.6	283861	499	Natural Gas	Natural Gas	0.045
CO	55127	Manchief Station	CT1	2002	260661.7	1.3	114.5	4381502	4168	Natural Gas	Natural Gas	0.045
CO	55127	Manchief Station	CT2	2002	266772.9	1.3	120.2	4481751	4215	Natural Gas	Natural Gas	0.045
CO	492	Martin Drake	5	2002	399761.1	1577.6	793.6	3915442	8671	Coal	Coal	0.12
CO	492	Martin Drake	6	2002	778866.7	3019.1	1414.7	7651219	8439	Coal	Coal	0.12
CO	492	Martin Drake	7	2002	1014376	3932.4	1996.7	9967348	7260	Coal	Coal	0.12
CO	527	Nucla	1	2002	922996.4	1486.8	1332.6	9001128	8265	Coal	Coal	0.12
CO	6248	Pawnee	1	2002	3968365.8	14832.4	4591.8	38786014	7563	Coal	Coal	0.12
CO	6761	Rawhide Energy Station	101	2002	2491624.2	898.3	4006.8	24284891	7916	Coal	Coal	0.12
CO	6761	Rawhide Energy Station	A	2002	13747.2		3.7	231328	396	Natural Gas	Natural Gas	0.045
CO	6761	Rawhide Energy Station	B	2002	2188.5		0.8	36832	66	Natural Gas	Natural Gas	0.045
CO	6761	Rawhide Energy Station	C	2002	4110.3		2.7	69155	122	Natural Gas	Natural Gas	0.045
CO	8219	Ray D Nixon	1	2002	1881113.9	4968.2	2830.9	18339258	8285	Coal	Coal	0.12
CO	8219	Ray D Nixon	2	2002	8293.8		2.3	139574	553	Natural Gas	Natural Gas	0.045
CO	8219	Ray D Nixon	3	2002	2087.5		0.8	35139	150	Natural Gas	Natural Gas	0.045
CO	477	Valmont	5	2002	1362313.4	3786.3	2056.9	13293777	7393	Coal	Coal	0.12
CO	55207	Valmont Combustion Turbine Facility	CT7	2002	17770.4		13.7	299018	1185	Natural Gas	Natural Gas	0.045
CO	55207	Valmont Combustion Turbine Facility	CT8	2002	17885.7		13.1	300987	1181	Natural Gas	Natural Gas	0.045
CO	478	Zuni	1	2002	35069.1		66	590132	4177	Natural Gas	Natural Gas	0.045
CO	478	Zuni	2	2002	3989.4		2.8	67135	1661	Natural Gas	Natural Gas	0.045
CO	478	Zuni	3	2002	12028.1		29.4	202401	539	Natural Gas	Natural Gas	0.045
KS	1235	Arthur Mullergren	3	2002	67408.1	0.4	129	1133717	2654	Natural Gas	Natural Gas	0.045
KS	3355	Chanute 2	14	2002	2704.1		1.9	45505	105	Natural Gas	Natural Gas	0.045
KS	1230	Cimarron River	1	2002	85124.5	0.5	159.3	1432397	4452	Natural Gas	Natural Gas	0.045
KS	1271	Coffeyville	4	2002	30683.5		31.5	516299	2154	Natural Gas	Natural Gas	0.045
KS	7013	East 12th Street	4	2002	2968.6		6.1	53026	695	Natural Gas	Natural Gas	0.045
KS	1336	Garden City	S-2	2002	93535.7	0.4	209.8	1573896	2870	Natural Gas	Natural Gas	0.045
KS	1240	Gordon Evans Energy Center	1	2002	113886.4	617.6	258.7	1544185	1893	Natural Gas	Natural Gas	0.045
KS	1240	Gordon Evans Energy Center	2	2002	244868.3	3210.4	2023.1	6844242	3603	Natural Gas	Natural Gas	0.045
KS	1240	Gordon Evans Energy Center	E1CT	2002	13487.7		4.6	224801	363	Natural Gas	Natural Gas	0.045
KS	1240	Gordon Evans Energy Center	E2CT	2002	16216		6.6	276910	433	Natural Gas	Natural Gas	0.045
KS	1240	Gordon Evans Energy Center	E3CT	2002	66153.3	0.3	15.3	1113547	945	Natural Gas	Natural Gas	0.045

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KS	108	Holcomb	SGU1	2002	2728827.3	1669.4	3849	26626279	8299	Coal	Coal	0.12
KS	1248	Hutchinson Energy Center	1	2002						Natural Gas	Natural Gas	0.045
KS	1248	Hutchinson Energy Center	2	2002						Natural Gas	Natural Gas	0.045
KS	1248	Hutchinson Energy Center	3	2002						Natural Gas	Natural Gas	0.045
KS	1248	Hutchinson Energy Center	4	2002	135996.3	734.4	267.1	1902244	2490	Natural Gas	Natural Gas	0.045
KS	6068	Jeffrey Energy Center	1	2002	5552739.3	20458.9	9601.6	54120215	8208	Coal	Coal	0.12
KS	6068	Jeffrey Energy Center	2	2002	6449234.2	23715.3	10891.5	62858016	8157	Coal	Coal	0.12
KS	6068	Jeffrey Energy Center	3	2002	6721075.7	23206.1	10807.4	65507710	8096	Coal	Coal	0.12
KS	1233	Judson Large	4	2002	216254	1.1	407.8	3638851	6806	Natural Gas	Natural Gas	0.045
KS	1294	Kaw	1	2002						Natural Gas	Natural Gas	0.045
KS	1294	Kaw	2	2002						Coal	Coal	0.12
KS	1294	Kaw	3	2002	7350.7		14.6	124012	463	Natural Gas	Natural Gas	0.045
KS	1241	La Cygne	1	2002	5602433.8	6648.1	30057.6	54604668	7590	Coal	Coal	0.12
KS	1241	La Cygne	2	2002	5743929.5	19355.1	8362	55983770	8134	Coal	Coal	0.12
KS	1250	Lawrence Energy Center	3	2002	561000.2	1965.3	728.5	5467804	7790	Coal	Coal	0.12
KS	1250	Lawrence Energy Center	4	2002	1142450.3	1429.8	1986.7	11138048	8498	Coal	Coal	0.12
KS	1250	Lawrence Energy Center	5	2002	3508525.9	4353.8	3546.2	34196134	8324	Coal	Coal	0.12
KS	1305	McPherson 2	1	2002	606.5		0.8	10203	58	Natural Gas	Natural Gas	0.045
KS	7515	McPherson 3	1	2002	6724.4		10.6	112740	231	Natural Gas	Natural Gas	0.045
KS	1242	Murray Gill Energy Center	1	2002						Natural Gas	Natural Gas	0.045
KS	1242	Murray Gill Energy Center	2	2002	1693.4		4.5	29035	100	Natural Gas	Natural Gas	0.045
KS	1242	Murray Gill Energy Center	3	2002	79988.3	452.3	181.6	1082865	1879	Natural Gas	Natural Gas	0.045
KS	1242	Murray Gill Energy Center	4	2002	20144.9	333.3	103.9	620470	1276	Natural Gas	Natural Gas	0.045
KS	6064	Nearman Creek	N1	2002	1923067.1	7625	3860.2	18782216	7477	Coal	Coal	0.12
KS	1243	Neosho Energy Center	7	2002	13.4			220	8	Natural Gas	Natural Gas	0.045
KS	1295	Quindaro	1	2002	448540	1283.3	1772.7	4442357	5978	Coal	Coal	0.12
KS	1295	Quindaro	2	2002	731297.2	2061.9	913.1	7234579	7890	Coal	Coal	0.12
KS	1239	Riverton	39	2002	266788.3	2392.7	584.8	2622178	8446	Coal	Coal	0.12
KS	1239	Riverton	40	2002	407769	1039.5	874.6	3992110	8170	Coal	Coal	0.12
KS	1252	Tecumseh Energy Center	10	2002	1257561.6	4515	1876.9	12256919	8329	Coal	Coal	0.12
KS	1252	Tecumseh Energy Center	9	2002	788385.2	2692.8	1530.7	7684021	8630	Coal	Coal	0.12
NM	55210	Afton Generating Station	1	2002	13834.3	0.2	8.1	179423	183	Natural Gas	Natural Gas	0.045
NM	2454	Cunningham	121B	2002	148770	0.8	237.3	2509619	5726	Natural Gas	Natural Gas	0.045
NM	2454	Cunningham	122B	2002	542656.2	2.7	1021.8	9154050	8375	Natural Gas	Natural Gas	0.045
NM	2454	Cunningham	123T	2002	40253	0.1	27	679029	724	Natural Gas	Natural Gas	0.045
NM	2454	Cunningham	124T	2002	45807.7	0.1	31.5	772730	824	Natural Gas	Natural Gas	0.045
NM	2442	Four Corners Steam Elec Station	1	2002	1408312.4	3113.8	5445.4	13740127	7453	Coal	Coal	0.12
NM	2442	Four Corners Steam Elec Station	2	2002	1706921.9	3345.3	5203.9	16632803	8147	Coal	Coal	0.12
NM	2442	Four Corners Steam Elec Station	3	2002	2037207.6	4324.3	5754	19873581	8406	Coal	Coal	0.12
NM	2442	Four Corners Steam Elec Station	4	2002	5926809.2	13274.6	16502.9	57787847	8145	Coal	Coal	0.12
NM	2442	Four Corners Steam Elec Station	5	2002	3850893.8	8789.6	8670.7	37592637	5887	Coal	Coal	0.12
NM	7967	Lordsburg Generating Station	1	2002	7892.3		13.5	132785	510	Natural Gas	Natural Gas	0.045
NM	7967	Lordsburg Generating Station	2	2002	8103.1		6.8	136337	461	Natural Gas	Natural Gas	0.045
NM	2446	Maddox	051B	2002	278825.3	1.4	422.4	4703558	6523	Natural Gas	Natural Gas	0.045
NM	54814	Milagro	1	2002	253582.2	1.2	50.6	4267029	8406	Natural Gas	Natural Gas	0.045
NM	54814	Milagro	2	2002	229221.7	1.1	46.9	3857071	7711	Natural Gas	Natural Gas	0.045
NM	55039	Person Generating Project	GT-1	2002	25863	0.1	11.7	434865	480	Natural Gas	Natural Gas	0.045
NM	87	Prewitt Escalante Generating Statio	1	2002	1759793.3	1191.9	3469.8	17152014	8108	Coal	Coal	0.12
NM	2450	Reeves Generating Station	1	2002	25993.6		47.5	437369	1555	Natural Gas	Natural Gas	0.045
NM	2450	Reeves Generating Station	2	2002	20379.1		38	342937	1282	Natural Gas	Natural Gas	0.045
NM	2450	Reeves Generating Station	3	2002	48131.8	0.1	87.7	809875	2191	Natural Gas	Natural Gas	0.045
NM	2444	Rio Grande	6	2002	119341.9	0.8	215	2008236	5769	Natural Gas	Natural Gas	0.045
NM	2444	Rio Grande	7	2002	131582.2	0.9	159.6	2214072	6617	Natural Gas	Natural Gas	0.045
NM	2444	Rio Grande	8	2002	250875	1.3	537.3	4221386	5363	Natural Gas	Natural Gas	0.045
NM	2451	San Juan	1	2002	2519850	2553.9	5209.6	24550141	7406	Coal	Coal	0.12
NM	2451	San Juan	2	2002	2807211.4	2705.8	5976.1	27460582	8463	Coal	Coal	0.12
NM	2451	San Juan	3	2002	4487946.2	5589.4	9404.2	43742324	8278	Coal	Coal	0.12
NM	2451	San Juan	4	2002	4674481.5	5918.6	9762.8	45582346	8405	Coal	Coal	0.12
OK	3006	Anadarko	3	2002	3736.2		8.7	62860	466	Natural Gas	Natural Gas	0.045
OK	3006	Anadarko	7	2002	9292.3		6.2	156365	438	Natural Gas	Natural Gas	0.045

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OK	3006	Anadarko	8	2002	8765.2		6.7	147480	443	Natural Gas	Natural Gas	0.045
OK	7757	Chouteau Power Plant	1	2002	228556.8	1.3	60.6	3845890	2848	Natural Gas	Natural Gas	0.045
OK	7757	Chouteau Power Plant	2	2002	256877.9	1.2	62.7	4322463	3247	Natural Gas	Natural Gas	0.045
OK	8059	Comanche (8059)	7251	2002	361711.1	2	1529.9	6086401	7605	Natural Gas	Natural Gas	0.045
OK	8059	Comanche (8059)	7252	2002	378655.3	2.2	1443.9	6371486	7886	Natural Gas	Natural Gas	0.045
OK	7185	Conoco	**1	2002	177871.2	4.8	253.4	2993122	7897	Blast Furnace Gas	Other Gas	0
OK	7185	Conoco	**2	2002	191127.7	4.9	252.3	3216120	8377	Blast Furnace Gas	Other Gas	0
OK	165	Grand River Dam Authority	1	2002	3669801.5	13428.1	8292.9	35878645	7956	Coal	Coal	0.12
OK	165	Grand River Dam Authority	2	2002	4245903.2	3797.3	7094.1	41497880	7779	Coal	Coal	0.12
OK	55146	Green Country Energy, LLC	CTGEN1	2002	265970.8	1.3	65.6	4475473	3289	Natural Gas	Natural Gas	0.045
OK	55146	Green Country Energy, LLC	CTGEN2	2002	280994.2	1.4	67.9	4728243	3335	Natural Gas	Natural Gas	0.045
OK	55146	Green Country Energy, LLC	CTGEN3	2002	261679.5	1.2	67.9	4403264	3324	Natural Gas	Natural Gas	0.045
OK	2951	Horseshoe Lake	10	2002	10724.7		6.5	180467	491	Natural Gas	Natural Gas	0.045
OK	2951	Horseshoe Lake	6	2002	305417.3	1.5	608.6	5139231	5357	Natural Gas	Natural Gas	0.045
OK	2951	Horseshoe Lake	7	2002	294323.4	50.2	357.3	4942621	4223	Natural Gas	Natural Gas	0.045
OK	2951	Horseshoe Lake	8	2002	265980.6	1.4	627.1	4475648	2675	Natural Gas	Natural Gas	0.045
OK	2951	Horseshoe Lake	9	2002	11094.4		7.1	186697	499	Natural Gas	Natural Gas	0.045
OK	6772	Hugo	1	2002	3332938.3	8556.3	3831.9	32490593	7864	Coal	Coal	0.12
OK	55457	McClain Energy Facility	CT1	2002	299647.2	1.4	92.7	5042137	3893	Natural Gas	Natural Gas	0.045
OK	55457	McClain Energy Facility	CT2	2002	274900.3	1.3	79.1	4625697	3481	Natural Gas	Natural Gas	0.045
OK	3008	Mooreland	1	2002	17365.2		56.4	292228	1069	Natural Gas	Natural Gas	0.045
OK	3008	Mooreland	2	2002	107935.5	0.5	140.8	1816241	3656	Natural Gas	Natural Gas	0.045
OK	3008	Mooreland	3	2002	9433.6		9.6	158744	315	Natural Gas	Natural Gas	0.045
OK	2952	Muskogee	3	2002	195632.8	1	416.9	3291908	3376	Natural Gas	Natural Gas	0.045
OK	2952	Muskogee	4	2002	3604378.1	8586.2	5924.8	35169194	7128	Coal	Coal	0.12
OK	2952	Muskogee	5	2002	3643972.2	9068.5	5573.3	35556691	7366	Coal	Coal	0.12
OK	2952	Muskogee	6	2002	4056011.6	9865.9	5828.6	39591431	7868	Coal	Coal	0.12
OK	2953	Mustang	1	2002	5664.8		10.6	95327	253	Natural Gas	Natural Gas	0.045
OK	2953	Mustang	2	2002	3908.2		6.9	65753	186	Natural Gas	Natural Gas	0.045
OK	2953	Mustang	3	2002	159760.1	0.7	566.2	2688239	4340	Natural Gas	Natural Gas	0.045
OK	2953	Mustang	4	2002	481433.8	2.1	1844.1	8101065	6529	Natural Gas	Natural Gas	0.045
OK	2963	Northeastern	3301A	2002	392639.5	1.9	94.1	6606855	4630	Natural Gas	Natural Gas	0.045
OK	2963	Northeastern	3301B	2002	423596.9	2.1	87.5	7127866	4650	Natural Gas	Natural Gas	0.045
OK	2963	Northeastern	3302	2002	551186.2	2.8	1994.9	9274771	4532	Natural Gas	Natural Gas	0.045
OK	2963	Northeastern	3313	2002	4239209.6	18048.1	8279.8	41317831	8609	Coal	Coal	0.12
OK	2963	Northeastern	3314	2002	3861042.8	16457.4	7630	37631949	8060	Coal	Coal	0.12
OK	55225	Oneta Energy Center (Panda Oneta)	CTG-1	2002	90943.1	0.5	23	1530311	1018	Natural Gas	Natural Gas	0.045
OK	55225	Oneta Energy Center (Panda Oneta)	CTG-2	2002	72590	0.4	18.7	1221469	834	Natural Gas	Natural Gas	0.045
OK	762	Ponca	2	2002	112.9		0.2	1902	8	Natural Gas	Natural Gas	0.045
OK	762	Ponca	3	2002	33589.7		23.6	565185	1475	Natural Gas	Natural Gas	0.045
OK	4940	Riverside (4940)	1501	2002	621869.2	3.1	1215.8	10464083	4501	Natural Gas	Natural Gas	0.045
OK	4940	Riverside (4940)	1502	2002	877193	4.3	1792.2	14760411	7476	Natural Gas	Natural Gas	0.045
OK	2956	Seminole (2956)	1	2002	815283.2	4.2	1191.2	13718634	7666	Natural Gas	Natural Gas	0.045
OK	2956	Seminole (2956)	2	2002	680817.5	3.5	1496.9	11456038	6115	Natural Gas	Natural Gas	0.045
OK	2956	Seminole (2956)	3	2002	650131.7	9.1	1312.8	10938561	6896	Natural Gas	Natural Gas	0.045
OK	6095	Sooner	1	2002	4325174.3	10644.3	7391.7	42181821	8625	Coal	Coal	0.12
OK	6095	Sooner	2	2002	3061159.3	7748.5	4937.9	29849643	6619	Coal	Coal	0.12
OK	2964	Southwestern	8002	2002	33676.9		83.7	566701	8496	Natural Gas	Natural Gas	0.045
OK	2964	Southwestern	8003	2002	553357.9	2.7	2734.2	9311182	7950	Natural Gas	Natural Gas	0.045
OK	2964	Southwestern	801N	2002	12000.2		34.1	201933	7833	Natural Gas	Natural Gas	0.045
OK	2964	Southwestern	801S	2002	12162.1		37	204618	7821	Natural Gas	Natural Gas	0.045
OK	2965	Tulsa	1402	2002	80916.1	0.4	240.1	1361586	2901	Natural Gas	Natural Gas	0.045
OK	2965	Tulsa	1403	2002						Natural Gas	Natural Gas	0.045
OK	2965	Tulsa	1404	2002	70265.8	0.2	198.6	1182302	2361	Natural Gas	Natural Gas	0.045
TX	10670	AES Deepwater, Inc.	1001	2002	899152.1	2788.8	2372	8609303	5042	Municipal Waste	Other	0
TX	3602	Alex Ty Cooke Generating Station	1	2002	49272.6	0.1	80.7	829146	2991	Natural Gas	Natural Gas	0.045
TX	3602	Alex Ty Cooke Generating Station	2	2002	28644		41.4	481990	1759	Natural Gas	Natural Gas	0.045
TX	4939	Barney M. Davis	1	2002	483318.9	88.4	875.7	7976325	5403	Natural Gas	Natural Gas	0.045
TX	4939	Barney M. Davis	2	2002	556510.3	2.8	527	9364343	6136	Natural Gas	Natural Gas	0.045
TX	55168	Bastrop Clean Energy Center	CTG-1A	2002	346687.8	1.8	161.3	5833673	4003	Natural Gas	Natural Gas	0.045

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TX	55168	Bastrop Clean Energy Center	CTG-1B	2002	316234.2	1.7	210.6	5321288	3895	Natural Gas	Natural Gas	0.045
TX	55195	Baytown Energy Center	CTG-1	2002	438682.2	4.7	32.1	7381639	4888	Natural Gas	Natural Gas	0.045
TX	55195	Baytown Energy Center	CTG-2	2002	488023.3	5.3	37.5	8211944	5427	Natural Gas	Natural Gas	0.045
TX	55195	Baytown Energy Center	CTG-3	2002	448687.5	4.9	30.8	7549998	4884	Natural Gas	Natural Gas	0.045
TX	3497	Big Brown	1	2002	5354233.9	43412.7	3810.1	50485258	8278	Coal	Coal	0.12
TX	3497	Big Brown	2	2002	4245873.9	34447.7	3394.6	40202337	6529	Coal	Coal	0.12
TX	55064	Blackhawk Station	1	2002	678695	3.9	376.3	11420347	8339	Natural Gas	Natural Gas	0.045
TX	55064	Blackhawk Station	2	2002	653267.1	3.9	411.9	10992535	8190	Natural Gas	Natural Gas	0.045
TX	55172	Bosque County Power Plant	GT-1	2002	18566.6		8	312412	272	Natural Gas	Natural Gas	0.045
TX	55172	Bosque County Power Plant	GT-2	2002	29392		8.3	494585	408	Natural Gas	Natural Gas	0.045
TX	55172	Bosque County Power Plant	GT-3	2002	720749.4	3.6	192	12127958	8100	Natural Gas	Natural Gas	0.045
TX	3561	Bryan	6	2002	12275.7		22.9	207641	3602	Natural Gas	Natural Gas	0.045
TX	3574	C E Newman	BW5	2002	4408.6		3.6	74173	1189	Natural Gas	Natural Gas	0.045
TX	3460	Cedar Bayou	CBY1	2002	788750	4	679.7	13272229	6291	Natural Gas	Natural Gas	0.045
TX	3460	Cedar Bayou	CBY2	2002	547534.2	2.8	621.4	9212594	3646	Natural Gas	Natural Gas	0.045
TX	3460	Cedar Bayou	CBY3	2002	1144988	5.7	579.1	19266635	5520	Natural Gas	Natural Gas	0.045
TX	55299	Channel Energy Center	CTG1	2002	805835.5	3.4	77.6	13558870	7945	Other Gas	Other Gas	0
TX	55299	Channel Energy Center	CTG2	2002	485518.5	2.4	45.5	8168765	5251	Other Gas	Other Gas	0
TX	54817	Cleburne Cogeneration Facility	EAST	2002	685700.6	3.5	177.8	11538102	7203	Natural Gas	Natural Gas	0.045
TX	50815	Cogen Lyondell, Inc.	ENG101	2002	197801.1	1.2	202	3328286	4468	Natural Gas	Natural Gas	0.045
TX	50815	Cogen Lyondell, Inc.	ENG201	2002	204354	1.2	205.8	3438714	4454	Natural Gas	Natural Gas	0.045
TX	50815	Cogen Lyondell, Inc.	ENG301	2002	141537	0.6	141.8	2381525	3370	Natural Gas	Natural Gas	0.045
TX	50815	Cogen Lyondell, Inc.	ENG401	2002	118001.9	0.6	123.5	1985644	2799	Natural Gas	Natural Gas	0.045
TX	50815	Cogen Lyondell, Inc.	ENG501	2002	126480.9	0.6	127.4	2128240	2953	Natural Gas	Natural Gas	0.045
TX	50815	Cogen Lyondell, Inc.	ENG601	2002	243120.1	1.2	83.2	4090779	4484	Natural Gas	Natural Gas	0.045
TX	6178	Coleto Creek	1	2002	4378288	14288.5	3554.2	42673354	8436	Coal	Coal	0.12
TX	3500	Collin	1	2002	57085.2	0.8	26.6	959950	1358	Natural Gas	Natural Gas	0.045
TX	55206	Corpus Christi Energy Center	CU1	2002	126917.4	0.6	34.3	2221266	1452	Natural Gas	Natural Gas	0.045
TX	55206	Corpus Christi Energy Center	CU2	2002	148820.4	0.8	38.3	2601559	1949	Natural Gas	Natural Gas	0.045
TX	6243	Dansby	1	2002	179994.9	1.2	192.6	3027751	8163	Natural Gas	Natural Gas	0.045
TX	3548	Decker Creek	1	2002	323490.2	1.5	286	5443290	3509	Natural Gas	Natural Gas	0.045
TX	3548	Decker Creek	2	2002	662586.5	5.6	564.1	11146989	7829	Natural Gas	Natural Gas	0.045
TX	8063	Decordova	1	2002	1788280	10.7	5630.7	30079343	7479	Natural Gas	Natural Gas	0.045
TX	3461	Deepwater	DWP9	2002	29340.9	0.1	32.3	493711	665	Natural Gas	Natural Gas	0.045
TX	3436	E S Joslin	1	2002	76790	0.4	179.2	1292129	1270	Natural Gas	Natural Gas	0.045
TX	3489	Eagle Mountain	1	2002	88448.9	0.3	192	1488340	2406	Natural Gas	Natural Gas	0.045
TX	3489	Eagle Mountain	2	2002	145081.1	3.7	249.1	2443032	2903	Natural Gas	Natural Gas	0.045
TX	3489	Eagle Mountain	3	2002	420807.8	2.1	494.2	7080983	4150	Natural Gas	Natural Gas	0.045
TX	55176	Eastman Cogeneration Facility	1	2002	813350.1	4.2	196.4	13686142	8039	Natural Gas	Natural Gas	0.045
TX	55176	Eastman Cogeneration Facility	2	2002	748483.4	3.7	174	12594587	7461	Natural Gas	Natural Gas	0.045
TX	55223	Ennis-Tractebel Power Company	GT-1	2002	423456.1	2.2	127.4	7125474	3734	Natural Gas	Natural Gas	0.045
TX	55365	Exelon Laporte Generating Station	GT-1	2002	2970.2	1.6	3.7	50315	224	Natural Gas	Natural Gas	0.045
TX	55365	Exelon Laporte Generating Station	GT-2	2002	1215.3	0.5	1.5	20590	92	Natural Gas	Natural Gas	0.045
TX	55365	Exelon Laporte Generating Station	GT-3	2002	3696.7	1.9	4.7	62656	215	Natural Gas	Natural Gas	0.045
TX	55365	Exelon Laporte Generating Station	GT-4	2002	2203.1	1.2	2.8	37334	141	Natural Gas	Natural Gas	0.045
TX	4938	Fort Phantom Power Station	1	2002	158724.9	0.8	321.8	2670829	3332	Natural Gas	Natural Gas	0.045
TX	4938	Fort Phantom Power Station	2	2002	402748.5	2.1	438.1	6776981	6780	Natural Gas	Natural Gas	0.045
TX	55226	Freestone Power Generation	GT1	2002	416812.7	2	87.1	7013702	4299	Natural Gas	Natural Gas	0.045
TX	55226	Freestone Power Generation	GT2	2002	430459.8	2.2	96.3	7243286	4399	Natural Gas	Natural Gas	0.045
TX	55226	Freestone Power Generation	GT3	2002	323669.8	1.7	76.8	5446340	3284	Natural Gas	Natural Gas	0.045
TX	55226	Freestone Power Generation	GT4	2002	288918.3	1.6	69.1	4861652	2930	Natural Gas	Natural Gas	0.045
TX	55098	Frontera Power Facility	1	2002	322408	1.5	87.9	5425145	4275	Natural Gas	Natural Gas	0.045
TX	55098	Frontera Power Facility	2	2002	285062.5	1.6	76	4796752	3600	Natural Gas	Natural Gas	0.045
TX	6136	Gibbons Creek Steam Electric Station	1	2002	3215146.4	10815.9	2381.9	31336586	7722	Coal	Coal	0.12
TX	3490	Graham	1	2002	353333.3	38.3	989.5	5965847	4636	Natural Gas	Natural Gas	0.045
TX	3490	Graham	2	2002	410942.5	23.2	1070.5	6974732	4033	Natural Gas	Natural Gas	0.045
TX	3464	Greens Bayou	GBY5	2002	193999.1	1	107.8	3264180	2671	Natural Gas	Natural Gas	0.045
TX	55086	Gregory Power Facility	101	2002	929418.7	4.6	284.5	15639300	8218	Natural Gas	Natural Gas	0.045
TX	55086	Gregory Power Facility	102	2002	946756.5	4.7	258.6	15931063	8104	Natural Gas	Natural Gas	0.045
TX	55153	Guadalupe Generating Station	CTG-1	2002	522406	2.5	195.7	8790454	6187	Natural Gas	Natural Gas	0.045

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TX	55153	Guadalupe Generating Station	CTG-2	2002	379021.3	1.8	152.2	6377715	4521	Natural Gas	Natural Gas	0.045
TX	55153	Guadalupe Generating Station	CTG-3	2002	342966.8	1.7	128.6	5771086	4198	Natural Gas	Natural Gas	0.045
TX	55153	Guadalupe Generating Station	CTG-4	2002	412104.2	1.9	119.8	6934502	4927	Natural Gas	Natural Gas	0.045
TX	7902	H W Pirkey Power Plant	1	2002	5265723.5	19475.4	4748.6	48367081	7700	Coal	Coal	0.12
TX	3491	Handley Steam Electric Station	1A	2002	6405.7		8.4	107798	617	Natural Gas	Natural Gas	0.045
TX	3491	Handley Steam Electric Station	1B	2002	4754.8		3.6	80024	595	Natural Gas	Natural Gas	0.045
TX	3491	Handley Steam Electric Station	2	2002	35611.5	0.1	90.7	599210	1065	Natural Gas	Natural Gas	0.045
TX	3491	Handley Steam Electric Station	3	2002	661141.2	3.4	811.4	11125011	4440	Natural Gas	Natural Gas	0.045
TX	3491	Handley Steam Electric Station	4	2002	530118.3	2.6	639.1	8920323	4282	Natural Gas	Natural Gas	0.045
TX	3491	Handley Steam Electric Station	5	2002	380821.2	1.9	468.9	6408043	2708	Natural Gas	Natural Gas	0.045
TX	6193	Harrington Station	061B	2002	3378963.3	9197	4647.1	32933342	8531	Coal	Coal	0.12
TX	6193	Harrington Station	062B	2002	3150196.3	8926.6	4330.3	30703664	7821	Coal	Coal	0.12
TX	6193	Harrington Station	063B	2002	3158293.3	8843.8	4162.1	30782560	8634	Coal	Coal	0.12
TX	55144	Hays Energy Project	STK1	2002	216288.2	1.1	40.6	3639416	2850	Natural Gas	Natural Gas	0.045
TX	55144	Hays Energy Project	STK2	2002	251783.6	1.1	42.3	4236793	3170	Natural Gas	Natural Gas	0.045
TX	55144	Hays Energy Project	STK3	2002	206462.2	1	41.4	3474128	2587	Natural Gas	Natural Gas	0.045
TX	55144	Hays Energy Project	STK4	2002	146973.6	0.8	22.5	2473083	1828	Natural Gas	Natural Gas	0.045
TX	7762	Hidalgo Energy Facility	HRSG1	2002	398410.3	2.1	101	6704089	5064	Natural Gas	Natural Gas	0.045
TX	7762	Hidalgo Energy Facility	HRSG2	2002	465809	2.3	119.7	7838241	5721	Natural Gas	Natural Gas	0.045
TX	3549	Holly Street	1	2002	19781.6		23.7	332854	597	Natural Gas	Natural Gas	0.045
TX	3549	Holly Street	2	2002	4070.4		4.6	68486	375	Natural Gas	Natural Gas	0.045
TX	3549	Holly Street	3	2002	87974	0.6	77.6	1480327	1616	Natural Gas	Natural Gas	0.045
TX	3549	Holly Street	4	2002	175442.2	0.9	187.5	2951265	2832	Natural Gas	Natural Gas	0.045
TX	7097	J K Spruce	**1	2002	4440721.1	4781.4	4145.8	43281895	7798	Coal	Coal	0.12
TX	3438	J L Bates	1	2002	125605.8	0.6	1346.9	2113499	4540	Natural Gas	Natural Gas	0.045
TX	3438	J L Bates	2	2002	109224.4	0.5	250.8	1837855	3503	Natural Gas	Natural Gas	0.045
TX	3604	J Robert Massengale Generating Station	GT1	2002	128835.7	0.9	50.9	2167905	7390	Natural Gas	Natural Gas	0.045
TX	6181	J T Deely	1	2002	3079186.3	9964.4	2849.2	30011592	8213	Coal	Coal	0.12
TX	6181	J T Deely	2	2002	3516017.7	11604.7	3285.3	34269229	8558	Coal	Coal	0.12
TX	3482	Jones Station	151B	2002	611853.4	3.1	1213.6	10321409	7692	Natural Gas	Natural Gas	0.045
TX	3482	Jones Station	152B	2002	683477.9	3.6	692.7	11529613	8448	Natural Gas	Natural Gas	0.045
TX	3476	Knox Lee Power Plant	2	2002	2574.1		3.1	43326	258	Natural Gas	Natural Gas	0.045
TX	3476	Knox Lee Power Plant	3	2002	2950.2		4	49645	248	Natural Gas	Natural Gas	0.045
TX	3476	Knox Lee Power Plant	4	2002	51330		63.9	863628	1441	Natural Gas	Natural Gas	0.045
TX	3476	Knox Lee Power Plant	5	2002	403853.9	2.2	483	6795289	5964	Natural Gas	Natural Gas	0.045
TX	3442	La Palma	7	2002	289769.6	1.2	628.1	4875851	5100	Natural Gas	Natural Gas	0.045
TX	3502	Lake Creek	1	2002	34816.2	0.1	82	585851	740	Natural Gas	Natural Gas	0.045
TX	3502	Lake Creek	2	2002	192486.2	1.2	478.2	3238521	3158	Natural Gas	Natural Gas	0.045
TX	3452	Lake Hubbard	1	2002	335450.1	12.3	371.8	5605395	3602	Natural Gas	Natural Gas	0.045
TX	3452	Lake Hubbard	2	2002	835411.8	29.6	244	13993792	5559	Natural Gas	Natural Gas	0.045
TX	55097	Lamar Power (Paris)	1	2002	562768.9	2.8	162.8	9469660	6758	Natural Gas	Natural Gas	0.045
TX	55097	Lamar Power (Paris)	2	2002	588721.4	2.9	143.2	9906382	7019	Natural Gas	Natural Gas	0.045
TX	55097	Lamar Power (Paris)	3	2002	562769.7	2.7	138.9	9469768	6802	Natural Gas	Natural Gas	0.045
TX	55097	Lamar Power (Paris)	4	2002	551195.2	2.7	149.1	9274961	6748	Natural Gas	Natural Gas	0.045
TX	3439	Laredo	1	2002	55806.9	0.1	128.3	939039	3838	Natural Gas	Natural Gas	0.045
TX	3439	Laredo	2	2002	42469.3		111	714627	3034	Natural Gas	Natural Gas	0.045
TX	3439	Laredo	3	2002	248647.5	1.7	239.9	4181362	6696	Natural Gas	Natural Gas	0.045
TX	3609	Leon Creek	3	2002						Natural Gas	Natural Gas	0.045
TX	3609	Leon Creek	4	2002						Natural Gas	Natural Gas	0.045
TX	3457	Lewis Creek	1	2002	771379.8	3.8	1100	12979986	7358	Natural Gas	Natural Gas	0.045
TX	3457	Lewis Creek	2	2002	684457.7	3.2	1108.9	11517206	6629	Natural Gas	Natural Gas	0.045
TX	298	Limestone	LIM1	2002	6929259.7	17008.9	8053.4	63647147	8531	Coal	Coal	0.12
TX	298	Limestone	LIM2	2002	6073036.9	13830.3	5704.3	55782456	8220	Coal	Coal	0.12
TX	3440	Lon C Hill	1	2002	3327.9		10.5	56001	217	Natural Gas	Natural Gas	0.045
TX	3440	Lon C Hill	2	2002	140.6		0.2	2368	56	Natural Gas	Natural Gas	0.045
TX	3440	Lon C Hill	3	2002	15566.9		24.8	261941	496	Natural Gas	Natural Gas	0.045
TX	3440	Lon C Hill	4	2002	122011.7	0.6	163	2053080	2456	Natural Gas	Natural Gas	0.045
TX	3477	Lone Star Power Plant	1	2002	5280.1		10.6	88839	229	Natural Gas	Natural Gas	0.045
TX	55154	Lost Pines 1	1	2002	685560.4	3.4	100.3	11535830	7395	Natural Gas	Natural Gas	0.045
TX	55154	Lost Pines 1	2	2002	701503.4	3.4	103.7	11804145	7520	Natural Gas	Natural Gas	0.045

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TX	55123	Magic Valley Generating Station	CTG-1	2002	433324.7	2.1	122.3	7291554	3974	Natural Gas	Natural Gas	0.045
TX	55123	Magic Valley Generating Station	CTG-2	2002	563001.2	2.9	147.5	9473507	5129	Natural Gas	Natural Gas	0.045
TX	6146	Martin Lake	1	2002	5969420.7	24836.6	9480.4	58228170	7833	Coal	Coal	0.12
TX	6146	Martin Lake	2	2002	5791472.6	22523.6	4495.3	56549708	7696	Coal	Coal	0.12
TX	6146	Martin Lake	3	2002	5962876.7	19023.6	4502.7	54401534	6916	Coal	Coal	0.12
TX	55091	Midlothian Energy	STK1	2002	456425.6	2.4	75.4	7680224	5595	Natural Gas	Natural Gas	0.045
TX	55091	Midlothian Energy	STK2	2002	443636.2	2.2	71.5	7465028	5412	Natural Gas	Natural Gas	0.045
TX	55091	Midlothian Energy	STK3	2002	475362.8	2.5	59.4	7998887	5922	Natural Gas	Natural Gas	0.045
TX	55091	Midlothian Energy	STK4	2002	429764.8	2.2	63.3	7231611	5328	Natural Gas	Natural Gas	0.045
TX	55091	Midlothian Energy	STK5	2002	354003.6	1.9	58.7	5956805	4088	Natural Gas	Natural Gas	0.045
TX	55091	Midlothian Energy	STK6	2002	374849.8	1.9	55.9	6307532	4396	Natural Gas	Natural Gas	0.045
TX	3610	Mission Road	3	2002	13.3			224	8	Natural Gas	Natural Gas	0.045
TX	6147	Monticello	1	2002	4375891.2	28643.3	4102.6	41513236	7573	Coal	Coal	0.12
TX	6147	Monticello	2	2002	4915613.1	34700	6224.6	47267771	8212	Coal	Coal	0.12
TX	6147	Monticello	3	2002	6327764.8	22975.8	5593	60149597	7797	Coal	Coal	0.12
TX	3483	Moore County Station	3	2002	14245.6		18.7	240299	819	Natural Gas	Natural Gas	0.045
TX	3492	Morgan Creek	3	2002						Natural Gas	Natural Gas	0.045
TX	3492	Morgan Creek	4	2002	7227.2		22.1	121616	287	Natural Gas	Natural Gas	0.045
TX	3492	Morgan Creek	5	2002	152922.7	0.7	434.3	2573232	3231	Natural Gas	Natural Gas	0.045
TX	3492	Morgan Creek	6	2002	513591.5	2.6	2455	8642139	3096	Natural Gas	Natural Gas	0.045
TX	3453	Mountain Creek Steam Electric Sta	2	2002	11915.1		31.6	200504	1028	Natural Gas	Natural Gas	0.045
TX	3453	Mountain Creek Steam Electric Sta	3A	2002	19800.7	0.1	39.7	333171	1054	Natural Gas	Natural Gas	0.045
TX	3453	Mountain Creek Steam Electric Sta	3B	2002	5037.1		12.9	84756	444	Natural Gas	Natural Gas	0.045
TX	3453	Mountain Creek Steam Electric Sta	6	2002	82993.2	46.4	128.9	1523986	2512	Natural Gas	Natural Gas	0.045
TX	3453	Mountain Creek Steam Electric Sta	7	2002	84851	55.8	183.9	1558277	3016	Natural Gas	Natural Gas	0.045
TX	3453	Mountain Creek Steam Electric Sta	8	2002	470691.5	17.5	340.6	7961179	3166	Natural Gas	Natural Gas	0.045
TX	55065	Mustang Station	1	2002	650351.4	3.4	165.6	10943392	7322	Natural Gas	Natural Gas	0.045
TX	55065	Mustang Station	2	2002	625499.8	3.1	195.4	10525210	7405	Natural Gas	Natural Gas	0.045
TX	50137	Newgulf	1	2002	1298.7		2.5	21856	34	Natural Gas	Natural Gas	0.045
TX	3456	Newman	**4	2002	221272.2	1	340.7	3723084	6007	Natural Gas	Natural Gas	0.045
TX	3456	Newman	**5	2002	263268.6	1.1	377.8	4430021	6833	Natural Gas	Natural Gas	0.045
TX	3456	Newman	1	2002	145005.7	0.7	180.3	2440015	6007	Natural Gas	Natural Gas	0.045
TX	3456	Newman	2	2002	205716.3	1.2	263.2	3461619	8176	Natural Gas	Natural Gas	0.045
TX	3456	Newman	3	2002	229753.8	1	517	3866041	6559	Natural Gas	Natural Gas	0.045
TX	3484	Nichols Station	141B	2002	119788.2	0.6	154	2020713	3039	Natural Gas	Natural Gas	0.045
TX	3484	Nichols Station	142B	2002	98057	0.6	152.5	1654111	2650	Natural Gas	Natural Gas	0.045
TX	3484	Nichols Station	143B	2002	308716.1	1.6	602.1	5207795	5674	Natural Gas	Natural Gas	0.045
TX	3454	North Lake	1	2002	237176.8	2.7	289.8	3983189	4932	Natural Gas	Natural Gas	0.045
TX	3454	North Lake	2	2002	213182.7	10.3	229.3	3565359	4403	Natural Gas	Natural Gas	0.045
TX	3454	North Lake	3	2002	425881.7	8.1	570.8	7135999	5006	Natural Gas	Natural Gas	0.045
TX	3493	North Main	4	2002	44739.5	0.3	76	752847	1536	Natural Gas	Natural Gas	0.045
TX	3627	North Texas	3	2002	654.5		1.8	11011	74	Natural Gas	Natural Gas	0.045
TX	3441	Nueces Bay	5	2002	0.2			2	2	Natural Gas	Natural Gas	0.045
TX	3441	Nueces Bay	6	2002	36703.9	0.1	48	617611	822	Natural Gas	Natural Gas	0.045
TX	3441	Nueces Bay	7	2002	578172.8	2.8	924.7	9728752	5828	Natural Gas	Natural Gas	0.045
TX	3611	O W Sommers	1	2002	295533.7	1.6	340.9	4972071	2603	Natural Gas	Natural Gas	0.045
TX	3611	O W Sommers	2	2002	311898	1.6	333.1	5245644	3229	Natural Gas	Natural Gas	0.045
TX	3523	Oak Creek Power Station	1	2002	59774.3	0.3	102.3	1005724	2063	Natural Gas	Natural Gas	0.045
TX	55215	Odessa-Ector Generating Station	GT1	2002	489618.3	2.4	116	8238735	5948	Natural Gas	Natural Gas	0.045
TX	55215	Odessa-Ector Generating Station	GT2	2002	537870.8	2.7	122.8	9050675	6462	Natural Gas	Natural Gas	0.045
TX	55215	Odessa-Ector Generating Station	GT3	2002	494603.9	2.6	127	8322672	6210	Natural Gas	Natural Gas	0.045
TX	55215	Odessa-Ector Generating Station	GT4	2002	450113.3	2.4	114.4	7574036	5635	Natural Gas	Natural Gas	0.045
TX	127	Oklaunion Power Station	1	2002	4711710.9	3738.2	8265.7	45923130	8105	Coal	Coal	0.12
TX	3466	P H Robinson	PHR1	2002	460096.8	2.4	686.6	7742033	3644	Natural Gas	Natural Gas	0.045
TX	3466	P H Robinson	PHR2	2002	490713.5	2.4	832.6	8257157	3494	Natural Gas	Natural Gas	0.045
TX	3466	P H Robinson	PHR3	2002	449212.7	2.1	847.6	7558836	2982	Natural Gas	Natural Gas	0.045
TX	3466	P H Robinson	PHR4	2002	466903.8	2.4	631.3	7856544	2217	Natural Gas	Natural Gas	0.045
TX	3524	Paint Creek Power Station	1	2002	128.3			2148	40	Natural Gas	Natural Gas	0.045
TX	3524	Paint Creek Power Station	2	2002						Natural Gas	Natural Gas	0.045
TX	3524	Paint Creek Power Station	3	2002	382.7		0.4	6438	78	Natural Gas	Natural Gas	0.045

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TX	3524	Paint Creek Power Station	4	2002	34488.5	0.1	62.2	580278	1311	Natural Gas	Natural Gas	0.045
TX	3455	Parkdale	1	2002	49569.9	0.2	120.6	834130	1691	Natural Gas	Natural Gas	0.045
TX	3455	Parkdale	2	2002	76178.3	0.4	149.3	1281822	2061	Natural Gas	Natural Gas	0.045
TX	3455	Parkdale	3	2002	92209.4	0.4	220.5	1551575	2454	Natural Gas	Natural Gas	0.045
TX	55047	Pasadena Power Plant	CG-1	2002	707368.7	3.5	178.4	11902916	8471	Natural Gas	Natural Gas	0.045
TX	55047	Pasadena Power Plant	CG-2	2002	727033.8	3.5	291.8	12233747	8182	Natural Gas	Natural Gas	0.045
TX	55047	Pasadena Power Plant	CG-3	2002	663738.8	3.4	159	11168635	8013	Natural Gas	Natural Gas	0.045
TX	3494	Permian Basin	5	2002	69807.1	0.3	143	1174630	2142	Natural Gas	Natural Gas	0.045
TX	3494	Permian Basin	6	2002	1303154.7	6.5	2781.4	21928102	7711	Natural Gas	Natural Gas	0.045
TX	3485	Plant X	111B	2002	18679.2	0.1	54.3	315092	934	Natural Gas	Natural Gas	0.045
TX	3485	Plant X	112B	2002	72236.5	0.4	62.3	1218527	3023	Natural Gas	Natural Gas	0.045
TX	3485	Plant X	113B	2002	116004.8	0.6	198.8	1956916	3910	Natural Gas	Natural Gas	0.045
TX	3485	Plant X	114B	2002	360661.2	1.9	645.6	6084071	7503	Natural Gas	Natural Gas	0.045
TX	4195	Powerlane Plant	2	2002	529.4		1.1	8845	435	Natural Gas	Natural Gas	0.045
TX	4195	Powerlane Plant	3	2002	6385.5		5.8	107135	1805	Natural Gas	Natural Gas	0.045
TX	3628	R W Miller	**4	2002	32980.5	0.1	17.2	554911	759	Natural Gas	Natural Gas	0.045
TX	3628	R W Miller	**5	2002	23556.8	0.1	11.6	396398	584	Natural Gas	Natural Gas	0.045
TX	3628	R W Miller	1	2002	997.3		0.9	16783	140	Natural Gas	Natural Gas	0.045
TX	3628	R W Miller	2	2002	113733.2	0.6	145.8	1913764	2958	Natural Gas	Natural Gas	0.045
TX	3628	R W Miller	3	2002	309507.9	1.7	252.5	5207995	5973	Natural Gas	Natural Gas	0.045
TX	3576	Ray Olinger	BW2	2002	193700.7	1	247.1	3208873	8639	Natural Gas	Natural Gas	0.045
TX	3576	Ray Olinger	BW3	2002	242241.7	1.2	263	4067479	7268	Natural Gas	Natural Gas	0.045
TX	3576	Ray Olinger	CE1	2002	104405.8	0.8	107.8	1756587	7785	Natural Gas	Natural Gas	0.045
TX	3576	Ray Olinger	GE4	2002	59526.4	0.2	13.8	1001665	1421	Natural Gas	Natural Gas	0.045
TX	55187	Reliant Energy Channelview Cogen	CHV1	2002	594912.4	2.8	50.3	10010514	5290	Natural Gas	Natural Gas	0.045
TX	55187	Reliant Energy Channelview Cogen	CHV2	2002	455407.6	2.3	39.2	7663087	4216	Natural Gas	Natural Gas	0.045
TX	55187	Reliant Energy Channelview Cogen	CHV3	2002	472723.6	2.4	45.2	7954489	4145	Natural Gas	Natural Gas	0.045
TX	55187	Reliant Energy Channelview Cogen	CHV4	2002	847958.1	4.1	74.4	14268562	7478	Natural Gas	Natural Gas	0.045
TX	55137	Rio Nogales Power Project, LP	CTG-1	2002	216520.4	1	52.9	3643399	2653	Natural Gas	Natural Gas	0.045
TX	55137	Rio Nogales Power Project, LP	CTG-2	2002	166500.4	0.9	40.3	2801682	2193	Natural Gas	Natural Gas	0.045
TX	55137	Rio Nogales Power Project, LP	CTG-3	2002	136447.7	0.6	34.6	2296012	1680	Natural Gas	Natural Gas	0.045
TX	3526	Rio Pecos Power Station	5	2002	1853.3		1.7	31199	190	Natural Gas	Natural Gas	0.045
TX	3526	Rio Pecos Power Station	6	2002	124756.5	0.3	184.1	2099235	6878	Natural Gas	Natural Gas	0.045
TX	3503	River Crest	1	2002	542.7		0.7	9133	36	Natural Gas	Natural Gas	0.045
TX	3459	Sabine	1	2002	664783.2	3.2	786.3	11188191	8476	Natural Gas	Natural Gas	0.045
TX	3459	Sabine	2	2002	704178.4	3.3	724	11850092	8492	Natural Gas	Natural Gas	0.045
TX	3459	Sabine	3	2002	738375.9	3.7	834.9	12429596	5667	Natural Gas	Natural Gas	0.045
TX	3459	Sabine	4	2002	1188052.3	6.1	2122.8	19997594	6760	Natural Gas	Natural Gas	0.045
TX	3459	Sabine	5	2002	1126740.4	5.5	902.1	18959596	8569	Natural Gas	Natural Gas	0.045
TX	55104	Sabine Cogeneration Facility	SAB-1	2002	263124.8	1.2	38.6	4427531	8687	Natural Gas	Natural Gas	0.045
TX	55104	Sabine Cogeneration Facility	SAB-2	2002	257443.8	1.2	36.1	4331955	8722	Natural Gas	Natural Gas	0.045
TX	3468	Sam Bertron	SRB1	2002	76988.8	0.3	105.2	1295445	2207	Natural Gas	Natural Gas	0.045
TX	3468	Sam Bertron	SRB2	2002	98948.9	0.5	105	1665036	2445	Natural Gas	Natural Gas	0.045
TX	3468	Sam Bertron	SRB3	2002	195404	1	158	3288126	4659	Natural Gas	Natural Gas	0.045
TX	3468	Sam Bertron	SRB4	2002	178183.8	0.9	130.8	2998246	4374	Natural Gas	Natural Gas	0.045
TX	6179	Sam Seymour	1	2002	3914296.9	13617.3	6129.6	38201367	7199	Coal	Coal	0.12
TX	6179	Sam Seymour	2	2002	4737413.5	16401.2	6911.4	46197882	8615	Coal	Coal	0.12
TX	6179	Sam Seymour	3	2002	3824088.5	1779.1	6077.2	37294554	8459	Coal	Coal	0.12
TX	3527	San Angelo Power Station	2	2002	371304.5	2	422.8	6247924	7442	Natural Gas	Natural Gas	0.045
TX	7325	San Jacinto Steam Electric Station	SJS1	2002	499882.3	2.3	106.2	8411463	8434	Natural Gas	Natural Gas	0.045
TX	7325	San Jacinto Steam Electric Station	SJS2	2002	480873.4	2.3	131.8	8091602	8438	Natural Gas	Natural Gas	0.045
TX	6183	San Miguel	SM-1	2002	3891516.9	13172.5	7120	35744881	7830	Coal	Coal	0.12
TX	1700	Sand Hill Energy Center	SH1	2002	30807.9		7	518479	1874	Natural Gas	Natural Gas	0.045
TX	1700	Sand Hill Energy Center	SH2	2002	31739.8		8.6	534065	1944	Natural Gas	Natural Gas	0.045
TX	1700	Sand Hill Energy Center	SH3	2002	31948.4		5.5	537618	1889	Natural Gas	Natural Gas	0.045
TX	1700	Sand Hill Energy Center	SH4	2002	31027.6		6.9	522109	1864	Natural Gas	Natural Gas	0.045
TX	6648	Sandow	4	2002	4602757.5	23330.4	7670	44670713	7382	Coal	Coal	0.12
TX	3559	Silas Ray	9	2002	19556.4		10.8	329093	714	Natural Gas	Natural Gas	0.045
TX	3601	Sim Gideon	1	2002	83913.4	0.1	130.9	1411867	3126	Natural Gas	Natural Gas	0.045
TX	3601	Sim Gideon	2	2002	91369.8	0.3	135.3	1537476	2865	Natural Gas	Natural Gas	0.045

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TX	3601	Sim Gideon	3	2002	643673.1	3.4	632.8	10830711	7848	Natural Gas	Natural Gas	0.045
TX	4266	Spencer	4	2002	12219.8	0.4	5.8	204529	1395	Natural Gas	Natural Gas	0.045
TX	4266	Spencer	5	2002	25257.6	1.9	19.7	420301	2871	Natural Gas	Natural Gas	0.045
TX	55120	SRW Cogen Limited Partnership	CTG-1	2002	786115.2	3.7	162.8	11372834	6692	Natural Gas	Natural Gas	0.045
TX	55120	SRW Cogen Limited Partnership	CTG-2	2002	911804.4	4	135.3	13062604	7649	Natural Gas	Natural Gas	0.045
TX	3504	Stryker Creek	1	2002	44619.8	0.2	164.9	750820	912	Natural Gas	Natural Gas	0.045
TX	3504	Stryker Creek	2	2002	619066.8	43	461.7	10549791	4462	Natural Gas	Natural Gas	0.045
TX	55015	Sweeny Cogeneration Facility	1	2002	436910.1	2.3	330.1	7351770	5591	Natural Gas	Natural Gas	0.045
TX	55015	Sweeny Cogeneration Facility	2	2002	688742.8	2.9	402.7	11589281	8253	Natural Gas	Natural Gas	0.045
TX	55015	Sweeny Cogeneration Facility	3	2002	657582.2	3.2	448.4	11065016	8225	Natural Gas	Natural Gas	0.045
TX	55015	Sweeny Cogeneration Facility	4	2002	754800.1	3.7	438.1	12700981	8480	Natural Gas	Natural Gas	0.045
TX	50615	Sweetwater Generating Plant	GT01	2002	67217	0.3	79.8	1130313	2552	Natural Gas	Natural Gas	0.045
TX	50615	Sweetwater Generating Plant	GT02	2002	26615	0.1	34.5	447613	382	Natural Gas	Natural Gas	0.045
TX	50615	Sweetwater Generating Plant	GT03	2002	228457.1	1.2	253.2	3844306	3850	Natural Gas	Natural Gas	0.045
TX	4937	T C Ferguson	1	2002	424581	2.4	645.3	7713672	5273	Natural Gas	Natural Gas	0.045
TX	3469	T H Wharton	THW2	2002	99684.5	0.4	119.6	1677386	1645	Natural Gas	Natural Gas	0.045
TX	55062	Tenaska Frontier Generation Station	1	2002	666611.8	3.4	189	11217012	6826	Natural Gas	Natural Gas	0.045
TX	55062	Tenaska Frontier Generation Station	2	2002	672611.9	3.5	174.2	11317998	6886	Natural Gas	Natural Gas	0.045
TX	55062	Tenaska Frontier Generation Station	3	2002	555921.8	3	172.4	9352658	5695	Natural Gas	Natural Gas	0.045
TX	55132	Tenaska Gateway Generating Station	OGTDB1	2002	548403.4	2.7	141.3	9227855	6863	Natural Gas	Natural Gas	0.045
TX	55132	Tenaska Gateway Generating Station	OGTDB2	2002	525457	2.6	130.6	8841853	6589	Natural Gas	Natural Gas	0.045
TX	55132	Tenaska Gateway Generating Station	OGTDB3	2002	505003.3	2.6	129.5	8494617	6392	Natural Gas	Natural Gas	0.045
TX	6194	Tolk Station	171B	2002	4228720.3	12702.7	5985.5	41215600	8326	Coal	Coal	0.12
TX	6194	Tolk Station	172B	2002	4259195	12171.2	6129.1	41512586	7704	Coal	Coal	0.12
TX	3506	Tradinghouse	1	2002	910186.5	4.6	1707.7	15315634	6046	Natural Gas	Natural Gas	0.045
TX	3506	Tradinghouse	2	2002	929266.2	4.7	3639.8	15636655	3948	Natural Gas	Natural Gas	0.045
TX	3507	Trinidad	9	2002	149724.5	0.8	253.1	2519371	2425	Natural Gas	Natural Gas	0.045
TX	7030	Twin Oaks Power, LP	U1	2002	1370470.1	2533.2	1273.7	12588068	8339	Coal	Coal	0.12
TX	7030	Twin Oaks Power, LP	U2	2002	1415987.5	2599.3	1136.2	13006198	8053	Coal	Coal	0.12
TX	3612	V H Braunig	1	2002	135762.2	0.7	191.7	2284134	2006	Natural Gas	Natural Gas	0.045
TX	3612	V H Braunig	2	2002	72115.2	0.2	86.8	1213157	1495	Natural Gas	Natural Gas	0.045
TX	3612	V H Braunig	3	2002	295068.3	1.4	328	4965089	3111	Natural Gas	Natural Gas	0.045
TX	3612	V H Braunig	CT01	2002	306034.2	1.6	91.3	5149679	3754	Natural Gas	Natural Gas	0.045
TX	3612	V H Braunig	CT02	2002	299709.3	1.5	85	5043169	3687	Natural Gas	Natural Gas	0.045
TX	3508	Valley (TXU)	1	2002	128610	7	256.1	2147810	2482	Natural Gas	Natural Gas	0.045
TX	3508	Valley (TXU)	2	2002	758693.3	21.3	1693.9	12696233	5039	Natural Gas	Natural Gas	0.045
TX	3508	Valley (TXU)	3	2002	153700.8	0.9	227.2	2586303	1945	Natural Gas	Natural Gas	0.045
TX	3443	Victoria	6	2002	15.3			260	15	Natural Gas	Natural Gas	0.045
TX	3443	Victoria	7	2002	1663.6		3	27996	75	Natural Gas	Natural Gas	0.045
TX	3443	Victoria	8	2002	99678.4	0.5	154.3	1677307	1751	Natural Gas	Natural Gas	0.045
TX	3470	W A Parish	WAP1	2002	92688	0.2	130.6	1559680	2463	Natural Gas	Natural Gas	0.045
TX	3470	W A Parish	WAP2	2002	90134.9	0.3	79.3	1516926	2455	Natural Gas	Natural Gas	0.045
TX	3470	W A Parish	WAP3	2002	87529.2	0.4	109.5	1472837	1270	Natural Gas	Natural Gas	0.045
TX	3470	W A Parish	WAP4	2002	734500.7	3.7	629.2	12359377	4906	Natural Gas	Natural Gas	0.045
TX	3470	W A Parish	WAP5	2002	5422153.1	21310	4482.7	52859502	8709	Coal	Coal	0.12
TX	3470	W A Parish	WAP6	2002	4571700.5	18005.7	3850.6	44689054	7567	Coal	Coal	0.12
TX	3470	W A Parish	WAP7	2002	4694715.9	18459.4	3208.9	45768474	8544	Coal	Coal	0.12
TX	3470	W A Parish	WAP8	2002	5014135.2	4046.9	3977.5	48879458	8480	Coal	Coal	0.12
TX	3613	W B Tuttle	1	2002	313.5		0.4	5275	22	Natural Gas	Natural Gas	0.045
TX	3613	W B Tuttle	2	2002	6141.7		13.3	103333	248	Natural Gas	Natural Gas	0.045
TX	3613	W B Tuttle	3	2002	5503.7		10.4	92709	156	Natural Gas	Natural Gas	0.045
TX	3613	W B Tuttle	4	2002	25755		41	433374	659	Natural Gas	Natural Gas	0.045
TX	3471	Webster	WEB3	2002	90454.2	0.5	93.6	1522019	1491	Natural Gas	Natural Gas	0.045
TX	6139	Welsh Power Plant	1	2002	4566474.7	12258.9	3806.8	44460713	8210	Coal	Coal	0.12
TX	6139	Welsh Power Plant	2	2002	4396259.2	11937.5	7479.9	42775451	8219	Coal	Coal	0.12
TX	6139	Welsh Power Plant	3	2002	4282556.4	11584	3644.1	41740250	7889	Coal	Coal	0.12
TX	3478	Wilkes Power Plant	1	2002	117883.6	1	141.6	1979983	3063	Natural Gas	Natural Gas	0.045
TX	3478	Wilkes Power Plant	2	2002	385785.7	2.1	429.4	6491503	4371	Natural Gas	Natural Gas	0.045
TX	3478	Wilkes Power Plant	3	2002	536712.2	2.7	498.9	9031094	5997	Natural Gas	Natural Gas	0.045
UT	7790	Bonanza	37987	2002	4560071.2	980.9	6712.1	44445147	8650	Coal	Coal	0.12

STATE	ORIS_ CODE	FACILITY_NAME	UNIT_ID	YEAR	SumOf CO2_TONS	SumOf SO2_TONS	SumOf NOX_TONS	SumOf HEAT_INPUT	SumOf TOTAL_ OPERATING_HOURS	DESCRIPTION_ SPECIFIC	DESCRIPTION_ GENERIC	CO2_ CONCENTRATION
UT	3644	Carbon	1	2002	628314.3	2720.7	1377	6123951	8471	Coal	Coal	0.12
UT	3644	Carbon	2	2002	904331.7	4043.4	2001.1	8815679	8393	Coal	Coal	0.12
UT	55848	Desert Power Plant	UNT1	2002	39315.2	0.3	91.7	666184	1670	Natural Gas	Natural Gas	0.045
UT	55848	Desert Power Plant	UNT2	2002	40213.6	0.3	65.7	681409	1706	Natural Gas	Natural Gas	0.045
UT	3648	Gadsby	1	2002	67625.9	0.2	68.6	1137893	2971	Natural Gas	Natural Gas	0.045
UT	3648	Gadsby	2	2002	98795.9	0.6	99.1	1662409	3874	Natural Gas	Natural Gas	0.045
UT	3648	Gadsby	3	2002	215126.3	1	130.4	3619934	6389	Natural Gas	Natural Gas	0.045
UT	3648	Gadsby	4	2002	7338.2		1.4	123550	1106	Natural Gas	Natural Gas	0.045
UT	3648	Gadsby	5	2002	5529		0.8	93015	694	Natural Gas	Natural Gas	0.045
UT	3648	Gadsby	6	2002	4886.7		0.7	82268	757	Natural Gas	Natural Gas	0.045
UT	6165	Hunter (Emery)	1	2002	3661997.9	3113.6	7447.3	35692776	8164	Coal	Coal	0.12
UT	6165	Hunter (Emery)	2	2002	3023690.8	2543	5750.1	29470715	6930	Coal	Coal	0.12
UT	6165	Hunter (Emery)	3	2002	3396076.6	1369.5	6661	33100397	8209	Coal	Coal	0.12
UT	8069	Huntington	1	2002	3298680.4	2630.9	6236.7	32151774	8164	Coal	Coal	0.12
UT	8069	Huntington	2	2002	2564916.5	11078.7	4946.1	24999211	6682	Coal	Coal	0.12
UT	6481	Intermountain	1SGA	2002	7632494.6	1859.7	15767.6	74390802	8494	Coal	Coal	0.12
UT	6481	Intermountain	2SGA	2002	7351167.5	1788.5	14488.6	71648775	8073	Coal	Coal	0.12
UT	55622	West Valley Generation Project	U1	2002	50834.9	0.2	8.4	855443	2274	Natural Gas	Natural Gas	0.045
UT	55622	West Valley Generation Project	U2	2002	42875.1	0.1	6.9	721448	2025	Natural Gas	Natural Gas	0.045
UT	55622	West Valley Generation Project	U3	2002	59193.2	0.1	9.6	996008	2778	Natural Gas	Natural Gas	0.045
UT	55622	West Valley Generation Project	U4	2002	59529.2	0.3	9.7	1001722	2678	Natural Gas	Natural Gas	0.045
UT	55622	West Valley Generation Project	U5	2002	33463.4		5.7	563105	1545	Natural Gas	Natural Gas	0.045
WY	4158	Dave Johnston	BW41	2002	1011561.7	3851.3	2341.4	9859293	8504	Coal	Coal	0.12
WY	4158	Dave Johnston	BW42	2002	1031358	4159.8	2298.1	10052222	8662	Coal	Coal	0.12
WY	4158	Dave Johnston	BW43	2002	2033498.2	6113.5	5026.9	19819757	8211	Coal	Coal	0.12
WY	4158	Dave Johnston	BW44	2002	2983732.7	5853	5352.5	29081696	8054	Coal	Coal	0.12
WY	8066	Jim Bridger	BW71	2002	3906249.9	4812.8	7412.7	38072586	7463	Coal	Coal	0.12
WY	8066	Jim Bridger	BW72	2002	4132909.6	5246.3	7358.4	40285426	7995	Coal	Coal	0.12
WY	8066	Jim Bridger	BW73	2002	4640809.4	6738.1	8313.1	45232242	8451	Coal	Coal	0.12
WY	8066	Jim Bridger	BW74	2002	4040756.1	3373.6	7757.4	39383588	7840	Coal	Coal	0.12
WY	6204	Laramie River	1	2002	4931152.5	3797.7	6728.3	48061877	8241	Coal	Coal	0.12
WY	6204	Laramie River	2	2002	4987144.7	3872.9	6687	48607657	8434	Coal	Coal	0.12
WY	6204	Laramie River	3	2002	4151861.6	3463.1	5544.8	40466511	6973	Coal	Coal	0.12
WY	4162	Naughton	1	2002	1289768.9	6320.6	3365.2	12583676	7755	Coal	Coal	0.12
WY	4162	Naughton	2	2002	1621885.5	7937.6	4306.4	15835525	7515	Coal	Coal	0.12
WY	4162	Naughton	3	2002	2798255	5051.9	5240.7	28425578	8233	Coal	Coal	0.12
WY	7504	Neil Simpson II	1	2002	933115.2	704.8	785.8	9094730	8689	Coal	Coal	0.12
WY	7504	Neil Simpson II	CT1	2002	120974.1	1.8	34.8	1338417	5256	Natural Gas	Natural Gas	0.045
WY	55477	Neil Simpson II (CT2)	CT2	2002	88298.2	1.9	41.3	1485749	5097	Natural Gas	Natural Gas	0.045
WY	6101	Wyodak	BW91	2002	3661350.6	8291.2	4696.5	35685721	8625	Coal	Coal	0.12

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1311 Or "1321" Or "1411" Or "1422" Or "1423" Or "1474" Or "1475" Or "1479" Or "1481" Or "1499" Or "2813" Or "2873" Or "2874" Or "3271" Or "3272" Or "3274" Or "3275" Or "3312" Or "3331" Or "3334" Or "3341" Or "3365" Or "4911" Or "1061"

STATEFIPS	COUNTYFIPS	STATEABBREV	COUNTYNAME	FACILITYID	FACILITYNAME	STREET	CITY	STATE	ZIP
4	13	AZ	MARICOPA CO	518	MOSAIC PRINTED CIRCUITS LLC	5815 S 25TH ST	PHOENIX	AZ	85040-
4	13	AZ	MARICOPA CO	582	STONE CREEK INC	4221 E RAYMOND ST	PHOENIX	AZ	85040-
4	13	AZ	MARICOPA CO	562	PHOENIX NEWSPAPERS INC	22600 N 19TH AVE	PHOENIX	AZ	85027-
4	13	AZ	MARICOPA CO	552	THORNWOOD FURNITURE MFG	5125 E MADISON ST	PHOENIX	AZ	85034-
4	13	AZ	MARICOPA CO	545	ROCKFORD CORPORATION	546 S ROCKFORD DR	TEMPE	AZ	85281-
4	13	AZ	MARICOPA CO	544	FLEETWOOD HOMES OF ARIZONA INC #21	6112 N 56TH AVE	GLENDALE	AZ	85311-
4	13	AZ	MARICOPA CO	532	TRADE PRINTERS INC	2122 W SHANGRI-LA RD	PHOENIX	AZ	85029-
4	13	AZ	MARICOPA CO	89	UNITED MODULAR	5301 W MADISON ST	PHOENIX	AZ	85043-
4	13	AZ	MARICOPA CO	52382	OCOTILLO POWER PLANT	1500 E UNIVERSITY DR	TEMPE	AZ	85281-
4	13	AZ	MARICOPA CO	69	PHOENIX HEAT TREATING INC	2405 W MOHAVE RD	PHOENIX	AZ	85009-6413
4	13	AZ	MARICOPA CO	508	SAMUEL LAWRENCE FURNITURE COMPANY	601 S 65TH AVE	PHOENIX	AZ	85043-
4	13	AZ	MARICOPA CO	458	BRYANT INDUSTRIES INC	788 W ILLINI ST	PHOENIX	AZ	85041-
4	13	AZ	MARICOPA CO	4384	WESTERN SHUTTER LLC	4038 E MADISON ST	PHOENIX	AZ	85034-
4	13	AZ	MARICOPA CO	4360	LITHO TECH INC	2020 N 22ND AVE	PHOENIX	AZ	85009-
4	13	AZ	MARICOPA CO	43135	ARIZONA PACIFIC SPAS	210 N 24TH ST	PHOENIX	AZ	85034-
4	13	AZ	MARICOPA CO	4278	SCOTTSDALE SHUTTERS INC	16087 N 80TH ST	SCOTTSDALE	AZ	85260-
4	13	AZ	MARICOPA CO	529	HIGHLAND PRODUCTS INC	43 N 48TH AVE	PHOENIX	AZ	85043-
4	13	AZ	MARICOPA CO	779	G & G PRINTERS INC	10201 N 21ST AVE	PHOENIX	AZ	85021-
4	13	AZ	MARICOPA CO	3536	HOLSUM BAKERY INC	2322 W LINCOLN ST	PHOENIX	AZ	85009-5827
4	13	AZ	MARICOPA CO	83	METAL-WELD SPECIALTIES INC	8137 N 83RD AVE	PEORIA	AZ	85345-
4	13	AZ	MARICOPA CO	827	VALLEY INDUSTRIAL PAINTING	1131 W WATKINS ST	PHOENIX	AZ	85007-
4	13	AZ	MARICOPA CO	826	LAMINATE TECHNOLOGY CORP	1104 W GENEVA DR	TEMPE	AZ	85282-
4	13	AZ	MARICOPA CO	813	KELLY MOORE PAINT CO INC	905 W ALAMEDA DR	TEMPE	AZ	85282-
4	13	AZ	MARICOPA CO	790	INTESYS TECHNOLOGIES INC	500 S 52ND ST	TEMPE	AZ	85281-7243
4	13	AZ	MARICOPA CO	62	MASTERCRAFT CABINETS INC	305 S BROOKS	MESA	AZ	85202-
4	13	AZ	MARICOPA CO	782	TREFFERS PRECISION INC	1021 N 22ND AVE	PHOENIX	AZ	85009-
4	13	AZ	MARICOPA CO	654	IRONWOOD LITHOGRAPHERS INC	455 S 52ND ST	TEMPE	AZ	85281-
4	13	AZ	MARICOPA CO	777	INSULFOAM	3401 W COCOPAH ST	PHOENIX	AZ	85009-
4	13	AZ	MARICOPA CO	744	M E GLOBAL INC	5857 S KYRENE RD	TEMPE	AZ	85283-1731
4	13	AZ	MARICOPA CO	733	PAN-GLO WEST	2401 W SHERMAN ST	PHOENIX	AZ	85009-
4	13	AZ	MARICOPA CO	72	WOODSTUFF MANUFACTURING INC	1635 S 43RD AVE	PHOENIX	AZ	85009-6026
4	13	AZ	MARICOPA CO	70	PARKER HANNIFIN CSS DIV/TEMPE PLANT	708 W 22ND ST	TEMPE	AZ	85282-
4	13	AZ	MARICOPA CO	693	MUNTERS CORP	802 S 59TH AVE	PHOENIX	AZ	85043-
4	13	AZ	MARICOPA CO	41751	GCR TRUCK TIRE CENTER	2815 N 32ND AVE	PHOENIX	AZ	85009-
4	13	AZ	MARICOPA CO	788	KIRKWOOD SHUTTERS LTD	22201 N 24TH AVE	PHOENIX	AZ	85027-
4	13	AZ	MARICOPA CO	3691	SUPREME OIL CO	2110 GRAND AVE	PHOENIX	AZ	85009-
4	13	AZ	MARICOPA CO	419	PARKER HANNIFIN GTFSD	7777 N GLEN HARBOR BLVD	GLENDALE	AZ	85307-
4	13	AZ	MARICOPA CO	388	STOROPACK INC	77 N 45TH AVE	PHOENIX	AZ	85043-
4	13	AZ	MARICOPA CO	38731	CLAYTON HOMES-EL MIRAGE	12345 W BUTLER DR	EL MIRAGE	AZ	85335-
4	13	AZ	MARICOPA CO	3802	HOLSUM BAKERY/TEMPE	710 W GENEVA DR	TEMPE	AZ	85252-
4	13	AZ	MARICOPA CO	3773	REDSTONE INDUSTRIES INC	5820 W SAN MIGUEL AVE	GLENDALE	AZ	85301-
4	13	AZ	MARICOPA CO	376	WESTERN PACKAGING	6051 N 56TH AVE	GLENDALE	AZ	85301-
4	13	AZ	MARICOPA CO	3966	INTEL CORP-OCOTILLO CAMPUS (FAB 12)	4500 S DOBSON RD	CHANDLER	AZ	85248-
4	13	AZ	MARICOPA CO	36939	NATURALLY VITAMIN	14810 N 73RD ST	SCOTTSDALE	AZ	85260-
4	13	AZ	MARICOPA CO	3976	CHOLLA CUSTOM CABINETS INC	1727 E DEER VALLEY DR	PHOENIX	AZ	85024-5604
4	13	AZ	MARICOPA CO	365	GAYLORD CONTAINER CORP	4932 W COLTER ST	GLENDALE	AZ	85301-
4	13	AZ	MARICOPA CO	36485	BILLBOARD POSTER COMPANY INC	3940 W MONTECITO AVE	PHOENIX	AZ	85019-
4	13	AZ	MARICOPA CO	363	THUNDERBIRD FURNITURE	7501 E REDFIELD RD	SCOTTSDALE	AZ	85260-3403
4	13	AZ	MARICOPA CO	36224	EARNHARDT DODGE AUTO BODY	1301 N COLORADO ST	GILBERT	AZ	85234-
4	13	AZ	MARICOPA CO	35541	ALLIED TUBE & CONDUIT CORP-PHX OPERATION	2525 N 27TH AVE	PHOENIX	AZ	85009-
4	13	AZ	MARICOPA CO	355	HONEYWELL INTERNATIONAL INC	111 S 34TH ST	PHOENIX	AZ	85034-
4	13	AZ	MARICOPA CO	354	IMSAMET OF ARIZONA	3829 S ESTRELLA PKWY	GOODYEAR	AZ	85338-
4	13	AZ	MARICOPA CO	3744	DESERT SUN FIBERGLASS SYSTEMS LTD	21412 N 14TH AVE	PHOENIX	AZ	85027-
4	13	AZ	MARICOPA CO	4028	B & D LITHO INC	3820 N 38TH AVE	PHOENIX	AZ	85019-
4	13	AZ	MARICOPA CO	937	THE HEIL COMPANY	1500 S 7TH ST	PHOENIX	AZ	85034-
4	13	AZ	MARICOPA CO	4175	SFPP LP	49 N 53RD AVE	PHOENIX	AZ	85043-
4	13	AZ	MARICOPA CO	4131	ST MICROELECTRONICS	1000 E BELL RD	PHOENIX	AZ	85022-
4	13	AZ	MARICOPA CO	4111	MAGIC WOODS INC	4210 N 39TH AVE	PHOENIX	AZ	85019-
4	13	AZ	MARICOPA CO	40927	CASE PRODUCTS	1401 E JACKSON	PHOENIX	AZ	85034-2308
4	13	AZ	MARICOPA CO	4083	CHRIS FISCHER PRODUCTIONS INC	4741 W POLK ST	PHOENIX	AZ	85043-
4	13	AZ	MARICOPA CO	3953	OAKCRAFT INC	7733 W OLIVE AVE	PEORIA	AZ	85345-
4	13	AZ	MARICOPA CO	403	VAW OF AMERICA INC	249 S 51ST AVE	PHOENIX	AZ	85043-
4	13	AZ	MARICOPA CO	4182	LEGENDS FURNITURE INC	5555 N 51ST AVE	GLENDALE	AZ	85301-
4	13	AZ	MARICOPA CO	40236	TEAM FORMS	2002 N 23RD AVE	PHOENIX	AZ	85009-
4	13	AZ	MARICOPA CO	40233	CITY OF SCOTTSDALE/WATER SERVICES DIV	16800 N HAYDEN RD	SCOTTSDALE	AZ	85261-
4	13	AZ	MARICOPA CO	4023	CREATIVE SHUTTERS INC	2009 W IRONWOOD DR	PHOENIX	AZ	85021-
4	13	AZ	MARICOPA CO	40222	HEXCEL SATELLITE PRODUCTS	1331 W HOUSTON AVE	GILBERT	AZ	85233-
4	13	AZ	MARICOPA CO	4007	PRECISION TRUCK PAINTING & REPAIR INC	2212 N 27TH AVE	PHOENIX	AZ	85009-
4	13	AZ	MARICOPA CO	3982	O'NEIL PRINTING INC	366 N 2ND AVE	PHOENIX	AZ	85003-
4	13	AZ	MARICOPA CO	3978	TEAM TWO DESIGN ASSOC INC	310 S 43RD AVE	PHOENIX	AZ	85009-

STATEFIPS	COUNTYFIPS	STATEABBREV	COUNTYNAME	FACILITYID	FACILITYNAME	STREET	CITY	STATE	ZIP
4	13	AZ	MARICOPA CO	4050	PILLSBURY BAKERIES & FOOD SERVICE	1120 W FAIRMONT DR	TEMPE	AZ	85282-
4	19	AZ	PIMA CO	0081	EL PASO NATURAL GAS	Unknown	UNKNOWN	AZ	00000
4	21	AZ	PINAL CO	0349	UNITED METRO MATERIALS, INC._PLANT # 47	Unknown	UNKNOWN	AZ	00000
4	21	AZ	PINAL CO	0164	SUNBELT REFINING CO. (HUNTWAY REFINING)	Unknown	UNKNOWN	AZ	00000
4	21	AZ	PINAL CO	0072	BIOSPHERE II, ENERGY CENTRE	Unknown	UNKNOWN	AZ	00000
4	19	AZ	PIMA CO	0425	TUCSON ELECTRIC POWER COMPANY (TEP)	Unknown	UNKNOWN	AZ	00000
4	19	AZ	PIMA CO	0401900699	SIERRITA MINE	6200 W. DUVAL MINE ROAD	GREEN VALLEY	AZ	856220527
4	19	AZ	PIMA CO	0401900310	ARIZONA PORTLAND CEMENT COMPANY	11115 N.CASA GRANDE HIGHWAY	RILLITO	AZ	85654
4	13	AZ	MARICOPA CO	881	MOTOROLA INC	1300 N ALMA SCHOOL RD	CHANDLER	AZ	85224-
4	19	AZ	PIMA CO	0082	IRVINGTON	Not Available	UNKNOWN	AZ	UNKNOWN
4	21	AZ	PINAL CO	U118	SAGUARO	Not Available	UNKNOWN	AZ	UNKNOWN
4	17	AZ	NAVAJO CO	0401701020	CHOLLA FLYASH	FOUR CORNERS CHOLLA PLANT	JOSEPH CITY	AZ	86032
4	17	AZ	NAVAJO CO	0401700776	PEN ROB LANDFILL	4 MILES NORTH I-40 ON PORTER D	JOSEPH CITY	AZ	86032
4	17	AZ	NAVAJO CO	0401700424	ABITIBI CONSOLIDATED SNOWFLAKE DIVISION	15 M.W.OF SNWFLK ON SPUR 277	SNOWFLAKE	AZ	85937
4	17	AZ	NAVAJO CO	0076	HATCH CONST. - STANSTEEL PLT MODLE #732	Unknown	UNKNOWN	AZ	00000
4	17	AZ	NAVAJO CO	0027	HATCH CONST.- STANSTEEL PLT MODLE #628	Unknown	UNKNOWN	AZ	00000
4	17	AZ	NAVAJO CO	0001	CHOLLA	Not Available	UNKNOWN	AZ	UNKNOWN
4	19	AZ	PIMA CO	0086	GRANITE CONSTRUCTION	Unknown	UNKNOWN	AZ	00000
4	25	AZ	YAVAPAI CO	0402501199	SELIGMAN COMPRESSOR STATION	9 MI EAST OF SELIGMAN	SELIGMAN	AZ	85337
4	1	AZ	APACHE CO	0034	TRANSWESTERN PIPELINE COMPANY	Unknown	UNKNOWN	AZ	00000
4	27	AZ	YUMA CO	U120	YUCCA	Not Available	UNKNOWN	AZ	UNKNOWN
4	27	AZ	YUMA CO	0404	CONDOR SEED PRODUCTION INC.	Unknown	UNKNOWN	AZ	00000
4	27	AZ	YUMA CO	0402702388	COPPER MOUNTAIN LANDFILL	AVENUE 35E & COUNTY 12TH ST.	WELLTON	AZ	85356
4	27	AZ	YUMA CO	0402700141	YUMA COGENERATION ASSOCIATES	280 N. 27TH DRIVE	YUMA	AZ	85364
4	27	AZ	YUMA CO	0331	ARIZONA PUBLIC SERVICE COMPANY (APS)	Unknown	UNKNOWN	AZ	00000
4	21	AZ	PINAL CO	0350	UNITED METRO MATERIALS, INC.(49)	Unknown	UNKNOWN	AZ	00000
4	25	AZ	YAVAPAI CO	0698	CHEMICAL LIME CO., AKA: CHEMSTAR LIME, I	Unknown	UNKNOWN	AZ	00000
4	21	AZ	PINAL CO	0402101392	BHP COPPER- SAN MANUEL OPERATIONS	200 SOUTH REDDINGTON ROAD	SAN MANUEL	AZ	85631
4	25	AZ	YAVAPAI CO	0402500864	GRAY WOLF REGIONAL LANDFILL	23355 EAST HIGHWAY 169, MP 11	DEWEY	AZ	86327
4	25	AZ	YAVAPAI CO	0402500701	PRINTPACK INC	6800 E 2ND ST	PRESCOTT VALLEY	AZ	86314
4	25	AZ	YAVAPAI CO	0402500421	PHOENIX CEMENT	CEMENT PLANT RD	CLARKDALE	AZ	86324
4	25	AZ	YAVAPAI CO	0402500405	PHELPS DODGE BAGDAD, INC.	TERMINUS OF HIGHWAY 96	BAGDAD	AZ	86321
4	25	AZ	YAVAPAI CO	0326	US VETERAN'S ADMINISTRATION (USVA)	Unknown	UNKNOWN	AZ	00000
4	25	AZ	YAVAPAI CO	0037	ASPHALT PAVING & SUPPLY	Unknown	UNKNOWN	AZ	00000
4	15	AZ	Mohave County	0401501232	NORTH STAR STEEL ARIZONA	3000 HWY 66 SOUTH	KINGMAN	AZ	86413
4	27	AZ	YUMA CO	0154	WESTERN ROCK PRODUCTS AZTEC QUARRY	Unknown	UNKNOWN	AZ	00000
4	13	AZ	MARICOPA CO	996	CHAPMAN CHEVROLET ISUZU INC	1717 E BASELINE RD	TEMPE	AZ	85283-
4	15	AZ	Mohave County	1115	ADVANTAGE BOATS, INC.	Unknown	UNKNOWN	AZ	00000
4	13	AZ	MARICOPA CO	R-07	United Metro Materials - McKellips Concrete Plant	Dobson & McKellips	Scottsdale	AZ	85256
4	13	AZ	MARICOPA CO	R-06	CalMat Arizona - Higley Asphalt Plant	Higley & Dobson	Mesa	AZ	85215
4	13	AZ	MARICOPA CO	R-05	CalMat Arizona - Mesa Asphalt Plant	1900 Longmore	Mesa	AZ	85201
4	13	AZ	MARICOPA CO	R-04	United Metro Materials - Beeline Asphalt Plant	Beeline Highway & McDowell Rd	Scottsdale	AZ	85256
4	13	AZ	MARICOPA CO	R-03	North Center Street Landfill	13602 E. Beeline Highway	Scottsdale	AZ	85256
4	13	AZ	MARICOPA CO	R-09	United Metro Materials - Beeline Concrete Plant	Beeline Highway & McDowell Rd.	Scottsdale	AZ	85256
4	13	AZ	MARICOPA CO	R-01	Salt River Landfill	13602 E. Beeline Highway	Scottsdale	AZ	85256
4	13	AZ	MARICOPA CO	R-10	CalMat Arizona - Mesa Concrete Plant	1900 Longmore	Mesa	AZ	85201
4	13	AZ	MARICOPA CO	991	RANDALLS VIP TRAILERS INC	17066 S 54TH ST	CHANDLER	AZ	85226-
4	13	AZ	MARICOPA CO	983	ISOLA LAMINATE SYSTEMS CORP	165 S PRICE RD	CHANDLER	AZ	85224-
4	13	AZ	MARICOPA CO	98	PALO VERDE NUCLEAR GENERATING STATION	5801 S WINTERSBURG RD	TONOPAH	AZ	85354-7529
4	13	AZ	MARICOPA CO	975	BUSE PRINTING & ADVERTISING	1616 E HARVARD ST	PHOENIX	AZ	85006-
4	13	AZ	MARICOPA CO	971	MECHTRONICS OF ARIZONA CORP	1601 E BROADWAY RD	PHOENIX	AZ	85040-2499
4	13	AZ	MARICOPA CO	961	BIG SURF	1500 N MCCLINTOCK DR	TEMPE	AZ	85281-
4	13	AZ	MARICOPA CO	948	NESCO MFG INC	1510 W DRAKE DR	TEMPE	AZ	85283-
4	13	AZ	MARICOPA CO	R-02	Tri-Cities Landfill	13602 E. Beeline Highway	Scottsdale	AZ	85256
4	15	AZ	Mohave County	0177	ARCO PRODUCTS-ROBERT L. & SHIRLEY WALKER	Unknown	UNKNOWN	AZ	00000
4	27	AZ	YUMA CO	1054	YUMA REGIONAL MEDICAL CENTER	Unknown	UNKNOWN	AZ	00000
4	15	AZ	Mohave County	0401501041	DUTCH FLAT COMPRESSOR STATION	NEAR LAKE HAVASU	LAKE HAVASU	AZ	86401
4	15	AZ	Mohave County	0401500815	MOJAVE TOPOCK COMPRESSOR STATION	5499 WEST NEEDLE MOUNTAIN ROAD	TOPOCK	AZ	86436
4	15	AZ	Mohave County	0401500522	HACKBERRY COMPRESSOR STATION	18 MILES EAST OF KINGMAN	KINGMAN	AZ	86471
4	15	AZ	Mohave County	0401500229	ARIZONA PROVING GROUND	#1 PROVING GROUND ROAD	YUCCA	AZ	86438
4	15	AZ	Mohave County	0238	MCCULLOCH CORP.	Unknown	UNKNOWN	AZ	00000
4	13	AZ	MARICOPA CO	R-08	United Metro Materials - Higley Concrete Plant	Higley & Thomas	Mesa	AZ	85215
4	15	AZ	Mohave County	0178	ARCO PRODUCTS-PRESTIGE STATIONS INC.	Unknown	UNKNOWN	AZ	00000
4	15	AZ	Mohave County	0402	POTTERS INDUSTRIES, INC.	Unknown	UNKNOWN	AZ	00000
4	15	AZ	Mohave County	0131	TRANSWESTERN PIPELINE COMPANY	Unknown	UNKNOWN	AZ	00000
4	13	AZ	MARICOPA CO	R-16	Salt River Sand & Rock - Beeline Facility	P.O. Box 728	Scottsdale	AZ	85256
4	13	AZ	MARICOPA CO	R-15	Salt River Sand & Rock - Dobson Facility	P.O. Box 728	Scottsdale	AZ	85256
4	13	AZ	MARICOPA CO	R-14	Salt River Sand & Rock - Higley Facility	P.O. Box 728	Scottsdale	AZ	85256
4	13	AZ	MARICOPA CO	R-13	United Metro Materials - Beeline Crushing Plant	Beeline Highway & McDowell Rd.	Scottsdale	AZ	85256
4	13	AZ	MARICOPA CO	R-12	Sunward Materials	1901 N. Alma School Rd.	Mesa	AZ	85201
4	13	AZ	MARICOPA CO	R-11	CalMat Arizona - Higley Concrete Plant	Higley & Dobson	Mesa	AZ	85215
4	15	AZ	Mohave County	0236	KINGMAN REGIONAL MEDICAL CENTER	Unknown	UNKNOWN	AZ	00000
4	13	AZ	MARICOPA CO	1075	91ST AVE WASTEWATER TREATMENT PLANT	5615 S 91ST AVE	TOLLESON	AZ	85353-

'1479" Or "1481" Or "1499" Or "2813" Or "2873" Or "2874" Or "3271" Or "3272" Or "327

FACILITYID	FACILITYNAME	FACILITYADDRESS	EPAREGION	INVNETORYYEAR	SIC	LATITUDE	LONGITUDE	CO	NH3	NOX	PMCON	PMFIL
518	MOSAIC PRINTED CIRCUITS LLC	5815 S 25TH ST PHOENIX AZ 85040-	9	1999	3672	34.6091	-86.9706		0.01			
582	STONE CREEK INC	4221 E RAYMOND ST PHOENIX AZ 85040-	9	1999	2511	34.6343	-87.0218				0.002	
562	PHOENIX NEWSPAPERS INC	22600 N 19TH AVE PHOENIX AZ 85027-	9	1999	2711	34.6433	-87.0415	0.148		0.232	0.009	
552	THORNWOOD FURNITURE MFG	5125 E MADISON ST PHOENIX AZ 85034-	9	1999	2511	34.3421	-86.9011				2.012	
545	ROCKFORD CORPORATION	546 S ROCKFORD DR TEMPE AZ 85281-	9	1999	3672	34.6199	-87.0807					
544	FLEETWOOD HOMES OF ARIZONA INC #21	6112 N 56TH AVE GLENDALE AZ 85311-	9	1999	2451	34.5973	-86.9607					
532	TRADE PRINTERS INC	2122 W SHANGRI-LA RD PHOENIX AZ 85029-	9	1999	2761	34.6163	-87.0175					
89	UNITED MODULAR	5301 W MADISON ST PHOENIX AZ 85043-	9	1999	2452	34.6316	-87.0415				0.003	
52382	OCOTILLO POWER PLANT	1500 E UNIVERSITY DR TEMPE AZ 85281-	9	1999	4911	34.6422	-87.0643	82.787	8.561	555.776	16.585	
69	PHOENIX HEAT TREATING INC	2405 W MOHAVE RD PHOENIX AZ 85009-6413	9	1999	3398	34.6091	-86.9716	1.182	3.243	1.407	0.08	
508	SAMUEL LAWRENCE FURNITURE COMPANY	601 S 65TH AVE PHOENIX AZ 85043-	9	1999	2511	32.3948	-86.3164	0.022		0.026	2.858	
458	BRYANT INDUSTRIES INC	788 W ILLINI ST PHOENIX AZ 85041-	9	1999	2431	32.4163	-86.2982				0.007	
4384	WESTERN SHUTTER LLC	4038 E MADISON ST PHOENIX AZ 85034-	9	1999	2431	32.3833	-86.3675				0.016	
4360	LITHO TECH INC	2020 N 22ND AVE PHOENIX AZ 85009-	9	1999	2752	32.3947	-86.3058					
43135	ARIZONA PACIFIC SPAS	210 N 24TH ST PHOENIX AZ 85034-	9	1999	3088	32.4019	-86.3089					
4278	SCOTTSDALE SHUTTERS INC	16087 N 80TH ST SCOTTSDALE AZ 85260-	9	1999	2431	32.2327	-86.2142					
529	HIGHLAND PRODUCTS INC	43 N 48TH AVE PHOENIX AZ 85043-	9	1999	3086	34.6009	-86.9575	0.761		0.906	0.052	
779	G & G PRINTERS INC	10201 N 21ST AVE PHOENIX AZ 85021-	9	1999	2752	34.6379	-87.096					
3536	HOLSUM BAKERY INC	2322 W LINCOLN ST PHOENIX AZ 85009-5827	9	1999	2051	30.7144	-88.0919	7.249		8.63	0.492	
83	METAL-WELD SPECIALTIES INC	8137 N 83RD AVE PEORIA AZ 85345-	9	1999	3446	34.6307	-87.0022					
827	VALLEY INDUSTRIAL PAINTING	1131 W WATKINS ST PHOENIX AZ 85007-	9	1999	3479	34.6307	-87.0175					
826	LAMINATE TECHNOLOGY CORP	1104 W GENEVA DR TEMPE AZ 85282-	9	1999	3672	34.6199	-86.9869	1.924		2.289	0.129	
813	KELLY MOORE PAINT CO INC	905 W ALAMEDA DR TEMPE AZ 85282-	9	1999	2851	34.6397	-87.0731					
790	INTESYS TECHNOLOGIES INC	500 S 52ND ST TEMPE AZ 85281-7243	9	1999	3479	34.6406	-87.0415	0.308		0.366	0.021	
62	MASTERCRAFT CABINETS INC	305 S BROOKS MESA AZ 85202-	9	1999	2434	34.5946	-86.9531	0.116		0.138	0.089	
782	TREFFERS PRECISION INC	1021 N 22ND AVE PHOENIX AZ 85009-	9	1999	3471	34.6352	-87.0349		0.85			
654	IRONWOOD LITHOGRAPHERS INC	455 S 52ND ST TEMPE AZ 85281-	9	1999	2752	34.5486	-86.9826					
777	INSULFOAM	3401 W COCOPAH ST PHOENIX AZ 85009-	9	1999	3086	34.6154	-87.0622	0.882		1.05	0.06	
744	M E GLOBAL INC	5857 S KYRENE RD TEMPE AZ 85283-1731	9	1999	3325	34.6073	-86.9651	47.672		8.99	17.634	
733	PAN-GLO WEST	2401 W SHERMAN ST PHOENIX AZ 85009-	9	1999	7699	34.637	-87.0371	0.527		0.628	0.036	
72	WOODSTUFF MANUFACTURING INC	1635 S 43RD AVE PHOENIX AZ 85009-6026	9	1999	2511	34.4242	-86.9238	0.13		0.155	3.826	
70	PARKER HANNIFIN CSS DIV/TEMPE PLANT	708 W 22ND ST TEMPE AZ 85282-	9	1999	3053	34.6055	-86.9651					
693	MUNTERS CORP	802 S 59TH AVE PHOENIX AZ 85043-	9	1999	3585	34.5901	-86.9498	0.15		0.179	0.01	
41751	GCR TRUCK TIRE CENTER	2815 N 32ND AVE PHOENIX AZ 85009-	9	1999	7534	32.4291	-86.3364				1.198	
788	KIRKWOOD SHUTTERS LTD	22201 N 24TH AVE PHOENIX AZ 85027-	9	1999	2431	34.6181	-87.0393		0.001		0.107	
3691	SUPREME OIL CO	2110 GRAND AVE PHOENIX AZ 85009-	9	1999	5171	31.7171	-87.2153					
419	PARKER HANNIFIN GTFSD	7777 N GLEN HARBOR BLVD GLENDALE AZ 85307-	9	1999	3724	32.3007	-86.4414					
388	STOROPACK INC	77 N 45TH AVE PHOENIX AZ 85043-	9	1999	3086	32.3932	-86.0708	0.131		0.156	0.009	
38731	CLAYTON HOMES-EL MIRAGE	12345 W BUTLER DR EL MIRAGE AZ 85335-	9	1999	2451	32.3526	-86.3571				0.043	
3802	HOLSUM BAKERY/TEMPE	710 W GENEVA DR TEMPE AZ 85252-	9	1999	2051	32.4015	-86.4025	0.92		1.095	0.062	
3773	REDSTONE INDUSTRIES INC	5820 W SAN MIGUEL AVE GLENDALE AZ 85301-	9	1999	3089	32.3527	-86.3837					
376	WESTERN PACKAGING	6051 N 56TH AVE GLENDALE AZ 85301-	9	1999	2671	32.3929	-86.3079					
3966	INTEL CORP-OCOTILLO CAMPUS (FAB 12)	4500 S DOBSON RD CHANDLER AZ 85248-	9	1999	3674	32.4118	-86.1472	6.049	2.005	9.461	0.549	
36939	NATURALLY VITAMIN	14810 N 73RD ST SCOTTSDALE AZ 85260-	9	1999	2834	32.3759	-86.3399	0.038		0.045	0.002	
3976	CHOLLA CUSTOM CABINETS INC	1727 E DEER VALLEY DR PHOENIX AZ 85024-5604	9	1999	2434	32.2327	-86.2142				0.025	
365	GAYLORD CONTAINER CORP	4932 W COLTER ST GLENDALE AZ 85301-	9	1999	2653	31.569	-87.2813	1.99	0.656	2.369	0.951	
36485	BILLBOARD POSTER COMPANY INC	3940 W MONTECITO AVE PHOENIX AZ 85019-	9	1999	7312	31.7316	-87.21					
363	THUNDERBIRD FURNITURE	7501 E REDFIELD RD SCOTTSDALE AZ 85260-3403	9	1999	2511	31.5176	-87.2959				0.045	
36224	EARNHARDT DODGE AUTO BODY	1301 N COLORADO ST GILBERT AZ 85234-	9	1999	7532	31.4577	-87.4094	0.083		0.098	0.006	
35541	ALLIED TUBE & CONDUIT CORP-PHX OPERATION	2525 N 27TH AVE PHOENIX AZ 85009-	9	1999	3317	31.5056	-87.3938	0.345		0.411	0.024	
355	HONEYWELL INTERNATIONAL INC	111 S 34TH ST PHOENIX AZ 85034-	9	1999	3724	31.5819	-87.49	31.362	0.496	76.548	0.686	
354	IMSAMET OF ARIZONA	3829 S ESTRELLA PKWY GOODYEAR AZ 85338-	9	1999	3341	31.5266	-87.2728	94.17		18.396	12.688	
3744	DESERT SUN FIBERGLASS SYSTEMS LTD	21412 N 14TH AVE PHOENIX AZ 85027-	9	1999	3089	32.3527	-86.3805					
4028	B & D LITHO INC	3820 N 38TH AVE PHOENIX AZ 85019-	9	1999	2752	32.3059	-86.3989					
937	THE HEIL COMPANY	1500 S 7TH ST PHOENIX AZ 85034-	9	1999	3799	34.564	-86.976					
4175	SFPP LP	49 N 53RD AVE PHOENIX AZ 85043-	9	1999	4226	32.276	-86.3704	5.506		3.905		
4131	ST MICROELECTRONICS	1000 E BELL RD PHOENIX AZ 85022-	9	1999	3674	32.3618	-86.0956	2.749	0.002	3.272	0.187	
4111	MAGIC WOODS INC	4210 N 39TH AVE PHOENIX AZ 85019-	9	1999	2512	32.4096	-86.2366					
40927	CASE PRODUCTS	1401 E JACKSON PHOENIX AZ 85034-2308	9	1999	2521	32.3165	-86.351				0.016	
4083	CHRIS FISCHER PRODUCTIONS INC	4741 W POLK ST PHOENIX AZ 85043-	9	1999	2431	32.4096	-86.2334				0.032	
3953	OAKCRAFT INC	7733 W OLIVE AVE PEORIA AZ 85345-	9	1999	2434	32.2921	-86.3416	0.072		0.086	0.061	
403	VAW OF AMERICA INC	249 S 51ST AVE PHOENIX AZ 85043-	9	1999	3354	32.4142	-86.412	11.887		17.023	9.879	
4182	LEGENDS FURNITURE INC	5555 N 51ST AVE GLENDALE AZ 85301-	9	1999	2511	32.3685	-86.3017				0.176	
40236	TEAM FORMS	2002 N 23RD AVE PHOENIX AZ 85009-	9	1999	2752	32.3929	-86.3058					
40233	CITY OF SCOTTSDALE/WATER SERVICES DIV	16800 N HAYDEN RD SCOTTSDALE AZ 85261-	9	1999	9511	32.3716	-86.3761	11.492		8.202	0.065	
4023	CREATIVE SHUTTERS INC	2009 W IRONWOOD DR PHOENIX AZ 85021-	9	1999	2431	32.2651	-86.3588				0.001	
40222	HEXCEL SATELLITE PRODUCTS	1331 W HOUSTON AVE GILBERT AZ 85233-	9	1999	3663	32.3962	-86.108					
4007	PRECISION TRUCK PAINTING & REPAIR INC	2212 N 27TH AVE PHOENIX AZ 85009-	9	1999	3479	32.3791	-86.4335					
3982	O'NEIL PRINTING INC	366 N 2ND AVE PHOENIX AZ 85003-	9	1999	2752	32.3553	-86.3571					
3978	TEAM TWO DESIGN ASSOC INC	310 S 43RD AVE PHOENIX AZ 85009-	9	1999	2511	32.3157	-86.2193				0.003	

FACILITYID	FACILITYNAME	FACILITYADDRESS	EPAREGION	INVNETORYYEAR	SIC	LATITUDE	LONGITUDE	CO	NH3	NOX	PMCON	PMFIL
4050	PILLSBURY BAKERIES & FOOD SERVICE	1120 W FAIRMONT DR TEMPE AZ 85282-	9	1999	2051	32.4114	-86.2323	0.431		0.513	0.038	
0081	EL PASO NATURAL GAS	Unknown UNKNOWN AZ 00000	9	1999	4924	32.4133	-84.9971	37.57		335.92		
0349	UNITED METRO MATERIALS, INC._PLANT # 47	Unknown UNKNOWN AZ 00000	9	1999	3273	33.7468	-86.5002				0.215	
0164	SUNBELT REFINING CO. (HUNTWAY REFINING)	Unknown UNKNOWN AZ 00000	9	1999	2911	33.5877	-86.25	4.5		18.4	0.181	
0072	BIOSPHERE II, ENERGY CENTRE	Unknown UNKNOWN AZ 00000	9	1999	8733	33.9346	-86.1994	58.64			0.49	
0425	TUCSON ELECTRIC POWER COMPANY (TEP)	Unknown UNKNOWN AZ 00000	9	1999	4931	33.7341	-86.1559	7.39		26.54	57.777	
0401900699	SIERRITA MINE	6200 W. DUVAL MINE ROAD GREEN VALLEY AZ 856220527	9	1999	1021	32.1783	-85.0283	400.846		106.411	15.534	
0401900310	ARIZONA PORTLAND CEMENT COMPANY	11115 N.CASA GRANDE HIGHWAY RILLITO AZ 85654	9	1999	3241	32.2861	-85.1697	1639.8		5519	18.714	
881	MOTOROLA INC	1300 N ALMA SCHOOL RD CHANDLER AZ 85224-	9	1999	3674	34.4431	-86.9173	7.268	1.225	9.358	0.48	
0082	IRVINGTON	Not Available UNKNOWN AZ UNKNOWN	9	1999	4911	32.2193	-84.9999	146.77	8.74	2404.97	83.142	
U118	SAGUARO	Not Available UNKNOWN AZ UNKNOWN	9	1999	4911	33.6803	-86.3217	54.79	7.31	558.11	12.856	
0401701020	CHOLLA FLYASH	FOUR CORNERS CHOLLA PLANT JOSEPH CITY AZ 86032	9	1999	1499	32.4163	-84.9957		1.32		0.161	
0401700776	PEN ROB LANDFILL	4 MILES NORTH I-40 ON PORTER D JOSEPH CITY AZ 86032	9	1999	4953	32.4633	-84.9944	3.275		4.136	0.79	
0401700424	ABITIBI CONSOLIDATED SNOWFLAKE DIVISION	15 M.W.OF SNWFLK ON SPUR 277 SNOWFLAKE AZ 85937	9	1999	2611	32.4294	-84.9995	97.8		2291.119	13.119	
0076	HATCH CONST. - STANSTEEL PLT MODLE #732	Unknown UNKNOWN AZ 00000	9	1999	1521	32.4457	-84.9991				6.581	
0027	HATCH CONST.- STANSTEEL PLT MODLE #628	Unknown UNKNOWN AZ 00000	9	1999	1521	32.4309	-84.9761				4.758	
0001	CHOLLA	Not Available UNKNOWN AZ UNKNOWN	9	1999	4911	32.432	-84.9899	915.94	1.32	13183.26	667.137	
0086	GRANITE CONSTRUCTION	Unknown UNKNOWN AZ 00000	9	1999	3272	32.4971	-85.0555				4.531	
0402501199	SELIGMAN COMPRESSOR STATION	9 MI EAST OF SELIGMAN SELIGMAN AZ 85337	9	1999	4922	33.1045	-86.7621	1.16		126.37		
0034	TRANSWESTERN PIPELINE COMPANY	Unknown UNKNOWN AZ 00000	9	1999	4922	32.0446	-86.7956	159.92		1252.38	1.057	
U120	YUCCA	Not Available UNKNOWN AZ UNKNOWN	9	1999	4911	33.2119	-86.809	170.72	6.5	239.63	11.179	
0404	CONDOR SEED PRODUCTION INC.	Unknown UNKNOWN AZ 00000	9	1999	723	33.1054	-86.7578				10.808	
0402702388	COPPER MOUNTAIN LANDFILL	AVENUE 35E & COUNTY 12TH ST. WELLTON AZ 85356	9	1999	4953	33.2048	-86.868	0.016		0	0	
0402700141	YUMA COGENERATION ASSOCIATES	280 N. 27TH DRIVE YUMA AZ 85364	9	1999	4911	33.1028	-86.8007	20.797	6.5	178.216	0.818	
0331	ARIZONA PUBLIC SERVICE COMPANY (APS)	Unknown UNKNOWN AZ 00000	9	1999	4911	33.2836	-86.6917	30.31		106.55	0.469	
0350	UNITED METRO MATERIALS, INC.(49)	Unknown UNKNOWN AZ 00000	9	1999	3273	33.7503	-86.4667			0.55	0.674	
0698	CHEMICAL LIME CO., AKA: CHEMSTAR LIME, I	Unknown UNKNOWN AZ 00000	9	1999	1499	33.1055	-86.8007	866.95		1196.83		
0402101392	BHP COPPER- SAN MANUEL OPERATIONS	200 SOUTH REDDINGTON ROAD SAN MANUEL AZ 85631	9	1999	1021	33.5941	-86.2597	0.604	0.03	3.016	0.032	
0402500864	GRAY WOLF REGIONAL LANDFILL	23355 EAST HIGHWAY 169, MP 11 DEWEY AZ 86327	9	1999	4953	33.2137	-86.7811	4.978		15.157	0.057	
0402500701	PRINTPACK INC	6800 E 2ND ST PRESCOTT VALLEY AZ 86314	9	1999	2671	33.6007	-86.5086	1.26		1.49		
0402500421	PHOENIX CEMENT	CEMENT PLANT RD CLARKDALE AZ 86324	9	1999	3241	33.6031	-86.2639	203.562		2610.53	40.629	
0402500405	PHELPS DODGE BAGDAD, INC.	TERMINUS OF HIGHWAY 96 BAGDAD AZ 86321	9	1999	1021	33.5828	-86.3341	220.581		56.459	108.227	
0326	US VETERAN'S ADMINISTRATION (USVA)	Unknown UNKNOWN AZ 00000	9	1999	4953	33.7684	-86.4871			11.67	0.66	
0037	ASPHALT PAVING & SUPPLY	Unknown UNKNOWN AZ 00000	9	1999	1611	33.5922	-86.2468				1.657	
0401501232	NORTH STAR STEEL ARIZONA	3000 HWY 66 SOUTH KINGMAN AZ 86413	9	1999	3312	32.4346	-84.9845	19.954		48.674	16.111	
0154	WESTERN ROCK PRODUCTS AZTEC QUARRY	Unknown UNKNOWN AZ 00000	9	1999	1499	33.2433	-86.4569	2.68		58.75	0.274	
996	CHAPMAN CHEVROLET ISUZU INC	1717 E BASELINE RD TEMPE AZ 85283-	9	1999	5511	34.6073	-87.0382					
1115	ADVANTAGE BOATS, INC.	Unknown UNKNOWN AZ 00000	9	1999	3732	32.177	-85.0297					
R-07	United Metro Materials - McKellips Concrete Plant	Dobson & McKellips Scottsdale AZ 85256	9	1999	3273	33.1209	-88.1629				0.006	
R-06	CalMat Arizona - Higley Asphalt Plant	Higley & Dobson Mesa AZ 85215	9	1999	2951	33.3179	-87.9045	1.763		2.937	0.76	
R-05	CalMat Arizona - Mesa Asphalt Plant	1900 Longmore Mesa AZ 85201	9	1999	2951	33.3827	-87.9223	3.433		5.754	1.482	
R-04	United Metro Materials - Beeline Asphalt Plant	Beeline Highway & McDowell Rd Scottsdale AZ 85256	9	1999	2951	33.1145	-88.1735	9.099		8.62	0.394	
R-03	North Center Street Landfill	13602 E. Beeline Highway Scottsdale AZ 85256	9	1999	4953	33.3594	-88.0167	21.19		1.13	0.043	
R-09	United Metro Materials - Beeline Concrete Plant	Beeline Highway & McDowell Rd. Scottsdale AZ 85256	9	1999	3273	33.3973	-88.1203				0.071	
R-01	Salt River Landfill	13602 E. Beeline Highway Scottsdale AZ 85256	9	1999	4953	32.6019	-87.3175	18.696		26.163	7.899	
R-10	CalMat Arizona - Mesa Concrete Plant	1900 Longmore Mesa AZ 85201	9	1999	3273	33.2614	-88.0896				0.47	
991	RANDALLS VIP TRAILERS INC	17066 S 54TH ST CHANDLER AZ 85226-	9	1999	3479	34.4953	-86.8303					
983	ISOLA LAMINATE SYSTEMS CORP	165 S PRICE RD CHANDLER AZ 85224-	9	1999	3679	34.5901	-86.9727	12.939		34.784	0.068	
98	PALO VERDE NUCLEAR GENERATING STATION	5801 S WINTERSBURG RD TONOPAH AZ 85354-7529	9	1999	4911	34.6307	-87.0087	20.957	5.903	49.055	12.101	
975	BUSE PRINTING & ADVERTISING	1616 E HARVARD ST PHOENIX AZ 85006-	9	1999	2752	34.628	-87.0993					
971	MECHTRONICS OF ARIZONA CORP	1601 E BROADWAY RD PHOENIX AZ 85040-2499	9	1999	3499	34.6289	-87.0251					
961	BIG SURF	1500 N MCCLINTOCK DR TEMPE AZ 85281-	9	1999	7996	34.6046	-87.0436	1.057		7.517	0.001	
948	NESCO MFG INC	1510 W DRAKE DR TEMPE AZ 85283-	9	1999	3086	34.6605	-86.9694					
R-02	Tri-Cities Landfill	13602 E. Beeline Highway Scottsdale AZ 85256	9	1999	4953	32.447	-87.501	214.5		11.44	0.438	
0177	ARCO PRODUCTS-ROBERT L. & SHIRLEY WALKER	Unknown UNKNOWN AZ 00000	9	1999	5541	31.7921	-85.8224					
1054	YUMA REGIONAL MEDICAL CENTER	Unknown UNKNOWN AZ 00000	9	1999	8062	33.2471	-86.8175	1.31		6.55	0.158	
0401501041	DUTCH FLAT COMPRESSOR STATION	NEAR LAKE HAVASU LAKE HAVASU AZ 86401	9	1999	4922	33.1579	-85.2898	10.065		121.941	0.254	
0401500815	MOJAVE TOPOCK COMPRESSOR STATION	5499 WEST NEEDLE MOUNTAIN ROAD TOPOCK AZ 86436	9	1999	4922	33.2902	-85.474	129.351		113.342	0.141	
0401500522	HACKBERRY COMPRESSOR STATION	18 MILES EAST OF KINGMAN KINGMAN AZ 86471	9	1999	4922	33.1253	-85.5648	3.654		397.63		
0401500229	ARIZONA PROVING GROUND	#1 PROVING GROUND ROAD YUCCA AZ 86438	9	1999	8734	33.1327	-85.36	56.235		10.255	0.025	
0238	MCCULLOCH CORP.	Unknown UNKNOWN AZ 00000	9	1999	3546	33.1509	-85.514			12.08		
R-08	United Metro Materials - Higley Concrete Plant	Higley & Thomas Mesa AZ 85215	9	1999	3273	33.1426	-88.161				1.085	
0178	ARCO PRODUCTS-PRESTIGE STATIONS INC.	Unknown UNKNOWN AZ 00000	9	1999	5541	31.7961	-85.9681					
0402	POTTERS INDUSTRIES, INC.	Unknown UNKNOWN AZ 00000	9	1999	3211	32.4335	-84.9728				3.308	
0131	TRANSWESTERN PIPELINE COMPANY	Unknown UNKNOWN AZ 00000	9	1999	4922	31.865	-86.0096				0.426	
R-16	Salt River Sand & Rock - Beeline Facility	P.O. Box 728 Scottsdale AZ 85256	9	1999	1442	31.7226	-85.8148	16.01		69.87	5.937	
R-15	Salt River Sand & Rock - Dobson Facility	P.O. Box 728 Scottsdale AZ 85256	9	1999	1442	31.752	-85.8725	8.65		37.75	2.399	
R-14	Salt River Sand & Rock - Higley Facility	P.O. Box 728 Scottsdale AZ 85256	9	1999	1442	31.78	-85.982	3.61		15.76	2.285	
R-13	United Metro Materials - Beeline Crushing Plant	Beeline Highway & McDowell Rd. Scottsdale AZ 85256	9	1999	1442	31.7881	-85.9787				2.762	
R-12	Sunward Materials	1901 N. Alma School Rd. Mesa AZ 85201	9	1999	1442	31.7943	-85.9692	2.415		28.269	0.134	
R-11	CalMat Arizona - Higley Concrete Plant	Higley & Dobson Mesa AZ 85215	9	1999	3273	31.7098	-86.1263				0.119	
0236	KINGMAN REGIONAL MEDICAL CENTER	Unknown UNKNOWN AZ 00000	9	1999	8062	31.7673	-85.9695	7.14		21.87	0.454	
1075	91ST AVE WASTEWATER TREATMENT PLANT	5615 S 91ST AVE TOLLESON AZ 85353-	9	1999	4952	34.4446	-86.2708	25.238		30.149	0.427	

'1479" Or "1481" Or "1499" Or "2813" Or "2873" Or "2874" Or "3271" Or "3272" Or "327

FACILITYID	FACILITYNAME	PMPRI	PM10FIL	PM10PRI	PM25FIL	PM25PRI	SO2	VOC
518	MOSAIC PRINTED CIRCUITS LLC							15.976
582	STONE CREEK INC		0.003	0.005	0.001	0.003		19.107
562	PHOENIX NEWSPAPERS INC		0.003	0.013	0.003	0.013	0.001	11.627
552	THORNWOOD FURNITURE MFG		2.315	4.328	1.367	3.379		57.823
545	ROCKFORD CORPORATION							6.864
544	FLEETWOOD HOMES OF ARIZONA INC #21							17.342
532	TRADE PRINTERS INC							10.649
89	UNITED MODULAR		0.003	0.006	0.001	0.004		13.524
52382	OCOTILLO POWER PLANT		5.745	22.334	5.223	21.811	8.447	15.482
69	PHOENIX HEAT TREATING INC		0.027	0.107	0.027	0.107	0.009	14.047
508	SAMUEL LAWRENCE FURNITURE COMPANY		3.287	6.145	1.366	4.223		64.818
458	BRYANT INDUSTRIES INC		0.007	0.014	0.002	0.009		40.321
4384	WESTERN SHUTTER LLC		0.019	0.035	0.007	0.023		19.042
4360	LITHO TECH INC							10.192
43135	ARIZONA PACIFIC SPAS							14.546
4278	SCOTTSDALE SHUTTERS INC							6.332
529	HIGHLAND PRODUCTS INC		0.017	0.069	0.017	0.069	0.006	66.619
779	G & G PRINTERS INC							4.845
3536	HOLSUM BAKERY INC		0.164	0.656	0.164	0.656	0.052	2.493
83	METAL-WELD SPECIALTIES INC							13.702
827	VALLEY INDUSTRIAL PAINTING							10.27
826	LAMINATE TECHNOLOGY CORP		0.043	0.175	0.043	0.175	0.013	11.771
813	KELLY MOORE PAINT CO INC							2.481
790	INTESYS TECHNOLOGIES INC		0.372	0.393	0.372	0.393	0.002	25.049
62	MASTERCRAFT CABINETS INC		0.097	0.186	0.034	0.123	0.001	60.292
782	TREFFERS PRECISION INC							6.215
654	IRONWOOD LITHOGRAPHERS INC							9.624
777	INSULFOAM		0.02	0.08	0.02	0.08	0.007	51.957
744	M E GLOBAL INC		6.56	24.201	5.795	23.431	3.376	22.338
733	PAN-GLO WEST		0.012	0.048	0.012	0.048	0.004	12.844
72	WOODSTUFF MANUFACTURING INC		4.398	8.224	2.348	6.172	0.001	384.734
70	PARKER HANNIFIN CSS DIV/TEMPE PLANT							14.907
693	MUNTERS CORP		0.003	0.014	0.003	0.014	0.001	11.927
41751	GCR TRUCK TIRE CENTER		2.182	3.38	0.994	2.191		14.451
788	KIRKWOOD SHUTTERS LTD		0.124	0.231	0.053	0.161		6.348
3691	SUPREME OIL CO							6.668
419	PARKER HANNIFIN GTFSD							32.154
388	STOROPACK INC		0.003	0.012	0.003	0.012	0.001	8.937
38731	CLAYTON HOMES-EL MIRAGE		0.262	0.305	0.236	0.279		11.364
3802	HOLSUM BAKERY/TEMPE		0.021	0.083	0.021	0.083	0.007	19.796
3773	REDSTONE INDUSTRIES INC							3.057
376	WESTERN PACKAGING							6.781
3966	INTEL CORP-OCOTILLO CAMPUS (FAB 12)		0.188	0.737	0.181	0.73	0.089	15.739
36939	NATURALLY VITAMIN		0.007	0.009	0.007	0.009		7.924
3976	CHOLLA CUSTOM CABINETS INC		0.029	0.054	0.01	0.035		14.148
365	GAYLORD CONTAINER CORP		0.985	1.937	0.472	1.424	0.014	12.26
36485	BILLBOARD POSTER COMPANY INC							22.76
363	THUNDERBIRD FURNITURE		0.051	0.096	0.017	0.061		23.282
36224	EARNHARDT DODGE AUTO BODY		0.002	0.008	0.002	0.008	0.001	10.224
35541	ALLIED TUBE & CONDUIT CORP-PHX OPERATION		0.008	0.033	0.008	0.033	0.004	12.359
355	HONEYWELL INTERNATIONAL INC		3.782	4.468	3.557	4.239	15.541	63.572
354	IMSAMET OF ARIZONA		3.587	16.276	3.326	16.014	0.047	0.427
3744	DESERT SUN FIBERGLASS SYSTEMS LTD							33.645
4028	B & D LITHO INC							10.939
937	THE HEIL COMPANY							9.92
4175	SFPP LP							48.761
4131	ST MICROELECTRONICS		0.062	0.249	0.062	0.249	0.02	24.203
4111	MAGIC WOODS INC							16.49
40927	CASE PRODUCTS		0.097	0.114	0.084	0.1		10.209
4083	CHRIS FISCHER PRODUCTIONS INC		0.038	0.07	0.015	0.048		14.411
3953	OAKCRAFT INC		0.066	0.127	0.023	0.083	0.001	71.879
403	VAW OF AMERICA INC		2.781	12.663	2.341	12.223	0.472	29.409
4182	LEGENDS FURNITURE INC		0.202	0.38	0.085	0.26		80.121
40236	TEAM FORMS							10.152
40233	CITY OF SCOTTSDALE/WATER SERVICES DIV		0.133	0.199	0.133	0.199	0.012	3.589
4023	CREATIVE SHUTTERS INC		0.001	0.003	0	0.001		13.624
40222	HEXCEL SATELLITE PRODUCTS							0.052
4007	PRECISION TRUCK PAINTING & REPAIR INC							11.478
3982	O'NEIL PRINTING INC							16.367
3978	TEAM TWO DESIGN ASSOC INC		0.003	0.006	0.001	0.003		21.579

FACILITYID	FACILITYNAME	PMPRI	PM10FIL	PM10PRI	PM25FIL	PM25PRI	SO2	VOC
4050	PILLSBURY BAKERIES & FOOD SERVICE		0.035	0.073	0.024	0.062	0.003	11.96
0081	EL PASO NATURAL GAS							
0349	UNITED METRO MATERIALS, INC._PLANT # 47		2.71	2.925	2.255	2.469		
0164	SUNBELT REFINING CO. (HUNTWAY REFINING)		0.33	0.511	0.33	0.511	0.11	26.25
0072	BIOSPHERE II, ENERGY CENTRE		6.81	7.3	6.45	6.94	5.7	11.18
0425	TUCSON ELECTRIC POWER COMPANY (TEP)		64.92	122.697	19.67	77.447	112.51	
0401900699	SIERRITA MINE		144.141	159.683	53.682	69.218	59.892	41.84
0401900310	ARIZONA PORTLAND CEMENT COMPANY		239.307	258.02	105.914	124.627	9.941	5.03
881	MOTOROLA INC		3.092	3.573	3.088	3.569	0.113	15.705
0082	IRVINGTON		29.589	112.732	15.318	98.461	2861.6	27.02
U118	SAGUARO		0.867	13.725	0.867	13.725	1.2	15.35
0401701020	CHOLLA FLYASH		0.758	0.916	0.71	0.87		
0401700776	PEN ROB LANDFILL		7.89	8.68	4.594	5.385	0.266	3.13
0401700424	ABITIBI CONSOLIDATED SNOWFLAKE DIVISION		45.739	58.859	17.843	30.962	1892.94	361.189
0076	HATCH CONST. - STANSTEEL PLT MODLE #732		33.07	39.651	10.18	16.761		
0027	HATCH CONST.- STANSTEEL PLT MODLE #628		23.91	28.668	7.36	12.118		
0001	CHOLLA		956.508	1623.644	544.847	1211.983	19062.1	109.88
0086	GRANITE CONSTRUCTION		241.14	245.671	10.8	15.331	57.86	
0402501199	SELIGMAN COMPRESSOR STATION						0.12	0.68
0034	TRANSWESTERN PIPELINE COMPANY		2.16	3.217	1.52	2.577	1.09	57.97
U120	YUCCA		0.193	11.372	0.193	11.372	2.3	13.66
0404	CONDOR SEED PRODUCTION INC.		31.48	42.288	26.02	36.828		
0402702388	COPPER MOUNTAIN LANDFILL		0	0	0	0	0	37.085
0402700141	YUMA COGENERATION ASSOCIATES		12.081	12.899	11.327	12.145	6.509	4.276
0331	ARIZONA PUBLIC SERVICE COMPANY (APS)		24.91	25.379	13.52	13.989	6.07	3.74
0350	UNITED METRO MATERIALS, INC.(49)		8.6	9.274	5.635	6.308		
0698	CHEMICAL LIME CO., AKA: CHEMSTAR LIME, I						1404.61	
0402101392	BHP COPPER- SAN MANUEL OPERATIONS		0.058	0.091	0.058	0.091	0.018	0.159
0402500864	GRAY WOLF REGIONAL LANDFILL		0.701	0.758	0.588	0.646	1.009	6.653
0402500701	PRINTPACK INC		0.11	0.11	0.11	0.11	0.009	51.48
0402500421	PHOENIX CEMENT		534.886	575.51	197.349	237.974	400.9	
0402500405	PHELPS DODGE BAGDAD, INC.		242.332	350.562	110.359	218.582	20.027	41.165
0326	US VETERAN'S ADMINISTRATION (USVA)		0.22	0.88	0.22	0.88	0.15	
0037	ASPHALT PAVING & SUPPLY		15.33	16.987	2.58	4.237		
0401501232	NORTH STAR STEEL ARIZONA		29.125	45.236	25.867	41.978	2.449	1.128
0154	WESTERN ROCK PRODUCTS AZTEC QUARRY		1.15	1.424	0.471	0.745	3.91	4.7
996	CHAPMAN CHEVROLET ISUZU INC							0.871
1115	ADVANTAGE BOATS, INC.							8.91
R-07	United Metro Materials - McKellips Concrete Plant		0.07	0.076	0.02	0.026		
R-06	CalMat Arizona - Higley Asphalt Plant		4.013	4.773	1.38	2.141	2.773	0.216
R-05	CalMat Arizona - Mesa Asphalt Plant		9.127	10.61	3.159	4.641	2.165	0.42
R-04	United Metro Materials - Beeline Asphalt Plant		4.973	5.369	1.746	2.141	13.984	6.705
R-03	North Center Street Landfill		0.427	0.47	0.4	0.443	0.44	8.27
R-09	United Metro Materials - Beeline Concrete Plant		0.825	0.895	0.243	0.312		
R-01	Salt River Landfill		79.501	87.4	53.112	61.01	1.954	19.653
R-10	CalMat Arizona - Mesa Concrete Plant		5.534	6.003	1.627	2.098		
991	RANDALLS VIP TRAILERS INC							7.519
983	ISOLA LAMINATE SYSTEMS CORP		1.147	1.214	1.147	1.214	0.024	6.619
98	PALO VERDE NUCLEAR GENERATING STATION		24.115	36.221	20.291	32.395	0.996	29.697
975	BUSE PRINTING & ADVERTISING							6.691
971	MECHTRONICS OF ARIZONA CORP							1.841
961	BIG SURF		0.025	0.026	0.025	0.026	0.003	0.308
948	NESCO MFG INC							11.894
R-02	Tri-Cities Landfill		4.332	4.77	4.061	4.499	4.46	27.64
0177	ARCO PRODUCTS-ROBERT L. & SHIRLEY WALKER							37.87
1054	YUMA REGIONAL MEDICAL CENTER		0.17	0.328	0.17	0.328	0.1	
0401501041	DUTCH FLAT COMPRESSOR STATION		3.921	4.175	3.921	4.175	0.181	5.21
0401500815	MOJAVE TOPOCK COMPRESSOR STATION		2.171	2.311	2.171	2.311	0.139	26.807
0401500522	HACKBERRY COMPRESSOR STATION						0.256	1.426
0401500229	ARIZONA PROVING GROUND		0.64	0.667	0.6	0.627	0.535	5.27
0238	MCCULLOCH CORP.						2.46	
R-08	United Metro Materials - Higley Concrete Plant		12.742	13.825	3.746	4.831		
0178	ARCO PRODUCTS-PRESTIGE STATIONS INC.							18.93
0402	POTTERS INDUSTRIES, INC.		11.05	14.358	4.99	8.298		
0131	TRANSWESTERN PIPELINE COMPANY		0.87	1.296	0.62	1.046		5.29
R-16	Salt River Sand & Rock - Beeline Facility		71.456	77.39	20.021	25.957	21.19	1.86
R-15	Salt River Sand & Rock - Dobson Facility		28.354	30.75	6.795	9.193	11.45	1.01
R-14	Salt River Sand & Rock - Higley Facility		28.045	30.33	8.159	10.445	4.78	0.42
R-13	United Metro Materials - Beeline Crushing Plant		34.817	37.579	0.318	3.08		
R-12	Sunward Materials		2.73	2.865	1.706	1.842	1.899	3.303
R-11	CalMat Arizona - Higley Concrete Plant		1.395	1.514	0.41	0.529		
0236	KINGMAN REGIONAL MEDICAL CENTER		2.19	2.644	2.19	2.644	0.75	1.87
1075	91ST AVE WASTEWATER TREATMENT PLANT		1.864	2.294	1.561	1.991	24.47	2.744

STATEFIPS	COUNTYFIPS	STATEABBREV	COUNTYNAME	FACILITYID	FACILITYNAME	STREET	CITY	STATE	ZIP	FACILITYADDRESS	EPA REGION
4	27	AZ	YUMA CO	0402700141	YUMA COGENERATION ASSOCIATES	280 N. 27TH DRIVE	YUMA	AZ	85364	280 N. 27TH DRIVE YUMA AZ 85364	9
4	27	AZ	YUMA CO	U120	YUCCA	Not Available	UNKNOWN	AZ	UNKNOWN	Not Available UNKNOWN AZ UNKNOWN	9
4	1	AZ	APACHE CO	0400100059	SALT RIVER PROJECT	6MI/NE ST.JOHNS-HWY191/B-1018	ST. JOHNS	AZ	85936	6MI/NE ST.JOHNS-HWY191/B-1018 ST. JOHNS AZ 85936	9
4	27	AZ	YUMA CO	0331	ARIZONA PUBLIC SERVICE COMPANY (APS)	Unknown	UNKNOWN	AZ	00000	Unknown UNKNOWN AZ 00000	9
4	21	AZ	PINAL CO	U118	SAGUARO	Not Available	UNKNOWN	AZ	UNKNOWN	Not Available UNKNOWN AZ UNKNOWN	9
4	19	AZ	PIMA CO	0082	IRVINGTON	Not Available	UNKNOWN	AZ	UNKNOWN	Not Available UNKNOWN AZ UNKNOWN	9
4	17	AZ	NAVAJO CO	0001	CHOLLA	Not Available	UNKNOWN	AZ	UNKNOWN	Not Available UNKNOWN AZ UNKNOWN	9
4	13	AZ	MARICOPA CO	98	PALO VERDE NUCLEAR GENERATING STATION	5801 S WINTERSBURG RD	TONOPAH	AZ	85354-7529	5801 S WINTERSBURG RD TONOPAH AZ 85354-7529	9
4	13	AZ	MARICOPA CO	52382	OCOTILLO POWER PLANT	1500 E UNIVERSITY DR	TEMPE	AZ	85281-	1500 E UNIVERSITY DR TEMPE AZ 85281-	9
4	13	AZ	MARICOPA CO	3316	SRP AGUA FRIA	7302 W NORTHERN AVE	GLENDALE	AZ	85303-	7302 W NORTHERN AVE GLENDALE AZ 85303-	9
4	13	AZ	MARICOPA CO	3315	SANTAN GENERATING PLANT	1005 S VAL VISTA DR	GILBERT	AZ	85296-	1005 S VAL VISTA DR GILBERT AZ 85296-	9
4	13	AZ	MARICOPA CO	3313	APS WEST PHX POWER PLANT	4606 W HADLEY ST	PHOENIX	AZ	85043-	4606 W HADLEY ST PHOENIX AZ 85043-	9
4	5	AZ	COCONINO CO	0170	US ARMY NAVAJO DEPOT ACTIVITY	Unknown	UNKNOWN	AZ	00000	Unknown UNKNOWN AZ 00000	9
4	5	AZ	COCONINO CO	0004	NAVAJO	Not Available	UNKNOWN	AZ	UNKNOWN	Not Available UNKNOWN AZ UNKNOWN	9
4	3	AZ	COCHISE CO	0400300037	AZ ELECTRIC POWER COOPERATIVE INC	3525 NORTH HIGHWAY 191	COCHISE	AZ	85606	3525 NORTH HIGHWAY 191 COCHISE AZ 85606	9
4	1	AZ	APACHE CO	0400100060	TUCSON ELECTRIC POWER CO-SPRINGERVILLE	OFF RTE191,APP.15 MI SPRINGER	SPRINGERVILLE	AZ	85938	OFF RTE191,APP.15 MI SPRINGER SPRINGERVILLE AZ 85938	9
4	13	AZ	MARICOPA CO	3317	SRP KYRENE STEAM PLANT	7005 S KYRENE RD	TEMPE	AZ	85283-	7005 S KYRENE RD TEMPE AZ 85283-	9
8	123	CO	WELD CO	0023	PUBLIC SERVICE CO FORT SAINT VRAIN PLT	16805 19.5 RD	WELD CNTY	CO	80651	16805 19.5 RD WELD CNTY CO 80651	8
8	77	CO	MESA CO	0035	PUBLIC SERVICE CO FRUITA STA	158 N MESA AVE	FRUITA	CO	815210000	158 N MESA AVE FRUITA CO 815210000	8
8	77	CO	MESA CO	0239	PUBLIC SERVICE CO ROSS RIDGE STATION	SEC 31 T8S R100W	DENVER	CO	80000	SEC 31 T8S R100W DENVER CO 80000	8
8	81	CO	MOFFAT CO	0018	TRI STATE GENERATION CRAIG	2101 S RANNEY	CRAIG	CO	81626	2101 S RANNEY CRAIG CO 81626	8
8	85	CO	MONTROSE CO	0001	TRI STATE GENERATION NUCLA	30739 DD 30 RD	MONTROSE CNTY	CO	81424	30739 DD 30 RD MONTROSE CNTY CO 81424	8
8	87	CO	MORGAN CO	0011	PUBLIC SERVICE CO PAWNEE PLT	14940 RD 24	BRUSH	CO	80723	14940 RD 24 BRUSH CO 80723	8
8	89	CO	Otero County	0004	WEST PLAINS ENERGY - ROCKY FORD STATION	300 S 14TH ST (14TH & WALNUT)	ROCKY FORD	CO	81067	300 S 14TH ST (14TH & WALNUT) ROCKY FORD CO 81067	8
8	99	CO	PROWERS CO	0006	LAMAR UTILITIES BOARD	100 N SECOND ST	LAMAR	CO	810522505	100 N SECOND ST LAMAR CO 810522505	8
8	101	CO	PUEBLO CO	0003	PUBLIC SERVICE CO COMANCHE PLT	2005 LIME RD	PUEBLO	CO	81006	2005 LIME RD PUEBLO CO 81006	8
8	101	CO	PUEBLO CO	0008	WEST PLAINS ENERGY - PUEBLO STATION	105 SOUTH VICTORIA	PUEBLO	CO	81003	105 SOUTH VICTORIA PUEBLO CO 81003	8
8	123	CO	WELD CO	0250	THERMO COGEN PARTNERSHIP FT LUPTON	6501 ROAD 31	FORT LUPTON	CO	80621	6501 ROAD 31 FORT LUPTON CO 80621	8
8	123	CO	WELD CO	0014	PUBLIC SERVICE CO FT LUPTON STATION	SEC 33 T2N R66W	FORT LUPTON	CO	80621	SEC 33 T2N R66W FORT LUPTON CO 80621	8
8	123	CO	WELD CO	0126	THERMO POWER & ELEC INC	510 18TH ST	GREELEY	CO	80631	510 18TH ST GREELEY CO 80631	8
8	77	CO	MESA CO	0002	PUBLIC SERVICE CO CAMEO PLT	NW SEC 34 T10S R98W	PALISADE	CO	81526	NW SEC 34 T10S R98W PALISADE CO 81526	8
8	107	CO	ROUTT CO	0001	PUBLIC SERVICE CO HAYDEN PLT	US HWY 40 - 12795 E YUTE	HAYDEN	CO	81639	US HWY 40 - 12795 E YUTE HAYDEN CO 81639	8
8	13	CO	BOULDER CO	0001	PUBLIC SERVICE CO - VALMONT	1800 N 63RD ST	BOULDER	CO	80301	1800 N 63RD ST BOULDER CO 80301	8
8	69	CO	LARIMER CO	0053	PLATTE RIVER POWER AUTHORITY - RAWHIDE	2700 E RD 82	WELLINGTON	CO	00000-0000	2700 E RD 82 WELLINGTON CO 00000-0000	8
8	123	CO	WELD CO	0412	THERMO GREELEY INC	846 N SIXTH AVE 0.5 MI W OF US	GREELEY	CO	80621-0188	846 N SIXTH AVE 0.5 MI W OF US GREELEY CO 80621-0188	8
8	1	CO	ADAMS CO	0001	PUBLIC SERVICE CO CHEROKEE PLT	6198 FRANKLIN ST	DENVER	CO	802161211	6198 FRANKLIN ST DENVER CO 802161211	8
8	3	CO	Alamosa County	0007	PUBLIC SERVICE CO ALAMOSA PLT	400 WASHINGTON ST	ALAMOSA	CO	81101	400 WASHINGTON ST ALAMOSA CO 81101	8
8	31	CO	DENVER CO	0007	PUBLIC SERVICE CO ZUNI PLT	1335 ZUNI ST	DENVER	CO	802042363	1335 ZUNI ST DENVER CO 802042363	8
8	31	CO	DENVER CO	0008	PUBLIC SERVICE CO - ARAPAHOE	2601 S PLATTE RIVER DR	DENVER	CO	802234210	2601 S PLATTE RIVER DR DENVER CO 802234210	8
8	31	CO	DENVER CO	0041	PUBLIC SERVICE CO DENVER STEAM PLT	19TH ST AT DELGANY ST	DENVER	CO	80202	19TH ST AT DELGANY ST DENVER CO 80202	8
8	41	CO	EL PASO CO	0004	COLORADO SPRINGS UTILITIES-DRAKE PLT	700 S CONEJOS ST	COLORADO SPRINGS	CO	809470001	700 S CONEJOS ST COLORADO SPRINGS CO 809470001	8
8	41	CO	EL PASO CO	0030	COLORADO SPRINGS UTILITIES - NIXON PLT	FOUNTAIN BLVD & US HWY I25	COLORADO SPRINGS	CO	808170000	FOUNTAIN BLVD & US HWY I25 COLORADO SPRINGS CO 808170000	8
8	43	CO	FREMONT CO	0003	WEST PLAINS ENERGY - W.N. CLARK STATION	550 W US HWY 50	CANON CITY	CO	81212	550 W US HWY 50 CANON CITY CO 81212	8
8	45	CO	Garfield County	0057	AMERICAN ATLAS NO 1/COLORADO GREENHOUSE	56 RD 352	RIFLE	CO	81650	56 RD 352 RIFLE CO 81650	8
8	59	CO	JEFFERSON CO	0059	PUBLIC SERVICE CO LOOKOUT CENTER	18201 W 1OTH AVE	GOLDEN	CO	804010000	18201 W 1OTH AVE GOLDEN CO 804010000	8
8	41	CO	EL PASO CO	0003	COLORADO SPRINGS UTILITIES-BIRDSALL PLT	213 NICHOLS BLVD	COLORADO SPRINGS	CO	80907	213 NICHOLS BLVD COLORADO SPRINGS CO 80907	8
8	63	CO	Kit Carson County	0003	TRI STATE GENERATION BURLINGTON	ROAD 50 & 21889 ROAD Z	BURLINGTON	CO	80807	ROAD 50 & 21889 ROAD Z BURLINGTON CO 80807	8
8	59	CO	JEFFERSON CO	1238	KN SERVICES - LAKEWOOD GENERATION FACILI	143 UNION BLVD	LAKEWOOD	CO	80228-1824	143 UNION BLVD LAKEWOOD CO 80228-1824	8
20	165	KS	RUSH CO	00001	LACROSSE MUNICIPAL POWER PLANT	202 E. 9TH	LACROSSE	KS	67548	202 E. 9TH LACROSSE KS 67548	7
20	151	KS	PRATT CO	00005	PRATT-MUNICIPAL POWER PLANT	321 W. 10TH	PRATT	KS	67124	321 W. 10TH PRATT KS 67124	7
20	155	KS	RENO CO	00033	WESTERN RESOURCES, INC. (HEC)	3200 E. 30TH	HUTCHINSON	KS	00000	3200 E. 30TH HUTCHINSON KS 00000	7
20	157	KS	REPUBLIC CO	00016	BELLEVILLE-MUNICIPAL POWER PLANT	810 M ST.	BELLEVILLE	KS	66935	810 M ST. BELLEVILLE KS 66935	7
20	159	KS	RICE CO	00024	STERLING MUNICIPAL POWER PLANT	333 NORTH BROADWAY	STERLING	KS	67579	333 NORTH BROADWAY STERLING KS 67579	7
20	167	KS	RUSSELL CO	00005	RUSSELL-MUNICIPAL POWER PLANT	9TH & ELM	RUSSELL	KS	67665	9TH & ELM RUSSELL KS 67665	7
20	163	KS	Rooks County	00014	STOCKTON-MUNICIPAL POWER PLANT	WEST HWY 24	STOCKTON	KS	67669	WEST HWY 24 STOCKTON KS 67669	7
20	149	KS	POTTAWATOMIE CO	00012	WAMEGO-MUNICIPAL POWER PLANT	3RD & POPLAR	WAMEGO	KS	665470000	3RD & POPLAR WAMEGO KS 665470000	7
20	133	KS	NEOSHO CO	00034	CITY OF ERIE	618 E. 2ND ST.	ERIE	KS	66733	618 E. 2ND ST. ERIE KS 66733	7
20	161	KS	Riley County	00007	KANSAS STATE UNIVERSITY	109 DYKSTRA HALL	MANHATTAN	KS	66502	109 DYKSTRA HALL MANHATTAN KS 66502	7
20	149	KS	POTTAWATOMIE CO	00001	WESTERN RESOURCES, INC. (JEC)	HWY 63 N, ON ACCESS ROAD	ST. MARYS	KS	00000	HWY 63 N, ON ACCESS ROAD ST. MARYS KS 00000	7
20	145	KS	PAWNEE CO	00010	LARNED-MUNICIPAL POWER PLANT	215 MAIN	LARNED	KS	67550	215 MAIN LARNED KS 67550	7
20	143	KS	Ottawa County	00013	MINNEAPOLIS-MUNICIPAL POWER PLANT	110 MARKLEY AVE.	MINNEAPOLIS	KS	67467	110 MARKLEY AVE. MINNEAPOLIS KS 67467	7
20	141	KS	Osborne County	00009	OSBORNE-MUNICIPAL POWER PLANT	N. LOCUST ST.	OSBORNE	KS	67473	N. LOCUST ST. OSBORNE KS 67473	7
20	139	KS	OSAGE CO	00014	OSAGE CITY-MUNICIPAL POWER PLANT	5TH & MAIN	OSAGE CITY	KS	66523	5TH & MAIN OSAGE CITY KS 66523	7
20	139	KS	OSAGE CO	00012	BURLINGAME-MUNICIPAL POWER PLANT	204 W. LINCOLN	BURLINGAME	KS	66413	204 W. LINCOLN BURLINGAME KS 66413	7
20	173	KS	SEDGWICK CO	00012	WESTERN RESOURCES, INC. (GORDON EVANS)	6001 NORTH 151ST ST. WEST	COLWICH	KS	67201	6001 NORTH 151ST ST. WEST COLWICH KS 67201	7
20	133	KS	NEOSHO CO	00047	CITY OF ERIE	121 NORTH POWER DRIVE	ERIE	KS	66733	121 NORTH POWER DRIVE ERIE KS 66733	7
20	191	KS	SUMNER CO	00019	WELLINGTON-MUNICIPAL POWER PLANT	520 S. OLIVE ST.	WELLINGTON	KS	67152	520 S. OLIVE ST. WELLINGTON KS 67152	7
20	133	KS	NEOSHO CO	00030	CITY OF CHANUTE ELEC. DEPT., PLANT #2	1415 NORTH GARFIELD	CHANUTE	KS	66720	1415 NORTH GARFIELD CHANUTE KS 66720	7
20	133	KS	NEOSHO CO	00028	CITY OF CHANUTE ELEC. DEPT., PLANT #3	4302 S. PLUMMER	CHANUTE	KS	66720	4302 S. PLUMMER CHANUTE KS 66720	7
20	131	KS	Nemaha County	00009	SABETHA-MUNICIPAL POWER PLANT	304 N. 11TH ST.	SABETHA	KS	66534	304 N. 11TH ST. SABETHA KS 66534	7
20	137	KS	NORTON CO	00005	NORTON-MUNICIPAL POWER PLANT	SOUTH MUNICIPAL ST.	NORTON	KS	67654	SOUTH MUNICIPAL ST. NORTON KS 67654	7
20	193	KS	THOMAS CO	00001	MIDWEST ENERGY, INC.	NORTH COUNTRY CLUB DRIVE	COLBY	KS	67701	NORTH COUNTRY CLUB DRIVE COLBY KS 67701	7
20	55	KS	FINNEY CO	00026	SUNFLOWER ELECTRIC POWER CORPORATION	WEST END OF ST. JOHN STREET	GARDEN CITY	KS	67846	WEST END OF ST. JOHN STREET GARDEN CITY KS 67846	7
20	125	KS	MONTGOMERY CO	00002	COFFEYVILLE-MUNICIPAL POWER PLANT	7TH & SANTA FE	COFFEYVILLE	KS	67337	7TH & SANTA FE COFFEYVILLE KS 67337	7
20	209	KS	WYANDOTTE CO	00049	BOARD OF PUBLIC UTILITIES - KAW	2015 KANSAS AVE.	KANSAS CITY	KS	00000	2015 KANSAS AVE. KANSAS CITY KS 00000	7
20	209	KS	WYANDOTTE CO	00048	BOARD OF PUBLIC UTILITIES - QUINDARO	3601 N. 12TH	KANSAS CITY	KS	00000	3601 N. 12TH KANSAS CITY KS 00000	7
20	209	KS	WYANDOTTE CO	00008	BOARD OF PUBLIC UTILITIES - NEARMAN	4240 N. 55TH	KANSAS CITY	KS	00000	4240 N. 55TH KANSAS CITY KS 00000	7
20	205	KS	WILSON CO	00018	FREDONIA MUNICIPAL POWER PLANT	ON FALL RIVER	FREDONIA	KS	66736	ON FALL RIVER FREDONIA KS 66736	7
20	205	KS	WILSON CO	00014	NEODESHA-MUNICIPAL POWER PLANT	WEST MAIN STREET	NEODESHA	KS	66757	WEST MAIN STREET NEODESHA KS 66757	7
20	201	KS	Washington County	00024	WASHINGTON-MUNICIPAL POWER PLANT	101 PARK ROAD	WASHINGTON	KS	66968	101 PARK ROAD WASHINGTON KS 66968	7

STATEFIPS	COUNTYFIPS	STATEABBREV	COUNTYNAME	FACILITYID	FACILITYNAME	STREET	CITY	STATE	ZIP	FACILITYADDRESS	EPA REGION
20	201	KS	Washington County	00012	UTILICORP UNITED, INC.	2 MILES NORTH	CLIFTON	KS	66937	2 MILES NORTH CLIFTON KS 66937	7
20	189	KS	STEVENS CO	00020	HUGOTON-MUNICIPAL POWER PLANT (#1)	115 E. 5TH	HUGOTON	KS	67951	115 E. 5TH HUGOTON KS 67951	7
20	193	KS	THOMAS CO	00007	COLBY MUNICIPAL POWER PLANT	120 N. STERLING	COLBY	KS	67701	120 N. STERLING COLBY KS 67701	7
20	173	KS	SEDGWICK CO	00014	WESTERN RESOURCES, INC.-MURRY GILL	6100 WEST 55TH ST. SOUTH	WICHITA	KS	67201	6100 WEST 55TH ST. SOUTH WICHITA KS 67201	7
20	191	KS	SUMNER CO	00056	WELLINGTON CITY POWER PLANT, GAS TURBINE	R. 1	WELLINGTON	KS	671520000	R. 1 WELLINGTON KS 671520000	7
20	191	KS	SUMNER CO	00055	CITY OF OXFORD, MUNICIPAL POWER PLANT	804 N. WATER	OXFORD	KS	67119	804 N. WATER OXFORD KS 67119	7
20	191	KS	SUMNER CO	00025	MULVANE-MUNICIPAL POWER PLANT	120 BOXELDER	MULVANE	KS	67110	120 BOXELDER MULVANE KS 67110	7
20	189	KS	STEVENS CO	00021	HUGOTON-MUNICIPAL POWER PLANT (#2)	1601 S. WASHINGTON	HUGOTON	KS	000000000	1601 S. WASHINGTON HUGOTON KS 000000000	7
20	187	KS	STANTON CO	00009	JOHNSON CITY MUNICIPAL POWER PLANT	402 S. MAIN	JOHNSON CITY	KS	67855	402 S. MAIN JOHNSON CITY KS 67855	7
20	185	KS	Stafford County	00017	STAFFORD-MUNICIPAL POWER PLANT	519 S. BOSTON	STAFFORD	KS	67578	519 S. BOSTON STAFFORD KS 67578	7
20	181	KS	SHERMAN CO	00005	GOODLAND-MUNICIPAL POWER PLANT	17TH & CHERRY	GOODLAND	KS	67735	17TH & CHERRY GOODLAND KS 67735	7
20	177	KS	SHAWNEE CO	00030	WESTERN RESOURCES, INC. (TEC)	2ND & DUPONT RD.	TOPEKA	KS	66542	2ND & DUPONT RD. TOPEKA KS 66542	7
20	175	KS	SEWARD CO	00001	UTILICORP UNITED, INC.	U.S. HWY 54 & CIMARRON RIVER	CIMARRON RIVER STA.	KS	67901	U.S. HWY 54 & CIMARRON RIVER CIMARRON RIVER STA. KS 67901	7
20	199	KS	Wallace County	00005	SHARON SPRINGS MUNICIPAL POWER PLANT	SOUTH HWY 27	SHARON SPRINGS	KS	67758	SOUTH HWY 27 SHARON SPRINGS KS 67758	7
20	15	KS	BUTLER CO	00010	AUGUSTA-MUNICIPAL POWER PLANT (#2)	615 E. 12TH ST.	AUGUSTA	KS	67010	615 E. 12TH ST. AUGUSTA KS 67010	7
20	39	KS	Decatur County	00009	OBERLIN-MUNICIPAL POWER PLANT	SOUTH RODEHAVER STREET	OBERLIN	KS	67749	SOUTH RODEHAVER STREET OBERLIN KS 67749	7
20	37	KS	Crawford County	00006	GIRARD-MUNICIPAL POWER PLANT	309 EAST BUFFALO	GIRARD	KS	66743	309 EAST BUFFALO GIRARD KS 66743	7
20	123	KS	MITCHELL CO	00012	BELOIT-MUNICIPAL POWER PLANT	215 S. CHESTNUT	BELOIT	KS	67420	215 S. CHESTNUT BELOIT KS 67420	7
20	35	KS	COWLEY CO	00006	WINFIELD MUNICIPAL POWER PLANT	WEST 14TH ST.	WINFIELD	KS	67156	WEST 14TH ST. WINFIELD KS 67156	7
20	59	KS	FRANKLIN CO	00006	OTTAWA-MUNICIPAL POWER PLANT	2ND & BEECH STREET	OTTAWA	KS	66067	2ND & BEECH STREET OTTAWA KS 66067	7
20	31	KS	Coffey County	00006	BURLINGTON-MUNICIPAL POWER PLANT	11TH & NIAGARA ST.	BURLINGTON	KS	66839	11TH & NIAGARA ST. BURLINGTON KS 66839	7
20	27	KS	CLAY CO	00007	CLAY CENTER PUBLIC UTILITIES	427 COURT ST.	CLAY CENTER	KS	67432	427 COURT ST. CLAY CENTER KS 67432	7
20	25	KS	CLARK CO	00001	ASHLAND-MUNICIPAL POWER PLANT	NORTH CHESTNUT	ASHLAND	KS	67831	NORTH CHESTNUT ASHLAND KS 67831	7
20	23	KS	Cheyenne County	00009	ST. FRANCIS POWER PLANT	621 WEST 1ST	ST. FRANCIS	KS	67756	621 WEST 1ST ST. FRANCIS KS 67756	7
20	41	KS	DICKINSON CO	00017	WESTERN RESOURCES, INC. - ABILENE ENERGY	3 MILES SE OF TOWN	ABILENE	KS	67410	3 MILES SE OF TOWN ABILENE KS 67410	7
20	21	KS	CHEROKEE CO	00002	EMPIRE DISTRICT ELECTRIC COMPANY (THE)	R. R. 1	RIVERTON	KS	66770	R. R. 1 RIVERTON KS 66770	7
20	35	KS	COWLEY CO	00012	WINFIELD MUNICIPAL POWER PLANT (NEW)	EAST 12TH STREET	WINFIELD	KS	67156	EAST 12TH STREET WINFIELD KS 67156	7
20	15	KS	BUTLER CO	00009	AUGUSTA-MUNICIPAL POWER PLANT (#1)	7TH & RR JUNC.	AUGUSTA	KS	67010	7TH & RR JUNC. AUGUSTA KS 67010	7
20	13	KS	Brown County	00029	CITY OF HORTON	602 E. 15TH ST.	HORTON	KS	66439	602 E. 15TH ST. HORTON KS 66439	7
20	9	KS	BARTON CO	00026	HOISINGTON-MUNICIPAL POWER PLANT	164 S. ELM ST.	HOISINGTON	KS	67544	164 S. ELM ST. HOISINGTON KS 67544	7
20	9	KS	BARTON CO	00025	ELLINWOOD-MUNICIPAL POWER PLANT	201 W. 1ST ST.	ELLINWOOD	KS	67526	201 W. 1ST ST. ELLINWOOD KS 67526	7
20	9	KS	BARTON CO	00002	UTILICORP UNITED, INC.	ARTHUR MULLERGREN STA	GREAT BEND	KS	675300170	ARTHUR MULLERGREN STA GREAT BEND KS 675300170	7
20	9	KS	BARTON CO	00001	MIDWEST ENERGY, INC.	1025 PATTON ROAD	GREAT BEND	KS	67530	1025 PATTON ROAD GREAT BEND KS 67530	7
20	3	KS	Anderson County	00001	GARNETT-MUNICIPAL POWER PLANT	SOUTH WALNUT STREET	GARNETT	KS	66032	SOUTH WALNUT STREET GARNETT KS 66032	7
20	1	KS	ALLEN CO	00019	CITY OF IOLA POWER PLANT	S. WASHINGTON ST.	IOLA	KS	667490000	S. WASHINGTON ST. IOLA KS 667490000	7
20	1	KS	ALLEN CO	00011	CITY OF IOLA POWER PLANT	WEST ON HWY 54	IOLA	KS	66749	WEST ON HWY 54 IOLA KS 66749	7
20	23	KS	Cheyenne County	00008	MIDWEST ENERGY, INC.	R. R. 1	BIRD CITY	KS	67731	R. R. 1 BIRD CITY KS 67731	7
20	105	KS	LINCOLN CO	00013	LINCOLN-MUNICIPAL POWER PLANT	405 W. SOUTH	LINCOLN	KS	67455	405 W. SOUTH LINCOLN KS 67455	7
20	121	KS	MIAMI CO	00001	OSAWATOMIE-MUNICIPAL POWER PLANT	JOHN BROWN PARK	OSAWATOMIE	KS	66064	JOHN BROWN PARK OSAWATOMIE KS 66064	7
20	119	KS	MEADE CO	00013	MEADE-MUNICIPAL POWER PLANT	623 E. CARTHAGE	MEADE	KS	67864	623 E. CARTHAGE MEADE KS 67864	7
20	113	KS	MC PHERSON CO	00046	BOARD OF PUBLIC UTILITIES - #3	S24-T19S-R3W	MCPHERSON	KS	67460	S24-T19S-R3W MCPHERSON KS 67460	7
20	113	KS	MC PHERSON CO	00014	MCPHERSON BOARD OF PUBLIC UTILITIES #2	1128 WEST AVE. A	MCPHERSON	KS	67460	1128 WEST AVE. A MCPHERSON KS 67460	7
20	31	KS	Coffey County	00021	WOLF CREEK NUCLEAR OPERATING CORP.	S7-T21S-R16E	BURLINGTON	KS	66839	S7-T21S-R16E BURLINGTON KS 66839	7
20	107	KS	LINN CO	00005	KANSAS CITY POWER & LIGHT CO.	R. R. 1	LACYGNE	KS	00000	R. R. 1 LACYGNE KS 00000	7
20	41	KS	DICKINSON CO	00034	HERINGTON-MUNICIPAL POWER PLANT	437 S. 5TH	HERINGTON	KS	674490000	437 S. 5TH HERINGTON KS 674490000	7
20	99	KS	Labette County	00001	WESTERN RESOURCES, INC. - NEOSHO ENERGY	8 MI E ON HWY 160	PARSONS	KS	00000	8 MI E ON HWY 160 PARSONS KS 00000	7
20	97	KS	KIOWA CO	00007	GREENSBURG-MUNICIPAL POWER PLANT	400 N. MAIN ST.	GREENSBURG	KS	67054	400 N. MAIN ST. GREENSBURG KS 67054	7
20	95	KS	KINGMAN CO	00004	KINGMAN-MUNICIPAL POWER PLANT	405 WEST SHERMAN	KINGMAN	KS	67068	405 WEST SHERMAN KINGMAN KS 67068	7
20	93	KS	KEARNEY CO	00019	CITY OF LAKIN	111 OSBORN DRIVE	LAKIN	KS	67860	111 OSBORN DRIVE LAKIN KS 67860	7
20	85	KS	Jackson County	00011	HOLTON-MUNICIPAL POWER PLANT	1000 NEW JERSEY	HOLTON	KS	66436	1000 NEW JERSEY HOLTON KS 66436	7
20	77	KS	HARPER CO	00013	ATTICA-MUNICIPAL POWER PLANT	101 N. HARPER	ATTICA	KS	670090000	101 N. HARPER ATTICA KS 670090000	7
20	77	KS	HARPER CO	00002	ANTHONY-MUNICIPAL POWER PLANT	3 MILES SOUTH OF ANTHONY	ANTHONY	KS	67003	3 MILES SOUTH OF ANTHONY ANTHONY KS 67003	7
20	65	KS	GRAHAM CO	00009	HILL CITY-MUNICIPAL POWER PLANT	724 S. POMEROY AVE.	HILL CITY	KS	67642	724 S. POMEROY AVE. HILL CITY KS 67642	7
20	45	KS	DOUGLAS CO	00011	BALDWIN CITY-MUNICIPAL POWER PLANT	605 HIGH STREET	BALDWIN CITY	KS	66006	605 HIGH STREET BALDWIN CITY KS 66006	7
20	57	KS	FORD CO	00001	UTILICORP UNITED, INC.	JUDSON LARGE STATION	DODGE CITY	KS	67801	JUDSON LARGE STATION DODGE CITY KS 67801	7
20	55	KS	FINNEY CO	00023	SUNFLOWER ELECTRIC POWER CORPORATION	S18-T24S-R33W	HOLCOMB	KS	67851	S18-T24S-R33W HOLCOMB KS 67851	7
20	45	KS	DOUGLAS CO	00014	WESTERN RESOURCES, INC.	1250 N. 1800 RD.	LAWRENCE	KS	66044	1250 N. 1800 RD. LAWRENCE KS 66044	7
20	91	KS	JOHNSON CO	00065	GARDNER ENERGY CENTER	1 MILE E. OF GARDNER	GARDNER	KS	66030	1 MILE E. OF GARDNER GARDNER KS 66030	7
20	109	KS	LOGAN CO	00009	OAKLEY-MUNICIPAL POWER PLANT	400 PRICE AVENUE	OAKLEY	KS	67748	400 PRICE AVENUE OAKLEY KS 67748	7
35	1	NM	BERNALILLO CO	3500100011	REEVES GENERATING STATION	4400 Paseo del Norte DR NE	Albuquerque	NM	87109	4400 Paseo del Norte DR NE Albuquerque NM 87109	6
35	45	NM	SAN JUAN CO	0002	FOUR CORNERS	Not Available	UNKNOWN	NM	UNKNOWN	Not Available UNKNOWN NM UNKNOWN	6
35	37	NM	QUAY CO	0002	TUCUMCARI	315 W Railroad Ave	Tucumcari	NM	88401	315 W Railroad Ave Tucumcari NM 88401	6
35	31	NM	MC KINLEY CO	0032	ESCALANTE	4 Mi N Of Prewitt	Prewitt	NM	87045	4 Mi N Of Prewitt Prewitt NM 87045	6
35	25	NM	LEA CO	0054	CUNNINGHAM	12.5 Mi West Of Hobbs	Hobbs	NM	88240	12.5 Mi West Of Hobbs Hobbs NM 88240	6
35	25	NM	LEA CO	0034	MADDOX STATION	8 Mi W. Hobbs on US 62/180	Hobbs	NM	88240	8 Mi W. Hobbs on US 62/180 Hobbs NM 88240	6
35	13	NM	DONA ANA CO	0025	PHYSICAL PLANT BOILERS	Nmsu Campus	Las Cruces	NM	88003	Nmsu Campus Las Cruces NM 88003	6
35	13	NM	DONA ANA CO	0002	RIO GRANDE GENERATING STATION	3501 Doniphan Road	Sunland Park	NM	88063	3501 Doniphan Road Sunland Park NM 88063	6
35	1	NM	BERNALILLO CO	3500100368	COBISA PERSON POWER PROJECT	725 Electric AVE SE	Albuquerque	NM	87105	725 Electric AVE SE Albuquerque NM 87105	6
35	47	NM	SAN MIGUEL CO	0004	LAS VEGAS TURBINE	West National St.	Las Vegas	NM	87701	West National St. Las Vegas NM 87701	6
35	45	NM	SAN JUAN CO	0902	SAN JUAN GENERATING STATION	San Juan Generating Station	Waterflow	NM	87421	San Juan Generating Station Waterflow NM 87421	6
35	7	NM	COLFAX CO	0001	RATON POWER PLANT	940 S. 2nd St	Raton	NM	87740	940 S. 2nd St Raton NM 87740	6
35	45	NM	SAN JUAN CO	0029	ANIMAS PLANT	501 Mccormick School Rd	Farmington	NM	87401	501 Mccormick School Rd Farmington NM 87401	6
32	3	NV	CLARK CO	0466	MOHAVE GENERATING STATION	2700 EDISON WAY	LAUGHLIN	NV	89029	2700 EDISON WAY LAUGHLIN NV 89029	9
32	1	NV	Churchill County	0197	AMOR IV CORP & STILLWATER GEOTHERMAL	5500 SODA LAKE ROAD	FALLON	NV	89406	5500 SODA LAKE ROAD FALLON NV 89406	9
32	1	NV	Churchill County	0756	CAITHNESS DIXIE VALLEY LLC	P O BOX 1270	FALLON	NV	89407-1270	P O BOX 1270 FALLON NV 89407-1270	9
32	3	NV	CLARK CO	0398	CLARK STATION	CLARK STATION	LAS VEGAS	NV	89151	CLARK STATION LAS VEGAS NV 89151	9
32	3	NV	CLARK CO	0400	REID GARDNER STATION	No Address Given	MOAPA	NV	89025	No Address Given MOAPA NV 89025	9
32	13	NV	HUMBOLDT CO	0457	VALMY GENERATING STATION	No Address Given	RENO	NV	89520-0026	No Address Given RENO NV 89520-0026	9
32	15	NV	Lander County	0223	BEOWAWE POWER LLC	1000 POWER PLANT PLACE	BEOWAWE	NV	89821	1000 POWER PLANT PLACE BEOWAWE NV 89821	9
32	19	NV	LYON CO	0091	SIERRA PACIFIC POWER COMPANY	6100 NEIL ROAD	RENO	NV	89520	6100 NEIL ROAD RENO NV 89520	9

STATEFIPS	COUNTYFIPS	STATEABBREV	COUNTYNAME	FACILITYID	FACILITYNAME	STREET	CITY	STATE	ZIP	FACILITYADDRESS	EPA REGION
32	29	NV	STOREY CO	0194	SIERRA PACIFIC POWER	INTERSTATE-80 EAST	SPARKS	NV	00000	INTERSTATE-80 EAST SPARKS NV 00000	9
32	31	NV	WASHOE CO	A01176A	EMPIRE ENERGY, LLC (FRMLY AMOR II)	SECT 21, T29N, R23E	EMPIRE	NV	89405-0000	SECT 21, T29N, R23E EMPIRE NV 89405-0000	9
32	31	NV	WASHOE CO	A90A	STEAMBOAT ENVIROSYSTEMS, LLC, UNITS 1,1A	1010 POWER PLANT DRIVE	RENO	NV	89511-0000	1010 POWER PLANT DRIVE RENO NV 89511-0000	9
32	3	NV	CLARK CO	0399	SUNRISE STATION	6200 VEGAS VALLEY DRIVE	LAS VEGAS	NV	89121	6200 VEGAS VALLEY DRIVE LAS VEGAS NV 89121	9
40	31	OK	COMANCHE CO	1211	CENTRAL AND SOUTH WEST SERVICES, INC.	P.O. Box 660164	Dallas	TX	752660164	P.O. Box 660164 Dallas TX 752660164	6
40	101	OK	MUSKOGEE CO	2209	OKLAHOMA GAS & ELECTRIC	P.O. Box 321, MC C610	Oklahoma City	OK	731010000	P.O. Box 321, MC C610 Oklahoma City OK 731010000	6
40	103	OK	NOBLE CO	2211	OKLAHOMA GAS & ELECTRIC	P.O. Box 321, MC C610	Oklahoma City	OK	731010000	P.O. Box 321, MC C610 Oklahoma City OK 731010000	6
40	79	OK	Le Flore County	1011	AES SHADY POINT, INC.	PO Box 1740	Panama	OK	749510000	PO Box 1740 Panama OK 749510000	6
40	71	OK	KAY CO	2929	OKLAHOMA GAS & ELECTRIC	PO Box 321, MC C610	Oklahoma City	OK	731010000	PO Box 321, MC C610 Oklahoma City OK 731010000	6
40	47	OK	GARFIELD CO	2207	OKLAHOMA GAS & ELECTRIC	P.O. Box 321, MC C610	Oklahoma City	OK	731010000	P.O. Box 321, MC C610 Oklahoma City OK 731010000	6
40	39	OK	CUSTER CO	4152	ONEOK PRODUCER SERVICES	P.O. Box 521120	Tulsa	OK	741521120	P.O. Box 521120 Tulsa OK 741521120	6
40	97	OK	MAYES CO	1799	GRAND RIVER DAM AUTHORITY	P.O. Box 609	Chouteau	OK	743370609	P.O. Box 609 Chouteau OK 743370609	6
40	23	OK	CHOCTAW CO	2700	WESTERN FARMERS ELECTRIC COOP	P.O. Box 429	Anadarko	OK	730050000	P.O. Box 429 Anadarko OK 730050000	6
40	17	OK	CANADIAN CO	2205	OKLAHOMA GAS & ELECTRIC	P.O. Box 321, MC C610	Oklahoma City	OK	731010000	P.O. Box 321, MC C610 Oklahoma City OK 731010000	6
40	15	OK	CADDO CO	2699	WESTERN FARMERS ELECTRIC COOP	Box 429	Anadarko	OK	730050000	Box 429 Anadarko OK 730050000	6
40	15	OK	CADDO CO	1214	CENTRAL AND SOUTH WEST SERVICES, INC.	P.O. Box 660164	Dallas	TX	752660164	P.O. Box 660164 Dallas TX 752660164	6
40	119	OK	PAYNE CO	1244	CITY OF CUSHING	Box 311, 100 Judy Adams Blvd.	Cushing	OK	740230311	Box 311, 100 Judy Adams Blvd. Cushing OK 740230311	6
40	107	OK	Okfuskee County	1216	CENTRAL AND SOUTH WEST SERVICES, INC.	P.O. Box 660164	Dallas	TX	752660164	P.O. Box 660164 Dallas TX 752660164	6
40	109	OK	OKLAHOMA CO	2208	OKLAHOMA GAS & ELECTRIC	P.O. Box 321, MC C610	Oklahoma City	OK	731010000	P.O. Box 321, MC C610 Oklahoma City OK 731010000	6
40	109	OK	OKLAHOMA CO	2212	OKLAHOMA GAS & ELECTRIC	P.O. Box 321, MC C610	Oklahoma City	OK	731270000	P.O. Box 321, MC C610 Oklahoma City OK 731270000	6
40	119	OK	PAYNE CO	1247	STILLWATER POWER	P.O. Box 1449	Stillwater	OK	740760000	P.O. Box 1449 Stillwater OK 740760000	6
40	131	OK	ROGERS CO	1212	CENTRAL AND SOUTH WEST SERVICES, INC.	P.O. Box 660164	Dallas	TX	752660164	P.O. Box 660164 Dallas TX 752660164	6
40	153	OK	WOODWARD CO	2701	WESTERN FARMERS ELECTRIC COOP	P.O. Box 429	Anadarko	OK	730050000	P.O. Box 429 Anadarko OK 730050000	6
40	133	OK	SEMINOLE CO	2210	OKLAHOMA GAS & ELECTRIC	P.O. Box 321, MC C610	Oklahoma City	OK	731010000	P.O. Box 321, MC C610 Oklahoma City OK 731010000	6
40	143	OK	TULSA CO	1213	CENTRAL AND SOUTH WEST SERVICES, INC.	P.O. Box 660164	Dallas	TX	752660164	P.O. Box 660164 Dallas TX 752660164	6
40	143	OK	TULSA CO	1215	CENTRAL AND SOUTH WEST SERVICES, INC.	P.O. Box 660164	Dallas	TX	752660164	P.O. Box 660164 Dallas TX 752660164	6
48	309	TX	MC LENNAN CO	MB0116C	TXU ELECTRIC CO	APPROX 11.5 M E OF WACO	WACO	TX	76701	APPROX 11.5 M E OF WACO WACO TX 76701	6
48	309	TX	MC LENNAN CO	MB0117A	TXU ELECTRIC CO	APPROX. 4.3 MI. S.W., OFF F.M.	WACO	TX	76701	APPROX. 4.3 MI. S.W., OFF F.M. WACO TX 76701	6
48	315	TX	MARION CO	ME0006A	SOUTHWESTERN ELECTRIC POWER CO	12 MI W OF AVINGER	AVINGER	TX	75630	12 MI W OF AVINGER AVINGER TX 75630	6
48	321	TX	MATAGORDA CO	MH0028D	STP NUCLEAROPERATING CO	ON F.M. 521, 8 MILES W. OF WAD	BAY CITY	TX	77404	ON F.M. 521, 8 MILES W. OF WAD BAY CITY TX 77404	6
48	331	TX	MILAM CO	MM0023J	TXU ELECTRIC CO	7 MI SW OF ROCKDALE	ROCKDALE	TX	76567	7 MI SW OF ROCKDALE ROCKDALE TX 76567	6
48	335	TX	MITCHELL CO	MO0014L	TXU ELECTRIC CO	5 MI. S.W. OF COLORADO CITY, T	COLORADO CITY	TX	79512	5 MI. S.W. OF COLORADO CITY, T COLORADO CITY TX 79512	6
48	341	TX	MOORE CO	MR0033U	SOUTHWESTERN PUBLIC SERVICE	5 MI SW ON FM 119	SUNRAY	TX	79086	5 MI SW ON FM 119 SUNRAY TX 79086	6
48	355	TX	NUECES CO	NE0025C	CENTRAL POWER AND LIGHT CO	3501 CALLICOATE ROAD	CORPUS CHRISTI	TX	78410	3501 CALLICOATE ROAD CORPUS CHRISTI TX 78410	6
48	303	TX	LUBBOCK CO	LN3604A	J.R. MASSENGALE	Not Available	UNKNOWN	TX	UNKNOWN	Not Available UNKNOWN TX UNKNOWN	6
48	353	TX	NOLAN CO	ND0054G	EEX POWER SYSTEMS	SOMEWHERE NEAR I. 20 S.E. OF S	SWEETWATER	TX	79556	SOMEWHERE NEAR I. 20 S.E. OF S SWEETWATER TX 79556	6
48	355	TX	NUECES CO	NE0024E	CENTRAL POWER AND LIGHT CO	4301 WALDRON ROAD	CORPUS CHRISTI	TX	78322	4301 WALDRON ROAD CORPUS CHRISTI TX 78322	6
48	343	TX	MORRIS CO	MS0011T	SOUTHWESTERN ELECTRIC POWER CO	OFF HWY 259, 40 M N OF LONGVIE	LONE STAR	TX	75668	OFF HWY 259, 40 M N OF LONGVIE LONE STAR TX 75668	6
48	339	TX	MONTGOMERY CO	MQ0009F	ENTERGY GULF STATES INC	2 MI. W. OF I. 45 N. ON LONGST	WILLIS	TX	77378	2 MI. W. OF I. 45 N. ON LONGST WILLIS TX 77378	6
48	303	TX	LUBBOCK CO	LN0206F	LUBBOCK POWER AND LIGHT	TEXAS TECH. COGENERATION	LUBBOCK	TX	79457	TEXAS TECH. COGENERATION LUBBOCK TX 79457	6
48	303	TX	LUBBOCK CO	LN0081B	SOUTHWESTERN PUBLIC SERVICE CO	SE OF LUBBOCK, TEXAS	LUBBOCK	TX	79401	SE OF LUBBOCK, TEXAS LUBBOCK TX 79401	6
48	303	TX	LUBBOCK CO	LN0057V	LUBBOCK POWER & LIGHT	AT THE INTERSECTION OF U.S. HW	LUBBOCK	TX	79457	AT THE INTERSECTION OF U.S. HW LUBBOCK TX 79457	6
48	299	TX	LLANO CO	LL0006O	LOWER COLORADO RIVER AUTHORITY	7 MI. W. OF MARBLE FALLS, TX.,	MARBLE FALLS	TX	78654	7 MI. W. OF MARBLE FALLS, TX., MARBLE FALLS TX 78654	6
48	293	TX	LIMESTONE CO	LI0027L	RELIANT ENERGY INC	9 MI. N. OF JEWETT, TX., ON F.	JEWETT	TX	75846	9 MI. N. OF JEWETT, TX., ON F. JEWETT TX 75846	6
48	279	TX	LAMB CO	LB0059G	SAVAGE TOLKCORPORATION	9 MILES E OF MULESHOE ON HWY 7	MULESHOE	TX	79347	9 MILES E OF MULESHOE ON HWY 7 MULESHOE TX 79347	6
48	279	TX	LAMB CO	LB0047N	SOUTHWESTERN PUBLIC SERVICE CO	N. OF SUDAN, TEXAS	MULESHOE	TX	79347	N. OF SUDAN, TEXAS MULESHOE TX 79347	6
48	279	TX	LAMB CO	LB0046P	SOUTHWESTERN PUBLIC SERVICE	NORTH OF AMHERST, TX	AMHERST	TX	79312	NORTH OF AMHERST, TX AMHERST TX 79312	6
48	277	TX	Lamar County	LA0045F	TENASKA IIITEXAS PARTNERS	PARIS, TEXAS	PARIS	TX	75460	PARIS, TEXAS PARIS TX 75460	6
48	251	TX	JOHNSON CO	JH0230L	TENASKA IV TEXAS PARTNERS LTD	CLEBURNE INDUSTRIAL PARK	CLEBURNE	TX	76031	CLEBURNE INDUSTRIAL PARK CLEBURNE TX 76031	6
48	355	TX	NUECES CO	NE0026A	CENTRAL POWER AND LIGHT CO	2002 NAVIGATION BOULEVARD	CORPUS CHRISTI	TX	78322	2002 NAVIGATION BOULEVARD CORPUS CHRISTI TX 78322	6
48	453	TX	TRAVIS CO	TH0004D	CITY OF AUSTIN	8003 DECKER LANE	AUSTIN	TX	78724	8003 DECKER LANE AUSTIN TX 78724	6
48	233	TX	HUTCHINSON CO	HW0024U	SOUTHWESTERN PUBLIC SERVICE	S.H. 207, 2 MI. N.	BORGER	TX	79007	S.H. 207, 2 MI. N. BORGER TX 79007	6
48	233	TX	HUTCHINSON CO	HW0081I	SOUTHWESTERN PUBLIC SERVICE CO	2 MI. N.E. OF BORGER ON STATE	BORGER	TX	79007	2 MI. N.E. OF BORGER ON STATE BORGER TX 79007	6
48	253	TX	JONES CO	JI0030K	CENTRAL & SOUTH WEST SERVICES INC	F.M. 2833, 7 MI. N. OF HWY. 35	ABILENE	TX	79601	F.M. 2833, 7 MI. N. OF HWY. 35 ABILENE TX 79601	6
48	449	TX	TITUS CO	TF0012D	SOUTHWESTERN ELECTRIC POWER CO	NORTH TWO MILES ON AN OILED CO	MOUNT PLEASANT	TX	75455	NORTH TWO MILES ON AN OILED CO MOUNT PLEASANT TX 75455	6
48	503	TX	YOUNG CO	YB0017V	TXU ELECTRIC CO	3 MI. NW OF GRAHAM	GRAHAM	TX	76046	3 MI. NW OF GRAHAM GRAHAM TX 76046	6
48	487	TX	WILBARGER CO	WI0025C	WEST TEXAS UTILITIES CO	3.5 MI. S.S.W. OF OKLAUNION, T	OKLAUNION	TX	76373	3.5 MI. S.S.W. OF OKLAUNION, T OKLAUNION TX 76373	6
48	487	TX	WILBARGER CO	WI0002O	WEST TEXAS UTILITIES	US 287 AND MAPLES ST	VERNON	TX	76384	US 287 AND MAPLES ST VERNON TX 76384	6
48	485	TX	WICHITA CO	WH0083W	MIRANT WICHITA FALLS LP	4511 ALLENDALE RD.	WICHITA FALLS	TX	76310	4511 ALLENDALE RD. WICHITA FALLS TX 76310	6
48	481	TX	WHARTON CO	WF0175P	NEWGULF POWER VENTURE INC	1611 WOODALL PROGRESS FREEWAY	NEWGULF	TX	77462	1611 WOODALL PROGRESS FREEWAY NEWGULF TX 77462	6
48	479	TX	WEBB CO	WE0005G	CENTRAL & SOUTHWEST SERVICES INC	0.5 MI. FROM I. 35 & SANTA MAR	LAREDO	TX	78040	0.5 MI. FROM I. 35 & SANTA MAR LAREDO TX 78040	6
48	475	TX	WARD CO	WC0028Q	TXU ELECTRIC CO	600 YUCCA DR., MONAHANS, TX.:	MONAHANS	TX	79756	600 YUCCA DR., MONAHANS, TX.: MONAHANS TX 79756	6
48	469	TX	VICTORIA CO	VC0026O	SOUTH TEXASELECTRIC COOPERATIVE INC	FM 447, 3 M W OF NURSERY	NURSERY	TX	77976	FM 447, 3 M W OF NURSERY NURSERY TX 77976	6
48	469	TX	VICTORIA CO	VC0003D	CENTRAL POWER AND LIGHT CO	1205 C.S. BOTTOM	VICTORIA	TX	77901	1205 C.S. BOTTOM VICTORIA TX 77901	6
48	453	TX	TRAVIS CO	TH0104V	UNIVERSITY OF TEXAS AT AUSTIN	24TH ST. & SAN JACINTO ST.	AUSTIN	TX	78701	24TH ST. & SAN JACINTO ST. AUSTIN TX 78701	6
48	453	TX	TRAVIS CO	TH0006W	CITY OF AUSTIN	2401 HOLLY STREET	AUSTIN	TX	78701	2401 HOLLY STREET AUSTIN TX 78701	6
48	201	TX	HARRIS CO	HG9954A	CALPINE CORPORATION	1400 JEFFERSON ROAD	PASADENA	TX	77506	1400 JEFFERSON ROAD PASADENA TX 77506	6
48	449	TX	TITUS CO	TF0013B	TXU ELECTRIC CO	7 MI. S.W. OF MT. PLEASANT OFF	MOUNT PLEASANT	TX	75455	7 MI. S.W. OF MT. PLEASANT OFF MOUNT PLEASANT TX 75455	6
48	231	TX	HUNT CO	HV0023K	GREENVILLE ELECTRIC SYSTEM	N. OF GREENVILLE NEAR THE INTE	GREENVILLE	TX	75401	N. OF GREENVILLE NEAR THE INTE GREENVILLE TX 75401	6
48	355	TX	NUECES CO	NE0035W	ROBSTOWN UTILITY SYSTEMS	1100 N 4TH STREET	ROBSTOWN	TX	78380	1100 N 4TH STREET ROBSTOWN TX 78380	6
48	441	TX	TAYLOR CO	TB0056E	WEST TEXAS UTILITIES CO	102 E.N. 2ND ST.	ABILENE	TX	79601	102 E.N. 2ND ST. ABILENE TX 79601	6
48	439	TX	TARRANT CO	TA0354E	TXU ELECTRIC CO	AT 4TH AND NORTH HOUSTON STREE	FORT WORTH	TX	76002	AT 4TH AND NORTH HOUSTON STREE FORT WORTH TX 76002	6
48	439	TX	TARRANT CO	TA0353G	TXU ELECTRIC CO	6604 EAST ROSEDALE	FORT WORTH	TX	76002	6604 EAST ROSEDALE FORT WORTH TX 76002	6
48	439	TX	TARRANT CO	TA0352I	TXU ELECTRIC CO	10 MI. N.W. ON FM 1220	FORT WORTH	TX	76002	10 MI. N.W. ON FM 1220 FORT WORTH TX 76002	6
48	401	TX	RUSK CO	RL0020K	TXU ELECTRIC CO	6 MI SW OF TATUM NEAR FM 2658	TATUM	TX	75691	6 MI SW OF TATUM NEAR FM 2658 TATUM TX 75691	6
48	395	TX	ROBERTSON CO	RI0035C	TEXAS NEW MEXICO POWER CO	8 MILES N OF CALVERT ON HWY 6	CALVERT	TX	77837	8 MILES N OF CALVERT ON HWY 6 CALVERT TX 77837	6
48	387	TX	RED RIVER CO	RE0012M	TXU ELECTRIC CO	APPROX 5.4 M SE ON US HWY 271	BOGATA	TX	75417	APPROX 5.4 M SE ON US HWY 271 BOGATA TX 75417	6
48	375	TX	POTTER CO	PG0041R	SOUTHWESTERN PUBLIC SERVICE CO	2.7 MI. N. ON LAKESIDE DR. FRO	AMARILLO	TX	79101	2.7 MI. N. ON LAKESIDE DR. FRO AMARILLO TX 79101	6
48	375	TX	POTTER CO	PG0040T	SOUTHWESTERN PUBLIC SERVICE CO	1.5 MI. N. ON LAKESIDE DRIVE F	AMARILLO	TX	79101	1.5 MI. N. ON LAKESIDE DRIVE F AMARILLO TX 79101	6
48	371	TX	PECOS CO	PE0259K	WEST TEXAS UTILITIES CO	APPROX 5 MILES NW OF FT STOCKT	FORT STOCKTON	TX	79735	APPROX 5 MILES NW OF FT STOCKT FORT STOCKTON TX 79735	6

STATEFIPS	COUNTYFIPS	STATEABBREV	COUNTYNAME	FACILITYID	FACILITYNAME	STREET	CITY	STATE	ZIP	FACILITYADDRESS	EPA REGION
48	367	TX	PARKER CO	PC0005T	BRAZOS ELECTRIC POWER COO	602 WEST LAKE DRIVE	WEATHERFORD	TX	76086	602 WEST LAKE DRIVE WEATHERFORD TX 76086	6
48	363	TX	PALO PINTO CO	PA0003W	BRAZOS ELECTRIC POWER COOPERATIVE IN	PALO PINTO	PALO PINTO	TX	76072	PALO PINTO PALO PINTO TX 76072	6
48	361	TX	ORANGE CO	OC0013O	ENTERGY GULF STATES INC	POWERHOUSE ROAD OFF OF FM 1442	BRIDGE CITY	TX	77611	POWERHOUSE ROAD OFF OF FM 1442 BRIDGE CITY TX 77611	6
48	451	TX	TOM GREEN CO	TG0044C	WEST TEXAS UTILITIES CO	ROUTE 5	SAN ANGELO	TX	76902	ROUTE 5 SAN ANGELO TX 76902	6
48	57	TX	CALHOUN CO	CB0008C	CENTRAL POWER AND LIGHT CO	FM 1593	POINT COMFORT	TX	77978	FM 1593 POINT COMFORT TX 77978	6
48	113	TX	DALLAS CO	DB0253Q	TXU ELECTRIC CO	5770 PARKDALE DRIVE	DALLAS	TX	75201	5770 PARKDALE DRIVE DALLAS TX 75201	6
48	113	TX	DALLAS CO	DB0252S	TXU ELECTRIC CO	2233 MOUNTAIN CREEK PARKWAY	DALLAS	TX	75201	2233 MOUNTAIN CREEK PARKWAY DALLAS TX 75201	6
48	113	TX	DALLAS CO	DB0251U	TXU ELECTRIC CO	14901 NORTHLAKE RD.	DALLAS	TX	75201	14901 NORTHLAKE RD. DALLAS TX 75201	6
48	113	TX	DALLAS CO	DB0249H	TXU ELECTRIC CO	555 BARNES BRIDGE ROAD	DALLAS	TX	75037	555 BARNES BRIDGE ROAD DALLAS TX 75037	6
48	105	TX	CROCKETT CO	CZ0017A	W TX UTILITIES CO	ONE MILE N.E. OF GIRVIN, TEXAS	GIRVIN	TX	79740	ONE MILE N.E. OF GIRVIN, TEXAS GIRVIN TX 79740	6
48	85	TX	COLLIN CO	CP0230L	THERMONETICS INC	2601 NORTH FLOYD ROAD	RICHARDSON	TX	75080	2601 NORTH FLOYD ROAD RICHARDSON TX 75080	6
48	85	TX	COLLIN CO	CP0065C	TXU ELECTRIC CO	APP 3M N OF FRISCO OFF US HWY	FRISCO	TX	75034	APP 3M N OF FRISCO OFF US HWY FRISCO TX 75034	6
48	85	TX	COLLIN CO	CP0026M	GARLAND MUNICIPAL POWER AND LIGHT	WEST END OF C.R. 489, 2 MI. W.	WYLIE	TX	75098	WEST END OF C.R. 489, 2 MI. W. WYLIE TX 75098	6
48	83	TX	Coleman County	CO0003M	CITY OF COLEMAN	201 NORTH COLORADO STREET	COLEMAN	TX	76834	201 NORTH COLORADO STREET COLEMAN TX 76834	6
48	81	TX	COKE CO	CN0005T	WEST TEXAS UTILITIES CO	ON SH 70 4 MI. SO. OF BLACKWEL	ABILENE	TX	79601	ON SH 70 4 MI. SO. OF BLACKWEL ABILENE TX 79601	6
48	227	TX	HOWARD CO	HT0065Q	POWER RESOURCES LTD	3 MI. E. ON I. 20 FROM BIG SPR	BIG SPRING	TX	79721	3 MI. E. ON I. 20 FROM BIG SPR BIG SPRING TX 79721	6
48	71	TX	CHAMBERS CO	CI0012D	RELIANT ENERGY INC	F.M. 1405, APPROX. 2 MI. S. OF	HOUSTON	TX	77001	F.M. 1405, APPROX. 2 MI. S. OF HOUSTON TX 77001	6
48	113	TX	DALLAS CO	DB0384A	GARLAND MUNICIPAL POWER AND LIGHT	525 E AVENUE B	GARLAND	TX	75040	525 E AVENUE B GARLAND TX 75040	6
48	61	TX	CAMERON CO	CD0009B	BROWNSVILLEPUBLIC UTILITIES BOARD	WEST 13TH ST. & POWER PLANT DR	BROWNSVILLE	TX	78520	WEST 13TH ST. & POWER PLANT DR BROWNSVILLE TX 78520	6
48	73	TX	CHEROKEE CO	CJ0026J	TXU ELECTRIC CO	LOCATED ON THE W SHORE OF STRY	DALLAS	TX	75201	LOCATED ON THE W SHORE OF STRY DALLAS TX 75201	6
48	41	TX	BRAZOS CO	BM0032V	TEXAS A & M UNIVERSITY	600 UNIVERSITY DRIVE	COLLEGE STATION	TX	77840	600 UNIVERSITY DRIVE COLLEGE STATION TX 77840	6
48	41	TX	BRAZOS CO	BM0010I	BRYAN MUNICIPAL ELECTRIC SYSTEM	601 ATKINS STREET	BRYAN	TX	77801	601 ATKINS STREET BRYAN TX 77801	6
48	41	TX	BRAZOS CO	BM0009Q	CITY OF BRYAN	5 MI. N.W. OF BRYAN OFF S.H. 6	BRYAN	TX	77801	5 MI. N.W. OF BRYAN OFF S.H. 6 BRYAN TX 77801	6
48	29	TX	BEXAR CO	BG0188E	CITY PUBLICSERVICE BOARD	207 MISSION RD. (AT HIGHLAND B	SAN ANTONIO	TX	78201	207 MISSION RD. (AT HIGHLAND B SAN ANTONIO TX 78201	6
48	29	TX	BEXAR CO	BG0187G	CITY PUBLICSERVICE	9843 PERRIN BEITEL ROAD	SAN ANTONIO	TX	78201	9843 PERRIN BEITEL ROAD SAN ANTONIO TX 78201	6
48	29	TX	BEXAR CO	BG0186I	CITY PUBLICSERVICE	16120 STREICH RD.	SAN ANTONIO	TX	78201	16120 STREICH RD. SAN ANTONIO TX 78201	6
48	29	TX	BEXAR CO	BG0059Q	CITY PUBLICSERVICE BOARD	7800 QUINTANA ROAD	SAN ANTONIO	TX	78201	7800 QUINTANA ROAD SAN ANTONIO TX 78201	6
48	29	TX	BEXAR CO	BG0057UB	CITY PUBLICSERVICE B	9599 GARDNER ROAD	SAN ANTONIO	TX	78201	9599 GARDNER ROAD SAN ANTONIO TX 78201	6
48	29	TX	BEXAR CO	BG0057UA	CITY PUBLICSERVICE B	9599 GARDNER ROAD	SAN ANTONIO	TX	78201	9599 GARDNER ROAD SAN ANTONIO TX 78201	6
48	29	TX	BEXAR CO	BG0057U	CITY PUBLICSERVICE	9599 GARDNER ROAD	SAN ANTONIO	TX	78201	9599 GARDNER ROAD SAN ANTONIO TX 78201	6
48	21	TX	BASTROP CO	BC0015L	LOWER COLORADO RIVER AUTHORITY	FOUR MIES NORTHEAST OF BASTROP	BASTROP	TX	78602	FOUR MIES NORTHEAST OF BASTROP BASTROP TX 78602	6
48	13	TX	ATASCOSA CO	AG0007G	SAN MIGUEL ELCTRC COOPERATIVE INC	11 MI. S., S.H. 16; 6 MI. E.,	CHRISTINE	TX	78012	11 MI. S., S.H. 16; 6 MI. E., CHRISTINE TX 78012	6
48	207	TX	HASKELL CO	HJ0022B	WEST TEXAS UTILITIES CO	P.O. BOX 605 HASKELL 79521	HASKELL	TX	79521	P.O. BOX 605 HASKELL 79521 HASKELL TX 79521	6
48	215	TX	HIDALGO CO	HN0013E	CENTRAL POWER AND LIGHT CO	LOOP 374	MISSION	TX	78572	LOOP 374 MISSION TX 78572	6
48	61	TX	CAMERON CO	CD0013K	CENTRAL POWER AND LIGHT CO	WEST STENGER RD.	SAN BENITO	TX	78586	WEST STENGER RD. SAN BENITO TX 78586	6
48	215	TX	HIDALGO CO	HN0403K	FRONTERA GENERATION LTD PARTNERSHIP	ONE MI. S. OF BUSINESS ROUTE 8	MISSION	TX	78572	ONE MI. S. OF BUSINESS ROUTE 8 MISSION TX 78572	6
48	121	TX	DENTON CO	DF0012T	DENTON MUNICIPAL UTILITIES	1701-A SPENCER ROAD	DENTON	TX	76201	1701-A SPENCER ROAD DENTON TX 76201	6
48	213	TX	HENDERSON CO	HM0017H	TXU ELECTRIC CO	1 MI S FM 764 0.5 MI W	TRINIDAD	TX	75163	1 MI S FM 764 0.5 MI W TRINIDAD TX 75163	6
48	203	TX	HARRISON CO	HH0037F	SOUTHWESTERN ELECTRIC POWER CO	RT 2 BOX 165	HALLSVILLE	TX	75650	RT 2 BOX 165 HALLSVILLE TX 75650	6
48	201	TX	HARRIS CO	HG4955K	RELIANT ENERGY INC	845 SENS ROAD	LA PORTE	TX	77572	845 SENS ROAD LA PORTE TX 77572	6
48	201	TX	HARRIS CO	HG1495V	AES DEEPWATER INC	701 LIGHT COMPANY ROAD	HOUSTON	TX	77001	701 LIGHT COMPANY ROAD HOUSTON TX 77001	6
48	201	TX	HARRIS CO	HG1169O	CALPINE CORPORATION	9602 BAYPORT RD.	PASADENA	TX	77507	9602 BAYPORT RD. PASADENA TX 77507	6
48	201	TX	HARRIS CO	HG0358Q	RELIANT ENERGY INC	IN LA PORTE	LA PORTE	TX	77571	IN LA PORTE LA PORTE TX 77571	6
48	201	TX	HARRIS CO	HG0357S	RELIANT ENERGY INC	16301 W. MONTGOMERY ST.	HOUSTON	TX	77052	16301 W. MONTGOMERY ST. HOUSTON TX 77052	6
48	201	TX	HARRIS CO	HG0356U	RELIANT ENERGY INC	901 LIGHT COMPANY ROAD	PASADENA	TX	77501	901 LIGHT COMPANY ROAD PASADENA TX 77501	6
48	201	TX	HARRIS CO	HG0355W	RELIANT ENERGY INC	19301 OLD GALVESTON ROAD	WEBSTER	TX	77598	19301 OLD GALVESTON ROAD WEBSTER TX 77598	6
48	201	TX	HARRIS CO	HG0354B	RELIANT ENERGY INC	12100 HIRAM CLARKE ROAD.	HOUSTON	TX	77052	12100 HIRAM CLARKE ROAD. HOUSTON TX 77052	6
48	149	TX	FAYETTE CO	FC0018G	LOWER COLORADO RIVER AUTHORITY	7 MI. E. OF LA GRANGE, TX., ON	LA GRANGE	TX	78945	7 MI. E. OF LA GRANGE, TX., ON LA GRANGE TX 78945	6
48	221	TX	HOOD CO	HQ0012T	TXU ELECTRIC CO	P.O. BOX 579	GRANBURY	TX	76048	P.O. BOX 579 GRANBURY TX 76048	6
48	201	TX	HARRIS CO	HG0353D	RELIANT ENERGY INC	12070 OLD BEAUMONT HIGHWAY	HOUSTON	TX	77049	12070 OLD BEAUMONT HIGHWAY HOUSTON TX 77049	6
48	141	TX	EL PASO CO	EE0029T	EL PASO ELECTRIC CO	N.W. OF INTERSECTION OF F.M. 3	EL PASO	TX	79901	N.W. OF INTERSECTION OF F.M. 3 EL PASO TX 79901	6
48	147	TX	FANNIN CO	FB0025U	TX UTILITIES ELECTRIC CO	ON HWY. 1752 N. OF SAVOY, TX.	SAVOY	TX	75479	ON HWY. 1752 N. OF SAVOY, TX. SAVOY TX 75479	6
48	157	TX	FORT BEND CO	FG0020V	RELIANT ENERGY INC	NEAR Y.U. JONES ROAD	FRESNO	TX	77545	NEAR Y.U. JONES ROAD FRESNO TX 77545	6
48	161	TX	FREESTONE CO	FI0020W	TXU ELECTRIC CO	9 MI. N.E. OF FAIRFIELD, TX.	FAIRFIELD	TX	75840	9 MI. N.E. OF FAIRFIELD, TX. FAIRFIELD TX 75840	6
48	167	TX	GALVESTON CO	GB0037T	RELIANT ENERGY INC	5501 HWY 146	HOUSTON	TX	77251	5501 HWY 146 HOUSTON TX 77251	6
48	167	TX	GALVESTON CO	GB0153Q	TEXAS CITY COGENERATION LP	CRNR OF 5TH AVE S AND GRANT AV	TEXAS CITY	TX	77590	CRNR OF 5TH AVE S AND GRANT AV TEXAS CITY TX 77590	6
48	175	TX	GOLIAD CO	GF0002R	CENTRAL SOUTH WEST SERVICES INC	SCHROEDER ROAD (FM 2987)	FANNIN	TX	77960	SCHROEDER ROAD (FM 2987) FANNIN TX 77960	6
48	197	TX	HARDEMAN CO	HE0013G	WEST TEXAS UTILITIES CO	LAKE PAULINE	QUANAH	TX	79252	LAKE PAULINE QUANAH TX 79252	6
48	183	TX	GREGG CO	GJ0043K	SOUTHWESTERN ELECTRIC POWER CO	KNOX LEE POWER PLT.	LONGVIEW	TX	75601	KNOX LEE POWER PLT. LONGVIEW TX 75601	6
48	163	TX	FRIO CO	FJ0012P	MEDINA ELECTRIC COOPERATIVE INC	1.5 MI. N. ON POWER PLANT RD.	PEARSALL	TX	78061	1.5 MI. N. ON POWER PLANT RD. PEARSALL TX 78061	6
48	141	TX	EL PASO CO	EE0157J	EL PASO ELECTRIC CO	651 HAWKINS BLVD.	EL PASO	TX	79901	651 HAWKINS BLVD. EL PASO TX 79901	6
48	185	TX	GRIMES CO	GK0012K	TEXAS MUNICIPAL POWER AGENCY	2 1/2 M N OF CARLOS OFF FM 244	BRYAN	TX	77801	2 1/2 M N OF CARLOS OFF FM 244 BRYAN TX 77801	6
49	53	UT	Washington County	11539	HILDALE CITY COGENERATION FACILITY	1325 West Utah Ave.	Hildale	UT	84784	1325 West Utah Ave. Hildale UT 84784	8
49	47	UT	UINTAH CO	107790	BONANZA	Not Available	UNKNOWN	UT	UNKNOWN	Not Available UNKNOWN UT UNKNOWN	8
49	49	UT	UTAH CO	10795	POWER PLANT	702 North 300 West	Provo	UT	84601	702 North 300 West Provo UT 84601	8
49	49	UT	UTAH CO	10819	WHITEHEAD POWER PLANT	450 West 700 North	Springville	UT	84663	450 West 700 North Springville UT 84663	8
49	53	UT	Washington County	10892	ST. GEORGE CITY POWER PLANT	795 E. Skyline Dr.	St. George	UT	84770	795 E. Skyline Dr. St. George UT 84770	8
49	35	UT	SALT LAKE CO	10355	GADSBY POWER PLANT	1407 West North Temple (rear)	Salt Lake City	UT	84116	1407 West North Temple (rear) Salt Lake City UT 84116	8
49	7	UT	CARBON CO	10096	SUNNYSIDE COGENERATION FACILITY	One Power Plant Road	Sunnyside	UT	84539	One Power Plant Road Sunnyside UT 84539	8
49	49	UT	UTAH CO	10823	PAYSON CITY POWER	1100 N 100 E	Payson	UT	84651	1100 N 100 E Payson UT 84651	8
49	27	UT	MILLARD CO	10327	INTERMOUNTAIN GENERATION STATION	850 W Brush Wellman Rd	Delta	UT	84624	850 W Brush Wellman Rd Delta UT 84624	8
49	15	UT	EMERY CO	10238	HUNTINGTON POWER PLANT	P. O. Box 680	Huntington	UT	84528	P. O. Box 680 Huntington UT 84528	8
49	11	UT	DAVIS CO	10120	POWER PLANT	253 S 200 W	Bountiful	UT	84010	253 S 200 W Bountiful UT 84010	8
49	7	UT	CARBON CO	10081	CARBON POWER PLANT	NA	Helper	UT	84526	NA Helper UT 84526	8
49	5	UT	Cache County	10058	POWER PLANT	305 South 300 West	Logan	UT	84321	305 South 300 West Logan UT 84321	8
49	1	UT	Beaver County	10319	BONNETT-GEOTHERMAL POWER PLANT	#1 Main	Sulphurdale	UT	84713	#1 Main Sulphurdale UT 84713	8
49	35	UT	SALT LAKE CO	10348	ELECTRICAL GENERATION PLANT	157 W 4800 S	Murray	UT	84107	157 W 4800 S Murray UT 84107	8
49	15	UT	EMERY CO	10237	HUNTER POWER PLANT	P.O. Box 569	Castledale	UT	84513	P.O. Box 569 Castledale UT 84513	8
56	45	WY	WESTON CO	00005	BLACK HILLS OSAGE	OSAGE POWER PLANT	OSAGE	WY	82723-0000	OSAGE POWER PLANT OSAGE WY 82723-0000	8
56	37	WY	SWEETWATER CO	01002	PACIFICORP_JIM BRIDGER	PO BOX 158	POINT OF ROCKS	WY	82901-0000	PO BOX 158 POINT OF ROCKS WY 82901-0000	8

STATEFIPS	COUNTYFIPS	STATEABBREV	COUNTYNAME	FACILITYID	FACILITYNAME	STREET	CITY	STATE	ZIP	FACILITYADDRESS	EPA REGION
56	31	WY	PLATTE CO	00001	BASIN ELECTRIC_LARAMIE RIVER STATION	LARAMIE RIVER PLANT	WHEATLAND	WY	82201-0000	LARAMIE RIVER PLANT WHEATLAND WY 82201-0000	8
56	23	WY	LINCOLN CO	00004	PACIFICORP_NAUGHTON POWER PLANT	6.5 MI SW OF KEMMERER, HWY 189	KEMMERER	WY	83101-0000	6.5 MI SW OF KEMMERER, HWY 189 KEMMERER WY 83101-0000	8
56	9	WY	CONVERSE CO	00001	PACIFICORP_DAVE JOHNSTON	1591 TANK FARM ROAD	GLENROCK	WY	82637-0000	1591 TANK FARM ROAD GLENROCK WY 82637-0000	8
56	5	WY	CAMPBELL CO	00063	BLACK HILLS POWER & LGT_SIMPSON 2	UNK	GILLETTE	WY	99999-0000	UNK GILLETTE WY 99999-0000	8
56	5	WY	CAMPBELL CO	00002	BLACK HILLS POWER & LGHT SIMPSON 1	3 MI NE OF GILLETTE	GILLETTE	WY	82718-9716	3 MI NE OF GILLETTE GILLETTE WY 82718-9716	8
56	5	WY	CAMPBELL CO	00046	PACIFICORP_WYODAK	3 MI E OF GILLETTE	GILLETTE	WY	82716-0000	3 MI E OF GILLETTE GILLETTE WY 82716-0000	8

FACILITYID	FACILITYNAME	INVNETORY YEAR	SIC	LATITUDE	LONGITUDE	CO	NH3	NOX	PMCON	PMFIL	PMPRI	PM10FIL	PM10PRI	PM25FIL	PM25PRI	SO2	VOC
0402700141	YUMA COGENERATION ASSOCIATES	1999	4911	33.1028	-86.8007	20.797	6.5	178.216	0.818			12.081	12.899	11.327	12.145	6.509	4.276
U120	YUCCA	1999	4911	33.2119	-86.809	170.72	6.5	239.63	11.179			0.193	11.372	0.193	11.372	2.3	13.66
0400100059	SALT RIVER PROJECT	1999	4911	32.2354	-85.4389	430.8		13127.8	595.47			991.298	1586.768	564.735	1160.203	19997.6	100.4
0331	ARIZONA PUBLIC SERVICE COMPANY (APS)	1999	4911	33.2836	-86.6917	30.31		106.55	0.469			24.91	25.379	13.52	13.989	6.07	3.74
U118	SAGUARO	1999	4911	33.6803	-86.3217	54.79	7.31	558.11	12.856			0.867	13.725	0.867	13.725	1.2	15.35
0082	IRVINGTON	1999	4911	32.2193	-84.9999	146.77	8.74	2404.97	83.142			29.589	112.732	15.318	98.461	2861.6	27.02
0001	CHOLLA	1999	4911	32.432	-84.9899	915.94	1.32	13183.26	667.137			956.508	1623.644	544.847	1211.983	19062.1	109.88
98	PALO VERDE NUCLEAR GENERATING STATION	1999	4911	34.6307	-87.0087	20.957	5.903	49.055	12.101			24.115	36.221	20.291	32.395	0.996	29.697
52382	OCOTILLO POWER PLANT	1999	4911	34.6422	-87.0643	82.787	8.561	555.776	16.585			5.745	22.334	5.223	21.811	8.447	15.482
3316	SRP AGUA FRIA	1999	4911	30.6683	-88.0437	488.738	17.61	3299.612	32.543			15.478	48.023	15.478	48.023	0.715	31.423
3315	SANTAN GENERATING PLANT	1999	4911	30.5544	-88.1697	336.707		1356.641	6.084			123.077	129.162	123.077	129.162	4.031	3.634
3313	APS WEST PHX POWER PLANT	1999	4911	30.7665	-88.0563	101.01		1430.233	3.191			44.485	47.68	44.137	47.332	4.954	25.505
0170	US ARMY NAVAJO DEPOT ACTIVITY	1999	4911	33.9501	-87.7813	0.65		2.98	0.146			0.14	0.286	0.05	0.196	1.28	0.16
0004	NAVAJO	1999	4911	32.2608	-87.79	1939.67	2.71	35275.25	1899.402			1956.637	3856.039	868.815	2768.216	9162.6	232.63
0400300037	AZ ELECTRIC POWER COOPERATIVE INC	1999	4911	32.5176	-87.8133	493.157	3.891	6636.37	348.437			919.308	1267.745	369.674	718.114	5968.965	59.701
0400100060	TUCSON ELECTRIC POWER CO-SPRINGERVILLE	1999	4911	34.6537	-86.6737	785.561	0.98	11730.15	620.45			708.923	1329.374	454.4	1074.858	18387.2	103.6
3317	SRP KYRENE STEAM PLANT	1999	4911	30.6629	-88.0364	39.03	1.091	230.301	2.27			5.759	8.032	5.737	8.01	37.147	1.86
0023	PUBLIC SERVICE CO FORT SAINT VRAIN PLT	1999	4911	38.0874	-107.7103	181.5	1.04	219.25	41.202			2.431	43.634	1.945	43.147	4.2	12.3
0035	PUBLIC SERVICE CO FRUITA STA	1999	4911	39.783	-105.1044	3.4		15.8	0.074			1.5	1.574	1.5	1.574	1.1	0.8
0239	PUBLIC SERVICE CO ROSS RIDGE STATION	1999	4911	37.2715	-107.5657												26.9
0018	TRI STATE GENERATION CRAIG	1999	4911	37.2833	-107.8384	7553.8	1.49	16761.08	969.351	0.03		577.459	1546.81	388.566	1357.918	10662.29	64.7
0001	TRI STATE GENERATION NUCLA	1999	4911	40.5822	-105.0792	140.64	0.1	1039.11	237.412			153.09	390.502	94.45	331.861	1475.81	9.61
0011	PUBLIC SERVICE CO PAWNEE PLT	1999	4911	40.5807	-105.0481	627.6	0.8	5320.72	254.451			162.523	416.973	77.831	332.281	16665.8	75.24
0004	WEST PLAINS ENERGY - ROCKY FORD STATION	1999	4911	37.1133	-104.6762	3.72		34.17	0.105			1.39	1.495	1.303	1.408	1.57	1.62
0006	LAMAR UTILITIES BOARD	1999	4911	39.1365	-108.73	21.9	1.73	301.3	3.315			0.051	3.367	0.051	3.367	0.3	0.8
0003	PUBLIC SERVICE CO COMANCHE PLT	1999	4911	39.0771	-108.5551	701.6	0.91	7079.2	268.325			210.426	478.751	86.737	355.062	13699.9	74.3
0008	WEST PLAINS ENERGY - PUEBLO STATION	1999	4911	39.331	-108.5915	9.13	0.44	108.75	0.762			1.323	2.085	1.241	2.003	1.62	1.77
0250	THERMO COGEN PARTNERSHIP FT LUPTON	1999	4911	38.2325	-104.6218	455.83		599.99	25.157			93.96	119.117	93.944	119.101	10.66	48.6
0014	PUBLIC SERVICE CO FT LUPTON STATION	1999	4911	38.0934	-103.8202	12.2		49.1	0.227			4.6	4.827	4.6	4.827	1.2	2.7
0126	THERMO POWER & ELEC INC	1999	4911	38.143	-102.6128	89.06		386.39	10.757			36.61	47.367	36.609	47.366	1.61	11.33
0002	PUBLIC SERVICE CO CAMEO PLT	1999	4911	39.7942	-105.0644	68.5	0.17	1889.26	96.077			160.029	256.106	68.32	164.396	3045.3	8.2
0001	PUBLIC SERVICE CO HAYDEN PLT	1999	4911	37.5309	-108.9391	369.9	0.55	7217.35	401.476			221.701	623.177	110.747	512.222	6678.4	44.4
0001	PUBLIC SERVICE CO - VALMONT	1999	4911	39.8488	-104.9965	102.75	0.23	1085.46	56.115			56.388	112.503	37.237	93.353	2836.02	14.19
0053	PLATTE RIVER POWER AUTHORITY - RAWHIDE	1999	4911	39.8776	-105.1017	49.9	0.38	4530.65	262.341			78.003	340.343	30.454	292.793	1117.2	38.04
0412	THERMO GREELEY INC	1999	4911	38.2703	-104.5874	97		96	0.36			7.3	7.66	7.3	7.66	0.9	55
0001	PUBLIC SERVICE CO CHEROKEE PLT	1999	4911	34.4893	-119.072	544.5	2.281	12444.76	484.337			251.483	735.82	126.75	611.084	18543	63.65
0007	PUBLIC SERVICE CO ALAMOSA PLT	1999	4911	38.6935	-121.9066	11.9		56.6	0.261			5.3	5.561	5.3	5.561	1.9	2.7
0007	PUBLIC SERVICE CO ZUNI PLT	1999	4911	38.1268	-103.1598	15.4	0.581	165.02	2.034			0.055	2.087	0.052	2.087	2.9	0.7
0008	PUBLIC SERVICE CO - ARAPAHOE	1999	4911	38.0968	-103.091	229.83	1.58	3952.71	135.153			79.431	214.583	43.023	178.172	4166.43	26.91
0041	PUBLIC SERVICE CO DENVER STEAM PLT	1999	4911	40.1614	-105.101	23		316.8	5.07			1.69	6.76	1.69	6.76	0.36	0.83
0004	COLORADO SPRINGS UTILITIES-DRAKE PLT	1999	4911	39.6668	-104.8846	213.08	1.01	5623.96	192.8			231.546	424.347	174.244	367.042	6596	24.43
0030	COLORADO SPRINGS UTILITIES - NIXON PLT	1999	4911	39.6371	-104.894	139.02	0.359	2583.98	129.402			159.14	288.542	118.415	247.818	4601.04	16.43
0003	WEST PLAINS ENERGY - W.N. CLARK STATION	1999	4911	39.5614	-104.9895	327.78	0.04	894.61	50.367			824.656	875.023	792.407	842.771	1197.99	3.28
0057	AMERICAN ATLAS NO 1/COLORADO GREENHOUSE	1999	4911	39.556	-104.4858	105.21		220.65	11.274			35.81	47.084	35.635	46.909	0.53	19.96
0059	PUBLIC SERVICE CO LOOKOUT CENTER	1999	4911	38.8844	-104.721	0.13		0.63	0.005			0.03	0.035	0.025	0.03	0.03	0.05
0003	COLORADO SPRINGS UTILITIES-BIRDSALL PLT	1999	4911	39.6917	-105.0011	14.11	0.67	47.1	2.53			2.84	5.37	2.358	4.888	0.73	0.93
0003	TRI STATE GENERATION BURLINGTON	1999	4911	39.5695	-108.2451	6.3		91.6	0.605			8	8.605	8	8.605	28.6	2.2
1238	KN SERVICES - LAKEWOOD GENERATION FACILI	1999	4911	39.4674	-107.8355	5.64		34.07	1.285			0.01	1.295	0.009	1.295		1.16
00001	LACROSSE MUNICIPAL POWER PLANT	1999	4911	39.5312	-95.3175	0.35		1.64	0.008			0.11	0.118	0.103	0.111	0.1	0.11
00005	PRATT-MUNICIPAL POWER PLANT	1999	4911	41.6106	-90.6079	7.97	0.31	26.61	0.435			0.086	0.521	0.079	0.514	0.08	0.52
00033	WESTERN RESOURCES, INC. (HEC)	1999	4911	37.8843	-95.3153	56.72	3.659	395.63	6.904			1.86	8.764	1.838	8.742	36.37	6.71
00016	BELLEVILLE-MUNICIPAL POWER PLANT	1999	4911	38.17	-95.3	7.42		53.64	0.042			0.61	0.652	0.58	0.622	0.48	1.61
00024	STERLING MUNICIPAL POWER PLANT	1999	4911	38.214	-95.3045	6		23.55	0.337			2.17	2.507	1.84	2.177	0.75	1.51
00005	RUSSELL-MUNICIPAL POWER PLANT	1999	4911	37.24	-98.57	245.49		963.12	13.69			88.18	101.87	74.762	88.45	31.8	61.88
00014	STOCKTON-MUNICIPAL POWER PLANT	1999	4911	39.5312	-95.3175	1.41		10.7	0.004			0.06	0.064	0.058	0.062	0.04	0.28
00012	WAMEGO-MUNICIPAL POWER PLANT	1999	4911	41.6776	-93.5719	13.94		88.12	0.049			0.78	0.829	0.747	0.794	0.51	2.86
00034	CITY OF ERIE	1999	4911	42.0794	-91.5989	3.36		15.47	0.079			1.05	1.129	0.984	1.064	1.02	1.05
00007	KANSAS STATE UNIVERSITY	1999	4911	39.6	-95.11	29.25		92.92	7.862			2.63	10.492	2.627	10.488	0.32	1.89
00001	WESTERN RESOURCES, INC. (JEC)	1999	4911	41.6776	-93.5719	2068.2	2.921	25716.34	1622.411			1478.497	3100.907	779.224	2401.632	58246.89	247.87
00010	LARNED-MUNICIPAL POWER PLANT	1999	4911	41.466	-91.0763	5.38	0.31	30.14	0.567			0.109	0.676	0.093	0.66	1.15	0.66
00013	MINNEAPOLIS-MUNICIPAL POWER PLANT	1999	4911	41.3917	-91.0569	7.5		53.67	0.047			0.67	0.717	0.636	0.683	0.53	1.65
00009	OSBORNE-MUNICIPAL POWER PLANT	1999	4911	41.466	-91.0763	0.35		2.81	0			0.01	0.01	0.01	0.01		0.06
00014	OSAGE CITY-MUNICIPAL POWER PLANT	1999	4911	41.3181	-91.0931	0.01		0.06									
00012	BURLINGAME-MUNICIPAL POWER PLANT	1999	4911	42.0794	-91.5989	2.15		16.16	0.008			0.12	0.128	0.115	0.123	0.08	0.44
00012	WESTERN RESOURCES, INC. (GORDON EVANS)	1999	4911	37.8	-96.86	414.3	15.91	3428.04	28.16			0.679	28.839	0.663	28.825	43.3	27.19
00047	CITY OF ERIE	1999	4911	42.0794	-91.5989	7.47		32.91								0.53	0.96
00019	WELLINGTON-MUNICIPAL POWER PLANT	1999	4911	38.9905	-96.7503	2.88	0.23	10.1	1.504			0.366	1.87	0.366	1.87	0.04	0.12
00030	CITY OF CHANUTE ELEC. DEPT., PLANT #2	1999	4911	40.5963	-91.4162	1.67		12.72	0.005			0.08	0.085	0.077	0.082	0.05	0.34
00028	CITY OF CHANUTE ELEC. DEPT., PLANT #3	1999	4911	40.5963	-91.4162	25.4		172.8	0.215			3	3.215	2.835	3.05	2.6	7.99
00009	SABETHA-MUNICIPAL POWER PLANT	1999	4911	42.4848	-90.804	11.65		76.9	0.117			1.6	1.717	1.51	1.627	1.42	2.8
00005	NORTON-MUNICIPAL POWER PLANT	1999	4911	42.0794	-91.5989	3.5		23.48	0.031			0.44	0.471	0.416	0.447	0.38	0.83
00001	MIDWEST ENERGY, INC.	1999	4911	37.45	-101.35	1.12		4.08	0.007			0.14	0.147	0.14	0.147	0.74	0.13
00026	SUNFLOWER ELECTRIC POWER CORPORATION	1999	4911	39.7335	-85.5875	64.85	1.4	638.29	5.563			6.716	12.278	6.699	12.261	0.48	48.64
00002	COFFEYVILLE-MUNICIPAL POWER PLANT	1999	4911	39.8104	-84.8955	18.13	1.45	49.58	2.568			0.044	2.612	0.044	2.612	0.26	0.63
00049	BOARD OF PUBLIC UTILITIES - KAW	1999	4911	38.15	-97.45	32.27	1.23	165.69	1.975			0.007	1.983	0.007	1.983	62.1	2.1
00048	BOARD OF PUBLIC UTILITIES - QUINDARO	1999	4911	37.1871	-98.0812	198.21	1.88	4198.61	81.03			69.398	150.427	41.934	122.964	6145.05	41.7
00008	BOARD OF PUBLIC UTILITIES - NEARMAN	1999	4911	37.8645	-96.2396	210.97	0.36	3391.68	96.239	1.39		153.606	249.845	97.767	194.004	6356.49	24.52
00018	FREDONIA MUNICIPAL POWER PLANT	1999	4911	37.64	-101.26	1.2		9.08	0.004			0.06	0.064	0.058	0.062	0.04	0.24
00014	NEODESHA-MUNICIPAL POWER PLANT	1999	4911	37.45	-101.35	2.01		9.25	0.048			0.63	0.678	0.591	0.638	0.61	0.63
00024	WASHINGTON-MUNICIPAL POWER PLANT	1999	4911	37.46	-101.49	1.89		12.63	0.018			0.24	0.258	0.226	0.244	0.22	0.44

FACILITYID	FACILITYNAME	INVNETORY YEAR	SIC	LATITUDE	LONGITUDE	CO	NH3	NOX	PMCON	PMFIL	PMPRI	PM10FIL	PM10PRI	PM25FIL	PM25PRI	SO2	VOC
00012	UTILICORP UNITED, INC.	1999	4911	37.55	-101.13	29.01		117.98	0.531			10.6	11.131	10.597	11.128	0.59	5.26
00020	HUGOTON-MUNICIPAL POWER PLANT (#1)	1999	4911	38.8901	-95.3118	0.09		0.12	0.003			0.02	0.023	0.017	0.02	0.01	0.01
00007	COLBY MUNICIPAL POWER PLANT	1999	4911	37.57	-101.2	0.78		4.09	0.015			0.2	0.215	0.188	0.203	0.19	0.22
00014	WESTERN RESOURCES, INC.-MURRY GILL	1999	4911	37.67	-96.97	154.82	10.53	992.09	19.37			6.869	26.24	6.3	25.67	1686.61	13.09
00056	WELLINGTON CITY POWER PLANT, GAS TURBINE	1999	4911	37.56	-101.19	8.22		29.54	0.049			1	1.049	1	1.049	0.05	0.9
00055	CITY OF OXFORD, MUNICIPAL POWER PLANT	1999	4911	37.54	-101.18	2.26		10.41	0.054			0.71	0.764	0.666	0.719	0.69	0.71
00025	MULVANE-MUNICIPAL POWER PLANT	1999	4911	38.9905	-96.7503	1.9		13.77	0.01			0.15	0.16	0.143	0.153	0.12	0.41
00021	HUGOTON-MUNICIPAL POWER PLANT (#2)	1999	4911	38.8901	-95.3118	116.71		222.31	11.835			43.16	54.995	36.597	48.432	10.78	28.59
00009	JOHNSON CITY MUNICIPAL POWER PLANT	1999	4911	38.92	-95.22	5.46		37.82	0.042			0.58	0.622	0.549	0.591	0.5	1.25
00017	STAFFORD-MUNICIPAL POWER PLANT	1999	4911	38.97	-95.26	0.05		0.23	0.001			0.01	0.011	0.009	0.01	0.01	0.01
00005	GOODLAND-MUNICIPAL POWER PLANT	1999	4911	39.75	-94.88	6.58		49.35	0.021			0.35	0.371	0.336	0.357	0.28	1.33
00030	WESTERN RESOURCES, INC. (TEC)	1999	4911	38.87	-97.21	209.06	1.121	2524.63	83.947			142.014	225.961	69.584	153.53	4609.89	20.97
00001	UTILICORP UNITED, INC.	1999	4911	37.228	-96.8517	62.3	1.86	162.3	5.341			2.725	8.066	2.725	8.066	0.37	4.68
00005	SHARON SPRINGS MUNICIPAL POWER PLANT	1999	4911	37.69	-101.2	0.03		0.16	0.001			0.01	0.011	0.009	0.01	0.01	0.01
00010	AUGUSTA-MUNICIPAL POWER PLANT (#2)	1999	4911	39.5296	-86.3776	43.16		100.48	0.062			0.4	0.462	0.339	0.401	0.1	7.44
00009	OBERLIN-MUNICIPAL POWER PLANT	1999	4911	41.6163	-87.0696	0.42		3.1	0.002			0.03	0.032	0.029	0.03	0.02	0.08
00006	GIRARD-MUNICIPAL POWER PLANT	1999	4911	41.4776	-87	17.52		40.84	0.131			0.85	0.981	0.72	0.852	13.52	3.01
00012	BELOIT-MUNICIPAL POWER PLANT	1999	4911	39.8525	-84.91	11.68		27.2	0.088			0.57	0.658	0.483	0.572	9.52	8.06
00006	WINFIELD MUNICIPAL POWER PLANT	1999	4911	38.4581	-87.2636	2.77		9.98	0.016			0.33	0.346	0.33	0.346	0.01	0.3
00006	OTTAWA-MUNICIPAL POWER PLANT	1999	4911	41.6818	-86.3032	34.42		101.91	0.125			1.91	2.035	1.866	1.991	0.08	16.82
00006	BURLINGTON-MUNICIPAL POWER PLANT	1999	4911	37.9896	-86.795	5.15		35.5	0.042			0.58	0.622	0.549	0.591	0.48	1.18
00007	CLAY CENTER PUBLIC UTILITIES	1999	4911	39.2945	-86.7866	12.62		115.15								0.38	8.9
00001	ASHLAND-MUNICIPAL POWER PLANT	1999	4911	38.5573	-86.4813	1.02		4.94	0.023			0.3	0.323	0.281	0.304	0.29	0.31
00009	ST. FRANCIS POWER PLANT	1999	4911	41.395	-85.4236	0.73		7.66	0.017			0.24	0.257	0.226	0.243	0.22	0.33
00017	WESTERN RESOURCES, INC. - ABILENE ENERGY	1999	4911	41.6266	-87.1332	3.61		14.08	0.014			0.29	0.304	0.29	0.304	0.15	0.09
00002	EMPIRE DISTRICT ELECTRIC COMPANY (THE)	1999	4911	41.48	-85.6107	113.88	0.17	1436.41	144.417			101.996	246.413	51.093	195.509	5000.49	14.69
00012	WINFIELD MUNICIPAL POWER PLANT (NEW)	1999	4911	38.3528	-87.2077		0.64	47.96	1.05			0.104	1.156	0.096	1.148	0.3	
00009	AUGUSTA-MUNICIPAL POWER PLANT (#1)	1999	4911	39.4843	-86.4186	4.03		9.48									0.69
00029	CITY OF HORTON	1999	4911	39.9749	-86.8337	6.98		32.12	0.166			2.19	2.356	2.053	2.219	2.13	2.19
00026	HOISINGTON-MUNICIPAL POWER PLANT	1999	4911	39.1765	-86.6249	2.86		19.93	0.021			0.29	0.311	0.274	0.295	0.24	0.64
00025	ELLINWOOD-MUNICIPAL POWER PLANT	1999	4911	40.6688	-86.1068	4.31		32.04	0.019			0.28	0.299	0.268	0.287	0.2	0.9
00002	UTILICORP UNITED, INC.	1999	4911	40.6616	-86.1022	27.64	3.69	287.6	6.34			0.109	6.45	0.109	6.45	0.6	6.33
00001	MIDWEST ENERGY, INC.	1999	4911	40.7726	-86.1291	1.31		8.6	0.012			0.17	0.182	0.16	0.172	0.16	0.31
00001	GARNETT-MUNICIPAL POWER PLANT	1999	4911	41.2942	-86.1357	12.59		35.55	0.11			0.71	0.82	0.601	0.712	2.15	2.03
00019	CITY OF IOLA POWER PLANT	1999	4911	41.3662	-86.3287	6.91		26.13	0.193			1.23	1.423	1.044	1.232	0.06	0.69
00011	CITY OF IOLA POWER PLANT	1999	4911	41.4502	-86.1512	21.97	0.32	42.07	1266.638			9.86	1276.498	9.244	1275.882	0.25	22.83
00008	MIDWEST ENERGY, INC.	1999	4911	41.4326	-85.425	0.39		1.83	0.009			0.12	0.129	0.113	0.122	0.12	0.12
00013	LINCOLN-MUNICIPAL POWER PLANT	1999	4911	37.9374	-87.4916	2.78		12.8	0.066			0.87	0.936	0.816	0.881	0.85	0.87
00001	OSAWATOMIE-MUNICIPAL POWER PLANT	1999	4911	37.9352	-87.3558	2.57		11.84	0.06			0.8	0.86	0.75	0.81	0.78	0.81
00013	MEADE-MUNICIPAL POWER PLANT	1999	4911	40.1981	-87.5275	9.85		77.05	0.016			0.29	0.306	0.29	0.306	1.1	1.92
00046	BOARD OF PUBLIC UTILITIES - #3	1999	4911	40.8352	-85.7375	63.7		32.82	0.217			4.39	4.607	4.39	4.607	0.13	5.46
00014	MCPHERSON BOARD OF PUBLIC UTILITIES #2	1999	4911	39.5327	-87.4282	25.17	0.279	105.86	0.676			3.658	4.334	3.658	4.334	0.18	4.48
00021	WOLF CREEK NUCLEAR OPERATING CORP.	1999	4911	38.0542	-86.6383			28.73									
00005	KANSAS CITY POWER & LIGHT CO.	1999	4911	39.9389	-87.4728	1376.67	3	35236.95	809.158			962.578	1771.736	443.241	1252.4	29919.53	232.87
00034	HERINGTON-MUNICIPAL POWER PLANT	1999	4911	41.6091	-87.0864	7.02		37.88	0.127			1.7	1.827	1.596	1.723	1.63	2
00001	WESTERN RESOURCES, INC. - NEOSHO ENERGY	1999	4911	38.1444	-87.5512	8.65	1.16	496.35	3.449			0.034	3.484	0.034	3.484	0.3	1.98
00007	GREENSBURG-MUNICIPAL POWER PLANT	1999	4911	38.1002	-87.5554	9.84		22.91									6.78
00004	KINGMAN-MUNICIPAL POWER PLANT	1999	4911	37.9892	-87.5876	201.24		364.5	1.947			12.54	14.487	10.631	12.578	0.36	92.49
00019	CITY OF LAKIN	1999	4911	37.9901	-87.5887	3.49		24	0.028			0.39	0.418	0.369	0.396	0.33	0.8
00011	HOLTON-MUNICIPAL POWER PLANT	1999	4911	39.0119	-87.4077	37.58		147.5	0.442			2.85	3.292	2.416	2.859	2.61	38.06
00013	ATTICA-MUNICIPAL POWER PLANT	1999	4911	39.5227	-85.7901	1.18		8.84	0.005			0.07	0.075	0.067	0.072	0.05	0.24
00002	ANTHONY-MUNICIPAL POWER PLANT	1999	4911	39.5091	-85.7892	36.52		85.03								0.04	25.18
00009	HILL CITY-MUNICIPAL POWER PLANT	1999	4911	41.6734	-86.1315	2.63		20.32	0.006			0.1	0.106	0.097	0.103	0.05	0.52
00011	BALDWIN CITY-MUNICIPAL POWER PLANT	1999	4911	38.0021	-87.8416	6.33		34.26	0.114			1.53	1.644	1.436	1.551	1.46	1.79
00001	UTILICORP UNITED, INC.	1999	4911	41.7481	-86.1185	220.31	8.39	623.28	14.287			0.249	14.536	0.249	14.536	1.5	14.42
00023	SUNFLOWER ELECTRIC POWER CORPORATION	1999	4911	39.302	-85.2303	329.28	0.62	4193.96	296.414			60.722	357.137	25.145	321.559	2430.7	52.52
00014	WESTERN RESOURCES, INC.	1999	4911	41.0436	-86.5967	342.16	0.92	5455	316.101			715.564	1031.665	302.84	618.938	3576.7	41.49
00065	GARDNER ENERGY CENTER	1999	4911	40.3871	-86.8545	18.74		67.3	0.112			2.28	2.392	2.28	2.392	0.09	2.05
00009	OAKLEY-MUNICIPAL POWER PLANT	1999	4911	39.3606	-87.4167	2.14		16.96	0.002			0.04	0.042	0.04	0.042		0.41
3500100011	REEVES GENERATING STATION	1999	4911	39.8615	-75.1522	325.41	2.93	451.89	17.526			22.934	40.456	19.054	36.575	0.44	18.43
0002	FOUR CORNERS	1999	4911	40.785	-74.2942	2136.94	3.25	45775.14	1699.444			4415.297	6114.742	2195.896	3895.34	42520.7	255.52
0002	TUCUMCARI	1999	4911	40.5876	-74.243	0.53		2.96	0.005			0.05	0.055	0.045	0.05	0.19	0.05
0032	ESCALANTE	1999	4911	40.562	-74.5222	242.39	2.224	4553.17	236.631			138.827	375.458	67.946	304.578	1514.51	27.39
0054	CUNNINGHAM	1999	4911	40.4527	-74.4026	312.98	22.349	1645.25	41.542			15.327	56.869	15.327	56.869	5	9
0034	MADDOX STATION	1999	4911	40.5667	-74.4292	117.34	12.759	675.26	18.252			4.136	22.388	4.136	22.388	2.04	7
0025	PHYSICAL PLANT BOILERS	1999	4911	40.7445	-74.0731	59		271.89	38.035			24.41	62.445	11.728	49.763	2.38	50.88
0002	RIO GRANDE GENERATING STATION	1999	4911	40.7402	-74.061	853.28	13.741	1066.51	25.034			0.407	25.442	0.407	25.442	2.5	31.78
3500100368	COBISA PERSON POWER PROJECT	1999	4911	39.7127	-75.1597	707		530	2.812			57	59.812	57	59.812	72	34
0004	LAS VEGAS TURBINE	1999	4911	40.9519	-74.2614	0.41		2.64								0.43	
0902	SAN JUAN GENERATING STATION	1999	4911	40.8351	-74.1301	1655.15	2.869	30016.7	1919.005			5764.812	7683.817	3046.467	4965.471	29501.99	200.14
0001	RATON POWER PLANT	1999	4911	40.7412	-74.0335	64.34	0.01	176.31	14.418			4.811	19.23	2.136	16.555	271.3	0.63
0029	ANIMAS PLANT	1999	4911	40.8654	-74.5514	13.89	0.46	84.99	0.812			0.014	0.826	0.014	0.826		54.63
0466	MOHAVE GENERATING STATION	1999	4911	41.23	-95.95	1126.62	2.21	19764.87	913.488			1186.424	2099.912	526.828	1440.318	38639.7	
0197	AMOR IV CORP & STILLWATER GEOTHERMAL	1999	4911	41.42	-96.49	0.51		5.746	0.001			0.039	0.039	0.038	0.039	0.118	34.541
0756	CAITHNESS DIXIE VALLEY LLC	1999	4911	41.25	-95.92	4.38		5.595	0.011			0.453	0.464	0.444	0.455	0.753	0.138
0398	CLARK STATION	1999	4911	41.22	-96.01		4.241	1033.49	8.151			0.319	8.47	0.319	8.47	0.6	
0400	REID GARDNER STATION	1999	4911	41.22	-95.95		0.599	9764.07	454.55			950.144	1404.693	549.804	1004.354	3193.4	
0457	VALMY GENERATING STATION	1999	4911	41.25	-95.93		0.7	6624.56	272.613			129.73	402.343	64.962	337.576	6828.3	0.045
0223	BEOWAWE POWER LLC	1999	4911	41.2	-95.93				0.156			2.495	2.65	2.414	2.57		
0091	SIERRA PACIFIC POWER COMPANY	1999	4911	41.26	-96.06		17.39	2618.75	32.597			0.715	33.312	0.697	33.294	32.1	

FACILITYID	FACILITYNAME	INVNETORY YEAR	SIC	LATITUDE	LONGITUDE	CO	NH3	NOX	PMCON	PMFIL	PMPRI	PM10FIL	PM10PRI	PM25FIL	PM25PRI	SO2	VOC
0194	SIERRA PACIFIC POWER	1999	4911	41.28	-96.04	50.85	18.52	2123.9	62.329			19.553	81.881	19.532	81.86	20.5	59.231
A01176A	EMPIRE ENERGY, LLC (FRMLY AMOR II)	1999	4911	41.26	-95.95												10.39
A90A	STEAMBOAT ENVIROSYSTEMS, LLC, UNITS 1,1A	1999	4911	41.2	-95.96												68
0399	SUNRISE STATION	1999	4911	41.36	-96.05	24.97	2.51	365	8.519			1.637	10.155	1.637	10.155	0.4	0.888
1211	CENTRAL AND SOUTH WEST SERVICES, INC.	1999	4911	39.7055	-80.846	822.88	23.34	4756.86	50.945			0.694	51.639	0.694	51.639	5.4	
2209	OKLAHOMA GAS & ELECTRIC	1999	4911	35.1893	-97.4152	2673.9	6.78	18127.4	501.595			610.96	1112.555	417.276	918.872	29668.7	187.6
2211	OKLAHOMA GAS & ELECTRIC	1999	4911	34.8402	-98.229	1997.5	1.29	14735.06	368.93		80.4	513.221	882.151	335.177	704.108	25138.8	139.9
1011	AES SHADY POINT, INC.	1999	4911	35.2711	-99.8264	1459.48		828.31	54.008			179.953	233.96	112.611	166.619	5259.57	18.19
2929	OKLAHOMA GAS & ELECTRIC	1999	4911	36.5823	-98.2623	1.3		458.54	13.155			5.166	18.321	5.166	18.321	18.2	15.5
2207	OKLAHOMA GAS & ELECTRIC	1999	4911	40.9005	-81.1166	4.96		68.44	0.028			0.572	0.6	0.572	0.6	0.04	0.16
4152	ONEOK PRODUCER SERVICES	1999	4911	41.168	-81.1983	41.6		23.6									15.79
1799	GRAND RIVER DAM AUTHORITY	1999	4911	34.3063	-97.1453	918.23	1.39	13731.1	587.888			546.182	1134.069	343.698	931.586	18355.31	118.28
2700	WESTERN FARMERS ELECTRIC COOP	1999	4911	40.59	-83.1	434.9	0.55	5362.31	165.076			192.266	357.342	130.838	295.914	9575.2	52.16
2205	OKLAHOMA GAS & ELECTRIC	1999	4911	41.69	-83.53	185.9	14.87	3589.47	36.367			0.442	36.808	0.442	36.808	5187.6	6.6
2699	WESTERN FARMERS ELECTRIC COOP	1999	4911	41.3369	-82.1245	742.46	0.59	1832.44	1.354			0.018	1.372	0.018	1.372	3.04	159.26
1214	CENTRAL AND SOUTH WEST SERVICES, INC.	1999	4911	41.7537	-81.1564	434.02	17.211	3346.5	28.669			0.65	29.319	0.642	29.31	3.51	17.42
1244	CITY OF CUSHING	1999	4911	36.1339	-99.4353	44.79		181.24	0.011			0.139	0.15	0.131	0.141	1.73	10.72
1216	CENTRAL AND SOUTH WEST SERVICES, INC.	1999	4911	34.6033	-98.5085	45.29		181.1	1.206			15.964	17.17	15.962	17.168	0.32	0.03
2208	OKLAHOMA GAS & ELECTRIC	1999	4911	35.7292	-99.298	196.7	15.65	1692.2	23.495			1.047	24.543	1.047	24.543	2.4	6.8
2212	OKLAHOMA GAS & ELECTRIC	1999	4911	35.6188	-98.862	3.7		13.3								0.3	
1247	STILLWATER POWER	1999	4911	36.0155	-99.9822		0.1	7.04	0.176			0.009	0.185	0.008	0.184		
1212	CENTRAL AND SOUTH WEST SERVICES, INC.	1999	4911	35.2056	-98.0395	1715.87	34.13	17577.74	404.264			354.824	759.087	239.806	644.07	16088.47	138.35
2701	WESTERN FARMERS ELECTRIC COOP	1999	4911	36.2567	-98.6611	263.68	9.92	806.87	18.469			0.946	19.414	0.946	19.414	1.8	18.15
2210	OKLAHOMA GAS & ELECTRIC	1999	4911	36.6458	-99.4642	824.2	85.661	4344.43	110.864			6.25	117.115	6.25	117.115	11.6	28.9
1213	CENTRAL AND SOUTH WEST SERVICES, INC.	1999	4911	35.8778	-97.8346	1172.58	8.719	3110.24	23.111			0.287	23.397	0.285	23.395	2.43	46.78
1215	CENTRAL AND SOUTH WEST SERVICES, INC.	1999	4911	35.9278	-97.9205	221.39	43.569	4147.58	79.756			1.395	81.151	1.389	81.145	8.91	9.51
MB0116C	TXU ELECTRIC CO	1999	4911	29.7977	-95.2853	2411.41	91.91	15170.18	166.704			2.929	169.632	2.922	169.623	20.33	161.3
MB0117A	TXU ELECTRIC CO	1999	4911	29.772	-95.2777	354.53	13.47	1311.52	22.786			0.451	23.237	0.445	23.228	2.62	26.48
ME0006A	SOUTHWESTERN ELECTRIC POWER CO	1999	4911	29.6222	-95.4189	953.7	0.04	2559.08	67.236			0.002	67.237	0.002	67.237	9	62.46
MH0028D	STP NUCLEAROPERATING CO	1999	4911	29.6444	-95.2594	12.45		46.81	0.086			0.824	0.91	0.744	0.831	0.79	1.99
MM0023J	TXU ELECTRIC CO	1999	4911	29.873	-95.5868	485.99	1.19	9050.84	268.034			1173.611	1441.645	836.22	1104.26	28738.75	77.62
MO0014L	TXU ELECTRIC CO	1999	4911	29.6216	-95.0434	1343.65	51.129	9024.06	90.242			11.213	101.454	11.209	101.45	9.66	95.21
MR0033U	SOUTHWESTERN PUBLIC SERVICE	1999	4911	29.5997	-95.0167	0.15		4.3								0.2	0.17
NE0025C	CENTRAL POWER AND LIGHT CO	1999	4911	29.761	-95.3634	800.3	30.589	2471.7	55.001			0.909	55.908	0.909	55.908	5.9	53.78
LN3604A	J.R. MASSENGALE	1999	4911	29.7309	-95.1515	12.85	0.49	42.84	0.873			0.015	0.886	0.015	0.886	0.095	1.02
ND0054G	EEX POWER SYSTEMS	1999	4911	29.8525	-95.5828	24.11		1106.67	2.223			41.139	43.36	41.139	43.36	11.41	8.17
NE0024E	CENTRAL POWER AND LIGHT CO	1999	4911	29.738	-95.185	1501.9	57.55	2814.44	101.457			6.834	108.292	6.834	108.292	10.7	98.67
MS0011T	SOUTHWESTERN ELECTRIC POWER CO	1999	4911	29.7151	-95.0952	27.66	1.05	121.79	1.346			0.031	1.378	0.031	1.378	0.1	1.81
MQ0009F	ENTERGY GULF STATES INC	1999	4911	29.8335	-95.2493	1217	43.05	2864.53	87.135			1.278	88.413	1.278	88.413	9.1	80.3
LN0206F	LUBBOCK POWER AND LIGHT	1999	4911	29.7258	-95.0194	186.38		78.89	0.408			8.262	8.67	8.262	8.67	0.83	11.27
LN0081B	SOUTHWESTERN PUBLIC SERVICE CO	1999	4911	29.7886	-95.5528	177.08	36.319	3086.15	62.394			6.135	68.529	5.839	68.232	6.92	62.53
LN0057V	LUBBOCK POWER & LIGHT	1999	4911	29.7192	-95.2766	228.5	8.081	582.53	14.307			6.159	20.466	6.159	20.466	1.49	17.46
LL0006O	LOWER COLORADO RIVER AUTHORITY	1999	4911	29.7158	-95.1819	148.8	20.21	1186.58	35.248			2.478	37.725	2.467	37.715	3.76	36.27
LI0027L	RELIANT ENERGY INC	1999	4911	29.6465	-95.064	1700.2	4.5	24867.28	607.401			3509.643	4117.045	2479.881	3087.281	32868.9	227.88
LB0059G	SAVAGE TOLKCORPORATION	1999	4911	29.7556	-95.1004				2.512			29.518	32.03	14.042	16.554		
LB0047N	SOUTHWESTERN PUBLIC SERVICE CO	1999	4911	29.7453	-95.209	1137.15	1.439	13468.26	441.162			201.255	642.416	87.752	528.909	29387.86	141.24
LB0046P	SOUTHWESTERN PUBLIC SERVICE	1999	4911	29.8263	-94.9296	30.69	12.249	782.16	22.131			1.404	23.533	1.397	23.527	2.31	21.07
LA0045F	TENASKA IIITEXAS PARTNERS	1999	4911	29.7027	-95.2601	166.6		1234.89	2.129			31.652	33.78	31.651	33.779	2.24	49.19
JH0230L	TENASKA IV TEXAS PARTNERS LTD	1999	4911	29.6174	-95.0456	28.5		205.62	37.139			14.459	51.598	14.459	51.598	4.94	37.99
NE0026A	CENTRAL POWER AND LIGHT CO	1999	4911	29.6989	-95.381	1133.4	43.14	2578.79	78.992			1.281	80.274	1.281	80.274	8.4	74.2
TH0004D	CITY OF AUSTIN	1999	4911	28.7952	-96.0497	890.65	33.068	1511.65	58.817			6.728	65.545	6.718	65.537	8.88	79.6
HW0024U	SOUTHWESTERN PUBLIC SERVICE	1999	4911	29.4853	-94.5575	1.09		4.4	0.009			0.191	0.2	0.191	0.2	0.01	0.24
HW0081I	SOUTHWESTERN PUBLIC SERVICE CO	1999	4911	31.6921	-101.5619	228.6		694.26	30.983			12.167	43.15	12.167	43.15	3.5	26
JI0030K	CENTRAL & SOUTH WEST SERVICES INC	1999	4911	29.6452	-95.4134	522.2	19.72	1026.71	36.491			0.586	37.076	0.586	37.076	3.9	34.19
TF0012D	SOUTHWESTERN ELECTRIC POWER CO	1999	4911	32.3465	-101.9995	1574.8	2.72	22905.95	619.25			643.401	1262.651	438.749	1057.998	37958.39	188.95
YB0017V	TXU ELECTRIC CO	1999	4911	30.0461	-93.8049	984.32	37.501	5579.42	66.739			1.113	67.854	1.113	67.854	6.91	64.46
WI0025C	WEST TEXAS UTILITIES CO	1999	4911	32.0624	-96.4753	1122.45	1.04	9907.83	588.203			324.917	913.12	221.887	810.09	8801.9	13.65
WI0002O	WEST TEXAS UTILITIES	1999	4911	31.7996	-94.7235	2.56		9.65	0.106			0.194	0.3	0.11	0.217	1.52	0.25
WH0083W	MIRANT WICHITA FALLS LP	1999	4911	31.5733	-94.6495	93.13		425.82	1.84			6.26	8.1	6.26	8.1	1.01	3.35
WF0175P	NEWGULF POWER VENTURE INC	1999	4911	35.8143	-101.9187	2.6		104.16	0.977			0.384	1.36	0.384	1.36	0.1	0.4
WE0005G	CENTRAL & SOUTHWEST SERVICES INC	1999	4911	35.8108	-101.6307	333.8	12.77	726.99	25.095			0.379	25.474	0.379	25.474	3.1	21.8
WC0028Q	TXU ELECTRIC CO	1999	4911	30.3366	-95.4633	1336.55	50.881	12990.41	92.671			7.744	100.415	7.744	100.415	21.03	91.95
VC0026O	SOUTH TEXASELECTRIC COOPERATIVE INC	1999	4911	31.869	-101.7751	16.76	0.519	57.93	0.987			0.989	1.976	0.985	1.974	0.18	2.71
VC0003D	CENTRAL POWER AND LIGHT CO	1999	4911	31.9552	-101.8896	509.6	19.42	1928.61	35.515			0.576	36.091	0.576	36.091	3.7	33.3
TH0104V	UNIVERSITY OF TEXAS AT AUSTIN	1999	4911	29.1431	-95.8912	97.13		684.9	4.148			12.443	16.59	12.398	16.545	0.2	13.26
TH0006W	CITY OF AUSTIN	1999	4911	28.9821	-96.0297	216.94	15.1	706.49	25.277			1.363	26.64	1.359	26.636	2.72	26.41
HG9954A	CALPINE CORPORATION	1999	4911	31.7668	-106.3923	23.8		171.23	3.444			38.096	41.54	38.096	41.54	5.54	24.9
TF0013B	TXU ELECTRIC CO	1999	4911	32.422	-102.1076	1680.89	3.349	20496	1323.375			1698.178	3021.553	1311.562	2634.935	100122	194.14
HV0023K	GREENVILLE ELECTRIC SYSTEM	1999	4911	29.2697	-94.8138	27.85	1.09	78.23	1.727			0.033	1.76	0.033	1.76	0.11	1.8
NE0035W	ROBSTOWN UTILITY SYSTEMS	1999	4911	29.7354	-95.1071	144		345.59	0.906			5.834	6.74	4.947	5.853	0.95	25.35
TB0056E	WEST TEXAS UTILITIES CO	1999	4911	30.9216	-96.1793	4.2	0.16	13.99	0.276			0.005	0.281	0.005	0.281	0.03	0.27
TA0354E	TXU ELECTRIC CO	1999	4911	30.3707	-95.0174	38.5	1.47	346.22	2.542			0.044	2.585	0.044	2.585	0.2	2.52
TA0353G	TXU ELECTRIC CO	1999	4911	30.4123	-94.9636	1228.86	46.729	3333.17	81.668			1.62	83.284	1.609	83.272	13.33	81.7
TA0352I	TXU ELECTRIC CO	1999	4911	30.0004	-94.9536	457.63	17.44	1467.1	30.171			0.526	30.697	0.526	30.696	3.11	29.97
RL0020K	TXU ELECTRIC CO	1999	4911	29.7037	-93.9291	1773.5	4.74	28360.66	975.931			3480.308	4456.24	2486.268	3462.201	111619.38	332.62
RI0035C	TEXAS NEW MEXICO POWER CO	1999	4911	29.8908	-94.0005	617.2	0.69	2537.05	801.658			261.491	1063.149	136.072	937.726	6335.41	11.85
RE0012M	TXU ELECTRIC CO	1999	4911	29.9566	-93.8976	60.68	2.31	538.42	4.216			0.068	4.286	0.068	4.286	0.5	3.98
PG0041R	SOUTHWESTERN PUBLIC SERVICE CO	1999	4911	33.0729	-98.1883	578.2	1.529	12686.97	426.314			301.804	728.118	172.322	598.638	28889.16	132.15
PG0040T	SOUTHWESTERN PUBLIC SERVICE CO	1999	4911	33.0368	-98.1027	55.21	20.6	1478.45	37.504			2.457	39.961	2.457	39.961	3.8	35.51
PE0259K	WEST TEXAS UTILITIES CO	1999	4911	35.9657	-101.6139	0.16		0.63	0.005			0.005	0.01	0.005	0.01	0.01	

FACILITYID	FACILITYNAME	INVNETORY YEAR	SIC	LATITUDE	LONGITUDE	CO	NH3	NOX	PMCON	PMFIL	PMPRI	PM10FIL	PM10PRI	PM25FIL	PM25PRI	SO2	VOC
PC0005T	BRAZOS ELECTRIC POWER COO	1999	4911	32.0026	-97.134	16.3	0.86	78.84	1.544			0.025	1.569	0.025	1.569	0.12	0.57
PA0003W	BRAZOS ELECTRIC POWER COOPERATIVE IN	1999	4911	32.3073	-95.6868	757.13	24.94	1740.08	46.939			11.293	58.231	11.293	58.231	5.8	69.4
OC0013O	ENTERGY GULF STATES INC	1999	4911	29.8521	-97.9647	1852	148.499	9379.67	281.651			14.412	296.06	14.412	296.06	29.7	265.21
TG0044C	WEST TEXAS UTILITIES CO	1999	4911	28.8585	-96.029	19.47	12.53	769.67	22.377			11.503	33.88	11.503	33.88	5.32	17.27
CB0008C	CENTRAL POWER AND LIGHT CO	1999	4911	35.9631	-84.0039	267.6	10.18	808.78	18.422			0.302	18.725	0.302	18.725	2.9	17.5
DB0253Q	TXU ELECTRIC CO	1999	4911	36.0019	-86.5042	205.08	7.81	1363.27	13.714			0.232	13.946	0.232	13.946	1.41	13.42
DB0252S	TXU ELECTRIC CO	1999	4911	35.8367	-86.4033	436.87	36.16	2939.86	68.12			3.531	71.653	3.531	71.653	7.03	62.17
DB0251U	TXU ELECTRIC CO	1999	4911	35.8681	-86.5825	722.64	27.691	2638.29	49.528			1.07	50.598	1.048	50.576	10.52	49.55
DB0249H	TXU ELECTRIC CO	1999	4911	35.8675	-86.4131	1128.64	43.222	2470.95	79.731			1.649	81.38	1.617	81.346	18.82	74.73
CZ0017A	W TX UTILITIES CO	1999	4911	35.9356	-84.3957	266.55	9.67	1100.63	22.827			0.975	23.802	0.975	23.802	2.47	16.9
CP0230L	THERMONETICS INC	1999	4911	36.57	-87.2906	19.56		39.98	0.208			0.304	0.51	0.275	0.482	0.26	6.41
CP0065C	TXU ELECTRIC CO	1999	4911	35.6658	-84.6667	25.4	3.4	138.61	5.802			0.43	6.232	0.426	6.228	1.6	5.82
CP0026M	GARLAND MUNICIPAL POWER AND LIGHT	1999	4911	35.6386	-87.0586	6.2	17.74	1070.18	33.697			0.87	34.567	0.87	34.567	3.5	6.51
CO0003M	CITY OF COLEMAN	1999	4911	35.6414	-87.2453	19.56		78.66								0.47	4.65
CN0005T	WEST TEXAS UTILITIES CO	1999	4911	35.6487	-87.0486	162.3	6.15	413.63	11.386			0.183	11.568	0.183	11.568	1.1	10.63
HT0065Q	POWER RESOURCES LTD	1999	4911	29.4602	-95.0444	30.44		836.59	10.23			30.671	40.9	29.967	40.195	9.64	7.17
CI0012D	RELIANT ENERGY INC	1999	4911	35.7711	-84.3331	3047	116.37	4417.74	206.309			4.105	210.415	4.073	210.382	44.13	201.19
DB0384A	GARLAND MUNICIPAL POWER AND LIGHT	1999	4911	35.36	-85.4306	24.33	0.919	76.33	1.66			0.027	1.688	0.027	1.688	0.07	1.67
CD0009B	BROWNSVILLEPUBLIC UTILITIES BOARD	1999	4911	36.0161	-83.9239	23.15	0.639	181.24	1.679			9.444	11.123	9.444	11.123	1.15	9.39
CJ0026J	TXU ELECTRIC CO	1999	4911	35.4411	-86.7797	429.92	40.319	2862.64	76.82			4.37	81.193	4.34	81.168	9.6	69.6
BM0032V	TEXAS A & M UNIVERSITY	1999	4911	35.95	-83.8614	184.95		539.57	8.554			31.431	39.98	31.382	39.931	7.57	24.36
BM0010I	BRYAN MUNICIPAL ELECTRIC SYSTEM	1999	4911	35.9572	-83.9372	47.7	1.72	169.2	3.076			1.16	4.235	1.16	4.235	0.41	3.19
BM0009Q	CITY OF BRYAN	1999	4911	35.9675	-83.8831	199.7	7.61	380.76	13.231			0.226	13.457	0.226	13.457	1.4	13.22
BG0188E	CITY PUBLICSERVICE BOARD	1999	4911	34.9905	-85.3978	15.2	0.58	107.43	2.369			2.477	4.846	2.058	4.427	0.1	1
BG0187G	CITY PUBLICSERVICE	1999	4911	35.0993	-85.267	139.83	5.319	561.06	20.03			19.108	39.138	15.882	35.912	0.9	9.16
BG0186I	CITY PUBLICSERVICE	1999	4911	35.0538	-85.2063	229.13	30.57	2685.38	54.9			3.656	58.557	3.652	58.553	5.07	66.26
BG0059Q	CITY PUBLICSERVICE BOARD	1999	4911	35.0839	-85.2702	29.55	1.12	234.75	3.801			3.242	7.043	2.695	6.497	0.2	3.87
BG0057UB	CITY PUBLICSERVICE B	1999	4911	35.0508	-85.3316	162.7	15.735	6169.5	421.603			83.639	505.242	34.633	456.236	6120.7	15.7
BG0057UA	CITY PUBLICSERVICE B	1999	4911	35.0628	-85.2636	938.7	25.62	10045.19	351.673			2681.228	3032.901	1297.683	1649.356	24103.29	112.7
BG0057U	CITY PUBLICSERVICE	1999	4911	35.0616	-85.0888	342.53	5.744	2252.54	90.036			27.974	118.009	12.371	102.414	13.43	80.4
BC0015L	LOWER COLORADO RIVER AUTHORITY	1999	4911	35.0531	-85.0856	262.22	35.299	2342.79	60.424			3.146	63.57	3.142	63.567	6.34	120.71
AG0007G	SAN MIGUEL ELCTRC COOPERATIVE INC	1999	4911	35.0434	-85.2665	927	1.17	6771.65	195.634			1629.607	1825.241	1158.809	1354.445	21349.99	17.5
HJ0022B	WEST TEXAS UTILITIES CO	1999	4911	29.6939	-95.714	210.05	7.85	1505.48	16.987			0.233	17.219	0.233	17.219	1.6	13.75
HN0013E	CENTRAL POWER AND LIGHT CO	1999	4911	31.5642	-96.0552	351.1	13.35	1605.45	25.306			0.397	25.702	0.397	25.702	3.4	24.55
CD0013K	CENTRAL POWER AND LIGHT CO	1999	4911	35.9667	-83.8919	426.3	14.811	1405.41	31.067			1.393	32.458	1.393	32.458	3.3	25.6
HN0403K	FRONTERA GENERATION LTD PARTNERSHIP	1999	4911	32.6884	-102.6483	1.6		54.72	0.565			11.455	12.02	11.455	12.02	0.77	
DF0012T	DENTON MUNICIPAL UTILITIES	1999	4911	35.5222	-89.5761	113.34	5.019	597.5	9.478			0.193	9.671	0.193	9.671	1.98	9.26
HM0017H	TXU ELECTRIC CO	1999	4911	31.8257	-96.0568	62.53	8.21	567.22	14.487			1.027	15.513	1.019	15.505	1.96	14.21
HH0037F	SOUTHWESTERN ELECTRIC POWER CO	1999	4911	30.0058	-96.8896	871.09	1.21	8847.46	244.082			896.585	1140.666	619.332	863.412	27781.5	40
HG4955K	RELIANT ENERGY INC	1999	4911	32.4554	-97.0453	261.2		367.77	38.857			15.202	54.059	15.202	54.059	5.1	20
HG1495V	AES DEEPWATER INC	1999	4911	32.927	-96.7648	326.82		3215.97	0.201			1.619	1.82	0.914	1.116	4099.71	6.54
HG1169O	CALPINE CORPORATION	1999	4911	32.789	-96.8209	958.28		1520.77	32.13			40.096	72.226	38.334	70.464	11.6	3.53
HG0358Q	RELIANT ENERGY INC	1999	4911	31.5935	-102.64	279.5	23.691	1192.9	42.034			2.797	44.83	2.797	44.83	4.41	42.62
HG0357S	RELIANT ENERGY INC	1999	4911	31.5985	-102.75	193.5	5.918	1022.04	24.041			125.463	149.504	122.947	146.987	7.91	45.5
HG0356U	RELIANT ENERGY INC	1999	4911	31.5121	-102.6522	25.2	3.49	286.26	6.998			0.104	7.102	0.104	7.102	0.7	6
HG0355W	RELIANT ENERGY INC	1999	4911	31.4917	-102.625	104	15.88	1060.8	28.93			0.948	29.878	0.948	29.878	3.1	27.1
HG0354B	RELIANT ENERGY INC	1999	4911	31.4918	-102.6583	7.94		22.43	0.047			0.983	1.03	0.983	1.03	0.06	0.52
FC0018G	LOWER COLORADO RIVER AUTHORITY	1999	4911	28.6711	-97.7928	1725.04	2.27	19560.76	818.699			5871.842	6690.541	2577.697	3396.395	33182.31	288.36
HQ0012T	TXU ELECTRIC CO	1999	4911	29.363	-94.9328	1617.56	61.54	7974.29	110.275			11.198	121.472	11.198	121.472	11.87	112.17
HG0353D	RELIANT ENERGY INC	1999	4911	31.4298	-102.3806	181.7	12.699	613.96	28.778			19.573	48.351	18.138	46.915	4.1	28.9
EE0029T	EL PASO ELECTRIC CO	1999	4911	32.3418	-102.5542	488.1	35.98	2627.53	65.067			1.068	66.134	1.068	66.134	7	30.35
FB0025U	TX UTILITIES ELECTRIC CO	1999	4911	28.3775	-97.5184	1371.42	52.361	4316.15	95.677			1.775	97.451	1.759	97.436	12.61	91.87
FG0020V	RELIANT ENERGY INC	1999	4911	29.4588	-98.4102	8788.4	47.51	33412.61	1372.752			470.702	1843.455	220.8	1593.557	67583.04	176.6
FI0020W	TXU ELECTRIC CO	1999	4911	29.0021	-95.4081	661.57	2.191	12928.45	1708.297			61.921	1770.217	31.761	1740.061	83771.67	102.24
GB0037T	RELIANT ENERGY INC	1999	4911	29.2305	-95.7312	2801.8	141.159	8671.9	287.326			74.38	361.706	62.467	349.792	26.16	241
GB0153Q	TEXAS CITY COGENERATION LP	1999	4911	29.4016	-95.2531	56.9		3016.47	1.539			31.191	32.73	31.191	32.73	9.47	1.59
GF0002R	CENTRAL SOUTH WEST SERVICES INC	1999	4911	26.9537	-98.2365	634.7	0.79	5572.39	230.166			280.644	510.81	191.499	421.665	22133.79	73.2
HE0013G	WEST TEXAS UTILITIES CO	1999	4911	29.8549	-94.9096	13.26	0.59	44.22	1.055			0.017	1.072	0.017	1.072	0.1	0.87
GJ0043K	SOUTHWESTERN ELECTRIC POWER CO	1999	4911	26.2091	-97.7202	583.97	22.21	1964.07	41.908			2.41	44.318	2.41	44.318	32.8	38.48
FJ0012P	MEDINA ELECTRIC COOPERATIVE INC	1999	4911	29.0146	-95.3682	23.42	0.89	78.07	1.816			0.027	1.843	0.027	1.843	0.17	1.54
EE0157J	EL PASO ELECTRIC CO	1999	4911	27.9411	-97.1199	91.1		112.5	0.611			12.389	13	12.389	13	0.2	
GK0012K	TEXAS MUNICIPAL POWER AGENCY	1999	4911	35.5654	-101.1236	472.2	0.63	5555.03	326.396			242.045	568.441	161.777	488.17	11991.29	56.66
11539	HILDALE CITY COGENERATION FACILITY	1999	4911	34.1611	-99.2922	20.45		42.56	0.164			3.236	3.4	3.236	3.4	1.71	5.52
107790	BONANZA	1999	4911	29.8143	-95.8813	392.44	0.5	5699.93	356.818			125.277	482.095	51.874	408.692	1134.9	47.08
10795	POWER PLANT	1999	4911	29.8102	-95.8897	6.39		15.4								6.61	1.1
10819	WHITEHEAD POWER PLANT	1999	4911	31.6383	-102.893	176.9		161.3								0.02	58.3
10892	ST. GEORGE CITY POWER PLANT	1999	4911	33.9433	-98.5386	7.9		119.4	0.855			11.315	12.17	10.895	11.75	0.03	0.9
10355	GADSBY POWER PLANT	1999	4911	32.2679	-94.7249	153.8	7.1	199.77	17.42			8.664	26.083	7.292	24.709	1.43	15.24
10096	SUNNYSIDE COGENERATION FACILITY	1999	4911	31.2395	-102.888	94.72		460.37	13.163			59.097	72.26	59.077	72.24	1058.57	17.55
10823	PAYSON CITY POWER	1999	4911	31.4577	-103.521	26.26		61.43	1.885			12.145	14.03	10.297	12.183	1.75	57.44
10327	INTERMOUNTAIN GENERATION STATION	1999	4911	36.0337	-100.7268	1312.43	1.67	28260.56	1447.216			495.959	1943.176	245.605	1692.821	3698.31	157.747
10238	HUNTINGTON POWER PLANT	1999	4911	31.6485	-101.7679	739.78	0.989	15018.72	602.753			989.526	1592.279	418.678	1021.432	13901.21	88.37
10120	POWER PLANT	1999	4911	31.1846	-103.0403	23.3		104.6	0.062			0.398	0.46	0.398	0.46	2.26	6.4
10081	CARBON POWER PLANT	1999	4911	32.7728	-97.8064	62.81	0.24	2980.35	97.151			99.161	196.31	45.743	142.893	4388.07	21.563
10058	POWER PLANT	1999	4911	32.1869	-94.3197	0.74		3.54	0.052			0.178	0.23	0.178	0.23	0.22	0.27
10319	BONNETT-GEOTHERMAL POWER PLANT	1999	4911	30.0636	-93.9768	0.18		0.46	0.002			0.028	0.03	0.028	0.03	0.03	0.03
10348	ELECTRICAL GENERATION PLANT	1999	4911	32.1946	-94.9598	0.24		0.32	0.001			0.009	0.01	0.007	0.009	0.01	0.84
10237	HUNTER POWER PLANT	1999	4911	31.154	-101.3447	1057.35	1.499	20305.39	1104.413			1164.229	2268.64	551.898	1656.308	7045.49	127.32
00005	BLACK HILLS OSAGE	1999	4911	45.66	-91.54	60.69	0.06	908.49	90.737			370.757	461.494	78.758	169.495	2592.99	7.29
01002	PACIFICORP_JIM BRIDGER	1999	4911	42.63	-88.63	2738.7	2.968	37991.28	2472.757			3178.359	5651.116	2207.715	4680.467	25784.7	319.4

FACILITYID	FACILITYNAME	INVNETORY YEAR	SIC	LATITUDE	LONGITUDE	CO	NH3	NOX	PMCON	PMFIL	PMPRI	PM10FIL	PM10PRI	PM25FIL	PM25PRI	SO2	VOC
00001	BASIN ELECTRIC_LARAMIE RIVER STATION	1999	4911	45.13	-90.34	1912.56	2.84	17689.07	1503.047			1261.199	2764.246	946.514	2449.562	11067.8	229.23
00004	PACIFICORP_NAUGHTON POWER PLANT	1999	4911	43.74	-87.71	752.8	0.971	13759.54	950.25			893.944	1844.193	805.461	1755.71	21864.6	87.8
00001	PACIFICORP_DAVE JOHNSTON	1999	4911	43.77	-88.1	923.5	1.23	17570.58	689.524			1434.894	2124.418	738.799	1428.322	27915.5	110.7
00063	BLACK HILLS POWER & LGT_SIMPSON 2	1999	4911	46	-91.49	200.6	0.172	815.19	87.205			88.657	175.862	55.879	143.084	641.4	4.8
00002	BLACK HILLS POWER & LGHT SIMPSON 1	1999	4911	45.13	-92.66	31.2	0.07	520.5	14.362			18.265	32.627	11.851	26.213	1008	4.4
00046	PACIFICORP_WYODAK	1999	4911	43.29	-89.73	520.7	0.68	5564.85	385.017			356.305	741.321	223.682	608.7	9082.4	62.4

P200_ STATE_ FIPS	P200_ COUNTY_ FIPS	P200_ SITE_ID	P200_ ORIS_ FACILITY_ CODE	P200_ SIC_ PRIMARY	P200_FACILITY_NAME	P200_ SITE_ DESCRIPTION	P200_ STREET_ LINE_1	P200_ STREET_ LINE_2	P200_ STREET_ LINE_3	P200_CITY	P200_ STATE	P200_ZIP_ CODE	P200_NH3 _EMISSION_ TON_SUM	MATCH_TYPE	MATCH_ MULTIPLE	MATCH_ RATIO	NH3_TO_ APPLY_ EMISSION_ TON_SUM	P300_ STATE_ FIPS	P300_ COUNTY_ FIPS	P300_SITE_ ID
04	021	0054		0116	MAGMA COPPER BOX 37 SUPERIOR 85273		Unknown			Not Available	AZ	00000	0.03	300_NO_NH3			0.03	04	021	0402101392
04	021	0032		0182	MAGMA METALS COMPANY-SAN MANUEL SMELTER		Unknown			Not Available	AZ	00000	0.63	300_NO_NH3			0.63	04	021	0402100102
04	019	2026		1021	ASARCO PIMA MINE		Unknown			Not Available	AZ	00000	0.18	NONE			0.18			
04	003	0003		2011	CHEMSTAR LIME - DOUGLAS PLANT		Unknown			Not Available	AZ	00000	0.1	300_NO_NH3			0.1	04	003	0400300176
04	005	0009		2421	KAIBAB FOREST PRODUCTS		Unknown			Not Available	AZ	00000	0.06	NONE			0.06			
04	003	0001		2873	APACHE NITROGEN PRODUCTS INC.		Unknown			Not Available	AZ	00000	3.11	300_HAS_NH3			3.11	04	003	0400301143
04	003	0002	160	4911	APACHE STATION		Not Available			Not Available	AZ	NOT AVAIL	3.89	300_NO_NH3			3.89	04	003	0400300037
04	017	0001	113	4911	CHOLLA		Not Available			Not Available	AZ	NOT AVAIL	1.32	300_NO_NH3			1.32	04	017	0401701020
04	001	0003	6177	4911	CORONADO		Not Available			Not Available	AZ	NOT AVAIL	1.02	NONE			1.02			
04	019	0082	126	4911	IRVINGTON		Not Available			Not Available	AZ	NOT AVAIL	8.74	NONE			8.74			
04	005	0004	4941	4911	NAVAJO		Not Available			Not Available	AZ	NOT AVAIL	2.71	NONE			2.71			
04	021	U118	118	4911	SAGUARO		Not Available			Not Available	AZ	NOT AVAIL	7.31	NONE			7.31			
04	001	0004	8223	4911	SPRINGERVILLE		Not Available			Not Available	AZ	NOT AVAIL	0.98	300_NO_NH3			0.98	04	001	0400100060
04	027	U120	120	4911	YUCCA		Not Available			Not Available	AZ	NOT AVAIL	6.5	300_NO_NH3			6.5	04	027	0402700141
32	021	0500		1459	BASIC INC.		Unknown			Not Available	NV	00000	0.17	NONE			0.17			
32	019	0387		3241	NEVADA CEMENT CO		Unknown			Not Available	NV	00000	4.91	300_NO_NH3			4.91	32	019	0387
32	003	0004		3275	GENSTAR BUILDING MATERIALS BLUE DIAMOND		Unknown			Not Available	NV	00000	2.53	NONE			2.53			
32	003	P003	2322	4911	CLARK		Not Available			Not Available	NV	NOT AVAIL	4.24	300_NO_NH3			4.24	32	003	0398
32	019	0001	2330	4911	FORT CHURCHILL		Not Available			Not Available	NV	NOT AVAIL	17.39	300_NO_NH3			17.39	32	019	0091
32	003	P001	2341	4911	MOHAVE		Not Available			Not Available	NV	NOT AVAIL	2.21	300_NO_NH3			2.21	32	003	0466
32	013	5001	8224	4911	NORTH VALMY		Not Available			Not Available	NV	NOT AVAIL	0.7	300_NO_NH3			0.7	32	013	0457
32	003	P002	2324	4911	REID GARDNER		Not Available			Not Available	NV	NOT AVAIL	0.6	300_NO_NH3			0.6	32	003	0400
32	003	P004	2326	4911	SUNRISE		Not Available			Not Available	NV	NOT AVAIL	2.51	300_NO_NH3			2.51	32	003	0399
32	029	0002	2336	4911	TRACY		Not Available			Not Available	NV	NOT AVAIL	18.52	300_NO_NH3			18.52	32	029	0194
										WINNEMUCCA	NV			300_HAS_NH3				32	013	0002

P200_FACILITY_NAME	P300_ORIS_FACILITY_CODE	P300_SIC_PRIMARY	P300_FACILITY_NAME	P300_SITE_DESCRIPTION	P300_STREET_LINE_1	P300_STREET_LINE_2	P300_STREET_LINE_3	P300_CITY	P300_STATE	P300_ZIP_CODE	P300_NH3_EMISSION_TON_SUM
MAGMA COPPER BOX 37 SUPERIOR 85273		1021	BHP COPPER- SAN MANUEL OPERATIONS	BHP COPPER- SAN MANUEL OP	200 SOUTH REDDINGTON ROAD			SAN MANUEL	AZ	85631	
MAGMA METALS COMPANY-SAN MANUEL SMELTER		3331	BHP COPPER - SAN MANUEL SMELTER	BHP COPPER - SAN MANUEL S	REDDINGTON ROAD			SAN MANUEL	AZ	85631	
ASARCO PIMA MINE								Not Available	AZ		
CHEMSTAR LIME - DOUGLAS PLANT		3274	CHEMICAL LINE COMPANY - DOUGLAS FACILITY	LIME PROCESSING FACILITY	HIGHWAY 80			DOUGLAS	AZ	85607	
KAIBAB FOREST PRODUCTS									AZ		
APACHE NITROGEN PRODUCTS INC.		2873	APACHE NITROGEN PRODUCTS INC	APACHE NITROGEN PRODUCTS	1436 S. APACHE POWDER RD.			BENSON	AZ	85602	0
APACHE STATION		4911	AZ ELECTRIC POWER COOPERATIVE INC	APACHE GENERATING STATION	3525 NORTH HIGHWAY 191			COCHISE	AZ	85606	
CHOLLA		1499	CHOLLA FLYASH	FLYASH TRANSFER FACILITY	FOUR CORNERS CHOLLA PLANT			JOSEPH CITY	AZ	86032	
CORONADO									AZ		
IRVINGTON									AZ		
NAVAJO									AZ		
SAGUARO									AZ		
SPRINGERVILLE		4911	TUCSON ELECTRIC POWER CO- SPRINGERVILLE	TUCSON ELECTRIC POWER CO-	OFF RTE191,APP.15 MI SPRINGER			SPRINGERVILLE	AZ	85938	
YUCCA		4911	YUMA COGENERATION ASSOCIATES	COGENERATION FACILITY	280 N. 27TH DRIVE			YUMA	AZ	85364	
BASIC INC.								Not Available	NV		
NEVADA CEMENT CO		3241	FERNLEY		No Address Giver			FERNLEY	NV	89408	
GENSTAR BUILDING MATERIALS BLUE DIAMOND									NV		
CLARK		4911	CLARK STATION		CLARK STATION			LAS VEGAS	NV	89151	
FORT CHURCHILL		4911	FORT CHURCHILL STATION		No Address Giver			RENO	NV	89520	
MOHAVE		4911	MOHAVE GENERATING STATION		2700 EDISON WAY			LAUGHLIN	NV	89029	
NORTH VALMY		4911	VALMY GENERATING STATION		No Address Giver			RENO	NV	89520-0026	
REID GARDNER		4911	REID GARDNER STATION		No Address Giver			MOAPA	NV	89025	
SUNRISE		4911	SUNRISE STATION		6200 VEGAS VALLEY DRIVE			LAS VEGAS	NV	89121	
TRACY		4911	TRACY		INTERSTATE-80 EAST			SPARKS	NV	00000	
		2819	none		5505 CYANCO DRIVE			WINNEMUCCA	NV	89445	3.2778

ORISPL	FIPST	FIPSCNY	ORISPL_ In_NEI_V300_ Draft	SiteID_ In_NEI_ V300_ Draft	FIPST_ NUM	FIPSCNY_ NUM	PSTAT ABB	CNTYNAME	PNAME	OPRNAME	OPPRNAME	PCANAME	PL TYPE
50805	04	017			4	17	AZ	NAVAJO	ABITIBI CONSOLIDATED SNOWFLAKE DIVISION	Abitibi Consolidated		Arizona Public Service Co/PCA	NU
141	04	013	141	3316	4	13	AZ	MARICOPA	AGUA FRIA	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist/PCA	UT
160	04	003	160	0400300037	4	3	AZ	COCHISE	APACHE STATION	Arizona Electric Pwr Coop Inc		WAPA - Phoenix (LC)/PCA	UT
54594	04	021	54594	0072	4	21	AZ	PINAL	BIOSPHERE 2 CENTER INC	Biosphere 2 Center Inc		WAPA - Phoenix (LC)/PCA	NU
112	04	025			4	25	AZ	YAVAPAI	CHILDS	Arizona Public Service Co	Pinnacle West Capital Corporation	Arizona Public Service Co/PCA	UT
113	04	017	113	0001	4	17	AZ	NAVAJO	CHOLLA	Arizona Public Service Co	Pinnacle West Capital Corporation	Arizona Public Service Co/PCA	UT
6177	04	001	6177	0400100059	4	1	AZ	APACHE	CORONADO	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist/PCA	UT
143	04	013			4	13	AZ	MARICOPA	CROSSCUT	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist/PCA	UT
152	04	015			4	15	AZ	MOHAVE	DAVIS	USBR-Lower Colorado Region	US Bureau Of Reclamation	WAPA - Phoenix (LC)/PCA	UT
114	04	003			4	3	AZ	COCHISE	DOUGLAS	Arizona Public Service Co	Pinnacle West Capital Corporation	Arizona Public Service Co/PCA	UT
153	04	005			4	5	AZ	COCONINO	GLEN CANYON	USBR-Upper Colorado Region	US Bureau Of Reclamation	WAPA - Rocky Mountains/PCA	UT
54838	04	013			4	13	AZ	MARICOPA	GOULD ELECTRONICS FOIL DIVISION	Japan Energy Corp Ltd		Salt River Proj Ag I & P Dist/PCA	NU
8902	04	015			4	15	AZ	MOHAVE	HOOVER	USBR-Lower Colorado Region	US Bureau Of Reclamation	WAPA - Phoenix (LC)/PCA	UT
145	04	013			4	13	AZ	MARICOPA	HORSE MESA	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist/PCA	UT
55257	04	019			4	19	AZ	PIMA	INA ROAD WATER POLLUTION CONTROL FACILITY	PIMA County Wastewater Manage		Tucson Electric Power Co/PCA	NU
115	04	025			4	25	AZ	YAVAPAI	IRVING	Arizona Public Service Co	Pinnacle West Capital Corporation	Arizona Public Service Co/PCA	UT
126	04	019	126	0082	4	19	AZ	PIMA	IRVINGTON	Tucson Electric Power Co	UniSource Energy Corporation	Tucson Electric Power Co/PCA	UT
147	04	013	147	3317	4	13	AZ	MARICOPA	KYRENE	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist/PCA	UT
148	04	013			4	13	AZ	MARICOPA	MORMON FLAT	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist/PCA	UT
4941	04	005	4941	0004	4	5	AZ	COCONINO	NAVAJO	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist/PCA	UT
54245	04	015			4	15	AZ	MOHAVE	NELSON PLANT GENERATORS	Chemical Lime Co		WAPA - Phoenix (LC)/PCA	NU
6088	04	019			4	19	AZ	PIMA	NORTH LOOP	Tucson Electric Power Co	UniSource Energy Corporation	Tucson Electric Power Co/PCA	UT
116	04	013	116	52382	4	13	AZ	MARICOPA	OCOTILLO	Arizona Public Service Co	Pinnacle West Capital Corporation	Arizona Public Service Co/PCA	UT
6008	04	013	6008	98	4	13	AZ	MARICOPA	PALO VERDE	Arizona Public Service Co	Pinnacle West Capital Corporation	Arizona Public Service Co/PCA	UT
149	04	013			4	13	AZ	MARICOPA	ROOSEVELT	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist/PCA	UT
118	04	021	118	U118	4	21	AZ	PINAL	SAGUARO	Arizona Public Service Co	Pinnacle West Capital Corporation	Arizona Public Service Co/PCA	UT
8068	04	013	8068	3315	4	13	AZ	MARICOPA	SANTAN	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist/PCA	UT
100	04	013			4	13	AZ	MARICOPA	SOUTH CONSOLIDATED	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist/PCA	UT
8223	04	001	8223	0400100060	4	1	AZ	APACHE	SPRINGERVILLE	Tucson Electric Power Co	UniSource Energy Corporation	Tucson Electric Power Co/PCA	UT
50238	04	013			4	13	AZ	MARICOPA	STARWOOD HOTELS RESORTS	Starwood Hotels Resorts		Salt River Proj Ag I & P Dist/PCA	NU
150	04	013			4	13	AZ	MARICOPA	STEWART MTN	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist/PCA	UT
117	04	013	117	3313	4	13	AZ	MARICOPA	WEST PHOENIX	Arizona Public Service Co	Pinnacle West Capital Corporation	Arizona Public Service Co/PCA	UT
120	04	027	120	U120	4	27	AZ	YUMA	YUCCA	Arizona Public Service Co	Pinnacle West Capital Corporation	Arizona Public Service Co/PCA	UT
54694	04	027			4	27	AZ	YUMA	YUMA COGENERATION ASSOCIATES	Yuma Cogeneration Associates		Arizona Public Service Co/PCA	NU
464	08	003			8	3	CO	ALAMOSA	ALAMOSA	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
10755	08	045			8	45	CO	GARFIELD	AMERICAN ATLAS 1 COGENERATION PLANT	American Atlas #1 Ltd		Public Service Co Of Colorado/PCA	NU
54630	08	037			8	37	CO	EAGLE	AMERICAN GYPSUM COGENERATION	Centex Eagle Gypsum Co LLC		Public Service Co Of Colorado/PCA	NU
6207	08	113			8	113	CO	SAN MIGUEL	AMES	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
465	08	031	465	0008	8	31	CO	DENVER	ARAPAHOE	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
54680	08	013			8	13	CO	BOULDER	BETASSO HYDROELECTRIC PLANT	City of Boulder		Public Service Co Of Colorado/PCA	NU
515	08	069			8	69	CO	LARIMER	BIG THOMPSON	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
512	08	051			8	51	CO	GUNNISON	BLUE MESA	USBR-Upper Colorado Region	US Bureau Of Reclamation	WAPA - Rocky Mountains/PCA	UT
466	08	031			8	31	CO	DENVER	BOULDER	City of Boulder		Public Service Co Of Colorado/PCA	NU
10683	08	087			8	87	CO	MORGAN	BRUSH COGEN PROJECT PHASE 2 BCP	Colorado Cogeneration Operator		Public Service Co Of Colorado/PCA	NU
55209	08	087			8	87	CO	MORGAN	BRUSH IV	Colorado Energy Management LLC		Public Service Co Of Colorado/PCA	NU
10682	08	087			8	87	CO	MORGAN	BRUSH POWER PROJECT PHASE 1 CPP	Colorado Cogeneration Operator		Public Service Co Of Colorado/PCA	NU
6619	08	063			8	63	CO	KIT CARSON	BURLINGTON	Tri-State G & T Assn Inc		WAPA - Rocky Mountains/PCA	UT
467	08	019			8	19	CO	CLEAR CREEK	CABIN CREEK	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
468	08	077	468	0002	8	77	CO	MESA	CAMEO	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
469	08	001	469	0001	8	1	CO	ADAMS	CHEROKEE	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
470	08	101	470	0003	8	101	CO	PUEBLO	COMANCHE	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
6021	08	081	6021	0018	8	81	CO	MOFFAT	CRAIG	Tri-State G & T Assn Inc		WAPA - Rocky Mountains/PCA	UT
6159	08	085			8	85	CO	MONTROSE	CRYSTAL	USBR-Upper Colorado Region	US Bureau Of Reclamation	WAPA - Rocky Mountains/PCA	UT
496	08	029			8	29	CO	DELTA	DELTA	Delta City of		WAPA - Rocky Mountains/PCA	UT
10421	08	117			8	117	CO	SUMMIT	DILLON HYDRO PLANT	Daniel M Nyman		Public Service Co Of Colorado/PCA	NU
54671	08	103			8	103	CO	RIO BLANCO	DRAGON TRAIL GAS PROCESSING PLANT	EnCana Oil & Gas (USA) Inc	EnCana Corporation (Canada)	Public Service Co Of Colorado/PCA	NU
513	08	069			8	69	CO	LARIMER	ESTES	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
518	08	069			8	69	CO	LARIMER	FLATIRON	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
10070	08	035			8	35	CO	DOUGLAS	FOOTHILLS HYDRO PLANT	Denver City & County of		WAPA - Rocky Mountains/PCA	NU
8067	08	001			8	1	CO	ADAMS	FORT LUPTON	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
6112	08	123	6112	0023	8	123	CO	WELD	FORT ST VRAIN	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
471	08	077			8	77	CO	MESA	FRUITA	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
493	08	041	493	0003	8	41	CO	EL PASO	GEORGE BIRDSALL	Colorado Springs City of		WAPA - Rocky Mountains/PCA	UT
472	08	019			8	19	CO	CLEAR CREEK	GEORGETOWN	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
516	08	117			8	117	CO	SUMMIT	GREEN MOUNTAIN	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
525	08	107	525	0001	8	107	CO	ROUTT	HAYDEN	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
54142	08	031			8	31	CO	DENVER	HILLCREST POWERPLANT	Denver City & County of		Public Service Co Of Colorado/PCA	NU
50205	08	067			8	67	CO	LA PLATA	IGNACIO GASOLINE PLANT	Ida West Operating Services		WAPA - Rocky Mountains/PCA	NU
54596	08	123			8	123	CO	WELD	JOHNSTOWN COGENERATION	Colorado Interstate Gas Co		Public Service Co Of Colorado/PCA	NU
508	08	099	508	0006	8	99	CO	PROWERS	LAMAR PLT	Lamar City of		Public Service Co Of Colorado/PCA	UT
509	08	013			8	13	CO	BOULDER	LONGMONT	Longmont City of		Public Service Co Of Colorado/PCA	UT
520	08	077			8	77	CO	MESA	LOWER MOLINA	USBR-Upper Colorado Region	US Bureau Of Reclamation	WAPA - Rocky Mountains/PCA	UT
494	08	041			8	41	CO	EL PASO	MANITOU	Colorado Springs City of		WAPA - Rocky Mountains/PCA	UT
492	08	041	492	0004	8	41	CO	EL PASO	MARTIN DRAKE	Colorado Springs City of		WAPA - Rocky Mountains/PCA	UT
517	08	069			8	69	CO	LARIMER	MARYS LAKE	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
7372	08	083			8	83	CO	MONTEZUMA	MCPHEE	USBR-Upper Colorado Region	US Bureau Of Reclamation	WAPA - Rocky Mountains/PCA	UT
10180	08	001			8	1	CO	ADAMS	METRO WASTEWATER RECLAMATION DISTRICT	Trigen		Public Service Co Of Colorado/PCA	NU
514	08	085			8	85	CO	MONTROSE	MORROW POINT	USBR-Upper Colorado Region	US Bureau Of Reclamation	WAPA - Rocky Mountains/PCA	UT

ORISPL	FIPST	FIPSCNY	ORISPL_ In_NEI_V300_ Draft	SiteID_ In_NEI_ V300_ Draft	FIPST_ NUM	FIPSCNY_ NUM	PSTAT ABB	CNTYNAME	PNAME	OPRNAME	OPPRNAME	PCANAME	PL TYPE
6208	08	065			8	65	CO	LAKE	MOUNT ELBERT	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
10423	08	093			8	93	CO	PARK	NORTH FORK HYDRO PLANT	David A Carpenter		WAPA - Rocky Mountains/PCA	NU
527	08	085	527	0001	8	85	CO	MONTROSE	NUCLA	Tri-State G & T Assn Inc		WAPA - Rocky Mountains/PCA	UT
473	08	077			8	77	CO	MESA	PALISADE	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
6248	08	087	6248	0011	8	87	CO	MORGAN	PAWNEE	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
519	08	069			8	69	CO	LARIMER	POLE HILL	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
460	08	101	460	0008	8	101	CO	PUEBLO	PUEBLO	Aquila Networks-Colorado	Aquila Inc	Public Service Co Of Colorado/PCA	UT
6761	08	069	6761	0053	8	69	CO	LARIMER	RAWHIDE	Platte River Power Authority		Public Service Co Of Colorado/PCA	UT
8219	08	041	8219	0030	8	41	CO	EL PASO	RAY D NIXON	Colorado Springs City of		WAPA - Rocky Mountains/PCA	UT
50267	08	077			8	77	CO	MESA	REDLANDS WATER & POWER CO	Redlands Water & Power Co NUGs	Redlands Water & Power Co	Public Service Co Of Colorado/PCA	NU
6516	08	089			8	89	CO	OTERO	ROCKY FORD	Aquila Networks-Colorado	Aquila Inc	Public Service Co Of Colorado/PCA	UT
495	08	041			8	41	CO	EL PASO	RUXTON	Colorado Springs City of		WAPA - Rocky Mountains/PCA	UT
474	08	015			8	15	CO	CHAFFEE	SALIDA 1	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
475	08	015			8	15	CO	CHAFFEE	SALIDA 2	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
476	08	045			8	45	CO	GARFIELD	SHOSHONE	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
10081	08	035			8	35	CO	DOUGLAS	STRONTIA SPRINGS HYDRO PLANT	Mark T Kirk		Public Service Co Of Colorado/PCA	NU
50435	08	065			8	65	CO	LAKE	SUGARLOAF HYDRO PLANT	STS Hydropower Ltd		Public Service Co Of Colorado/PCA	NU
6206	08	067			8	67	CO	LA PLATA	TACOMA	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
54729	08	103			8	103	CO	RIO BLANCO	TAYLOR DRAW HYDROELECTRIC FACILITY	Rio Blanco Water Conserv Dist		WAPA - Rocky Mountains/PCA	NU
50707	08	123			8	123	CO	WELD	TCP 122	Thermo Cogeneration Partner LP		Public Service Co Of Colorado/PCA	NU
50708	08	123			8	123	CO	WELD	TCP 150	Thermo Cogeneration Partner LP		Public Service Co Of Colorado/PCA	NU
7233	08	041			8	41	CO	EL PASO	TESLA	Colorado Springs City of		WAPA - Rocky Mountains/PCA	UT
50709	08	123			8	123	CO	WELD	THERMO GREELEY INC	Thermo Cogeneration Partner LP		Public Service Co Of Colorado/PCA	NU
50676	08	123			8	123	CO	WELD	THERMO POWER ELECTRIC INC	Thermo Power & Electric Inc		Public Service Co Of Colorado/PCA	NU
7373	08	083			8	83	CO	MONTEZUMA	TOWAOC	USBR-Upper Colorado Region	US Bureau Of Reclamation	WAPA - Rocky Mountains/PCA	UT
10003	08	059			8	59	CO	JEFFERSON	TRIGEN COLORADO ENERGY CORP	Trigen		Public Service Co Of Colorado/PCA	NU
54372	08	013			8	13	CO	BOULDER	UNIVERSITY OF COLORADO	University of Colorado		Public Service Co Of Colorado/PCA	NU
521	08	077			8	77	CO	MESA	UPPER MOLINA	USBR-Upper Colorado Region	US Bureau Of Reclamation	WAPA - Rocky Mountains/PCA	UT
50206	08	067			8	67	CO	LA PLATA	VALLECITO HYDROELECTRIC	Ptarmigan Res & Engy Inc		WAPA - Rocky Mountains/PCA	NU
477	08	013	477	0001	8	13	CO	BOULDER	VALMONT	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
462	08	043	462	0003	8	43	CO	FREMONT	W N CLARK	Aquila Networks-Colorado	Aquila Inc	Public Service Co Of Colorado/PCA	UT
10422	08	049			8	49	CO	GRAND	WILLIAMS FORK HYDRO PLANT	Paul D Penny		WAPA - Rocky Mountains/PCA	NU
478	08	031	478	0007	8	31	CO	DENVER	ZUNI	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
1251	20	041			20	41	KS	DICKINSON	ABILENE CT	Westar Energy		Westar Energy/PCA	UT
1258	20	077			20	77	KS	HARPER	ANTHONY	Anthony City of		Aquila Networks - WPK/PCA	UT
1235	20	009	1235	00002	20	9	KS	BARTON	ARTHUR MULLERGREN	Aquila Networks-Kansas	Aquila Inc	Aquila Networks - WPK/PCA	UT
1259	20	025			20	25	KS	CLARK	ASHLAND	Ashland City of		Aquila Networks - WPK/PCA	UT
1262	20	045			20	45	KS	DOUGLAS	BALDWIN	Baldwin City City of		Kansas City Power & Light Co/PCA	UT
1263	20	157			20	157	KS	REPUBLIC	BELLEVILLE	Belleville City of		Aquila Networks - WPK/PCA	UT
1264	20	123			20	123	KS	MITCHELL	BELOIT	Beloit City of		Aquila Networks - WPK/PCA	UT
1224	20	023			20	23	KS	CHEYENNE	BIRD CITY	Midwest Energy Inc		Westar Energy/PCA	UT
1265	20	139			20	139	KS	OSAGE	BURLINGAME	Burlingame City of		Westar Energy/PCA	UT
1266	20	031			20	31	KS	COFFEY	BURLINGTON	Burlington City of		Westar Energy/PCA	UT
1268	20	133					KS	NEOSHO	CHANUTE 2				UT
7018	20	133			20	133	KS	NEOSHO	CHANUTE 3	Chanute City of		Westar Energy/PCA	UT
1230	20	175	1230	00001	20	175	KS	SEWARD	CIMARRON RIVER	Aquila Networks-Kansas	Aquila Inc	Aquila Networks - WPK/PCA	UT
1270	20	027			20	27	KS	CLAY	CLAY CENTER	Clay Center City of		Westar Energy/PCA	UT
8037	20	201			20	201	KS	WASHINGTON	CLIFTON	Aquila Networks-Kansas	Aquila Inc	Aquila Networks - WPK/PCA	UT
1271	20	125	1271	00002	20	125	KS	MONTGOMERY	COFFEYVILLE	Coffeyville City of		Westar Energy/PCA	UT
1225	20	193			20	193	KS	THOMAS	COLBY	Midwest Energy Inc		Westar Energy/PCA	UT
1272	20	193			20	193	KS	THOMAS	COLBY	Colby City of		Sunflower Electric Power Corp/PCA	UT
7013	20	035	7013	00012	20	35	KS	COWLEY	EAST 12TH STREET	Winfield City of		Westar Energy/PCA	UT
1274	20	009			20	9	KS	BARTON	ELLINWOOD	Ellinwood City of		Westar Energy/PCA	UT
1275	20	051					KS	ELLIS	ELLIS				UT
10857	20	205			20	205	KS	WILSON	FREDONIA	Archer Daniels Midland Co		Westar Energy/PCA	NU
1336	20	055	1336	00026	20	55	KS	FINNEY	GARDEN CITY	Sunflower Electric Power Corp		Sunflower Electric Power Corp/PCA	UT
7281	20	091			20	91	KS	JOHNSON	GARDNER	Gardner City of		Kansas City Power & Light Co/PCA	UT
1278	20	003			20	3	KS	ANDERSON	GARNETT MUNICIPAL	Garnett City of		Kansas City Power & Light Co/PCA	UT
1240	20	173	1240	00012	20	173	KS	SEDGWICK	GORDON EVANS EC	Westar Energy		Westar Energy/PCA	UT
1334	20	009			20	9	KS	BARTON	GREAT BEND	Midwest Energy Inc		Westar Energy/PCA	UT
1281	20	097			20	97	KS	KIOWA	GREENSBURG	Greensburg City of		Aquila Networks - WPK/PCA	UT
1283	20	041			20	41	KS	DICKINSON	HERINGTON	Herington City of		Westar Energy/PCA	UT
1285	20	065			20	65	KS	GRAHAM	HILL CITY	Hill City City of		Sunflower Electric Power Corp/PCA	UT
1286	20	009			20	9	KS	BARTON	HOISINGTON	Hoisington City of		Aquila Networks - WPK/PCA	UT
108	20	055	108	00023	20	55	KS	FINNEY	HOLCOMB	Sunflower Electric Power Corp		Sunflower Electric Power Corp/PCA	UT
1287	20	085			20	85	KS	JACKSON	HOLTON	Holton City of		Westar Energy/PCA	UT
1289	20	189			20	189	KS	STEVENS	HUGOTON 1	Hugoton City of		Sunflower Electric Power Corp/PCA	UT
7011	20	189			20	189	KS	STEVENS	HUGOTON 2	Hugoton City of		Sunflower Electric Power Corp/PCA	UT
1248	20	155	1248	00033	20	155	KS	RENO	HUTCHINSON EC	Westar Energy		Westar Energy/PCA	UT
1291	20	001	1291	00011	20	1	KS	ALLEN	IOLA	Iola City of		Westar Energy/PCA	UT
6068	20	149	6068	00001	20	149	KS	POTTAWATOMIE	JEFFREY EC	Westar Energy		Westar Energy/PCA	UT
6579	20	187			20	187	KS	STANTON	JOHNSON	Johnson City of		Sunflower Electric Power Corp/PCA	UT
1233	20	057	1233	00001	20	57	KS	FORD	JUDSON LARGE	Aquila Networks-Kansas	Aquila Inc	Aquila Networks - WPK/PCA	UT
50453	20	209			20	209	KS	WYANDOTTE	KANSAS CITY	Joe Schriner		Kansas City City Of/PCA	NU
10279	20	045			20	45	KS	DOUGLAS	KANSAS RIVER PROJECT	Bowersock Mills Power Co, The		Westar Energy/PCA	NU
54811	20	161			20	161	KS	RILEY	KANSAS STATE UNIVERSITY UTILITIES POWER PLANT	Kansas State University		Westar Energy/PCA	NU
1294	20	209	1294	00049	20	209	KS	WYANDOTTE	KAW	Kansas City City of		Kansas City City Of/PCA	UT
1296	20	095			20	95	KS	KINGMAN	KINGMAN	Kingman City of		Aquila Networks - WPK/PCA	UT

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1241	20	107	1241	00005	20	107	KS	LINN	LACYGNE	Kansas City Power & Light Co	Great Plains Energy Inc	Kansas City Power & Light Co/PCA	UT
1299	20	145	1299	00010	20	145	KS	PAWNEE	LARNED	Larned City of		Westar Energy/PCA	UT
1250	20	045	1250	00014	20	45	KS	DOUGLAS	LAWRENCE EC	Westar Energy		Westar Energy/PCA	UT
1300	20	105			20	105	KS	LINCOLN	LINCOLN	Lincoln Center City of		Aquila Networks - WPK/PCA	UT
50317	20	173			20	173	KS	SEDGWICK	LOVE BOX CO	Love Box Co Inc		Westar Energy/PCA	NU
1305	20	113	1305	00014	20	113	KS	MCPHERSON	MCPHERSON 2	McPherson City of		Westar Energy/PCA	UT
7515	20	113			20	113	KS	MCPHERSON	MCPHERSON 3	McPherson City of		Westar Energy/PCA	UT
1306	20	119			20	119	KS	MEADE	MEADE	Meade City of		Aquila Networks - WPK/PCA	UT
1307	20	143			20	143	KS	OTTAWA	MINNEAPOLIS	Minneapolis City of		Westar Energy/PCA	UT
1308	20	173			20	173	KS	SEDGWICK	MULVANE	Mulvane City of		Westar Energy/PCA	UT
1242	20	173	1242	00014	20	173	KS	SEDGWICK	MURRAY GILL EC	Westar Energy		Westar Energy/PCA	UT
6064	20	209	6064	00008	20	209	KS	WYANDOTTE	NEARMAN CREEK	Kansas City City of		Kansas City City Of/PCA	UT
1309	20	205			20	205	KS	WILSON	NEODESHA	Neodesha City of		Westar Energy/PCA	UT
1243	20	099	1243	00001	20	99	KS	LABETTE	NEOSHO	Westar Energy		Westar Energy/PCA	UT
1310	20	137			20	137	KS	NORTON	NORTON	Norton City of		Aquila Networks - WPK/PCA	UT
1313	20	139			20	139	KS	OSAGE	OSAGE CITY	Osage City City of		Westar Energy/PCA	UT
1314	20	121			20	121	KS	MIAMI	OSAWATOMIE	Osawatomie City of		Kansas City Power & Light Co/PCA	UT
1315	20	141			20	141	KS	OSBORNE	OSBORNE	Osborne City of		Aquila Networks - WPK/PCA	UT
1261	20	015			20	15	KS	BUTLER	PLANT NO 1	Augusta City of		Westar Energy/PCA	UT
6791	20	015			20	15	KS	BUTLER	PLANT NO 2	Augusta City of		Westar Energy/PCA	UT
1317	20	151	1317	00005	20	151	KS	PRATT	PRATT	Pratt City of		Aquila Networks - WPK/PCA	UT
7447	20	151			20	151	KS	PRATT	PRATT 2	Pratt City of		Aquila Networks - WPK/PCA	UT
1295	20	209	1295	00048	20	209	KS	WYANDOTTE	QUINDARO	Kansas City City of		Kansas City City Of/PCA	UT
50053	20	155					KS	RENO	REPUBLIC PAPERBOARD CO INC				NU
1239	20	021	1239	00002	20	21	KS	CHEROKEE	RIVERTON	Empire District Electric Co		Empire District Electric Co/PCA	UT
1319	20	167			20	167	KS	RUSSELL	RUSSELL	Russell City of		Aquila Networks - WPK/PCA	UT
1320	20	131			20	131	KS	NEMAHA	SABETHA	Sabetha City of		Westar Energy/PCA	UT
1324	20	199			20	199	KS	WALLACE	SHARON SPRING	Sharon Springs City of		Sunflower Electric Power Corp/PCA	UT
1321	20	023			20	23	KS	CHEYENNE	ST FRANCIS	St Francis City of		Sunflower Electric Power Corp/PCA	UT
1322	20	185			20	185	KS	STAFFORD	ST JOHN	St John City of		Westar Energy/PCA	UT
1325	20	185			20	185	KS	STAFFORD	STAFFORD	Stafford City of		Westar Energy/PCA	UT
1326	20	159			20	159	KS	RICE	STERLING	Sterling City of		Westar Energy/PCA	UT
1327	20	163			20	163	KS	ROOKS	STOCKTON	Stockton City of		Aquila Networks - WPK/PCA	UT
1252	20	177	1252	00030	20	177	KS	SHAWNEE	TECUMSEH EC	Westar Energy		Westar Energy/PCA	UT
1328	20	149			20	149	KS	POTTAWATOMIE	WAMEGO	Wamego City of		Westar Energy/PCA	UT
1329	20	201			20	201	KS	WASHINGTON	WASHINGTON	Washington City of		Westar Energy/PCA	UT
7339	20	191			20	191	KS	SUMNER	WELLINGTON CITY	Wellington City of		Westar Energy/PCA	UT
1330	20	191	1330	00019	20	191	KS	SUMNER	WELLINGTON MUNICIPAL	Wellington City of		Westar Energy/PCA	UT
1332	20	035			20	35	KS	COWLEY	WEST 14TH STREET	Winfield City of		Westar Energy/PCA	UT
50169	20	173			20	173	KS	SEDGWICK	WICHITA PLANT	Vulcan Materials Co		Westar Energy/PCA	NU
210	20	031			20	31	KS	COFFEY	WOLF CREEK	Wolf Creek Nuclear Oper Corp		Kansas City Power & Light Co/PCA	UT
2465	35	045	2465	0029	35	45	NM	SAN JUAN	ANIMAS	Farmington City of		WAPA - Rocky Mountains/PCA	UT
54221	35	045			35	45	NM	SAN JUAN	BLANCO COMPRESSOR STATION	El Paso Corporation	El Paso Energy	WAPA - Rocky Mountains/PCA	NU
2453	35	015			35	15	NM	EDDY	CARLSBAD	Southwestern Public Service Co	Xcel Energy Inc	Southwestern Public Service Co/PCA	UT
54667	35	017			35	17	NM	GRANT	CHINO MINES CO	Phelps Dodge Corp		Public Service Co Of NM/PCA	NU
50997	35	031			35	31	NM	MCKINLEY	CINIZA REFINERY	Giant Industries Arizona Inc		Public Service Co Of NM/PCA	NU
50905	35	001			35	1	NM	BERNALILLO	COGENERATION PLANT	University of New Mexico		Public Service Co Of NM/PCA	NU
2454	35	025	2454	0054	35	25	NM	LEA	CUNNINGHAM	Southwestern Public Service Co	Xcel Energy Inc	Southwestern Public Service Co/PCA	UT
6402	35	051			35	51	NM	SIERRA	ELEPHANT BUTTE	USBR-Upper Colorado Region	US Bureau Of Reclamation	WAPA - Rocky Mountains/PCA	UT
87	35	031	87	0032	35	31	NM	MCKINLEY	ESCALANTE	Tri-State G & T Assn Inc		WAPA - Rocky Mountains/PCA	UT
50906	35	001			35	1	NM	BERNALILLO	FORD UTILITIES CENTER	University of New Mexico		Public Service Co Of NM/PCA	NU
2442	35	045	2442	0002	35	45	NM	SAN JUAN	FOUR CORNERS	Arizona Public Service Co	Pinnacle West Capital Corporation	Arizona Public Service Co/PCA	UT
54208	35	023			35	23	NM	HIDALGO	HIDALGO SMELTER	Phelps Dodge Corp		Public Service Co Of NM/PCA	NU
2447	35	047			35	47	NM	SAN MIGUEL	LAS VEGAS	Public Service Co of NM	PNM Resources Inc	Public Service Co Of NM/PCA	UT
2446	35	025	2446	0034	35	25	NM	LEA	MADDOX	Southwestern Public Service Co	Xcel Energy Inc	Southwestern Public Service Co/PCA	UT
54814	35	045			35	45	NM	SAN JUAN	MILAGRO COGENERATION PLANT	Williams Energy		WAPA - Rocky Mountains/PCA	NU
584	35	045			35	45	NM	SAN JUAN	NAVAJO DAM	Farmington City of		WAPA - Rocky Mountains/PCA	UT
54975	35	013			35	13	NM	DONA ANA	NEW MEXICO STATE UNIVERSITY	New Mexico State University		ERCOT ISO/PCA	NU
55312	35	017					NM	GRANT	PHELPS DODGE COBRE MINING CO				NU
54734	35	017			35	17	NM	GRANT	PHELPS DODGE TYRONE INC	Phelps Dodge Corp		Public Service Co Of NM/PCA	NU
2468	35	007	2468	0001	35	7	NM	COLFAX	RATON	Raton Public Service Co		Public Service Co Of Colorado/PCA	UT
2450	35	001	2450	3500100011	35	1	NM	BERNALILLO	REEVES	Public Service Co of NM	PNM Resources Inc	Public Service Co Of NM/PCA	UT
2444	35	013	2444	0002	35	13	NM	DONA ANA	RIO GRANDE	El Paso Electric Co	El Paso Energy	ERCOT ISO/PCA	UT
2451	35	045	2451	0902	35	45	NM	SAN JUAN	SAN JUAN	Public Service Co of NM	PNM Resources Inc	Public Service Co Of NM/PCA	UT
54669	35	045			35	45	NM	SAN JUAN	SAN JUAN BASIN GAS PLANT	Conoco		Public Service Co Of NM/PCA	NU
10339	35	001			35	1	NM	BERNALILLO	SOUTHSIDE WATER RECLAMATION PLANT	Albuquerque City of		Public Service Co Of NM/PCA	NU
2469	35	037			35	37	NM	QUAY	TUCUMCARI	Southwestern Public Service Co	Xcel Energy Inc	Southwestern Public Service Co/PCA	UT
54205	35	045			35	45	NM	SAN JUAN	WILLIAMS FIELD SERVICES KUTZ PLANT	Williams Energy		WAPA - Rocky Mountains/PCA	NU
10671	40	079			40	79	OK	LE FLORE	AES SHADY POINT INC	AES NUGs	AES Corp	Oklahoma Gas & Electric Co/PCA	NU
3006	40	015	3006	2699	40	15	OK	CADDO	ANADARKO	Western Farmers Elec Coop Inc		Western Farmers Elec Coop Inc/PCA	UT
3000	40	119	3000	1247	40	119	OK	PAYNE	BOOMER LAKE STATION	Stillwater Utilities Authority		Grand River Dam Authority/PCA	UT
6415	40	089			40	89	OK	MCCURTAIN	BROKEN BOW	USCE-Tulsa District	US Army Corp Of Engineers	Southwestern Power Admin/PCA	UT
50991	40	097			40	97	OK	MAYES	CALPINE PRYOR INC	Calpine		American Electric Power - West (SPP)/PCA	NU
54702	40	093			40	93	OK	MAJOR	CHANEY DELL PLANT	Western Gas Resources		Western Farmers Elec Coop Inc/PCA	NU
8059	40	031	8059	1211	40	31	OK	COMANCHE	COMANCHE	Public Service Co of Oklahoma	American Electric Power Co Inc	American Electric Power - West (SPP)/PCA	UT
7185	40	071	7185	2929	40	71	OK	KAY	CONOCO	Oklahoma Gas & Electric Co	OGE Energy Corporation	Oklahoma Gas & Electric Co/PCA	UT
2975	40	119			40	119	OK	PAYNE	CUSHING	Cushing City of		Grand River Dam Authority/PCA	UT
2950	40	047			40	47	OK	GARFIELD	ENID	Oklahoma Gas & Electric Co	OGE Energy Corporation	Oklahoma Gas & Electric Co/PCA	UT

ORISPL	FIPST	FIPSCNY	ORISPL_ In_NEI_V300_ Draft	SiteID_ In_NEI_ V300_ Draft	FIPST_ NUM	FIPSCNY_ NUM	PSTAT ABB	CNTYNAME	PNAME	OPRNAME	OPPRNAME	PCANAME	PL TYPE
6419	40	061			40	61	OK	HASKELL	EUFAULA	USCE-Tulsa District	US Army Corp Of Engineers	Southwestern Power Admin/PCA	UT
3003	40	021			40	21	OK	CHEROKEE	FORT GIBSON	USCE-Tulsa District	US Army Corp Of Engineers	Southwestern Power Admin/PCA	UT
165	40	097	165	1799	40	97	OK	MAYES	GRDA	Grand River Dam Authority		Grand River Dam Authority/PCA	UT
2951	40	109	2951	2208	40	109	OK	OKLAHOMA	HORSESHOE LAKE	Oklahoma Gas & Electric Co	OGE Energy Corporation	Oklahoma Gas & Electric Co/PCA	UT
6772	40	023	6772	2700	40	23	OK	CHOCTAW	HUGO	Western Farmers Elec Coop Inc		Western Farmers Elec Coop Inc/PCA	UT
7545	40	071			40	71	OK	KAY	KAW HYDRO	Oklahoma Municipal Power Auth		American Electric Power - West (SPP)/PCA	UT
2984	40	143			40	143	OK	TULSA	KEYSTONE	USCE-Tulsa District	US Army Corp Of Engineers	Southwestern Power Admin/PCA	UT
2986	40	073			40	73	OK	KINGFISHER	KINGFISHER	Kingfisher City of		Western Farmers Elec Coop Inc/PCA	UT
2991	40	055			40	55	OK	GREER	MANGUM	Mangum City of		Western Farmers Elec Coop Inc/PCA	UT
2980	40	097			40	97	OK	MAYES	MARKHAM	Grand River Dam Authority		Grand River Dam Authority/PCA	UT
3008	40	153	3008	2701	40	153	OK	WOODWARD	MOORELAND	Western Farmers Elec Coop Inc		Western Farmers Elec Coop Inc/PCA	UT
2952	40	101	2952	2209	40	101	OK	MUSKOGEE	MUSKOGEE	Oklahoma Gas & Electric Co	OGE Energy Corporation	Oklahoma Gas & Electric Co/PCA	UT
10362	40	101			40	101	OK	MUSKOGEE	MUSKOGEE MILL	Fort James Operating Co		Oklahoma Gas & Electric Co/PCA	NU
2953	40	017	2953	2205	40	17	OK	CANADIAN	MUSTANG	Oklahoma Gas & Electric Co	OGE Energy Corporation	Oklahoma Gas & Electric Co/PCA	UT
2963	40	131	2963	1212	40	131	OK	ROGERS	NORTHEASTERN	Public Service Co of Oklahoma	American Electric Power Co Inc	American Electric Power - West (SPP)/PCA	UT
54779	40	119			40	119	OK	PAYNE	OKLAHOMA STATE UNIVERSITY	Oklahoma State University		Oklahoma Gas & Electric Co/PCA	NU
2981	40	097			40	97	OK	MAYES	PENSACOLA	Grand River Dam Authority		Grand River Dam Authority/PCA	UT
762	40	071	762	1314	40	71	OK	KAY	PONCA	Ponca City City of		Oklahoma Gas & Electric Co/PCA	UT
52188	40	071			40	71	OK	KAY	PONCA CITY REFINERY	Conoco		Oklahoma Gas & Electric Co/PCA	NU
2997	40	071			40	71	OK	KAY	PONCA DIESEL	Ponca City City of		Oklahoma Gas & Electric Co/PCA	UT
50558	40	109			40	109	OK	OKLAHOMA	POWERSMITH COGEN PROJECT	General Electric Co	General Electric Company	Oklahoma Gas & Electric Co/PCA	NU
4940	40	143	4940	1215	40	143	OK	TULSA	RIVERSIDE	Public Service Co of Oklahoma	American Electric Power Co Inc	American Electric Power - West (SPP)/PCA	UT
2985	40	135			40	135	OK	SEQUOYAH	ROBERT S KERR	USCE-Tulsa District	US Army Corp Of Engineers	Southwestern Power Admin/PCA	UT
2982	40	097			40	97	OK	MAYES	SALINA	Grand River Dam Authority		Grand River Dam Authority/PCA	UT
2956	40	133	2956	2210	40	133	OK	SEMINOLE	SEMINOLE	Oklahoma Gas & Electric Co	OGE Energy Corporation	Oklahoma Gas & Electric Co/PCA	UT
6095	40	103	6095	2211	40	103	OK	NOBLE	SOONER	Oklahoma Gas & Electric Co	OGE Energy Corporation	Oklahoma Gas & Electric Co/PCA	UT
2964	40	015	2964	1214	40	15	OK	CADDO	SOUTHWESTERN	Public Service Co of Oklahoma	American Electric Power Co Inc	American Electric Power - West (SPP)/PCA	UT
3004	40	135			40	135	OK	SEQUOYAH	TENKILLER FERRY	USCE-Tulsa District	US Army Corp Of Engineers	Southwestern Power Admin/PCA	UT
2965	40	143	2965	1213	40	143	OK	TULSA	TULSA	Public Service Co of Oklahoma	American Electric Power Co Inc	American Electric Power - West (SPP)/PCA	UT
50307	40	027			40	27	OK	CLEVELAND	UNIVERSITY OF OKLAHOMA	University of Oklahoma		Oklahoma Gas & Electric Co/PCA	NU
50192	40	089			40	89	OK	MCCURTAIN	VALLIANT OK	Weyerhaeuser Co		American Electric Power - West (SPP)/PCA	NU
50660	40	143			40	143	OK	TULSA	WALTER B HALL RESOURCE RECOVERY FACILITY	Ogden Energy		American Electric Power - West (SPP)/PCA	NU
2987	40	101			40	101	OK	MUSKOGEE	WEBBERS FALLS	USCE-Tulsa District	US Army Corp Of Engineers	Southwestern Power Admin/PCA	UT
2966	40	107			40	107	OK	OKFUSKEE	WELEETKA	Public Service Co of Oklahoma	American Electric Power Co Inc	American Electric Power - West (SPP)/PCA	UT
2958	40	153			40	153	OK	WOODWARD	WOODWARD	Oklahoma Gas & Electric Co	OGE Energy Corporation	Oklahoma Gas & Electric Co/PCA	UT
50198	40	089			40	89	OK	MCCURTAIN	WRIGHT CITY OK	Weyerhaeuser Co		American Electric Power - West (SPP)/PCA	NU
3581	48	187			48	187	TX	GUADALUPE	ABBOTT TP 3	Guadalupe Blanco River Auth		ERCOT ISO/PCA	UT
3517	48	441	3517	TB0056E	48	441	TX	TAYLOR	ABILENE	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
10670	48	201			48	201	TX	HARRIS	AES DEEPWATER INC	AES NUGs	AES Corp	ERCOT ISO/PCA	NU
6128	48	465			48	465	TX	VAL VERDE	AMISTAD DAM & POWER	International Bound & Wtr Comm		ERCOT ISO/PCA	UT
3594	48	453			48	453	TX	TRAVIS	AUSTIN	Lower Colorado River Authority		ERCOT ISO/PCA	UT
54940	48	453			48	453	TX	TRAVIS	AUSTIN STATE HOSPITAL	Austin State Hospital		ERCOT ISO/PCA	NU
4939	48	355	4939	NE0024E	48	355	TX	NUECES	BARNEY M DAVIS	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
10317	48	309			48	309	TX	MCLENNAN	BAYLOR UNIVERSITY COGENERATION	Aramark Corp		ERCOT ISO/PCA	NU
10298	48	201			48	201	TX	HARRIS	BAYOU COGENERATION PLANT	Air Liquide America Corp		ERCOT ISO/PCA	NU
10692	48	201			48	201	TX	HARRIS	BAYTOWN TURBINE GENERATOR PROJECT	Exxon Mobil		ERCOT ISO/PCA	NU
50625	48	245			48	245	TX	JEFFERSON	BEAUMONT REFINERY	Exxon Mobil		Entergy Electric System/PCA	NU
54458	48	461			48	461	TX	UPTON	BENEDUM PLANT	Western Gas Resources		ERCOT ISO/PCA	NU
3497	48	161	3497	FI0020W	48	161	TX	FREESTONE	BIG BROWN	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
10569	48	227			48	227	TX	HOWARD	BIG SPRING TEXAS REFINERY	Fina Oil Chemical Co		ERCOT ISO/PCA	NU
54979	48	227			48	227	TX	HOWARD	BIG SPRING WIND POWER FACILITY	New World Power TX Ren Elec LP		ERCOT ISO/PCA	NU
55064	48	233	55064	HW0081I	48	233	TX	HUTCHINSON	BLACK HAWK STATION	Quixx Power Services		Southwestern Public Service Co/PCA	NU
50067	48	233			48	233	TX	HUTCHINSON	BORGER PLANT	Sid Richardson Carbon Ltd		Southwestern Public Service Co/PCA	NU
50404	48	057			48	57	TX	CALHOUN	BP CHEMICALS GREEN LAKE PLANT	BP Amoco		ERCOT ISO/PCA	NU
7131	48	303			48	303	TX	LUBBOCK	BRANDON STATION	Lubbock City of		Southwestern Public Service Co/PCA	UT
55053	48	497			48	497	TX	WISE	BRIDGEPORT GAS PROCESSING PLANT	Mitchell Gas Services LP		ERCOT ISO/PCA	NU
3558	48	445			48	445	TX	TERRY	BROWNFIELD	Brownfield City of		Southwestern Public Service Co/PCA	UT
3561	48	041	3561	BM0010I	48	41	TX	BRAZOS	BRYAN	Bryan City of		ERCOT ISO/PCA	UT
3595	48	053			48	53	TX	BURNET	BUCHANAN	Lower Colorado River Authority		ERCOT ISO/PCA	UT
3574	48	113	3574	DB0384A	48	113	TX	DALLAS	C E NEWMAN	Garland City of		ERCOT ISO/PCA	UT
52176	48	227			48	227	TX	HOWARD	C R WING COGENERATION PLANT	Power Resources Ltd		ERCOT ISO/PCA	NU
791	48	091			48	91	TX	COMAL	CANYON	Guadalupe Blanco River Auth		ERCOT ISO/PCA	UT
3460	48	071	3460	CI0012D	48	71	TX	CHAMBERS	CEDAR BAYOU	Texas Genco	CenterPoint Energy	ERCOT ISO/PCA	NU
10243	48	355			48	355	TX	NUECES	CELANESE ENGINEERING RESIN INC	Celanese Engineering Resin Inc		ERCOT ISO/PCA	NU
10184	48	453			48	453	TX	TRAVIS	CENTRAL UTILITY PLANT	Minnesota Mining & Mfg Co		ERCOT ISO/PCA	NU
10418	48	039			48	39	TX	BRAZORIA	CHOCOLATE BAYOU PLANT	Solutia Inc		ERCOT ISO/PCA	NU
10154	48	039			48	39	TX	BRAZORIA	CHOCOLATE BAYOU WORKS	BP Amoco		ERCOT ISO/PCA	NU
10741	48	201			48	201	TX	HARRIS	CLEAR LAKE COGENERATION LTD	Calpine		ERCOT ISO/PCA	NU
50815	48	201			48	201	TX	HARRIS	COGEN LYONDELL INC	Dynegy Marketing & Trade	Dynegy Inc	ERCOT ISO/PCA	NU
10804	48	245					TX	JEFFERSON	COGEN POWER LP				NU
3566	48	083			48	83	TX	COLEMAN	COLEMAN	Coleman City of		ERCOT ISO/PCA	UT
6178	48	175	6178	GF0002R	48	175	TX	GOLIAD	COLETO CREEK	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
3500	48	085	3500	CP0065C	48	85	TX	COLLIN	COLLIN	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
6145	48	425			48	425	TX	SOMERVELL	COMANCHE PEAK	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
9	48	141			48	141	TX	EL PASO	COPPER	El Paso Electric Co	El Paso Energy	ERCOT ISO/PCA	UT
50475	48	355			48	355	TX	NUECES	CORPUS CHRISTI PLANT	Occidental Chemical Corp		ERCOT ISO/PCA	NU
10203	48	355			48	355	TX	NUECES	CORPUS CHRISTI REFINERY	Coastal Refining&Marketing Inc		ERCOT ISO/PCA	NU
6243	48	041	6243	BM0009Q	48	41	TX	BRAZOS	DANSBY	Bryan City of		ERCOT ISO/PCA	UT

ORISPL	FIPST	FIPSCNY	ORISPL_ In_NEI_V300_ Draft	SiteID_ In_NEI_ V300_ Draft	FIPST_ NUM	FIPSCNY_ NUM	PSTAT ABB	CNTYNAME	PNAME	OPRNAME	OPPRNAME	PCANAME	PL TYPE
3548	48	453	3548	TH0004D	48	453	TX	TRAVIS	DECKER CREEK	Austin City of		ERCOT ISO/PCA	UT
8063	48	221	8063	HQ0012T	48	221	TX	HOOD	DECORDOVA	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
3461	48	201	3461	HG0356U	48	201	TX	HARRIS	DEEPWATER	Texas Genco	CenterPoint Energy	ERCOT ISO/PCA	NU
50471	48	201			48	201	TX	HARRIS	DEER PARK PLANT	Occidental Chemical Corp		ERCOT ISO/PCA	NU
55399	48	201			48	201	TX	HARRIS	DELAWARE MOUNTAIN WINDFARM	General Electric Wind Energy	General Electric Company	ERCOT ISO/PCA	NU
6416	48	181			48	181	TX	GRAYSON	DENISON	USCE-Tulsa District	US Army Corp Of Engineers	Southwestern Power Admin/PCA	UT
50569	48	121			48	121	TX	DENTON	DFW GAS RECOVERY	DFW Gas Recovery		ERCOT ISO/PCA	NU
3582	48	187			48	187	TX	GUADALUPE	DUNLAP TP 1	Guadalupe Blanco River Auth		ERCOT ISO/PCA	UT
3436	48	057	3436	CB0008C	48	57	TX	CALHOUN	E S JOSLIN	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
3489	48	439	3489	TA0352I	48	439	TX	TARRANT	EAGLE MOUNTAIN	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
3437	48	323			48	323	TX	MAVERICK	EAGLE PASS	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
54943	48	365			48	365	TX	PANOLA	EAST TEXAS GAS PLANT	Duke Energy Power Services	Duke Energy Corporation	American Electric Power - West (SPP)/PCA	NU
54332	48	227			48	227	TX	HOWARD	EAST VEALMOOR GAS PLANT	Vealmoor Gas Plant		OFF-G/PCA	NU
54461	48	467					TX	VAN ZANDT	EDGEWOOD GAS PLANT				NU
50615	48	353			48	353	TX	NOLAN	ENCOGEN ONE	EEX Power Systems		ERCOT ISO/PCA	NU
10072	48	233			48	233	TX	HUTCHINSON	ENGINEERED CARBONS BORGER COGENERATION	Engineered Carbons Inc		Southwestern Public Service Co/PCA	NU
10187	48	361			48	361	TX	ORANGE	ENGINEERED CARBONS ECHO COGENERATION	Engineered Carbons Inc		Entergy Electric System/PCA	NU
10261	48	071			48	71	TX	CHAMBERS	ENTERPRISE PRODUCTS OPERATING LP	Enterprise Products Operatg LP		ERCOT ISO/PCA	NU
54962	48	499			48	499	TX	WOOD	EXXON HAWKINS GAS PLANT	Exxon Mobil		American Electric Power - West (SPP)/PCA	NU
10436	48	201			48	201	TX	HARRIS	EXXON MOBIL CO USA BAYTOWN PP3 PP4	Exxon Mobil		ERCOT ISO/PCA	NU
6410	48	427			48	427	TX	STARR	FALCON DAM & POWER	International Bound & Wtr Comm		ERCOT ISO/PCA	UT
6179	48	149	6179	FC0018G	48	149	TX	FAYETTE	FAYETTE POWER PRJ	Lower Colorado River Authority		ERCOT ISO/PCA	UT
10554	48	057			48	57	TX	CALHOUN	FORMOSA UTILITY VENTURE LTD	Formosa Plastics Corp		ERCOT ISO/PCA	NU
10136	48	157			48	157	TX	FORT BEND	FORT BEND UTILITIES CO	Imperial Co		ERCOT ISO/PCA	NU
4938	48	253	4938	JI0030K	48	253	TX	JONES	FORT PHANTOM	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
3520	48	371			48	371	TX	PECOS	FORT STOCKTON	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
55311	48	039			48	39	TX	BRAZORIA	FREEPORT	BASF		ERCOT ISO/PCA	NU
55098	48	215			48	215	TX	HIDALGO	FRONTERA GENERATION FACILITY	CSW Energy Inc		ERCOT ISO/PCA	NU
54948	48	003			48	3	TX	ANDREWS	FULLERTON PLANT	GPM Gas Services Co		ERCOT ISO/PCA	NU
6136	48	185	6136	GK0012K	48	185	TX	GRIMES	GIBBONS CREEK	Texas Municipal Power Agency		ERCOT ISO/PCA	UT
3490	48	503	3490	YB0017V	48	503	TX	YOUNG	GRAHAM	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
3597	48	053			48	53	TX	BURNET	GRANITE SHOALS	Lower Colorado River Authority		ERCOT ISO/PCA	UT
3464	48	201	3464	HG0353D	48	201	TX	HARRIS	GREENS BAYOU	Texas Genco	CenterPoint Energy	ERCOT ISO/PCA	NU
3583	48	177			48	177	TX	GONZALES	H 4	Guadalupe Blanco River Auth		ERCOT ISO/PCA	UT
3584	48	177			48	177	TX	GONZALES	H 5	Guadalupe Blanco River Auth		ERCOT ISO/PCA	UT
3491	48	439	3491	TA0353G	48	439	TX	TARRANT	HANDLEY	Exelon Generation	Exelon Corporation	ERCOT ISO/PCA	NU
6193	48	375	6193	PG0041R	48	375	TX	POTTER	HARRINGTON	Southwestern Public Service Co	Xcel Energy Inc	Southwestern Public Service Co/PCA	UT
3465	48	201			48	201	TX	HARRIS	HIRAM CLARKE	Texas Genco	CenterPoint Energy	ERCOT ISO/PCA	NU
3549	48	453	3549	TH0006W	48	453	TX	TRAVIS	HOLLY STREET	Austin City of		ERCOT ISO/PCA	UT
50043	48	201			48	201	TX	HARRIS	HOUSTON CHEMICAL COMPLEX BATTLEGROUND SITE	Occidental Chemical Corp		ERCOT ISO/PCA	NU
55313	48	409			48	409	TX	SAN PATRICIO	INGLESIDE COGENERATION	Occidental Chemical Corp		ERCOT ISO/PCA	NU
3598	48	053			48	53	TX	BURNET	INKS	Lower Colorado River Authority		ERCOT ISO/PCA	UT
10425	48	361			48	361	TX	ORANGE	INLAND PAPERBOARD AND PACKAGING	Inland Corp		Entergy Electric System/PCA	NU
7097	48	029	7097	BG0057UB	48	29	TX	BEXAR	J K SPRUCE	San Antonio Public Service Bd		ERCOT ISO/PCA	UT
3438	48	215	3438	HN0013E	48	215	TX	HIDALGO	J L BATES	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
3604	48	303	3604	LN3604A	48	303	TX	LUBBOCK	J ROBERT MASSENGALE	Lubbock City of		Southwestern Public Service Co/PCA	UT
6181	48	029	6181	BG0057UA	48	29	TX	BEXAR	J T DEELY	San Antonio Public Service Bd		ERCOT ISO/PCA	UT
55052	48	081			48	81	TX	COKE	JAMESON GAS PROCESSING PLANT	Mitchell Gas Services LP		ERCOT ISO/PCA	NU
54637	48	245			48	245	TX	JEFFERSON	JCO OXIDES OLEFINS PLANT	Huntsman Corp		Entergy Electric System/PCA	NU
3482	48	303	3482	LN0081B	48	303	TX	LUBBOCK	JONES	Southwestern Public Service Co	Xcel Energy Inc	Southwestern Public Service Co/PCA	UT
3476	48	183	3476	GJ0043K	48	183	TX	GREGG	KNOX LEE	Southwestern Electric Power Co	American Electric Power Co Inc	American Electric Power - West (SPP)/PCA	UT
50026	48	355			48	355	TX	NUECES	KOCH PETROLEUM GROUP LP CORPUS REFINERY	Koch		ERCOT ISO/PCA	NU
3442	48	061	3442	CD0013K	48	61	TX	CAMERON	LA PALMA	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
3502	48	309	3502	MB0117A	48	309	TX	MCLENNAN	LAKE CREEK	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
3452	48	113	3452	DB0249H	48	113	TX	DALLAS	LAKE HUBBARD	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
3521	48	197	3521	HE0013G	48	197	TX	HARDEMAN	LAKE PAULINE	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
3439	48	479	3439	WE0005G	48	479	TX	WEBB	LAREDO	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
3609	48	029	3609	BG0059Q	48	29	TX	BEXAR	LEON CREEK	San Antonio Public Service Bd		ERCOT ISO/PCA	UT
3457	48	339	3457	MQ0009F	48	339	TX	MONTGOMERY	LEWIS CREEK	Entergy Gulf States Inc	Entergy Corporation	Entergy Electric System/PCA	UT
794	48	121			48	121	TX	DENTON	LEWISVILLE	Denton City of		ERCOT ISO/PCA	UT
298	48	293	298	LI0027L	48	293	TX	LIMESTONE	LIMESTONE	Texas Genco	CenterPoint Energy	ERCOT ISO/PCA	NU
3440	48	355	3440	NE0025C	48	355	TX	NUECES	LON C HILL	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
3477	48	343	3477	MS0011T	48	343	TX	MORRIS	LONE STAR	Southwestern Electric Power Co	American Electric Power Co Inc	American Electric Power - West (SPP)/PCA	UT
54971	48	343			48	343	TX	MORRIS	LONE STAR STEEL CO	Lone Star Steel Co		American Electric Power - West (SPP)/PCA	NU
50249	48	005			48	5	TX	ANGELINA	LUFKIN TEXAS	Champion International Corp		ERCOT ISO/PCA	NU
3599	48	053			48	53	TX	BURNET	MARBLE FALLS	Lower Colorado River Authority		ERCOT ISO/PCA	UT
3600	48	453			48	453	TX	TRAVIS	MARSHALL FORD	Lower Colorado River Authority		ERCOT ISO/PCA	UT
6146	48	401	6146	RL0020K	48	401	TX	RUSK	MARTIN LAKE	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
54459	48	461			48	461	TX	UPTON	MIDKIFF PLANT	Western Gas Resources		ERCOT ISO/PCA	NU
3610	48	029	3610	BG0188E	48	29	TX	BEXAR	MISSION ROAD	San Antonio Public Service Bd		ERCOT ISO/PCA	UT
6147	48	449	6147	TF0013B	48	449	TX	TITUS	MONTICELLO	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
3483	48	341			48	341	TX	MOORE	MOORE COUNTY	Southwestern Public Service Co	Xcel Energy Inc	Southwestern Public Service Co/PCA	UT
3492	48	335	3492	MO0014L	48	335	TX	MITCHELL	MORGAN CREEK	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
3557	48	363			48	363	TX	PALO PINTO	MORRIS SHEPPARD	Brazos River Authority		ERCOT ISO/PCA	UT
54976	48	467			48	467	TX	VAN ZANDT	MORTON SALT CO GRAND SALINE	Rohm & Haas Co		American Electric Power - West (SPP)/PCA	NU
3453	48	113	3453	DB0252S	48	113	TX	DALLAS	MOUNTAIN CREEK	Exelon Generation	Exelon Corporation	ERCOT ISO/PCA	NU
55065	48	501			48	501	TX	YOAKUM	MUSTANG STATION	North American Energy Services		Southwestern Public Service Co/PCA	NU
50137	48	481	50137	WF0175P	48	481	TX	WHARTON	NEWGULF	CSW Energy Inc		ERCOT ISO/PCA	NU

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3456	48	141	3456	EE0029T	48	141	TX	EL PASO	NEWMAN	El Paso Electric Co	El Paso Energy	ERCOT ISO/PCA	UT
3484	48	375	3484	PG0040T	48	375	TX	POTTER	NICHOLS	Southwestern Public Service Co	Xcel Energy Inc	Southwestern Public Service Co/PCA	UT
3585	48	187			48	187	TX	GUADALUPE	NOLTE	Guadalupe Blanco River Auth		ERCOT ISO/PCA	UT
54972	48	203			48	203	TX	HARRISON	NORIT AMERICAS INC MARSHALL PLANT	Norit Americas Inc		American Electric Power - West (SPP)/PCA	NU
3454	48	113	3454	DB0251U	48	113	TX	DALLAS	NORTH LAKE	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
3493	48	439	3493	TA0354E	48	439	TX	TARRANT	NORTH MAIN	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
54443	48	329			48	329	TX	MIDLAND	NORTH RILEY	Union Oil Co of California		Southwestern Public Service Co/PCA	NU
3627	48	367	3627	PC0005T	48	367	TX	PARKER	NORTH TEXAS	Brazos Electric Power Coop Inc		ERCOT ISO/PCA	UT
3441	48	355	3441	NE0026A	48	355	TX	NUECES	NUECES BAY	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
3611	48	029	3611	BG0057U	48	29	TX	BEXAR	O W SOMMERS	San Antonio Public Service Bd		ERCOT ISO/PCA	UT
3523	48	081	3523	CN0005T	48	81	TX	COKE	OAK CREEK	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
127	48	487	127	WI0025C	48	487	TX	WILBARGER	OKLAUNION	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
54676	48	201			48	201	TX	HARRIS	OYSTER CREEK UNIT VIII	Dow Chemical		ERCOT ISO/PCA	NU
3466	48	167	3466	GB0037T	48	167	TX	GALVESTON	P H ROBINSON	Texas Genco	CenterPoint Energy	ERCOT ISO/PCA	NU
3524	48	207	3524	HJ0022B	48	207	TX	HASKELL	PAINT CREEK	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
3455	48	113	3455	DB0253Q	48	113	TX	DALLAS	PARKDALE	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
10638	48	201			48	201	TX	HARRIS	PASADENA	Air Products		ERCOT ISO/PCA	NU
55047	48	201	55047	HG1169O	48	201	TX	HARRIS	PASADENA COGENERATION LP	Calpine		ERCOT ISO/PCA	NU
3630	48	163	3630	FJ0012P	48	163	TX	FRIO	PEARSALL	Medina Electric Coop Inc		ERCOT ISO/PCA	UT
3494	48	475	3494	WC0028Q	48	475	TX	WARD	PERMIAN BASIN	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
54628	48	141			48	141	TX	EL PASO	PHELPS DODGE REFINING CORP	Phelps Dodge Corp		ERCOT ISO/PCA	NU
7902	48	203	7902	HH0037F	48	203	TX	HARRISON	PIRKEY	Southwestern Electric Power Co	American Electric Power Co Inc	American Electric Power - West (SPP)/PCA	UT
3485	48	279	3485	LB0046P	48	279	TX	LAMB	PLANT X	Southwestern Public Service Co	Xcel Energy Inc	Southwestern Public Service Co/PCA	UT
50973	48	245			48	245	TX	JEFFERSON	PORT ARTHUR REFINERY	Motiva Enterprises LLC		Entergy Electric System/PCA	NU
52108	48	245			48	245	TX	JEFFERSON	PORT ARTHUR REFINERY	Clark Refining & Marketing Inc		Entergy Electric System/PCA	NU
10568	48	245			48	245	TX	JEFFERSON	PORT ARTHUR TEXAS REFINERY	ATOFINA Petrolchemicals Inc		Entergy Electric System/PCA	NU
52131	48	167			48	167	TX	GALVESTON	POWER STATION 3	BP Amoco		ERCOT ISO/PCA	NU
52132	48	167			48	167	TX	GALVESTON	POWER STATION 4	BP Amoco		ERCOT ISO/PCA	NU
4195	48	231	4195	HV0023K	48	231	TX	HUNT	POWERLANE PLANT	Greenville Electric Util Sys		ERCOT ISO/PCA	UT
54364	48	485			48	485	TX	WICHITA	PPG INDUSTRIES INC WORKS 4	PPG Industries Inc		ERCOT ISO/PCA	NU
3525	48	377			48	377	TX	PRESIDIO	PRESIDIO	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
50241	48	141			48	141	TX	EL PASO	PROVIDENCE MEMORIAL HOSPITAL	Tenet Hospital Ltd		ERCOT ISO/PCA	NU
52069	48	057			48	57	TX	CALHOUN	PT COMFORT OPERATIONS	Alcoa NUGS	Alcoa, Inc	ERCOT ISO/PCA	NU
54748	48	245			48	245	TX	JEFFERSON	PT NECHES PLANT	Air Liquide America Corp		Entergy Electric System/PCA	NU
3628	48	363	3628	PA0003W	48	363	TX	PALO PINTO	R W MILLER	Brazos Electric Power Coop Inc		ERCOT ISO/PCA	UT
3576	48	085	3576	CP0026M	48	85	TX	COLLIN	RAY OLINGER	Garland City of		ERCOT ISO/PCA	UT
796	48	121			48	121	TX	DENTON	RAY ROBERTS	Denton City of		ERCOT ISO/PCA	UT
54291	48	355			48	355	TX	NUECES	REYNOLDS METALS CO SHERWIN PLANT	Reynolds Metals Co Sherwin Plt		ERCOT ISO/PCA	NU
52065	48	201			48	201	TX	HARRIS	RHODIA INC HOUSTON PLANT	Aventis		ERCOT ISO/PCA	NU
50054	48	201			48	201	TX	HARRIS	RICE UNIVERSITY	William Marsh Rice University		ERCOT ISO/PCA	NU
54338	48	061			48	61	TX	CAMERON	RIO GRANDE VALLEY SUGAR GROWERS INC	Rio Grande Sugar Growers Co		ERCOT ISO/PCA	NU
3526	48	105	3526	CZ0017A	48	105	TX	CROCKETT	RIO PECOS	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
3503	48	387	3503	RE0012M	48	387	TX	RED RIVER	RIVER CREST	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
3487	48	233			48	233	TX	HUTCHINSON	RIVERVIEW	Southwestern Public Service Co	Xcel Energy Inc	Southwestern Public Service Co/PCA	UT
7200	48	241			48	241	TX	JASPER	ROBERT D WILLIS	USCE-Fort Worth District	US Army Corp Of Engineers	ERCOT ISO/PCA	UT
3608	48	355			48	355	TX	NUECES	ROBSTOWN	Robstown City of		ERCOT ISO/PCA	UT
54253	48	167			48	167	TX	GALVESTON	S&L COGENERATION	Praxair Inc		ERCOT ISO/PCA	NU
3459	48	361	3459	OC0013O	48	361	TX	ORANGE	SABINE	Entergy Gulf States Inc	Entergy Corporation	Entergy Electric System/PCA	UT
10789	48	361			48	361	TX	ORANGE	SABINE RIVER WORKS	E I DuPont De Nemours & Co		Entergy Electric System/PCA	NU
3468	48	201	3468	HG0358Q	48	201	TX	HARRIS	SAM BERTRON	Texas Genco	CenterPoint Energy	ERCOT ISO/PCA	NU
3631	48	469	3631	VC0026O	48	469	TX	VICTORIA	SAM RAYBURN	South Texas Electric Coop Inc		ERCOT ISO/PCA	UT
6413	48	241			48	241	TX	JASPER	SAM RAYBURN	USCE-Fort Worth District	US Army Corp Of Engineers	ERCOT ISO/PCA	UT
3527	48	451	3527	TG0044C	48	451	TX	TOM GREEN	SAN ANGELO	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
7325	48	201	7325	HG4955K	48	201	TX	HARRIS	SAN JACINTO SES	Texas Genco	CenterPoint Energy	ERCOT ISO/PCA	NU
6183	48	013	6183	AG0007G	48	13	TX	ATASCOSA	SAN MIGUEL	San Miguel Electric Coop Inc		ERCOT ISO/PCA	UT
6648	48	331	6648	MM0023J	48	331	TX	MILAM	SANDOW	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
52071	48	331			48	331	TX	MILAM	SANDOW	Alcoa NUGS	Alcoa, Inc	ERCOT ISO/PCA	NU
10167	48	057			48	57	TX	CALHOUN	SEADRIFT COKE LP	Seadrift Coke L P		ERCOT ISO/PCA	NU
50150	48	057			48	57	TX	CALHOUN	SEADRIFT PLANT UNION CARBIDE CORP	Union Carbide		ERCOT ISO/PCA	NU
3616	48	187					TX	GUADALUPE	SEGUIN				UT
50253	48	201			48	201	TX	HARRIS	SHELDON TEXAS	Champion International Corp		ERCOT ISO/PCA	NU
50304	48	201			48	201	TX	HARRIS	SHELL DEER PARK	Shell		ERCOT ISO/PCA	NU
3559	48	061	3559	CD0009B	48	61	TX	CAMERON	SI RAY	Brownsville Public Utils Board		ERCOT ISO/PCA	UT
3601	48	021	3601	BC0015L	48	21	TX	BASTROP	SIM GIDEON	Lower Colorado River Authority		ERCOT ISO/PCA	UT
55000	48	123			48	123	TX	DE WITT	SMALL HYDRO OF TEXAS INC	Small Hydro of Texas Inc		ERCOT ISO/PCA	NU
50141	48	203			48	203	TX	HARRISON	SNIDER INDUSTRIES INC	Snider Industries Inc		American Electric Power - West (SPP)/PCA	NU
6251	48	321			48	321	TX	MATAGORDA	SOUTH TEXAS	Texas Genco	CenterPoint Energy	ERCOT ISO/PCA	NU
50127	48	485			48	485	TX	WICHITA	SOUTHERN ENERGY WICHITA FALLS LP	Vetrotex America		ERCOT ISO/PCA	NU
50263	48	209			48	209	TX	HAYS	SOUTHWEST TEXAS STATE UNIVERSITY COGEN	Southwest Texas State Univ		ERCOT ISO/PCA	NU
4266	48	121	4266	DF0012T	48	121	TX	DENTON	SPENCER	Denton City of		ERCOT ISO/PCA	UT
55390	48	113			48	113	TX	DALLAS	STATE FARM INS CO ISC CENTRAL	Daniel Norris		ERCOT ISO/PCA	NU
3504	48	073	3504	CJ0026J	48	73	TX	CHEROKEE	STRYKER CREEK	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
55015	48	039	55015	BL0622F	48	39	TX	BRAZORIA	SWEENY COGENERATION FACILITY	Sweeny Cogeneration LP		ERCOT ISO/PCA	NU
3469	48	201	3469	HG0357S	48	201	TX	HARRIS	T H WHARTON	Texas Genco	CenterPoint Energy	ERCOT ISO/PCA	NU
50109	48	277			48	277	TX	LAMAR	TENASKA III TEXAS PARTNERS	North American Energy Services		ERCOT ISO/PCA	NU
54817	48	251	54817	JH0230L	48	251	TX	JOHNSON	TENASKA IV TEXAS PARTNERS LTD CLEBURNE COGEN	North American Energy Services		ERCOT ISO/PCA	NU
54097	48	067			48	67	TX	CASS	TEXARKANA MILL	International Paper Co		American Electric Power - West (SPP)/PCA	NU
52088	48	167			48	167	TX	GALVESTON	TEXAS CITY COGENERATION LP	Texas City Cogeneration L P		ERCOT ISO/PCA	NU

ORISPL	FIPST	FIPSCNY	ORISPL_ In_NEI_ V300_ Draft	SiteID_ In_NEI_ V300_ Draft	FIPST_ NUM	FIPSCNY_ NUM	PSTAT ABB	CNTYNAME	PNAME	OPRNAME	OPPRNAME	PCANAME	PL TYPE
52097	48	167					TX	GALVESTON	TEXAS CITY PLANT				NU
50153	48	167			48	167	TX	GALVESTON	TEXAS CITY PLANT UNION CARBIDE CORP	Union Carbide		ERCOT ISO/PCA	NU
50229	48	201			48	201	TX	HARRIS	TEXAS PETROCHEMICALS CORP	Texas Petrochemicals Corp		ERCOT ISO/PCA	NU
52120	48	039			48	39	TX	BRAZORIA	THE DOW CHEMICAL CO TEXAS OPERATIONS	Dow Chemical		ERCOT ISO/PCA	NU
54321	48	245			48	245	TX	JEFFERSON	THE GOODYEAR&TIRE RUBBER CO	Goodyear Tire & Rubber Co		Entergy Electric System/PCA	NU
4937	48	299	4937	LL0006O	48	299	TX	LLANO	THOMAS C FERGUSON	Lower Colorado River Authority		ERCOT ISO/PCA	UT
7030	48	395	7030	RI0035C	48	395	TX	ROBERTSON	TNP ONE	Sempra Energy Resources	Sempra Energy	ERCOT ISO/PCA	NU
6595	48	351			48	351	TX	NEWTON	TOLEDO BEND	Entergy Gulf States Inc	Entergy Corporation	Entergy Electric System/PCA	UT
6194	48	279	6194	LB0047N	48	279	TX	LAMB	TOLK	Southwestern Public Service Co	Xcel Energy Inc	Southwestern Public Service Co/PCA	UT
3586	48	187			48	187	TX	GUADALUPE	TP 4	Guadalupe Blanco River Auth		ERCOT ISO/PCA	UT
3506	48	309	3506	MB0116C	48	309	TX	MCLENNAN	TRADINGHOUSE	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
3507	48	213	3507	HM0017H	48	213	TX	HENDERSON	TRINIDAD	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
3602	48	303	3602	LN0057V	48	303	TX	LUBBOCK	TY COOKE	Lubbock City of		Southwestern Public Service Co/PCA	UT
50118	48	453			48	453	TX	TRAVIS	UNIVERSITY OF TEXAS AT AUSTIN	University of Texas at Austin		ERCOT ISO/PCA	NU
54607	48	113			48	113	TX	DALLAS	UNIVERSITY OF TEXAS AT DALLAS	Win Sam Inc		ERCOT ISO/PCA	NU
54606	48	029			48	29	TX	BEXAR	UNIVERSITY OF TEXAS AT SAN ANTONIO	Thermonetics Div of Win Sam		ERCOT ISO/PCA	NU
3612	48	029	3612	BG0186I	48	29	TX	BEXAR	V H BRAUNIG	San Antonio Public Service Bd		ERCOT ISO/PCA	UT
50121	48	355			48	355	TX	NUECES	VALERO REFINERY	Valero Refining Co		ERCOT ISO/PCA	NU
52013	48	167			48	167	TX	GALVESTON	VALERO REFINING CO TEXAS CITY REFINERY	Valero Refining Co		ERCOT ISO/PCA	NU
52012	48	201			48	201	TX	HARRIS	VALERO REFINING CO TEXAS HOUSTON REFINERY	Valero Refining Co		ERCOT ISO/PCA	NU
3508	48	147	3508	FB0025U	48	147	TX	FANNIN	VALLEY	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
3623	48	487			48	487	TX	WILBARGER	VERNON	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
3443	48	469	3443	VC0003D	48	469	TX	VICTORIA	VICTORIA	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
10790	48	469			48	469	TX	VICTORIA	VICTORIA TEXAS PLANT	E I DuPont De Nemours & Co		ERCOT ISO/PCA	NU
54520	48	439			48	439	TX	TARRANT	VILLAGE CREEK WASTEWATER TREATMENT PLANT	Ft Worth City of		ERCOT ISO/PCA	NU
3470	48	157	3470	FG0020V	48	157	TX	FORT BEND	W A PARISH	Texas Genco	CenterPoint Energy	ERCOT ISO/PCA	NU
3613	48	029	3613	BG0187G	48	29	TX	BEXAR	W B TUTTLE	San Antonio Public Service Bd		ERCOT ISO/PCA	UT
54049	48	465					TX	VAL VERDE	WASHINGTON VENEER DIVISION				NU
52122	48	501			48	501	TX	YOAKUM	WASSON CO2 REMOVAL PLANT	Occidental Chemical Corp		Southwestern Public Service Co/PCA	NU
3471	48	201	3471	HG0355W	48	201	TX	HARRIS	WEBSTER	Texas Genco	CenterPoint Energy	ERCOT ISO/PCA	NU
6139	48	449	6139	TF0012D	48	449	TX	TITUS	WELSH	Southwestern Electric Power Co	American Electric Power Co Inc	American Electric Power - West (SPP)/PCA	UT
55367	48	461			48	461	TX	UPTON	WEST TEXAS WIND ENERGY LLC	Daniel Norris		ERCOT ISO/PCA	NU
54966	48	229			48	229	TX	HUDSPETH	WEST TEXAS WINDPLANT	LG&E Power Services	E.ON (Germany)	ERCOT ISO/PCA	NU
54330	48	201			48	201	TX	HARRIS	WESTHOLLOW TECHNOLOGY CENTER	Shell		ERCOT ISO/PCA	NU
50101	48	241			48	241	TX	JASPER	WESTVACO EVADALE	MeadWestvaco Corp		Entergy Electric System/PCA	NU
6414	48	035			48	35	TX	BOSQUE	WHITNEY	USCE-Fort Worth District	US Army Corp Of Engineers	ERCOT ISO/PCA	UT
3478	48	315	3478	ME0006A	48	315	TX	MARION	WILKES	Southwestern Electric Power Co	American Electric Power Co Inc	American Electric Power - West (SPP)/PCA	UT
55025	48	371			48	371	TX	PECOS	YATES GAS PLANT	Marathon Oil Co		ERCOT ISO/PCA	NU
3641	49	049			49	49	UT	UTAH	AMERICAN FORK	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
3688	49	049			49	49	UT	UTAH	BARTHOLOMEW	Springville City of		Pacificorp-East/PCA	UT
6536	49	001			49	1	UT	BEAVER	BEAVER LOWER HYDRO 1	Beaver City Corp		Pacificorp-East/PCA	UT
3664	49	001			49	1	UT	BEAVER	BEAVER MID HYDRO 2	Beaver City Corp		Pacificorp-East/PCA	UT
7340	49	001			49	1	UT	BEAVER	BEAVER UPPER HYDRO 3	Beaver City Corp		Pacificorp-East/PCA	UT
299	49	001			49	1	UT	BEAVER	BLUNDELL	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
7790	49	047	7790	107790	49	47	UT	UINTAH	BONANZA	Deseret Generation & Tran Coop		Pacificorp-East/PCA	UT
3699	49	017			49	17	UT	GARFIELD	BOULDER	Garkane Power Assn Inc		WAPA - Rocky Mountains/PCA	UT
3665	49	011			49	11	UT	DAVIS	BOUNTIFUL CITY	Bountiful City City of		Pacificorp-East/PCA	UT
6182	49	003			49	3	UT	BOX ELDER	BOX ELDER	Brigham City Corp		Pacificorp-East/PCA	UT
3666	49	003			49	3	UT	BOX ELDER	BRIGHAM CITY	Brigham City Corp		Pacificorp-East/PCA	UT
3644	49	007	3644	10081	49	7	UT	CARBON	CARBON	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
3685	49	021			49	21	UT	IRON	CENTER CREEK	Parowan City Corp		Pacificorp-East/PCA	UT
3646	49	003			49	3	UT	BOX ELDER	CUTLER	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
6404	49	051			49	51	UT	WASATCH	DEER CREEK	USBR-Upper Colorado Region	US Bureau Of Reclamation	WAPA - Rocky Mountains/PCA	UT
4263	49	043			49	43	UT	SUMMIT	ECHO DAM	Bountiful City City of		Pacificorp-East/PCA	UT
6405	49	009			49	9	UT	DAGGETT	FLAMING GORGE	USBR-Upper Colorado Region	US Bureau Of Reclamation	WAPA - Rocky Mountains/PCA	UT
3647	49	039			49	39	UT	SANPETE	FOUNTAIN GREEN	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
3648	49	035	3648	10355	49	35	UT	SALT LAKE	GADSBY	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
10778	49	049			49	49	UT	UTAH	GENEVA STEEL	Geneva Steel		Pacificorp-East/PCA	NU
3651	49	035			49	35	UT	SALT LAKE	GRANITE	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
3634	49	053			49	53	UT	WASHINGTON	GUNLOCK	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
7069	49	053			49	53	UT	WASHINGTON	GUNLOCK HYDRO	St George City of		Pacificorp-East/PCA	UT
7111	49	051			49	51	UT	WASATCH	HEBER CITY	Heber Light & Power Co		Pacificorp-East/PCA	UT
3689	49	049			49	49	UT	UTAH	HOBBLE CREEK	Springville City of		Pacificorp-East/PCA	UT
6165	49	015	6165	10237	49	15	UT	EMERY	HUNTER	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
8069	49	015	8069	10238	49	15	UT	EMERY	HUNTINGTON	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
7034	49	005			49	5	UT	CACHE	HYDRO II	Logan City of		Pacificorp-East/PCA	UT
3675	49	005			49	5	UT	CACHE	HYDRO III	Logan City of		Pacificorp-East/PCA	UT
3668	49	039			49	39	UT	SANPETE	HYDRO PLANT NO 1	Ephraim City of		Pacificorp-East/PCA	UT
925	49	039			49	39	UT	SANPETE	HYDRO PLANT NO 3	Ephraim City of		Pacificorp-East/PCA	UT
7133	49	039			49	39	UT	SANPETE	HYDRO PLANT NO 4	Ephraim City of		Pacificorp-East/PCA	UT
3674	49	005			49	5	UT	CACHE	HYRUM	Hyrum City Corp		Pacificorp-East/PCA	UT
6481	49	027	6481	10327	49	27	UT	MILLARD	INTERMOUNTAIN	Los Angeles City of		Los Angeles Dept of Water & Power/PCA	UT
159	49	051			49	51	UT	WASATCH	LAKE CREEK	Heber Light & Power Co		Pacificorp-East/PCA	UT
6537	49	035			49	35	UT	SALT LAKE	LITTLE COTTONWOOD	Murray City of		Pacificorp-East/PCA	UT
6553	49	057			49	57	UT	WEBER	LITTLE MOUNTAIN	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
10215	49	035			49	35	UT	SALT LAKE	LONE PEAK PARTNERS POWER CO	Snowbird Utilites		Pacificorp-East/PCA	NU
3679	49	041			49	41	UT	SEVIER	LOWER	Monroe City of		Pacificorp-East/PCA	UT
3681	49	039			49	39	UT	SANPETE	LOWER-UNIT	Mt Pleasant City of		Pacificorp-East/PCA	UT

ORISPL	FIPST	FIPSCNY	ORISPL_ In_NEI_V300_ Draft	SiteID_ In_NEI_ V300_ Draft	FIPST_ NUM	FIPSCNY_ NUM	PSTAT ABB	CNTYNAME	PNAME	OPRNAME	OPPRNAME	PCANAME	PL TYPE
1020	49	039			49	39	UT	SANPETE	MANTI LOWER	Manti City of		Pacificorp-East/PCA	UT
3676	49	039			49	39	UT	SANPETE	MANTI UPPER	Manti City of		Pacificorp-East/PCA	UT
7043	49	041			49	41	UT	SEVIER	MONROE PUMPING STA	Monroe City of		Pacificorp-East/PCA	UT
3683	49	035			49	35	UT	SALT LAKE	MURRAY CITY	Murray City of		Pacificorp-East/PCA	UT
3655	49	049			49	49	UT	UTAH	OLMSTEAD	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
3692	49	049			49	49	UT	UTAH	PAYSON	Strawberry Water Users Assn		Pacificorp-East/PCA	UT
7362	49	053			49	53	UT	WASHINGTON	PINE VALLEY	St George City of		Pacificorp-East/PCA	UT
7132	49	057			49	57	UT	WEBER	PINE VIEW DAM	Bountiful City City of		Pacificorp-East/PCA	UT
3656	49	057			49	57	UT	WEBER	PIONEER	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
52119	49	035			49	35	UT	SALT LAKE	PRIMARY CHILDRENS MEDICAL CENTER	Primary Childrens Medical Cntr		Pacificorp-East/PCA	NU
3686	49	049			49	49	UT	UTAH	PROVO	Provo City Corp		Pacificorp-East/PCA	UT
52039	49	053			49	53	UT	WASHINGTON	QUAIL CREEK HYDRO PLANT #1	Washington County Wtr Consv Dt		WAPA - Rocky Mountains/PCA	NU
6538	49	021			49	21	UT	IRON	RED CREEK	Parowan City Corp		Pacificorp-East/PCA	UT
3636	49	053			49	53	UT	WASHINGTON	SAND COVE	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
3658	49	051			49	51	UT	WASATCH	SNAKE CREEK	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
3673	49	051			49	51	UT	WASATCH	SNAKE CREEK	Heber Light & Power Co		Pacificorp-East/PCA	UT
3691	49	049			49	49	UT	UTAH	SPANISH FORK	Strawberry Water Users Assn		Pacificorp-East/PCA	UT
3690	49	049			49	49	UT	UTAH	SPRING CREEK	Springville City of		Pacificorp-East/PCA	UT
7080	49	053			49	53	UT	WASHINGTON	ST GEORGE	St George City of		Pacificorp-East/PCA	UT
3659	49	035			49	35	UT	SALT LAKE	STAIRS	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
50951	49	007			49	7	UT	CARBON	SUNNYSIDE COGENERATION ASSOCIATES	Sunnyside Cogeneration Assoc		Pacificorp-East/PCA	NU
3704	49	013			49	13	UT	DUCHESNE	UINTAH	Moon Lake Electric Assn Inc		WAPA - Rocky Mountains/PCA	UT
7016	49	039			49	39	UT	SANPETE	UNIT 3	Mt Pleasant City of		Pacificorp-East/PCA	UT
7015	49	039			49	39	UT	SANPETE	UNIT 4	Mt Pleasant City of		Pacificorp-East/PCA	UT
3680	49	041			49	41	UT	SEVIER	UPPER	Monroe City of		Pacificorp-East/PCA	UT
7027	49	049			49	49	UT	UTAH	UPPER BARTHOLOMEW	Springville City of		Pacificorp-East/PCA	UT
3643	49	001			49	1	UT	BEAVER	UPPER BEAVER	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
3682	49	039			49	39	UT	SANPETE	UPPER-UNIT	Mt Pleasant City of		Pacificorp-East/PCA	UT
3635	49	053			49	53	UT	WASHINGTON	VEYO	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
55302	49	011			49	11	UT	DAVIS	WASATCH ENERGY SYSTEMS	Davis CSWM & Energy RSSD		Pacificorp-East/PCA	NU
3661	49	057			49	57	UT	WEBER	WEBER	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
7028	49	049			49	49	UT	UTAH	WHITEHEAD	Springville City of		Pacificorp-East/PCA	UT
3705	49	013			49	13	UT	DUCHESNE	YELLOWSTONE	Moon Lake Electric Assn Inc		WAPA - Rocky Mountains/PCA	UT
6409	56	025			56	25	WY	NATRONA	ALCOVA	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
52129	56	041			56	41	WY	UINTA	ANSCHUTZ RANCH EAST	BP Amoco		Pacificorp-East/PCA	NU
55278	56	013			56	13	WY	FREMONT	BEAVER CREEK GAS PLANT	Devon SFS Operating Inc		WAPA - Rocky Mountains/PCA	NU
55134	56	037	55134	00042	56	37	WY	SWEETWATER	BLACKS FORK GAS PROCESSING PLANT	Questar Gas Management Co		Pacificorp-West/PCA	NU
505	56	013			56	13	WY	FREMONT	BOYSEN	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
7317	56	029			56	29	WY	PARK	BUFFALO BILL	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
4158	56	009	4158	00001	56	9	WY	CONVERSE	DAVE JOHNSTON	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
52127	56	029			56	29	WY	PARK	ELK BASIN GASOLINE PLANT	BP Amoco		Pacificorp-West/PCA	NU
4185	56	023			56	23	WY	LINCOLN	FONTENELLE	USBR-Upper Colorado Region	US Bureau Of Reclamation	WAPA - Rocky Mountains/PCA	UT
4176	56	025			56	25	WY	NATRONA	FREMONT CANYON	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
54318	56	037	54318	00002	56	37	WY	SWEETWATER	GENERAL CHEMICAL	General Chemical Corp		Pacificorp-West/PCA	NU
4177	56	031			56	31	WY	PLATTE	GLENDO	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
4178	56	031			56	31	WY	PLATTE	GUERNSEY	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
6408	56	029			56	29	WY	PARK	HEART MOUNTAIN	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
8066	56	037	8066	01002	56	37	WY	SWEETWATER	JIM BRIDGER	PacifiCorp-West	ScottishPower PLC	Pacificorp-West/PCA	UT
4180	56	007			56	7	WY	CARBON	KORTES	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
6204.1	56	031			56	31	WY	PLATTE	LARAMIE RIVER 1	Basin Electric Power Coop-East	Basin Electric Power Coop	WAPA - Upper Great Plains East/PCA	UT
6204.2	56	031			56	31	WY	PLATTE	LARAMIE RIVER 2&3	Basin Electric Power Coop-West	Basin Electric Power Coop	WAPA - Rocky Mountains/PCA	UT
4162	56	023	4162	00004	56	23	WY	LINCOLN	NAUGHTON	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
4150	56	005	4150	00002	56	5	WY	CAMPBELL	NEIL SIMPSON	Black Hills Power & Light	Black Hills Corp	WAPA - Rocky Mountains/PCA	UT
7504	56	005	7504	00063	56	5	WY	CAMPBELL	NEIL SIMPSON II	Black Hills Power & Light	Black Hills Corp	WAPA - Rocky Mountains/PCA	UT
4151	56	045	4151	00005	56	45	WY	WESTON	OSAGE	Black Hills Power & Light	Black Hills Corp	WAPA - Rocky Mountains/PCA	UT
674	56	013			56	13	WY	FREMONT	PILOT BUTTE	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
55203	56	021			56	21	WY	LARAMIE	PONNEQUIN PHASE 1	Energy Unlimited Inc		Public Service Co Of Colorado/PCA	NU
4182	56	007			56	7	WY	CARBON	SEMINOE	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
54472	56	037	54472	00022	56	37	WY	SWEETWATER	SF PHOSPHATES LTD CO	SF Phosphates Ltd Co		Pacificorp-West/PCA	NU
4183	56	029			56	29	WY	PARK	SHOSHONE	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
54374	56	007	54374	00001	56	7	WY	CARBON	SINCLAIR OIL REFINERY	Sinclair Oil Corp		Pacificorp-West/PCA	NU
7541	56	029			56	29	WY	PARK	SPIRIT MOUNTAIN	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
6393	56	023			56	23	WY	LINCOLN	STRAWBERRY CREEK	Lower Valley Energy Inc		Bonneville Power Admin/PCA	UT
7050	56	023			56	23	WY	LINCOLN	VIVA NAUGHTON	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
6101	56	005	6101	00046	56	5	WY	CAMPBELL	WYODAK	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT

PNAME	PREV UTIL	LAT	LON	NUMBLR	NUMGEN	SOURCEM	PLPRIMFL	PLFFLCTG	CAPFAC	BOILCAP	NAMEPCAP	CHPFLAG	USETHRMO	PWRTOHT	ELCALLOC	PLNUCONN
ABITIBI CONSOLIDATED SNOWFLAKE DIVISION	0	35.2863	110.2885	0	2	E	SUB	C	0.5541	0	70.55	U	3155479			Y
AGUA FRIA	0	33.5569	112.2175	3	6	T,E	GAS	G	0.3803	3672	613.422		0	N/A	N/A	
APACHE STATION	0	32.0556	109.8861	3	6	T	COL	C	0.7062	4515.2	559.142		0	N/A	N/A	
BIOSPHERE 2 CENTER INC	0	32.9836	111.3255	0	2	E	NG	G	0.0932	0	3.048	U	2590			Y
CHILDS	0	34.7053	112.4042	0	1	Z	WT		0.4414	0	5.4		0	N/A	N/A	
CHOLLA	0	34.9414	110.3003	4	4	T	COL	C	0.7017	10506	1105.436		0	N/A	N/A	
CORONADO	0	34.5778	109.2717	2	2	T	COL	C	0.8717	7471.84	821.88		0	N/A	N/A	
CROSSCUT	0	33.35	112.49	0	5	Z	WT		0.0181	0	33		0	N/A	N/A	
DAVIS	0	35.6134	113.6474	0	1	Z	WT		0.5911	0	240		0	N/A	N/A	
DOUGLAS	0	31.8799	109.754	0	1	E	OIL	O	0.0196	0	21.4		0	N/A	N/A	
GLEN CANYON	0	35.6337	112.0444	0	1	Z	WT		0.3642	0	1296		0	N/A	N/A	
GOULD ELECTRONICS FOIL DIVISION	0	33.35	112.49	0	2	E	NG	G	0.0599	0	1.05	U	818			Y
HOOVER	0	35.6134	113.6474	0	1	Z	WT		0.3148	0	1039.4		0	N/A	N/A	
HORSE MESA	0	33.35	112.49	0	2	Z	WT		0.1957	0	129.578		0	N/A	N/A	
INA ROAD WATER POLLUTION CONTROL FACILITY	0	31.9699	111.8899	0	7	E	NG	G	0.4703	0	4.54	U	70733			Y
IRVING	0	34.7053	112.4042	0	1	Z	WT		0.8549	0	1.6		0	N/A	N/A	
IRVINGTON	0	32.16	110.9044	4	6	T,E	COL	C	0.3352	3633.92	558.5		0	N/A	N/A	
KYRENE	0	33.3547	111.9364	2	6	T,E	GAS	G	0.1345	1349.12	334.85		0	N/A	N/A	
MORMON FLAT	0	33.35	112.49	0	2	Z	WT		0.1598	0	57.845		0	N/A	N/A	
NAVAJO	0	36.9125	111.3917	3	3	T	COL	C	0.8574	22072.8	2409.48		0	N/A	N/A	
NELSON PLANT GENERATORS	0	35.6134	113.6474	0	1	E	DFO	O	0.0237	0	2.27		0	N/A	N/A	Y
NORTH LOOP	0	31.9699	111.8899	0	3	E	GAS	G	0.07	0	81		0	N/A	N/A	
OCOTILLO	0	33.4467	111.9417	2	5	T,E	GAS	G	0.2561	2176	333.897		0	N/A	N/A	
PALO VERDE	0	33.35	112.49	0	1	Z	UR		0.8239	0	4209.57		0	N/A	N/A	
ROOSEVELT	0	33.35	112.49	0	1	Z	WT		0.113	0	36.018		0	N/A	N/A	
SAGUARO	0	32.5522	111.2992	2	4	T,E	GAS	G	0.2126	2448	356.25		0	N/A	N/A	
SANTAN	0	33.35	112.49	0	4	E	GAS	G	0.4091	0	414		0	N/A	N/A	
SOUTH CONSOLIDATED	0	33.35	112.49	0	1	Z	WT		0.0882	0	1.4		0	N/A	N/A	
SPRINGERVILLE	0	34.3186	109.1636	2	2	T	COL	C	0.7896	7656.8	849.6		0	N/A	N/A	
STARWOOD HOTELS RESORTS	0	33.35	112.49	0	3	E	NG	G	0.2868	0	1.65	U	11235			Y
STEWART MTN	0	33.35	112.49	0	1	Z	WT		0.2408	0	10.4		0	N/A	N/A	
WEST PHOENIX	0	33.4428	112.1536	0	8	E	GAS	G	0.2244	0	621.75		0	N/A	N/A	
YUCCA	0	33.22	113.94	1	5	T,E	GAS	G	0.153	0	278.66		0	N/A	N/A	
YUMA COGENERATION ASSOCIATES	0	32.7504	114.0678	0	2	E	NG	G	0.8036	0	62.64	U	202460			Y
ALAMOSA	0	37.5541	105.7477	0	2	E	GAS	G	0.0183	0	33.1		0	N/A	N/A	
AMERICAN ATLAS 1 COGENERATION PLANT	0	39.7286	107.5255	0	4	E	NG	G	0.2098	0	85	U	166015			Y
AMERICAN GYPSUM COGENERATION	0	39.6415	106.6443	0	4	E	DFO	O	0.2934	0	9.848	U	1000000			Y
AMES	0	37.9645	108.3899	0	1	Z	WT		0.3152	0	3.6		0	N/A	N/A	
ARAPAHOE	0	39.67	105.0028	4	4	T	COL	C	0.6865	3100.8	232		0	N/A	N/A	
BETASSO HYDROELECTRIC PLANT	0	40.0884	105.3453	0	1	Z	WAT		0.2588	0	3		0	N/A	N/A	Y
BIG THOMPSON	0	40.6281	105.5665	0	1	Z	WT		0.2525	0	4.5		0	N/A	N/A	
BLUE MESA	0	38.7019	106.9407	0	1	Z	WT		0.3184	0	86.4		0	N/A	N/A	
BOULDER	1	39.7114	104.9217	0	1	Z	WT		0.0976	0	20		0	N/A	N/A	Y
BRUSH COGEN PROJECT PHASE 2 BCP	0	40.2627	103.807	0	2	E	NG	G	0.426	0	74	U	810984			Y
BRUSH IV	0	40.2627	103.807	0	2	E	NG	G	0.0469	0	70	U	457013			Y
BRUSH POWER PROJECT PHASE 1 CPP	0	40.2627	103.807	0	3	E	NG	G	0.1369	0	88	A		N/A		Y
BURLINGTON	0	39.3061	102.6048	0	2	E	OIL	O	0.0531	0	129.4		0	N/A	N/A	
CABIN CREEK	0	39.7085	105.6604	0	1	Z	WT		-0.046	0	300		0	N/A	N/A	
CAMEO	0	39.1333	108.3167	2	2	T,E	COL	C	0.9561	0	66		0	N/A	N/A	
CHEROKEE	0	39.8697	104.379	4	6	T	COL	C	0.7575	7386.16	715.5		0	N/A	N/A	
COMANCHE	0	38.2081	104.5747	2	2	T	COL	C	0.6888	6892.48	700		0	N/A	N/A	
CRAIG	0	40.4628	107.59	3	3	T	COL	C	0.8391	12403.2	1339.2		0	N/A	N/A	
CRYSTAL	0	38.4104	108.2795	0	1	Z	WT		0.6754	0	28		0	N/A	N/A	
DELTA	0	38.9431	107.9389	0	7	E	GAS	G	0.014	0	4.957		0	N/A	N/A	
DILLON HYDRO PLANT	0	39.6484	106.1078	0	1	Z	WAT		0.8065	0	1.807		0	N/A	N/A	Y
DRAGON TRAIL GAS PROCESSING PLANT	0	29.8336	95.4383	0	2	E	NG	G	0.4225	0	1.225		0	N/A	N/A	Y
ESTES	0	40.6281	105.5665	0	1	Z	WT		0.2821	0	45		0	N/A	N/A	
FLATIRON	0	40.6281	105.5665	0	2	Z	WT		0.2062	0	94.5		0	N/A	N/A	
FOOTHILLS HYDRO PLANT	0	39.348	104.9944	0	1	Z	WAT		0.4789	0	3.125		0	N/A	N/A	Y
FORT LUPTON	0	39.8697	104.379	0	2	E	GAS	G	0.082	0	78.4		0	N/A	N/A	
FORT ST VRAIN	0	40.501	104.3121	2	3	T	GAS	G	0.5192	1876.8	601		0	N/A	N/A	
FRUITA	0	38.9331	108.2266	0	1	E	GAS	G	0.0142	0	18.65		0	N/A	N/A	
GEORGE BIRDSALL	0	38.83	104.52	3	3	E	GAS	G	0.2164	0	58.823		0	N/A	N/A	
GEORGETOWN	0	39.7085	105.6604	0	1	Z	WT		0.4353	0	1.44		0	N/A	N/A	
GREEN MOUNTAIN	0	39.6484	106.1078	0	1	Z	WT		0.1827	0	26		0	N/A	N/A	
HAYDEN	0	40.4856	107.185	2	2	T	COL	C	0.8098	4017.44	447		0	N/A	N/A	
HILLCREST POWERPLANT	0	39.7114	104.9217	0	1	Z	WAT		0.5636	0	2		0	N/A	N/A	Y
IGNACIO GASOLINE PLANT	0	37.3198	107.9299	0	1	E	NG	G	0.8629	0	6.196	U	2775000			Y
JOHNSTOWN COGENERATION	0	40.501	104.3121	0	1	E	NG	G	0.0742	0	3.3	U	7500			Y
LAMAR PLT	0	37.95	102.4	1	5	E	GAS	G	0.212	0	35	C		N/A		
LONGMONT	0	40.0884	105.3453	0	1	Z	WT		0.1935	0	0.6		0	N/A	N/A	
LOWER MOLINA	0	38.9331	108.2266	0	1	Z	WT		0.302	0	4.86		0	N/A	N/A	
MANITOU	0	38.8248	104.5616	0	1	Z	WT		0.3651	0	5		0	N/A	N/A	
MARTIN DRAKE	0	38.8244	104.8331	3	3	T	COL	C	0.7262	2733.6	294.057		0	N/A	N/A	
MARYS LAKE	0	40.6281	105.5665	0	1	Z	WT		0.6206	0	8.1		0	N/A	N/A	
MCPHEE	0	37.3189	108.5081	0	1	Z	WT		0.5144	0	1.283		0	N/A	N/A	
METRO WASTEWATER RECLAMATION DISTRICT	0	39.8697	104.379	0	4	E	OBG		0.2932	0	4.8	U	624000			Y
MORROW POINT	0	38.4104	108.2795	0	1	Z	WT		0.2074	0	173.334		0	N/A	N/A	

PNAME	PREV UTIL	LAT	LON	NUMBLR	NUMGEN	SOURCEM	PLPRIMFL	PLFFLCTG	CAPFAC	BOILCAP	NAMEPCAP	CHPFLAG	USETHRMO	PWRTOHT	ELCALLOC	PLNUCONN
MOUNT ELBERT	0	39.2179	106.3564	0	1	Z	WT		-0.0523	0	200		0	N/A	N/A	
NORTH FORK HYDRO PLANT	0	39.1311	105.7593	0	1	Z	WAT		0.4121	0	5.5		0	N/A	N/A	Y
NUCLA	0	38.2386	108.5072	1	4	T	COL	C	0.6586	1258	113.88		0	N/A	N/A	
PALISADE	0	38.9331	108.2266	0	1	Z	WT		0.6611	0	3		0	N/A	N/A	
PAWNEE	0	40.2694	103.6933	1	1	T	COL	C	0.7628	5010.24	547		0	N/A	N/A	
POLE HILL	0	40.6281	105.5665	0	1	Z	WT		0.4828	0	38.2		0	N/A	N/A	
PUEBLO	0	38.17	104.51	1	6	E	GAS	G	0.209	0	25		0	N/A	N/A	
RAWHIDE	0	40.8583	105.0269	1	1	T	COL	C	0.7639	2584	293.625		0	N/A	N/A	
RAY D NIXON	0	38.6306	104.7056	3	3	T	COL	C	0.6593	1972	301.66		0	N/A	N/A	
REDLANDS WATER & POWER CO	0	38.9331	108.2266	0	1	Z	WAT		0.7038	0	1.4		0	N/A	N/A	Y
ROCKY FORD	0	37.9543	103.7289	0	5	E	OIL	O	0.0778	0	10		0	N/A	N/A	
RUXTON	0	38.8248	104.5616	0	1	Z	WT		0.1802	0	1.25		0	N/A	N/A	
SALIDA 1	0	38.7401	106.2645	0	1	Z	WT		0.4679	0	0.75		0	N/A	N/A	
SALIDA 2	0	38.7401	106.2645	0	1	Z	WT		0.528	0	0.56		0	N/A	N/A	
SHOSHONE	0	39.7286	107.5255	0	1	Z	WT		0.8454	0	14.4		0	N/A	N/A	
STRONTIA SPRINGS HYDRO PLANT	0	39.348	104.9944	0	1	Z	WAT		0.7471	0	1.025		0	N/A	N/A	Y
SUGARLOAF HYDRO PLANT	0	39.2179	106.3564	0	1	Z	WAT		0.3431	0	2.5		0	N/A	N/A	Y
TACOMA	0	37.3198	107.9299	0	1	Z	WT		0.2178	0	8		0	N/A	N/A	
TAYLOR DRAW HYDROELECTRIC FACILITY	0	39.9376	108.0437	0	1	Z	WAT		0.5928	0	2.3		0	N/A	N/A	Y
TCP 122	0	40.501	104.3121	0	3	E	NG	G	0.6091	0	126	U	168397			Y
TCP 150	0	40.501	104.3121	0	4	E	NG	G	0.536	0	178.22	U	206986			Y
TESLA	0	38.8248	104.5616	0	1	Z	WT		0.274	0	27.64		0	N/A	N/A	
THERMO GREELEY INC	0	40.501	104.3121	0	1	E	NG	G	0.5875	0	37	U	748476			Y
THERMO POWER ELECTRIC INC	0	40.501	104.3121	0	3	E	NG	G	0.6392	0	110.844	U	300454			Y
TOWAOC	0	37.3189	108.5081	0	1	Z	WT		0.232	0	11.495		0	N/A	N/A	
TRIGEN COLORADO ENERGY CORP	0	39.5219	105.2228	0	4	E	SUB	C	0.9406	0	35.4	U	4362151			Y
UNIVERSITY OF COLORADO	0	40.0884	105.3453	0	3	E	NG	G	0.478	0	33	U	36844.7			Y
UPPER MOLINA	0	38.9331	108.2266	0	1	Z	WT		0.2923	0	8.64		0	N/A	N/A	
VALLECITO HYDROELECTRIC	0	37.3198	107.9299	0	3	Z	WAT		0.3156	0	5.844		0	N/A	N/A	Y
VALMONT	0	40.0694	105.2022	1	2	T,E	COL	C	0.7913	1740.8	211.45		0	N/A	N/A	
W N CLARK	0	38.47	105.44	2	2	E	COL	C	0.82	0	38.5		0	N/A	N/A	
WILLIAMS FORK HYDRO PLANT	0	40.0856	106.14	0	1	Z	WAT		0.4229	0	3		0	N/A	N/A	Y
ZUNI	0	39.7375	105.0181	3	2	T	GAS	G	0.089	1672.8	101	U	294000			
ABILENE CT	0	38.8712	97.1354	0	1	E	GAS	G	0.0074	0	77		0	N/A	N/A	
ANTHONY	0	37.1921	98.0754	0	3	E	GAS	G	0.0499	0	11.1		0	N/A	N/A	
ARTHUR MULLERGREN	0	38.4053	98.8694	1	1	T	GAS	G	0.3029	0	81.6		0	N/A	N/A	
ASHLAND	0	37.237	99.8243	0	5	E	OIL	O	0.0007	0	4.975		0	N/A	N/A	
BALDWIN	0	38.8985	95.2785	0	5	E	OIL	O	0.0064	0	7.085		0	N/A	N/A	
BELLEVILLE	0	39.8279	97.6503	0	7	E	GAS	G	0.0265	0	13.125	C		N/A		
BELOIT	0	39.3933	98.209	0	7	E	GAS	G	0.0261	0	19.35		0	N/A	N/A	
BIRD CITY	0	39.7857	101.7305	0	2	E	OIL	O	0.0028	0	4		0	N/A	N/A	
BURLINGAME	0	38.6519	95.7251	0	5	E	GAS	G	0.0323	0	4.594		0	N/A	N/A	
BURLINGTON	0	38.2363	95.7331	0	6	E	GAS	G	0.0371	0	8.5		0	N/A	N/A	
CHANUTE 2							GAS				4					
CHANUTE 3	0	37.5588	95.3066	0	5	E	GAS	G	0.0706	0	32.865		0	N/A	N/A	
CIMARRON RIVER	0	37.0592	100.9322	1	2	T,E	GAS	G	0.1794	0	65		0	N/A	N/A	
CLAY CENTER	0	39.3495	97.1649	0	8	E	GAS	G	0.1047	0	24.6		0	N/A	N/A	
CLIFTON	0	39.7841	97.0872	0	2	E	GAS	G	0.0278	0	88		0	N/A	N/A	
COFFEYVILLE	0	37.0475	95.5436	2	2	T,E	GAS	G	0.1572	0	58.75		0	N/A	N/A	
COLBY	0	39.4061	101.1267	0	1	E	GAS	G	0.0058	0	16		0	N/A	N/A	
COLBY	0	39.3507	101.0555	0	6	E	OIL	O	0.0009	0	17.36		0	N/A	N/A	
EAST 12TH STREET	0	37.2631	97.0717	1	1	T	GAS	G	0.0806	0	26.5		0	N/A	N/A	
ELLINWOOD	0	38.4789	98.756	0	5	E	GAS	G	0.0099	0	8.5		0	N/A	N/A	
ELLIS							COL				5.685					
FREDONIA	0	37.5593	95.7436	0	3	E	NG	G	0.1846	0	4.05	U	51983			Y
GARDEN CITY	0	38.0007	100.6644	1	4	T,E	GAS	G	0.0838	836.4	244		0	N/A	N/A	
GARDNER	0	38.8978	94.8318	0	2	E	GAS	G	0.0253	0	39.2		0	N/A	N/A	
GARNETT MUNICIPAL	0	38.2139	95.2917	0	8	E	OIL	O	0.0139	0	15.492		0	N/A	N/A	
GORDON EVANS EC	0	37.7903	97.5217	4	4	T	GAS	G	0.1404	5059.2	671		0	N/A	N/A	
GREAT BEND	0	38.4789	98.756	0	6	E	GAS	G	0.0077	0	10		0	N/A	N/A	
GREENSBURG	0	37.5583	99.2853	0	5	E	GAS	G	0.0225	0	7.8		0	N/A	N/A	
HERINGTON	0	38.8712	97.1354	0	5	E	OIL	O	0.0344	0	9.74		0	N/A	N/A	
HILL CITY	0	39.3498	99.8827	0	6	E	GAS	G	0.0088	0	7.265		0	N/A	N/A	
HOISINGTON	0	38.4789	98.756	0	5	E	GAS	G	0.0098	0	14.2		0	N/A	N/A	
HOLCOMB	0	37.9319	100.9719	1	1	T	COL	C	0.7251	3400	388		0	N/A	N/A	
HOLTON	0	39.4346	95.7998	0	6	E	GAS	G	0.0456	0	15.37		0	N/A	N/A	
HUGOTON 1	0	37.1919	101.3113	0	2	E	GAS	G	0.0427	0	2.24		0	N/A	N/A	
HUGOTON 2	0	37.1919	101.3113	0	7	E	GAS	G	0.2072	0	19.295		0	N/A	N/A	
HUTCHINSON EC	0	38.0892	97.8717	4	8	T,E	GAS	G	0.0563	2937.6	552		0	N/A	N/A	
IOLA	0	37.9367	95.3544	2	12	E	GAS	G	0.0438	0	38.5		0	N/A	N/A	
JEFFREY EC	0	39.2856	96.1083	3	3	T	COL	C	0.7611	20604	2160		0	N/A	N/A	
JOHNSON	0	37.5633	101.7838	0	7	E	GAS	G	0.0341	0	6.781		0	N/A	N/A	
JUDSON LARGE	0	37.7328	99.9492	1	1	T	GAS	G	0.3402	1496	148.75		0	N/A	N/A	
KANSAS CITY	0	39.0964	94.755	0	1	E	NG	G	0.2761	0	2	U	561371			Y
KANSAS RIVER PROJECT	0	38.8985	95.2785	0	7	Z	WAT		0.6637	0	2.637		0	N/A	N/A	Y
KANSAS STATE UNIVERSITY UTILITIES POWER PLANT	0	39.3049	96.6752	0	2	E	NG	G	0.0519	0	4	U	568000			Y
KAW	0	39.0864	94.6517	2	3	T	GAS	G	0.0568	1122	129		0	N/A	N/A	
KINGMAN	0	37.5589	98.1355	0	8	E	GAS	G	0.2717	0	21.55		0	N/A	N/A	

PNAME	PREV UTIL	LAT	LON	NUMBLR	NUMGEN	SOURCEM	PLPRIMFL	PLFFLCTG	CAPFAC	BOILCAP	NAMEPCAP	CHPFLAG	USETHRMO	PWRTOHT	ELCALLOC	PLNUCONN
LACYGNE	0	38.3481	94.6456	2	2	T	COL	C	0.6426	14848.48	1578		0	N/A	N/A	
LARNED	0	38.2072	99.1428	1	4	E	GAS	G	0.0586	0	19.25		0	N/A	N/A	
LAWRENCE EC	0	39.0078	95.2681	3	4	T	COL	C	0.4976	5537.92	603		0	N/A	N/A	
LINCOLN	0	39.0451	98.2089	0	6	E	OIL	O	0.0019	0	10.65		0	N/A	N/A	
LOVE BOX CO	0	37.6935	97.4801	0	3	E	NG	G	0.1883	0	2.175	U	50400			Y
MCPHERSON 2	0	38.3719	97.6869	1	4	T,E	GAS	G	0.0218	0	197		0	N/A	N/A	
MCPHERSON 3	0	38.3917	97.6479	1	1	T	GAS	G	0.0329	0	115.6		0	N/A	N/A	
MEADE	0	37.2377	100.3708	0	5	E	GAS	G	0.0742	0	8.2		0	N/A	N/A	
MINNEAPOLIS	0	39.1323	97.6504	0	7	E	GAS	G	0.0533	0	10.2		0	N/A	N/A	
MULVANE	0	37.6935	97.4801	0	6	E	GAS	G	0.0251	0	6.29		0	N/A	N/A	
MURRAY GILL EC	0	37.6935	97.4801	4	4	T	GAS	G	0.1225	3604	347		0	N/A	N/A	
NEARMAN CREEK	0	39.1714	94.6958	1	1	T	COL	C	0.7244	2380	261		0	N/A	N/A	
NEODESHA	0	37.5593	95.7436	0	4	E	OIL	O	0.0031	0	8.15		0	N/A	N/A	
NEOSHO	0	37.1917	95.2977	1	3	T	GAS	G	0.0425	0	109		0	N/A	N/A	
NORTON	0	39.7842	99.9034	0	5	E	GAS	G	0.0162	0	11.25		0	N/A	N/A	
OSAGE CITY	0	38.6519	95.7251	0	6	E	GAS	G	0.0279	0	9.45		0	N/A	N/A	
OSAWATOMIE	0	38.5637	94.8373	0	4	E	OIL	O	0.0072	0	7		0	N/A	N/A	
OSBORNE	0	39.3504	98.7677	0	8	E	OIL	O	0.0004	0	8.585		0	N/A	N/A	
PLANT NO 1	0	37.7817	96.8379	0	7	E	GAS	G	0.0222	0	9.742		0	N/A	N/A	
PLANT NO 2	0	37.7817	96.8379	0	3	E	GAS	G	0.0991	0	14		0	N/A	N/A	
PRATT	0	37.6842	98.7947	2	4	E	GAS	G	0.0517	0	23.5		0	N/A	N/A	
PRATT 2	0	37.6478	98.7394	0	1	E	OIL	O	0.0091	0	8		0	N/A	N/A	
QUINDARO	0	39.0878	94.6464	2	8	T,E	COL	C	0.2003	2312	487.97		0	N/A	N/A	
REPUBLIC PAPERBOARD CO INC							GAS				2.5					
RIVERTON	0	37.0667	94.7	2	5	T,E	COL	C	0.3761	0	132.64		0	N/A	N/A	
RUSSELL	0	38.9151	98.7628	0	10	E	GAS	G	0.1176	0	30.383		0	N/A	N/A	
SABETHA	0	39.7834	96.0135	0	10	E	GAS	G	0.0259	0	17.436		0	N/A	N/A	
SHARON SPRING	0	38.9163	101.7622	0	4	E	GAS	G	0.0063	0	3.117		0	N/A	N/A	
ST FRANCIS	0	39.7857	101.7305	0	4	E	OIL	O	0.0062	0	5.9		0	N/A	N/A	
ST JOHN	0	38.0427	98.747	0	3	E	OIL	O	0.0016	0	4.6		0	N/A	N/A	
STAFFORD	0	38.0427	98.747	0	5	E	GAS	G	0.0151	0	5.1		0	N/A	N/A	
STERLING	0	38.3476	98.201	0	4	E	GAS	G	0.0228	0	6.155		0	N/A	N/A	
STOCKTON	0	39.3503	99.3244	0	5	E	OIL	O	-0.0048	0	6.294		0	N/A	N/A	
TECUMSEH EC	0	39.0528	95.5683	2	4	T,E	COL	C	0.5251	2359.6	290		0	N/A	N/A	
WAMEGO	0	39.3463	96.366	0	9	E	GAS	G	0.0308	0	12.995		0	N/A	N/A	
WASHINGTON	0	39.7841	97.0872	0	7	E	GAS	G	0.0066	0	9.136		0	N/A	N/A	
WELLINGTON CITY	0	37.2379	97.4773	0	1	E	GAS	G	0.0726	0	20		0	N/A	N/A	
WELLINGTON MUNICIPAL	0	37.2833	97.4703	1	2	E	GAS	G	0.0683	0	21		0	N/A	N/A	
WEST 14TH STREET	0	37.2631	97.0717	0	1	E	GAS	G	0.0123	0	11		0	N/A	N/A	
WICHITA PLANT	0	37.6935	97.4801	0	1	E	NG	G	0.0659	0	32.7	U	162107			Y
WOLF CREEK	0	38.2363	95.7331	0	1	Z	UR		0.837	0	1235.79		0	N/A	N/A	
ANIMAS	0	36.51	108.33	1	6	E	GAS	G	0.4569	0	50.3		0	N/A	N/A	
BLANCO COMPRESSOR STATION	0	36.5003	108.2327	0	2	E	NG	G	0.9251	0	3		0	N/A	N/A	Y
CARLSBAD	0	32.4827	104.2867	0	1	E	GAS	G	0.0244	0	16.32		0	N/A	N/A	
CHINO MINES CO	0	32.5365	108.3272	0	2	E	NG	G	0.4349	0	46.5		0	N/A	N/A	Y
CINIZA REFINERY	0	35.4809	108.1758	0	2	E	NG	G	0.8167	0	6	U	316880			Y
COGENERATION PLANT	0	35.0442	106.6727	0	1	E	NG	G	0.5867	0	2.5	U	1550000			Y
CUNNINGHAM	0	32.7131	103.3533	4	4	T	GAS	G	0.3195	2754	519.2		0	N/A	N/A	
ELEPHANT BUTTE	0	33.0429	107.17	0	1	Z	WT		0.3713	0	27.945		0	N/A	N/A	
ESCALANTE	0	35.4144	108.0825	1	1	T	COL	C	0.8841	2416.72	233	U	988800			
FORD UTILITIES CENTER	0	35.0442	106.6727	0	1	E	NG	G	0.332	0	1.5	U	508375			Y
FOUR CORNERS	0	36.6906	108.4822	5	5	T	COL	C	0.7509	20461.2	2269.8		0	N/A	N/A	
HIDALGO SMELTER	0	32.0549	108.6283	0	5	E	NG	G	0.1124	0	37.5	U	105.43			Y
LAS VEGAS	0	35.4563	104.6792	0	1	E	OIL	O	0.0227	0	20		0	N/A	N/A	
MADDOX	0	32.7131	103.3017	1	3	T,E	GAS	G	0.3337	1101.6	213		0	N/A	N/A	
MILAGRO COGENERATION PLANT	0	36.5003	108.2327	2	2	T,E	NG	G	0.9426	0	60.8	U	782840			Y
NAVAJO DAM	0	36.5003	108.2327	0	1	Z	WT		0.4934	0	30		0	N/A	N/A	
NEW MEXICO STATE UNIVERSITY	0	32.4202	106.8195	0	1	E	NG	G	0.8461	0	4.75	U	158145			Y
PHELPS DODGE COBRE MINING CO							FO1				1.6					
PHELPS DODGE TYRONE INC	0	32.5365	108.3272	0	15	E	DFO	O	0.1344	0	45.4		0	N/A	N/A	Y
RATON	0	36.6	104.65	2	3	E	COL	C	0.2924	0	12.75	C		N/A		
REEVES	0	35.0442	106.6727	3	3	T	GAS	G	0.165	2108	154		0	N/A	N/A	
RIO GRANDE	0	31.805	106.5475	3	3	T	GAS	G	0.4177	2627.52	266.5		0	N/A	N/A	
SAN JUAN	0	36.8833	108.4833	4	4	T	COL	C	0.7948	17968.32	1779		0	N/A	N/A	
SAN JUAN BASIN GAS PLANT	0	36.5003	108.2327	0	4	E	NG	G	0.9737	0	8.06		0	N/A	N/A	Y
SOUTHSIDE WATER RECLAMATION PLANT	0	35.0442	106.6727	0	2	E	NG	G	0.8867	0	2.27	U	46609			Y
TUCUMCARI	0	35.1724	103.585	0	7	E	OIL	O	0.0007	0	17.45		0	N/A	N/A	
WILLIAMS FIELD SERVICES KUTZ PLANT	0	36.5003	108.2327	0	2	E	NG	G	0.3155	0	4.8	U	69249			Y
AES SHADY POINT INC	0	34.9471	94.7464	0	2	E	SUB	C	0.7568	0	350	U	1453224			Y
ANADARKO	0	35.0844	98.2256	3	6	T,E	GAS	G	0.4596	0	374		0	N/A	N/A	
BOOMER LAKE STATION	0	36.094	96.9874	2	2	E	GAS	G	0.1447	0	22.7		0	N/A	N/A	
BROKEN BOW	0	34.0615	94.8087	0	1	Z	WT		0.1373	0	100		0	N/A	N/A	
CALPINE PRYOR INC	0	36.2925	95.2225	0	7	E	NG	G	0.2606	0	133.2	U	1771682			Y
CHANEY DELL PLANT	0	36.334	98.5319	0	3	E	NG	G	0.4035	0	2.35		0	N/A	N/A	Y
COMANCHE	0	34.5542	98.2061	2	4	T	GAS	G	0.6316	1338.24	280.822		0	N/A	N/A	
CONOCO	0	36.7963	97.106	2	2	T	GAS	G	0.3673	0	66	C		N/A		
CUSHING	0	36.094	96.9874	0	11	E	GAS	G	0.006	0	24.6		0	N/A	N/A	
ENID	0	36.3792	97.7825	0	4	E	GAS	G	0.0085	0	60		0	N/A	N/A	

PNAME	PREV UTIL	LAT	LON	NUMBLR	NUMGEN	SOURCEM	PLPRIMFL	PLFFLCTG	CAPFAC	BOILCAP	NAMEPCAP	CHPFLAG	USETHRMO	PWRTOHT	ELCALLOC	PLNUCONN
EUFAULA	0	35.2581	95.1344	0	1	Z	WT		0.3416	0	90		0	N/A	N/A	
FORT GIBSON	0	35.9	95.0307	0	1	Z	WT		0.393	0	45		0	N/A	N/A	
GRDA	0	36.1889	95.2892	2	2	T	COL	C	0.7101	10336	1010		0	N/A	N/A	
HORSESHOE LAKE	0	35.5089	97.1875	5	4	T	GAS	G	0.1347	7235.2	851		0	N/A	N/A	
HUGO	0	34.0292	95.3167	1	1	T	COL	C	0.793	4284	400		0	N/A	N/A	
KAW HYDRO	0	36.7963	97.106	0	1	Z	WT		0.5482	0	25.6		0	N/A	N/A	
KEYSTONE	0	36.1397	96.0295	0	1	Z	WT		0.5002	0	70		0	N/A	N/A	
KINGFISHER	0	35.9451	97.9419	0	5	E	GAS	G	0.0142	0	9.1		0	N/A	N/A	
MANGUM	0	34.9208	99.5673	0	6	E	GAS	G	0.0272	0	7.635		0	N/A	N/A	
MARKHAM	0	36.2925	95.2225	0	1	Z	WT		0.1393	0	120		0	N/A	N/A	
MOORELAND	0	36.4375	99.2208	3	3	T	GAS	G	0.2514	3424.48	305		0	N/A	N/A	
MUSKOGEE	0	35.7653	95.2883	4	4	T	COL	C	0.6256	17233.92	1889		0	N/A	N/A	
MUSKOGEE MILL	0	35.56	95.408	0	3	E	SUB	C	0.5187	0	114	U	2280000			Y
MUSTANG	0	35.4814	97.675	4	6	T,E	GAS	G	0.1547	5317.6	610		0	N/A	N/A	
NORTHEASTERN	0	36.4222	95.7047	4	5	T,E	COL	C	0.627	14824	1498.68		0	N/A	N/A	
OKLAHOMA STATE UNIVERSITY	0	36.094	96.9874	0	3	E	NG	G	0.1769	0	8	U	286485			Y
PENSACOLA	0	36.2925	95.2225	0	1	Z	WT		0.2661	0	110.9		0	N/A	N/A	
PONCA	0	36.82	97.15	2	2	T	GAS	G	0.0203	0	68.2		0	N/A	N/A	
PONCA CITY REFINERY	0	36.7963	97.106	0	3	E	OG		0.3844	0	18	U	3686236			Y
PONCA DIESEL	0	36.7963	97.106	0	7	E	GAS	G	0.405	0	28.3		0	N/A	N/A	
POWERSMITH COGEN PROJECT	0	35.5514	97.4072	0	2	E	NG	G	0.7275	0	111.51	U	733413			Y
RIVERSIDE	0	35.9858	95.9519	2	3	T,E	GAS	G	0.4228	8840	885.26		0	N/A	N/A	
ROBERT S KERR	0	35.468	94.7817	0	1	Z	WT		0.599	0	110		0	N/A	N/A	
SALINA	0	36.2925	95.2225	0	1	Z	WT		-0.0505	0	288		0	N/A	N/A	
SEMINOLE	0	34.9664	96.7258	3	4	T,E	GAS	G	0.2428	15387.04	1724		0	N/A	N/A	
SOONER	0	36.4544	97.05	2	2	T	COL	C	0.7294	10423.04	1136		0	N/A	N/A	
SOUTHWESTERN	0	35.1014	98.3531	4	4	T,E	GAS	G	0.2676	4392.8	450.992		0	N/A	N/A	
TENKILLER FERRY	0	35.468	94.7817	0	1	Z	WT		0.2937	0	39.1		0	N/A	N/A	
TULSA	0	36.1014	95.9892	3	4	T,E	GAS	G	0.0998	4331.6	443.25		0	N/A	N/A	
UNIVERSITY OF OKLAHOMA	0	35.1534	97.4062	0	4	E	NG	G	0.1003	0	16.8	U	498713			Y
VALLIANT OK	0	34.0615	94.8087	0	1	E	BL		0.3817	0	57.8	U	13092688			Y
WALTER B HALL RESOURCE RECOVERY FACILITY	0	36.1397	96.0295	0	1	E,W	MWC		0.0273	0	16.8	U	18938			Y
WEBBERS FALLS	0	35.56	95.408	0	1	Z	WT		0.4185	0	60		0	N/A	N/A	
WELEETKA	0	35.4644	96.3029	0	4	E	GAS	G	0.0252	0	163		0	N/A	N/A	
WOODWARD	0	36.4837	99.2806	0	1	E	GAS	G	0.0015	0	11		0	N/A	N/A	
WRIGHT CITY OK	0	34.0615	94.8087	0	1	E	WDS		0.6064	0	5	U	1752303			Y
ABBOTT TP 3	0	29.6175	97.9721	0	1	Z	WT		0.3091	0	2.8		0	N/A	N/A	
ABILENE	1	32.3	99.89	2	1	E	GAS	G	0.0729	0	15		0	N/A	N/A	Y
AES DEEPWATER INC	0	29.8336	95.4383	0	1	E	PC	O	0.7707	0	184	U	122143			Y
AMISTAD DAM & POWER	0	29.7652	101.2299	0	1	Z	WT		0.1488	0	66		0	N/A	N/A	
AUSTIN	0	30.3241	97.7711	0	1	Z	WT		0.1965	0	16.136		0	N/A	N/A	
AUSTIN STATE HOSPITAL	0	30.3241	97.7711	0	1	E	NG	G	0.7855	0	1	U	32324			Y
BARNEY M DAVIS	1	27.6064	97.3117	2	2	T	GAS	G	0.6096	6474.96	647.143		0	N/A	N/A	Y
BAYLOR UNIVERSITY COGENERATION	0	31.5536	97.2029	0	1	E	NG	G	0.7205	0	3.447	U	157222			Y
BAYOU COGENERATION PLANT	0	29.8336	95.4383	0	4	E	NG	G	0.9761	0	300	U	11000000			Y
BAYTOWN TURBINE GENERATOR PROJECT	0	29.8336	95.4383	0	4	E	NG	G	0.8039	0	212	U	7007900			Y
BEAUMONT REFINERY	0	29.8641	94.135	0	9	E	NG	G	0.5568	0	204.84	U	1657046			Y
BENEDUM PLANT	0	31.3656	102.0461	0	2	E	NG	G	0.2639	0	2		0	N/A	N/A	Y
BIG BROWN	1	31.8206	96.0547	2	2	T	COL	C	0.8219	10948	1186.8		0	N/A	N/A	Y
BIG SPRING TEXAS REFINERY	0	32.3059	101.4342	0	1	E	NG	G	0.9336	0	1.5	U	6357887			Y
BIG SPRING WIND POWER FACILITY	0	32.3059	101.4342	0	1	Z	WND		0.3332	0	34.32		0	N/A	N/A	Y
BLACK HAWK STATION	0	35.8398	101.3542	2	2	T,E	NG	G	0.6683	0	253.8	U	1000000			Y
BORGER PLANT	0	35.8398	101.3542	0	1	E	OG		0.7054	0	37.5	U	1701698			Y
BP CHEMICALS GREEN LAKE PLANT	0	28.3954	96.6261	0	2	E	OG		0.6315	0	38.8		0	N/A	N/A	Y
BRANDON STATION	0	33.6096	101.8209	0	1	E	GAS	G	0.7484	0	21	C		N/A		
BRIDGEPORT GAS PROCESSING PLANT	0	33.2125	97.6518	0	4	E	NG	G	0.5969	0	1.52		0	N/A	N/A	Y
BROWNFIELD	0	33.1732	102.3346	0	6	E	GAS	G	0.0044	0	21.92		0	N/A	N/A	
BRYAN	0	30.6442	96.3725	4	5	T,E	GAS	G	0.0847	1455.2	138		0	N/A	N/A	
BUCHANAN	0	30.7304	98.1415	0	1	Z	WT		0.0637	0	47.85		0	N/A	N/A	
C E NEWMAN	0	32.9125	96.6228	5	5	T,E	GAS	G	0.0616	0	96.5		0	N/A	N/A	
C R WING COGENERATION PLANT	0	32.3059	101.4342	0	3	E	NG	G	0.6773	0	230.08	U	1039812			Y
CANYON	0	29.816	98.3222	0	1	Z	WT		0.1437	0	6		0	N/A	N/A	
CEDAR BAYOU	1	29.75	94.9256	3	3	T	GAS	G	0.4079	21148	2295		0	N/A	N/A	Y
CELANESE ENGINEERING RESIN INC	0	27.777	97.4878	0	2	E	NG	G	0.7445	0	43.74	U	1465000			Y
CENTRAL UTILITY PLANT	0	30.3241	97.7711	0	3	E	NG	G	0.2534	0	14.46	U	75500			Y
CHOCOLATE BAYOU PLANT	0	29.2062	95.4646	0	4	E	NG	G	0.1901	0	55.3	U	2400036			Y
CHOCOLATE BAYOU WORKS	0	29.2062	95.4646	0	1	E	NG	G	0.7932	0	41	U	1982666			Y
CLEAR LAKE COGENERATION LTD	0	29.8336	95.4383	0	5	E	NG	G	0.8982	0	377	U	239306			Y
COGEN LYONDELL INC	0	29.8336	95.4383	0	7	E	NG	G	0.806	0	564	U	11365650			Y
COGEN POWER LP							WH				5					
COLEMAN	0	31.7606	99.4588	0	9	E	GAS	G	0.0039	0	16.86		0	N/A	N/A	
COLETO CREEK	1	28.7128	97.2142	1	1	T	COL	C	0.966	5710.64	570.057		0	N/A	N/A	Y
COLLIN	1	33.2028	96.8108	1	1	T	GAS	G	0.2172	1564	156.25		0	N/A	N/A	Y
COMANCHE PEAK	1	32.2029	97.7801	0	1	Z	UR		0.8671	0	2430		0	N/A	N/A	Y
COPPER	0	31.6948	106.3128	0	1	E	GAS	G	0.1218	0	80.55		0	N/A	N/A	
CORPUS CHRISTI PLANT	0	27.777	97.4878	0	1	E	NG	G	0.7237	0	45.176	U	2346327			Y
CORPUS CHRISTI REFINERY	0	27.777	97.4878	0	2	E	NG	G	0.8597	0	40	U	2243006			Y
DANSBY	0	30.7217	96.4611	1	1	T	GAS	G	0.3756	1054	105		0	N/A	N/A	

PNAME	PREV UTIL	LAT	LON	NUMBLR	NUMGEN	SOURCEM	PLPRIMFL	PLFFLCTG	CAPFAC	BOILCAP	NAMEPCAP	CHPFLAG	USETHRMO	PWRTOHT	ELCALLOC	PLNUCONN
DECKER CREEK	0	30.3036	97.6128	2	7	T,E	GAS	G	0.2726	7106	932.58		0	N/A	N/A	
DECORDOVA	1	32.4017	97.7186	1	5	T,E	GAS	G	0.4038	7405.2	1157.112		0	N/A	N/A	Y
DEEPWATER	1	29.7231	95.2261	1	1	T	GAS	G	0.1161	1632	187.85		0	N/A	N/A	Y
DEER PARK PLANT	0	29.8336	95.4383	0	4	E	NG	G	0.7939	0	111.06	U	1565872			Y
DELAWARE MOUNTAIN WINDFARM	0	29.8336	95.4383	0	1	Z	WND		0.2863	0	30		0	N/A	N/A	Y
DENISON	0	33.6763	96.6622	0	1	Z	WT		0.3165	0	70		0	N/A	N/A	
DFW GAS RECOVERY	0	33.2075	97.116	0	2	E	LFG		0.8128	0	6		0	N/A	N/A	Y
DUNLAP TP 1	0	29.6175	97.9721	0	1	Z	WT		0.3679	0	3.6		0	N/A	N/A	
E S JOSLIN	1	28.65	96.5417	1	1	T	GAS	G	0.2922	2167.84	234.874		0	N/A	N/A	Y
EAGLE MOUNTAIN	1	32.9058	97.4794	3	3	T	GAS	G	0.1513	6589.2	706.15		0	N/A	N/A	Y
EAGLE PASS	1	28.643	100.3891	0	1	Z	WT		0.4623	0	12		0	N/A	N/A	Y
EAST TEXAS GAS PLANT	0	32.183	94.3071	0	7	E	NG	G	0.5608	0	2.2		0	N/A	N/A	Y
EAST VEALMOOR GAS PLANT	0	32.3059	101.4342	0	7	E	NG	G	0.5076	0	1.925		0	N/A	N/A	N
EDGEWOOD GAS PLANT							GAS				3					
ENCOGEN ONE	0	32.3034	100.4054	0	4	E	NG	G	0.7104	0	265.97	U	1209179			Y
ENGINEERED CARBONS BORGER COGENERATION	0	35.8398	101.3542	0	1	E	OG		0.7178	0	20		0	N/A	N/A	Y
ENGINEERED CARBONS ECHO COGENERATION	0	30.0547	93.9088	0	1	E	OG		0.2438	0	10		0	N/A	N/A	Y
ENTERPRISE PRODUCTS OPERATING LP	0	29.7077	94.6667	0	8	E	NG	G	0.8433	0	25.7	U	874000			Y
EXXON HAWKINS GAS PLANT	0	32.7806	95.4085	0	5	E	NG	G	0.3053	0	7.51		0	N/A	N/A	Y
EXXON MOBIL CO USA BAYTOWN PP3 PP4	0	29.8336	95.4383	0	11	E	NG	G	0.873	0	215	U	10071900			Y
FALCON DAM & POWER	0	26.5177	98.7449	0	1	Z	WT		0.1504	0	31.5		0	N/A	N/A	
FAYETTE POWER PRJ	0	29.9172	96.7506	3	3	T	COL	C	0.8019	15702.56	1690		0	N/A	N/A	
FORMOSA UTILITY VENTURE LTD	0	28.3954	96.6261	0	8	E	NG	G	0.6723	0	652.2	U	12276495			Y
FORT BEND UTILITIES CO	0	29.5254	95.7569	0	4	E	NG	G	0.5046	0	6.155	U	1166338			Y
FORT PHANTOM	1	32.5825	99.6825	2	2	T	GAS	G	0.4489	3404.08	337.322		0	N/A	N/A	Y
FORT STOCKTON	1	30.7119	102.6783	0	1	E	GAS	G	0.0004	0	5		0	N/A	N/A	Y
FREEPORT	0	29.2062	95.4646	0	2	E	NG	G	0.7962	0	92.7	U	8541096			Y
FRONTERA GENERATION FACILITY	0	26.4226	98.2239	2	3	T,E	NG	G	0.338	0	511		0	N/A	N/A	Y
FULLERTON PLANT	0	32.305	102.6376	0	6	E	NG	G	0.5842	0	3		0	N/A	N/A	Y
GIBBONS CREEK	0	30.6167	96.0778	1	1	T	COL	C	0.8444	4488	443.97		0	N/A	N/A	
GRAHAM	1	33.1347	98.6119	2	2	T	GAS	G	0.4124	5780	634.775		0	N/A	N/A	Y
GRANITE SHOALS	0	30.7304	98.1415	0	1	Z	WT		0.1031	0	45		0	N/A	N/A	
GREENS BAYOU	1	29.8208	95.2183	1	7	T,E	GAS	G	0.1162	4153.44	878.4		0	N/A	N/A	Y
H 4	0	29.447	97.4944	0	1	Z	WT		0.3193	0	2.4		0	N/A	N/A	
H 5	0	29.447	97.4944	0	1	Z	WT		0.0132	0	2.4		0	N/A	N/A	
HANDLEY	1	32.7286	97.2192	6	5	T	GAS	G	0.2396	13791.76	1433.35		0	N/A	N/A	Y
HARRINGTON	0	35.2989	101.7475	3	3	T	COL	C	0.8487	10942.56	1080		0	N/A	N/A	
HIRAM CLARKE	1	29.6483	95.4508	0	6	E	GAS	G	0.0236	0	96		0	N/A	N/A	Y
HOLLY STREET	0	30.25	97.7167	4	4	T	GAS	G	0.2547	5032	558		0	N/A	N/A	
HOUSTON CHEMICAL COMPLEX BATTLEGROUND SITE	0	29.8336	95.4383	0	3	E	NG	G	0.8644	0	200	U	4718770			Y
INGLESIDE COGENERATION	0	28.0115	97.5202	0	3	E	NG	G	0.625	0	528	U	11091649			Y
INKS	0	30.7304	98.1415	0	1	Z	WT		0.1037	0	15		0	N/A	N/A	
INLAND PAPERBOARD AND PACKAGING	0	30.0547	93.9088	0	1	E	BL		0.6379	0	48	U	5778000			Y
J K SPRUCE	0	29.3064	98.3203	1	1	T	COL	C	0.832	5191.12	546		0	N/A	N/A	
J L BATES	1	26.2167	98.4083	2	2	T	GAS	G	0.3588	1842.8	166		0	N/A	N/A	Y
J ROBERT MASSENGALE	0	33.61	101.8	6	5	T,E	GAS	G	0.0817	0	107		0	N/A	N/A	
J T DEELY	0	29.3072	98.3228	2	2	T	COL	C	0.7083	7888	892		0	N/A	N/A	
JAMESON GAS PROCESSING PLANT	0	31.8895	100.53	0	3	E	NG	G	0.9353	0	1.25		0	N/A	N/A	Y
JCO OXIDES OLEFINS PLANT	0	29.8641	94.135	0	2	E	NG	G	0.8289	0	77.2	U	2627352			Y
JONES	0	33.5239	101.7397	2	2	T	GAS	G	0.546	4849.76	496		0	N/A	N/A	
KNOX LEE	0	32.3744	94.6431	4	4	T	GAS	G	0.3226	4942.24	458.694		0	N/A	N/A	
KOCH PETROLEUM GROUP LP CORPUS REFINERY	0	27.777	97.4878	0	1	E	NG	G	0.5588	0	55	U	550000			Y
LA PALMA	1	26.1333	97.6389	3	4	T,E	GAS	G	0.2888	2045.44	242.325		0	N/A	N/A	Y
LAKE CREEK	1	31.4633	96.9867	2	5	T,E	GAS	G	0.3198	4216	321.625		0	N/A	N/A	Y
LAKE HUBBARD	1	32.8361	96.5461	2	2	T	GAS	G	0.3281	8602	927.519		0	N/A	N/A	Y
LAKE PAULINE	1	34.3	99.74	4	2	E	GAS	G	0.0677	0	40		0	N/A	N/A	Y
LAREDO	1	27.5667	99.5089	3	3	T	GAS	G	0.4992	1890.4	168.29		0	N/A	N/A	Y
LEON CREEK	0	29.3508	98.575	2	2	T	GAS	G	0.0547	1972	189		0	N/A	N/A	
LEWIS CREEK	0	30.4367	95.5478	2	2	T	GAS	G	0.6005	4588.64	542.8		0	N/A	N/A	
LEWISVILLE	0	33.2075	97.116	0	1	Z	WT		0.0974	0	2.8		0	N/A	N/A	
LIMESTONE	1	31.4222	96.2525	2	2	T	COL	C	0.7936	15014.4	1626.8		0	N/A	N/A	Y
LON C HILL	1	27.85	97.6167	4	4	T	GAS	G	0.3452	5377.44	510.874		0	N/A	N/A	Y
LONE STAR	0	32.9125	94.7131	1	1	T	GAS	G	0.1611	0	40		0	N/A	N/A	
LONE STAR STEEL CO	0	33.1216	94.7358	0	2	E	NG	G	0.0123	0	31.25		0	N/A	N/A	Y
LUFKIN TEXAS	0	31.2763	94.5662	0	6	E	NG	G	0.5576	0	84.926	U	5257304			Y
MARBLE FALLS	0	30.7304	98.1415	0	1	Z	WT		0.0966	0	30		0	N/A	N/A	
MARSHALL FORD	0	30.3241	97.7711	0	1	Z	WT		0.0925	0	102.545		0	N/A	N/A	
MARTIN LAKE	1	32.2606	94.5708	3	3	T	COL	C	0.7926	22032	2379.75		0	N/A	N/A	Y
MIDKIFF PLANT	0	31.3656	102.0461	0	3	E	NG	G	0.5791	0	3.6		0	N/A	N/A	Y
MISSION ROAD	0	29.3975	98.4883	1	1	T	GAS	G	0.0557	1020	114		0	N/A	N/A	
MONTICELLO	1	33.0917	95.0417	3	3	T	COL	C	0.7132	18460.64	1980.05		0	N/A	N/A	Y
MOORE COUNTY	0	35.8377	101.8925	1	1	T	GAS	G	0.1218	0	49		0	N/A	N/A	
MORGAN CREEK	1	32.3361	100.9156	5	11	T,E	GAS	G	0.301	8758.4	1364.223		0	N/A	N/A	Y
MORRIS SHEPPARD	0	32.7596	98.3157	0	1	Z	WT		0.0161	0	25		0	N/A	N/A	
MORTON SALT CO GRAND SALINE	0	32.5966	95.7626	0	1	E	NG	G	0.6421	0	1.5	U	326928			Y
MOUNTAIN CREEK	1	32.7233	96.9361	6	5	T	GAS	G	0.2719	9288.8	958.491		0	N/A	N/A	Y
MUSTANG STATION	0	33.1735	102.8289	2	3	T,E	NG	G	0.5298	0	521.055		0	N/A	N/A	Y
NEWGULF	0	29.2983	96.2438	1	2	T,E	NG	G	0.0366	0	91.25		0	N/A	N/A	Y

PNAME	PREV UTIL	LAT	LON	NUMBLR	NUMGEN	SOURCEM	PLPRIMFL	PLFFLCTG	CAPFAC	BOILCAP	NAMEPCAP	CHPFLAG	USETHRMO	PWRTOHT	ELCALLOC	PLNUCONN
NEWMAN	0	31.9842	106.4319	5	6	T	GAS	G	0.4148	3582.24	568.375		0	N/A	N/A	
NICHOLS	0	35.2831	101.7458	3	3	T	GAS	G	0.2383	4600.88	476		0	N/A	N/A	
NOLTE	0	29.6175	97.9721	0	1	Z	WT		0.2964	0	2.4		0	N/A	N/A	
NORIT AMERICAS INC MARSHALL PLANT	0	32.5618	94.3725	0	1	E	LIG	C	0.6896	0	2	U	2789130			Y
NORTH LAKE	1	32.9506	96.975	3	3	T	GAS	G	0.3093	6840.8	708.605		0	N/A	N/A	Y
NORTH MAIN	1	32.7608	97.3364	1	3	T	GAS	G	0.1429	0	116.25		0	N/A	N/A	Y
NORTH RILEY	0	31.8691	102.0313	0	2	E	NG	G	0.8912	0	2	U	31260			Y
NORTH TEXAS	0	32.7803	97.6953	3	3	T,E	GAS	G	0.0502	0	71		0	N/A	N/A	
NUECES BAY	1	27.8169	97.4167	3	3	T	GAS	G	0.5054	5146.24	513.694		0	N/A	N/A	Y
O W SOMMERS	0	29.3078	98.3244	2	2	T	GAS	G	0.3282	7833.6	892		0	N/A	N/A	
OAK CREEK	1	31.89	100.53	1	1	T	GAS	G	0.4979	0	75		0	N/A	N/A	Y
OKLAUNION	1	34.0825	99.1753	1	1	T	COL	C	0.7667	6664	663.943		0	N/A	N/A	Y
OYSTER CREEK UNIT VIII	0	29.8336	95.4383	0	4	E	NG	G	0.6606	0	498.045	U	7915000			Y
P H ROBINSON	1	29.4869	94.9797	4	4	T	GAS	G	0.4591	21243.2	2314.5		0	N/A	N/A	Y
PAINT CREEK	1	33.0811	99.5778	4	4	T	GAS	G	0.2332	2386.8	218.145		0	N/A	N/A	Y
PARKDALE	1	32.7767	96.7236	3	3	T	GAS	G	0.2057	3910	340.625		0	N/A	N/A	Y
PASADENA	0	29.8336	95.4383	0	1	E	NG	G	0.6074	0	4	U	276646			Y
PASADENA COGENERATION LP	0	29.8336	95.4383	3	5	T,E	NG	G	0.2842	0	760.9	U	1149467			Y
PEARSALL	0	29.0939	99.4122	3	3	E	GAS	G	0.0912	0	66		0	N/A	N/A	
PERMIAN BASIN	1	31.5839	102.9636	2	7	T,E	GAS	G	0.3218	6290	1097.844		0	N/A	N/A	Y
PHELPS DODGE REFINING CORP	0	31.6948	106.3128	0	5	E	NG	G	0.5299	0	19.81	U	301102			Y
PIRKEY	0	32.4606	94.485	1	1	T	COL	C	0.7528	6664	660.402		0	N/A	N/A	
PLANT X	0	34.1661	102.4111	4	4	T	GAS	G	0.2272	4692	434.4		0	N/A	N/A	
PORT ARTHUR REFINERY	0	29.8641	94.135	0	7	E	NG	G	0.6387	0	125.35	U	16653725			Y
PORT ARTHUR REFINERY	0	29.8641	94.135	0	6	E	NG	G	0.6791	0	74.75	U	4709609			Y
PORT ARTHUR TEXAS REFINERY	0	29.8641	94.135	0	1	E	OG		0.7878	0	38.4	U	100000			Y
POWER STATION 3	0	29.3171	94.9773	0	6	E	NG	G	0.3552	0	118.127	U	1217154			Y
POWER STATION 4	0	29.3171	94.9773	0	3	E	NG	G	0.8621	0	191.123	U	9875328			Y
POWERLANE PLANT	0	33.1744	96.1256	3	3	T,E	GAS	G	0	0	84.7		0	N/A	N/A	
PPG INDUSTRIES INC WORKS 4	0	34.0121	98.6874	0	4	E	DFO	O	0.015	0	6.03		0	N/A	N/A	Y
PRESIDIO	1	29.9458	104.386	0	2	E	OIL	O	0.0008	0	2.272		0	N/A	N/A	Y
PROVIDENCE MEMORIAL HOSPITAL	0	31.6948	106.3128	0	2	E	DFO	O	0.0032	0	4.36	U	297			Y
PT COMFORT OPERATIONS	0	28.3954	96.6261	0	4	E	NG	G	0.6603	0	63.1	U	9415173			Y
PT NECHES PLANT	0	29.8641	94.135	0	1	E	NG	G	0.8171	0	38	U	947247.04			Y
R W MILLER	0	32.6581	98.3103	5	5	T	GAS	G	0.3375	4012	603.636		0	N/A	N/A	
RAY OLINGER	0	33.0681	96.4528	3	3	T	GAS	G	0.3594	3595.84	345		0	N/A	N/A	
RAY ROBERTS	0	33.2075	97.116	0	1	Z	WT		0.2127	0	1.2		0	N/A	N/A	
REYNOLDS METALS CO SHERWIN PLANT	0	27.777	97.4878	0	6	E	NG	G	0.7438	0	39	U	4706568			Y
RHODIA INC HOUSTON PLANT	0	29.8336	95.4383	0	2	E	OTS		0.8915	0	6.5	U	1130851			Y
RICE UNIVERSITY	0	29.8336	95.4383	0	2	E	NG	G	0.5298	0	7.106	U	256190			Y
RIO GRANDE VALLEY SUGAR GROWERS INC	0	26.1416	97.5059	0	3	E	AB		0.23	0	7.5	U	2525123			Y
RIO PECOS	1	31.0867	102.3694	2	3	T	GAS	G	0.4316	1441.6	126.968		0	N/A	N/A	Y
RIVER CREST	1	33.3933	95.1467	1	1	T	GAS	G	0.1857	1292	112.5		0	N/A	N/A	Y
RIVERVIEW	0	35.8398	101.3542	0	1	E	GAS	G	0.0282	0	25		0	N/A	N/A	
ROBERT D WILLIS	0	30.6999	93.9944	0	1	Z	WT		0.4958	0	7.2		0	N/A	N/A	
ROBSTOWN	0	27.777	97.4878	0	8	E	GAS	G	0.1684	0	21.071		0	N/A	N/A	
S&L COGENERATION	0	29.3171	94.9773	0	1	E	NG	G	0.6087	0	55	U	1767492			Y
SABINE	0	30.0206	93.8753	5	5	T	GAS	G	0.4748	18126.08	2051.2		0	N/A	N/A	
SABINE RIVER WORKS	0	30.0547	93.9088	0	4	E	NG	G	0.8035	0	105.525	U	4248993			Y
SAM BERTRON	1	29.7297	95.1719	4	6	T,E	GAS	G	0.2437	5372	875.26		0	N/A	N/A	Y
SAM RAYBURN	0	28.79	96.98	1	5	E	GAS	G	0.0512	0	47.7		0	N/A	N/A	
SAM RAYBURN	0	30.6999	93.9944	0	1	Z	WT		0.0813	0	52		0	N/A	N/A	
SAN ANGELO	1	31.3933	100.4922	1	2	T	GAS	G	0.786	811.92	110		0	N/A	N/A	Y
SAN JACINTO SES	1	29.8336	95.4383	2	2	T	GAS	G	0.8849	0	176.4	C		N/A		Y
SAN MIGUEL	0	28.7089	98.4722	1	1	T	COL	C	0.8297	4153.44	410		0	N/A	N/A	
SANDOW	1	30.5642	97.0639	1	1	T	COL	C	0.6874	5610	590.64		0	N/A	N/A	Y
SANDOW	0	30.7839	96.9655	0	3	E	LIG	C	0.8791	0	363		0	N/A	N/A	Y
SEADRIFT COKE LP	0	28.3954	96.6261	0	1	E	OG		0.5954	0	7.6	U	952672			Y
SEADRIFT PLANT UNION CARBIDE CORP	0	28.3954	96.6261	0	8	E	NG	G	0.5806	0	168	U	696378			Y
SEGUIN							OIL				0.5					
SHELDON TEXAS	0	29.8336	95.4383	0	3	E	NG	G	0.2809	0	97.25	U	3877785			Y
SHELL DEER PARK	0	29.8336	95.4383	0	4	E	NG	G	0.8373	0	250	U	21909268			Y
SI RAY	0	25.9131	97.5222	2	4	T,E	GAS	G	0.0868	0	145		0	N/A	N/A	
SIM GIDEON	0	30.1417	97.275	3	3	T	GAS	G	0.3957	5221.04	639		0	N/A	N/A	
SMALL HYDRO OF TEXAS INC	0	29.0987	97.3657	0	3	Z	WAT		0.2268	0	1.767		0	N/A	N/A	Y
SNIDER INDUSTRIES INC	0	32.5618	94.3725	0	1	E	WDS		0.3322	0	5	U	230265			Y
SOUTH TEXAS	1	28.806	95.9432	0	1	Z	UR		0.8049	0	2708.64		0	N/A	N/A	Y
SOUTHERN ENERGY WICHITA FALLS LP	0	34.0121	98.6874	0	4	E	NG	G	0.6925	0	80		0	N/A	N/A	Y
SOUTHWEST TEXAS STATE UNIVERSITY COGEN	0	30.0543	98.0028	0	1	E	NG	G	0.6513	0	6	U	15547			Y
SPENCER	0	33.2042	97.1028	5	5	T,E	GAS	G	0.1697	2310.64	173.945		0	N/A	N/A	
STATE FARM INS CO ISC CENTRAL	0	32.7669	96.7773	0	6	E	DFO	O	0.0016	0	10.95		0	N/A	N/A	Y
STRYKER CREEK	1	31.9381	94.9883	2	7	T,E	GAS	G	0.3799	6596	713.48		0	N/A	N/A	Y
SWEENY COGENERATION FACILITY	0	29.2062	95.4646	3	4	T,E	NG	G	0.6753	0	460	U	5000000			Y
T H WHARTON	1	29.9417	95.5306	1	18	T,E	GAS	G	0.3232	2348.72	1421.52		0	N/A	N/A	Y
TENASKA III TEXAS PARTNERS	0	33.6603	95.583	0	3	E	NG	G	0.6799	0	250	U	697313			Y
TENASKA IV TEXAS PARTNERS LTD CLEBURNE COGEN	0	32.3444	97.3516	1	2	T,E	NG	G	0.629	0	282.6	U	407639			Y
TEXARKANA MILL	0	33.0865	94.3482	0	2	E	BL		0.7758	0	65	U	8056246			Y
TEXAS CITY COGENERATION LP	0	29.3171	94.9773	0	4	E	NG	G	0.895	0	450	U	3541775			Y

PNAME	PREV UTIL	LAT	LON	NUMBLR	NUMGEN	SOURCEM	PLPRIMFL	PLFFLCTG	CAPFAC	BOILCAP	NAMEPCAP	CHPFLAG	USETHRMO	PWRTOHT	ELCALLOC	PLNUCONN
TEXAS CITY PLANT							GAS				41.5					
TEXAS CITY PLANT UNION CARBIDE CORP	0	29.3171	94.9773	0	2	E	NG	G	0.5954	0	96	U	5904004			Y
TEXAS PETROCHEMICALS CORP	0	29.8336	95.4383	0	1	E	NG	G	0.9715	0	35	U	14807288			Y
THE DOW CHEMICAL CO TEXAS OPERATIONS	0	29.2062	95.4646	0	16	E	NG	G	0.5558	0	1378.839	U	20771525			Y
THE GOODYEAR&TIRE RUBBER CO	0	29.8641	94.135	0	5	E	NG	G	0.8067	0	34.877	U	9075322			Y
THOMAS C FERGUSON	0	30.5564	98.3694	1	1	T	GAS	G	0.3707	4153.44	446		0	N/A	N/A	
TNP ONE	1	31.0928	96.6933	2	2	T	COL	C	0.7242	2992	349.2		0	N/A	N/A	Y
TOLEDO BEND	0	30.714	93.732	0	1	Z	WT		0.1451	0	81		0	N/A	N/A	
TOLK	0	34.1847	102.5686	2	2	T	COL	C	0.818	10327.84	1136		0	N/A	N/A	
TP 4	0	29.6175	97.9721	0	1	Z	WT		0.3455	0	2.4		0	N/A	N/A	
TRADINGHOUSE	1	31.5728	96.9644	2	2	T	GAS	G	0.4469	12861.52	1379.7		0	N/A	N/A	Y
TRINIDAD	1	32.1336	96.1019	1	3	T,E	GAS	G	0.1867	2423.52	243.36		0	N/A	N/A	Y
TY COOKE	0	33.5164	101.7917	2	5	T,E	GAS	G	0.3172	0	150.65		0	N/A	N/A	
UNIVERSITY OF TEXAS AT AUSTIN	0	30.3241	97.7711	0	5	E	NG	G	0.3508	0	103.427	U	2156987			Y
UNIVERSITY OF TEXAS AT DALLAS	0	32.7669	96.7773	0	1	E	NG	G	0.0939	0	3.5	U	4577			Y
UNIVERSITY OF TEXAS AT SAN ANTONIO	0	29.4332	98.4635	0	1	E	NG	G	0.1439	0	3.47	U	6243.72			Y
V H BRAUNIG	0	29.2561	98.3814	5	3	T	GAS	G	0.2271	8486.4	894		0	N/A	N/A	
VALERO REFINERY	0	27.777	97.4878	0	3	E	OG		0.4625	0	64.7	U	2729405			Y
VALERO REFINING CO TEXAS CITY REFINERY	0	29.3171	94.9773	0	3	E	NG	G	0.7123	0	39.56	U	1930000			Y
VALERO REFINING CO TEXAS HOUSTON REFINERY	0	29.8336	95.4383	0	2	E	NG	G	0.7196	0	34.296	U	2172128			Y
VALLEY	1	33.6436	96.365	3	3	T	GAS	G	0.3102	10598.48	1175.49		0	N/A	N/A	Y
VERNON	1	34.1135	99.2133	0	5	E	OIL	O	0	0	11.28		0	N/A	N/A	Y
VICTORIA	1	28.7894	97.0103	3	3	T	GAS	G	0.221	4750.48	460.874		0	N/A	N/A	Y
VICTORIA TEXAS PLANT	0	28.8017	96.9749	0	1	E	NG	G	0.9867	0	80	U	2931120			Y
VILLAGE CREEK WASTEWATER TREATMENT PLANT	0	32.7712	97.2911	0	4	E	OBG		0.353	0	4		0	N/A	N/A	Y
W A PARISH	1	29.4833	95.6331	8	9	T,E	COL	C	0.5229	35656.48	3969.12		0	N/A	N/A	Y
W B TUTTLE	0	29.5303	98.4178	4	4	T	GAS	G	0.083	4692	495		0	N/A	N/A	
WASHINGTON VENEER DIVISION							WW				7.5					
WASSON CO2 REMOVAL PLANT	0	33.1735	102.8289	0	1	E	NG	G	0.7311	0	23.4	U	183582			Y
WEBSTER	1	29.5261	95.1081	1	2	T,E	GAS	G	0.1338	3400	426.36		0	N/A	N/A	Y
WELSH	0	33.0403	94.8372	3	3	T	COL	C	0.8036	15475.44	1536.963		0	N/A	N/A	
WEST TEXAS WIND ENERGY LLC	0	31.3656	102.0461	0	1	Z	WND		0.3588	0	75		0	N/A	N/A	Y
WEST TEXAS WINDPLANT	0	31.3158	105.4522	0	1	Z	WND		0.2752	0	33.6		0	N/A	N/A	Y
WESTHOLLOW TECHNOLOGY CENTER	0	29.8336	95.4383	0	1	E	NG	G	1.0351	0	3.725	U	160000			Y
WESTVACO EVADALE	0	30.6999	93.9944	0	3	E	BL		0.876	0	57.74	U	64014894			Y
WHITNEY	0	31.8957	97.6407	0	1	Z	WT		0.0435	0	30		0	N/A	N/A	
WILKES	0	32.8486	94.5469	3	3	T	GAS	G	0.3378	7980.48	807.388		0	N/A	N/A	
YATES GAS PLANT	0	30.7119	102.6783	0	2	E	NG	G	0.5194	0	5.6	U	98000			Y
AMERICAN FORK	0	40.1895	111.5237	0	1	Z	WT		0.7042	0	0.95		0	N/A	N/A	
BARTHOLOMEW	0	40.1895	111.5237	0	1	Z	WT		0.1769	0	1.5		0	N/A	N/A	
BEAVER LOWER HYDRO 1	0	38.3615	113.2123	0	1	Z	WT		0.2142	0	0.275		0	N/A	N/A	
BEAVER MID HYDRO 2	0	38.3615	113.2123	0	1	Z	WT		0.5489	0	0.625		0	N/A	N/A	
BEAVER UPPER HYDRO 3	0	38.3615	113.2123	0	1	Z	WT		0.7462	0	0.65		0	N/A	N/A	
BLUNDELL	0	38.3615	113.2123	0	1	Z	GE		0.6643	0	26.095		0	N/A	N/A	
BONANZA	0	40.0833	109.2833	1	1	T	COL	C	0.8391	4284	400		0	N/A	N/A	
BOULDER	0	37.8449	111.3074	0	1	Z	WT		0.6258	0	4.2		0	N/A	N/A	
BOUNTIFUL CITY	0	40.9611	112.1154	0	7	E	GAS	G	0.1325	0	14.15		0	N/A	N/A	
BOX ELDER	0	41.5004	112.9581	0	1	Z	WT		0.8863	0	0.5		0	N/A	N/A	
BRIGHAM CITY	0	41.5004	112.9581	0	1	Z	WT		0.2217	0	1.2		0	N/A	N/A	
CARBON	0	39.7264	110.8639	2	2	T	COL	C	0.8304	1951.6	188.636		0	N/A	N/A	
CENTER CREEK	0	37.8118	113.2589	0	1	Z	WT		0.0407	0	0.6		0	N/A	N/A	
CUTLER	0	41.5004	112.9581	0	1	Z	WT		0.237	0	30		0	N/A	N/A	
DEER CREEK	0	40.2892	111.242	0	1	Z	WT		0.5754	0	4.95		0	N/A	N/A	
ECHO DAM	0	40.9156	110.82	0	1	Z	WT		0.2054	0	4.5		0	N/A	N/A	
FLAMING GORGE	0	40.8274	109.524	0	1	Z	WT		0.3137	0	151.95		0	N/A	N/A	
FOUNTAIN GREEN	0	39.4228	111.6307	0	1	Z	WT		0.7021	0	0.16		0	N/A	N/A	
GADSBY	0	40.7667	111.9292	3	3	T	GAS	G	0.3258	2713.2	251.636		0	N/A	N/A	
GENEVA STEEL	0	40.1895	111.5237	0	1	E	BFG	C	0.7038	0	50	U	2255819			Y
GRANITE	0	40.6737	111.906	0	1	Z	WT		0.3554	0	2		0	N/A	N/A	
GUNLOCK	0	37.3091	113.4754	0	1	Z	WT		0.2096	0	0.75		0	N/A	N/A	
GUNLOCK HYDRO	0	37.3091	113.4754	0	1	Z	WT		0.1292	0	0.372		0	N/A	N/A	
HEBER CITY	0	40.2892	111.242	0	7	E	GAS	G	0.129	0	6.5		0	N/A	N/A	
HOBBLE CREEK	0	40.1895	111.5237	0	1	Z	WT		0.2869	0	0.3		0	N/A	N/A	
HUNTER	0	39.1667	111.0261	3	3	T	COL	C	0.755	13568.72	1440.568		0	N/A	N/A	
HUNTINGTON	0	39.3792	111.075	2	2	T	COL	C	0.8084	8976	996		0	N/A	N/A	
HYDRO II	0	41.685	111.7887	0	1	Z	WT		0.3115	0	6.6		0	N/A	N/A	
HYDRO III	0	41.685	111.7887	0	2	Z	WT		0.2552	0	2.02		0	N/A	N/A	
HYDRO PLANT NO 1	0	39.4228	111.6307	0	1	Z	WT		0.2671	0	0.2		0	N/A	N/A	
HYDRO PLANT NO 3	0	39.4228	111.6307	0	1	Z	WT		0.1154	0	2.89		0	N/A	N/A	
HYDRO PLANT NO 4	0	39.4228	111.6307	0	1	Z	WT		0.2873	0	0.12		0	N/A	N/A	
HYRUM	0	41.685	111.7887	0	1	Z	WT		0.5861	0	0.5		0	N/A	N/A	
INTERMOUNTAIN	0	39.5108	112.5792	2	2	T	COL	C	0.9177	16592	1640		0	N/A	N/A	
LAKE CREEK	0	40.2892	111.242	0	1	Z	WT		0.3435	0	1.5		0	N/A	N/A	
LITTLE COTTONWOOD	0	40.6737	111.906	0	1	Z	WT		0.1824	0	4.9		0	N/A	N/A	
LITTLE MOUNTAIN	0	41.2499	111.9563	0	1	E	GAS	G	0.4396	0	16	C		N/A		
LONE PEAK PARTNERS POWER CO	0	40.6737	111.906	0	3	E	NG	G	0.8846	0	1.95	U	949805			Y
LOWER	0	38.7739	111.9076	0	1	Z	WT		0.5958	0	0.26		0	N/A	N/A	
LOWER-UNIT	0	39.4228	111.6307	0	1	Z	WT		0.5753	0	0.15		0	N/A	N/A	

PNAME	PREV UTIL	LAT	LON	NUMBLR	NUMGEN	SOURCEM	PLPRIMFL	PLFFLCTG	CAPFAC	BOILCAP	NAMEPCAP	CHPFLAG	USETHRMO	PWRTOHT	ELCALLOC	PLNUCONN
MANTI LOWER	0	39.4228	111.6307	0	1	Z	WT		0.2213	0	1.2		0	N/A	N/A	
MANTI UPPER	0	39.4228	111.6307	0	1	Z	WT		0.3386	0	1.6		0	N/A	N/A	
MONROE PUMPING STA	0	38.7739	111.9076	0	1	Z	WT		0.2032	0	0.1		0	N/A	N/A	
MURRAY CITY	0	40.6737	111.906	0	4	E	GAS	G	0.0016	0	7.2		0	N/A	N/A	
OLMSTEAD	0	40.1895	111.5237	0	1	Z	WT		0.3031	0	10.3		0	N/A	N/A	
PAYSON	0	40.1895	111.5237	0	1	Z	WT		0.5357	0	0.4		0	N/A	N/A	
PINE VALLEY	0	37.3091	113.4754	0	1	Z	WT		0.21	0	0.6		0	N/A	N/A	
PINE VIEW DAM	0	41.2499	111.9563	0	1	Z	WT		0.2454	0	1.8		0	N/A	N/A	
PIONEER	0	41.2499	111.9563	0	1	Z	WT		0.379	0	5		0	N/A	N/A	
PRIMARY CHILDRENS MEDICAL CENTER	0	40.6737	111.906	0	3	E	NG	G	0.5556	0	1.95	U	31509			Y
PROVO	0	40.1895	111.5237	0	5	E	GAS	G	0.1391	0	17.5		0	N/A	N/A	
QUAIL CREEK HYDRO PLANT #1	0	37.3091	113.4754	0	1	Z	WAT		0.4047	0	2.34		0	N/A	N/A	Y
RED CREEK	0	37.8118	113.2589	0	1	Z	WT		0.0287	0	0.6		0	N/A	N/A	
SAND COVE	0	37.3091	113.4754	0	1	Z	WT		0.1704	0	0.8		0	N/A	N/A	
SNAKE CREEK	0	40.2892	111.242	0	1	Z	WT		0.2438	0	1.18		0	N/A	N/A	
SNAKE CREEK	0	40.2892	111.242	0	1	Z	WT		0.4608	0	0.8		0	N/A	N/A	
SPANISH FORK	0	40.1895	111.5237	0	1	Z	WT		0.2343	0	3.75		0	N/A	N/A	
SPRING CREEK	0	40.1895	111.5237	0	1	Z	WT		0.0329	0	0.5		0	N/A	N/A	
ST GEORGE	0	37.3091	113.4754	0	2	E	OIL	O	0.14	0	14		0	N/A	N/A	
STAIRS	0	40.6737	111.906	0	1	Z	WT		0.6049	0	1		0	N/A	N/A	
SUNNYSIDE COGENERATION ASSOCIATES	0	39.6407	110.5648	0	1	E	WOC	C	0.8474	0	58.103		0	N/A	N/A	Y
UINTAH	0	40.3199	110.4395	0	1	Z	WT		0.4894	0	1.2		0	N/A	N/A	
UNIT 3	0	39.4228	111.6307	0	1	Z	WT		0.4455	0	0.225		0	N/A	N/A	
UNIT 4	0	39.4228	111.6307	0	1	Z	WT		0.2878	0	1.25		0	N/A	N/A	
UPPER	0	38.7739	111.9076	0	1	Z	WT		0.4312	0	0.26		0	N/A	N/A	
UPPER BARTHOLOMEW	0	40.1895	111.5237	0	1	Z	WT		0.0662	0	0.2		0	N/A	N/A	
UPPER BEAVER	0	38.3615	113.2123	0	1	Z	WT		0.438	0	2.52		0	N/A	N/A	
UPPER-UNIT	0	39.4228	111.6307	0	1	Z	WT		0.6732	0	0.175		0	N/A	N/A	
VEYO	0	37.3091	113.4754	0	1	Z	WT		0.0648	0	0.5		0	N/A	N/A	
WASATCH ENERGY SYSTEMS	0	40.9611	112.1154	0	1	E	MSW		0.6516	0	1.6	U	985000			Y
WEBER	0	41.2499	111.9563	0	1	Z	WT		0.5408	0	3.85		0	N/A	N/A	
WHITEHEAD	0	40.1895	111.5237	0	3	E	GAS	G	0.0669	0	21		0	N/A	N/A	
YELLOWSTONE	0	40.3199	110.4395	0	1	Z	WT		0.4926	0	0.9		0	N/A	N/A	
ALCOVA	0	42.9662	106.8065	0	1	Z	WT		0.391	0	36		0	N/A	N/A	
ANSCHUTZ RANCH EAST	0	41.2874	110.5468	0	2	E	NG	G	0.6685	0	50.6	U	358000			Y
BEAVER CREEK GAS PLANT	0	43.1348	108.7769	0	2	E	NG	G	0.6957	0	5	U	249884			Y
BLACKS FORK GAS PROCESSING PLANT	0	41.634	108.7785	0	3	E	NG	G	0.3568	0	1.452		0	N/A	N/A	Y
BOYSEN	0	43.1348	108.7769	0	1	Z	WT		0.4169	0	15		0	N/A	N/A	
BUFFALO BILL	0	44.4095	109.8025	0	1	Z	WT		0.4516	0	18		0	N/A	N/A	
DAVE JOHNSTON	0	42.8333	105.7667	4	4	T	COL	C	0.7921	7548	816.772		0	N/A	N/A	
ELK BASIN GASOLINE PLANT	0	44.4095	109.8025	0	2	E	NG	G	0.5623	0	2	U	303046			Y
FONTENELLE	0	42.4468	110.546	0	1	Z	WT		0.6536	0	10		0	N/A	N/A	
FREMONT CANYON	0	42.9662	106.8065	0	1	Z	WT		0.4738	0	66.8		0	N/A	N/A	
GENERAL CHEMICAL	0	41.634	108.7785	0	2	E	SUB	C	0.8626	0	30	U	3789561			Y
GLENDO	0	42.1218	104.9652	0	1	Z	WT		0.2735	0	38		0	N/A	N/A	
GUERNSEY	0	42.1218	104.9652	0	1	Z	WT		0.429	0	6.4		0	N/A	N/A	
HEART MOUNTAIN	0	44.4095	109.8025	0	1	Z	WT		0.3077	0	5		0	N/A	N/A	
JIM BRIDGER	0	41.75	108.8	4	4	T	COL	C	0.7988	21651.2	2311.5		0	N/A	N/A	
KORTES	0	41.717	106.9999	0	1	Z	WT		0.3947	0	36		0	N/A	N/A	
LARAMIE RIVER 1	0	42.1086	104.8711	1	1	T	COL	C	0.8513	5474	570		0	N/A	N/A	
LARAMIE RIVER 2&3	0	42.1086	104.8711	2	2	T	COL	C	0.8513	10948	1100		0	N/A	N/A	
NAUGHTON	0	41.7572	110.5986	3	3	T	COL	C	0.8666	7235.2	707.2		0	N/A	N/A	
NEIL SIMPSON	0	44.25	105.54	1	2	E	COL	C	0.771	0	23.76		0	N/A	N/A	
NEIL SIMPSON II	0	44.2477	105.5462	2	2	T	COL	C	0.7349	0	120		0	N/A	N/A	
OSAGE	0	43.84	104.56	3	3	E	COL	C	0.8121	0	34.5		0	N/A	N/A	
PILOT BUTTE	0	43.1348	108.7769	0	1	Z	WT		0.1872	0	1.6		0	N/A	N/A	
PONNEQUIN PHASE 1	0	41.3275	104.6653	0	1	Z	WND		0.232	0	5.25		0	N/A	N/A	Y
SEMINOE	0	41.717	106.9999	0	1	Z	WT		0.3158	0	45		0	N/A	N/A	
SF PHOSPHATES LTD CO	0	41.634	108.7785	0	1	E	OTS		0.8252	0	11.5	U	1420000			Y
SHOSHONE	0	44.4095	109.8025	0	1	Z	WT		0.8371	0	3		0	N/A	N/A	
SINCLAIR OIL REFINERY	0	41.717	106.9999	0	4	E	OG		0.397	0	3.35	U	2373185			Y
SPIRIT MOUNTAIN	0	44.4095	109.8025	0	1	Z	WT		0.3744	0	4.5		0	N/A	N/A	
STRAWBERRY CREEK	0	42.4468	110.546	0	1	Z	WT		0.723	0	1.5		0	N/A	N/A	
VIVA NAUGHTON	0	42.4468	110.546	0	1	Z	WT		0.1254	0	0.742		0	N/A	N/A	
WYODAK	0	44.2833	105.4	1	1	T	COL	C	0.8402	3565.92	362.07		0	N/A	N/A	

strStateFacilityIdentifier	strSIC Primary	strNAICS Primary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXY Coordinate Type
T$12468	1061	2122	AMERICAN MINERALS INC.		2010 4TH ST. N.E.	DEMING	NM	88031	USA	-107.734	32.27778		LATLON
T$12022	1061	2122	AMERICAN MINERALS INC.		3666 DONIPHAN DR.	EL PASO	TX	79922	USA	-106.552	31.8093		LATLON
0278	1311	211111	AMOCO PROD. CO. - J.B. GARDNER A #1	NATURAL GAS PROCESSING	SW/4 NW/4 SEC 22 T32N R10W	LAPLATA COUNTY	CO	80000	USA	-107.92	37.005	13	LATLON
0280	1311	211111	AMOCO PRODUCTION - EVELYN PAYNE GU #1	NATURAL GAS PROCESSING	SENW SEC 32 T35N R6W	LA PLATA COUNTY	CO	80000	USA	-107.551	37.258	13	LATLON
0083	1311	211111	AMOCO PRODUCTION CO PICNIC FLATS	NATURAL GAS PROCESSING	SE SEC 25 T33N R11W	LA PLATA COUNTY	CO	80000	USA	-107.99	37.0732	13	LATLON
0279	1311	211111	AMOCO PRODUCTION CO - ROBERT DULIN D #1	NATURAL GAS PROCESSING	NW/4 SE/4 SEC. 26 T35N R7W	LAPLATA COUNTY	CO	80000	USA	-107.605	37.2725	13	LATLON
0273	1311	211111	AMOCO PRODUCTION CO GEARHART WELL #1-6	NATURAL GAS PROCESSING	SEC 6 T34N R7W	LA PLATA	CO	00000	USA	-107.678	37.244	13	LATLON
0274	1311	211111	AMOCO PRODUCTION CO LORETT FEDERAL GU #1	NATURAL GAS PROCESSING	SEC 13 T34N R8W	LA PLATA	CO	00000	USA	-107.668	37.1913	13	LATLON
0025	1311	211111	AMOCO PRODUCTION CO WATTENBERG PLT	NATURAL GAS PROCESSING	NE/SE/4 SEC 32 T3S R65W	ADAMS	CO	00000000(	USA	-104.678	39.7448	13	LATLON
0277	1311	211111	AMOCO PRODUCTION CO.- ROBIN FRAZIER A	NATURAL GAS PROCESSING	NW/4 NW/4 SEC 23 T32N R10W	LA PLATA COUNTY	CO	80000	USA	-107.903	37.005	13	LATLON
0444	1311	211111	ANTELOPE ENERGY COMPANY-TERANCE PLANT	OIL & GAS PROCESSING	NW NE SEC 18 T10N R58W	RAYMER N 17 MI OF	CO	00000	USA	-103.897	40.8454	13	LATLON
081230099	1311	211111	ASSOCIATED NATURAL GAS GREELEY PLT	ICE-NG.			CO		USA	-104.853	40.49639		LATLON
081230074	1311	211111	ASSOCIATED NATURAL GAS INC SINGLETREE	ICE-NG.			CO		USA	-104.812	40.14556		LATLON
081230015	1311	211111	ASSOCIATED NATURAL GAS INC SPINDLE PLT	ICE-NG.			CO		USA	-104.882	40.08917		LATLON
081230075	1311	211111	ASSOCIATED NATURAL GAS INC SURREY PLT	ICE-NG.			CO		USA	-104.886	40.01583		LATLON
081230076	1311	211111	ASSOCIATED NATURAL GAS INC WEST SPINDLE	ICE-NG.			CO		USA	-104.886	40.0875		LATLON
081230125	1311	211111	ASSOCIATED NATURAL GAS SPINDLE AIR PLT	ICE-NG.			CO		USA	-104.885	40.0875		LATLON
081230068	1311	211111	ASSOCIATED NATURAL GAS WATTENBERG	ICE-NG.			CO		USA	-104.894	40.12111		LATLON
0145	1311	211111	BARGARTH INC GRAND VALLEY GAS PROC	NATURAL GAS COMRESSION AND	SEC 36 T5S R96W	GARFIELD	CO	81227	USA	-108.112	39.3219	12	LATLON
0089	1311	211111	BARRETT RESOURCES CORP RULISON ANVIL PTS	NATURAL GAS PROCESSING	SEC 29 T6S R94W	RIFLE	CO	81601	USA	-107.91	39.4961	13	LATLON
0029	1311	211111	BITTER CREEK PIPELINES - YENTER C.S.	NATURAL GAS PROCESSING (PLAN	SEC 3 T8N R54W	STERLING	CO	80751	USA	-103.396	40.6909	13	LATLON
0016	1311	211111	BURR OIL & GAS INC. - CROSS CANYON #1		SW/NE SEC 7 T38N R19W	PAPOOSE CANYON GATHERING FIELD	CO	80000	USA	-108.985	37.566	12	LATLON
1189	1311	211111	CASCADE OIL & GAS INC	NAT GAS PROCESSING	NW/4 SECT 11 T1S R64W	ADAMS CNTY	CO	00000000(	USA	-104.518	39.9776	13	LATLON
080330012	1311	211111	CELSIUS ENERGY CO DOVE CREEK PLT	ICE-NG.			CO		USA	-108.87	37.76		LATLON
080810066	1311	211111	CELSIUS ENERGY CO HIAWATHA CO2 EXTR FAC	ICE-NG.			CO		USA	-108.625	40.99028		LATLON
0153	1311	211111	CER CORP MWX-1 GAS WELL	NATURAL GAS PROCESSING PLAN	SW NW 4 SEC 34 T6S R94W	RIFLE	CO	80000	USA	-107.881	39.4833	13	LATLON
0034	1311	211111	CHEVRON USA PRODUCTION CO RANGELY FIELD	CRUDE OIL TERTIARY RECOVERY	100 CHEVRON RD	RANGELY	CO	81648	USA	-108.928	40.1042	12	LATLON
081030055	1311	211111	COLORADO INTERSTATE GAS CO GREASEWOOD				CO		USA	-108.191	39.89694		LATLON
0001	1311	211111	COLORADO INTERSTATE GAS CO KIT CARSON	NATURAL GAS PROCESSING	3073 US HWY 287	KIT CARSON	CO	80825	USA	-102.621	38.673	13	LATLON
0007	1311	211111	COLORADO INTERSTATE GAS CO VILAS C S	NATURAL GAS PROCESSING	SEC 20 T31S R45W	VILAS	CO	80944	USA	-102.472	37.3237	13	LATLON
081030036	1311	211111	CONOCO INC DRAGON TRAIL GAS PROC PLT	ICE-NG.			CO		USA	-108.809	39.83139		LATLON
081030032	1311	211111	CONOCO INC NATURAL GAS WEST DOUGLAS	ICE-NG.			CO		USA	-108.757	39.81111		LATLON
0103	1311	211111	CUSTOM ENERGY CONSTRUCTION INC BUCK PEAK	GAS PROCESSING STATION	SESW SEC 9 T6N R90W	BUCK PEAK GAS PROCESSING STN	CO	00000	USA	-107.498	40.4858	13	LATLON
0099	1311	211111	DUKE ENERGY FIELD SERVICES - GREELEY	NATURAL GAS GATHERING	SEC 25 T5N R66W	WELD COUNTY	CO	00000-000	USA	-104.853	40.4965	13	LATLON
0049	1311	211111	DUKE ENERGY FIELD SERVICES - ROGGEN	NATURAL GAS GATHERING AND PI	35409 COUNTY ROAD 18	WELD COUNTY	CO	00000-000	USA	-104.39	40.1193	13	LATLON
0015	1311	211111	DUKE ENERGY FIELD SERVICES - SPINDLE	NATURAL GAS GATHERING AND PI	0.5 MILES N OF HWY 52	WELD COUNTY	CO	00000-000	USA	-104.883	40.0893	13	LATLON
0036	1311	211111	EL PASO CORPORATION - DRAGON TRAIL GAS	NATURAL GAS PROCESSING (FORI	3606 COUNTY ROAD 116	RANGELY	CO	81648	USA	-108.809	39.8308	12	LATLON
0016	1311	211111	EL PASO CORPORATION - EAST DRAGON TRAIL	FORMERLY CONOCO - NATURAL G	SEC 36 T2S R102W	RANGELY	CO	84108	USA	-108.79	39.8296	12	LATLON
081010098	1311	211111	FUEL RESOURCES DEV SYNHYTEC	ICE-Diesel			CO		USA	-104.714	38.21917		LATLON
0333	1311	211111	GATEWAY PROCESSING CO	GAS TREATING & PROCESSING	NW OF MACK	MESA COUNTY	CO	80000	USA	-108.22	38.931		LATLON
080810124	1311	211111	GRYNBERG PETROLEUM COMPANY SUGAR LOAF	ICE-NG.			CO		USA	-108.683	40.94472		LATLON
080810123	1311	211111	GRYNBERG PETROLEUM COMPANY BLUE GRAVEL	ICE-NG.			CO		USA	-107.651	40.69417		LATLON
0019	1311	211111	HORSESHOE OPERATING INC LA DRY CREEK	NATURAL GAS PROCESSING	SEC 21 T25S R48W	LAS ANIMAS	CO	81054	USA	-102.803	37.8602	13	LATLON
080110018	1311	211111	HORSESHOE OPERATING INC WAGON TRAIL	ICE-NG.			CO		USA	-102.821	38.06417		LATLON
080010501	1311	211111	IRONDALE GAS PROCESSING CO IRONDALE CS2	ICE-NG.			CO		USA	-104.38	39.86694		LATLON
0082	1311	211111	KN GAS GATHERING BLACK SULPHUR LIQUIDS	NATURAL GAS PROCESSING	SEC 20 T2S R97W	RANGELY	CO	81648	USA	-108.305	39.8625	12	LATLON
081030083	1311	211111	KN GAS GATHERING PICEANCE CREEK	ICE-NG.			CO		USA	-108.266	40.04056		LATLON
080050519	1311	211111	KOCH HYDROCARBON CO DENVER CTL PLT	ICE-NG.			CO		USA	-104.354	39.64139		LATLON
080010628	1311	211111	KOCH HYDROCARBON CO KALLSEN PLT	ICE-NG.			CO		USA	-104.333	39.87861		LATLON
080010629	1311	211111	KOCH HYDROCARBON CO LINNEBURG PLT	ICE-NG.			CO		USA	-103.956	39.94056		LATLON
080010627	1311	211111	KOCH HYDROCARBON CO STATE PLT	ICE-NG.			CO		USA	-104.677	39.96222		LATLON
080310950	1311	211111	KOCH HYDROCARBON CO THIRD CREEK PLT	ICE-NG.			CO		USA	-104.697	39.88472		LATLON
080990057	1311	211111	MARATHON OIL CO SNIFF E1	ICE-NG.			CO		USA	-102.784	38.04944		LATLON
080830033	1311	211111	MID AMERICA PIPELINE CO DOLORES STA	Turbine:			CO		USA	-108.433	37.41444		LATLON
0031	1311	211111	MITCHELL ENERGY CORP HELLS HOLE CANYON	NATURAL GAS PROCESSING	SEC 31 T1S R103W	RANGELY	CO	81648	USA	-109.005	39.9236	12	LATLON
0005	1311	211111	MULL DRILLING CO INC SORRENTO FIELD	NATURAL GAS PROCESSING	NE SEC 5 T14S R49W	KIT CARSON	CO	80825	USA	-102.603	38.8709	13	LATLON
080770180	1311	211111	NATL FUEL CORP	ICE-NG.			CO		USA	-108	39.26583		LATLON
081230127	1311	211111	NORTH AMERICAN RESOURCES CO ARISTOCRAT	ICE-NG.			CO		USA	-104.617	40.25		LATLON
0319	1311	211111	NORTH AMERICAN RESOURCES CO FT LUPTON	NATURAL GAS PROCESSING	SE/4 SW/4 SW/4 SEC 11 T2N R66W	FORT LUPTON	CO	80621	USA	-104.739	40.1486	13	LATLON
0950	1311	211111	NORTH AMERICAN RESOURCES CO THIRD CREEK	NATURAL GAS PROCESSING - THIS	SEC 18 T2S R65W	DENVER	CO	80249	USA	-104.749	39.78118	13	LATLON
0628	1311	211111	NORTH AMERICAN RESOURCES CO_ KALLSEN	FORMERLY OWNED BY KOCH HYD	NE NW SEC 16 T2S R62W	STRASBURG OFF I70 N 10 MI OF	CO	00000000(	USA	-104.331	39.8811	13	LATLON
081070047	1311	211111	NORTHERN NATURAL GAS CO ENRON ROUTT NO 1	Turbine:			CO		USA	-107.394	40.29889		LATLON
080770183	1311	211111	PUBLIC SERVICE CO ASBURY	ICE-NG.			CO		USA	-108.647	39.23028		LATLON
0121	1311	211111	PUBLIC SERVICE CO BAXTER STATION	NATURAL GAS PROCESSING	SEC 3 T8S R104W	RIFLE	CO	81650	USA	-108.863	39.3958	12	LATLON
081030016	1311	211111	PUBLIC SERVICE CO DRAGON TRAIL	ICE-NG.			CO		USA	-108.79	39.82972		LATLON
0086	1311	211111	PUBLIC SERVICE CO GREASEWOOD STATION	NATURAL GAS PROCESSING	SEC 5 T2S R96W	MEEKER	CO	81641	USA	-108.192	39.9058	12	LATLON
080770182	1311	211111	PUBLIC SERVICE CO HUNTER CANYON	ICE-NG.			CO		USA	-108.591	39.33139		LATLON
081030056	1311	211111	PUBLIC SERVICE CO INDIAN VALLEY				CO		USA	-108.193	40.10139		LATLON
0087	1311	211111	PUBLIC SERVICE CO NORTH DOUGLAS STATION	NATURAL GAS PROCESSING	62584 HWY 139 SEC18 T1S R101W	RANGELY	CO	81648	USA	-108.774	39.9599	12	LATLON
0122	1311	211111	PUBLIC SERVICE CO RIFLE COMP STA	NATURAL GAS PROCESSING	SEC 18 T6S R93W	GARFIELD CNTY	CO	81650	USA	-107.817	39.5254	13	LATLON
081030048	1311	211111	PUBLIC SERVICE CO WHITE RIVER DOME	ICE-NG.			CO		USA	-108.191	40.09861		LATLON
0024	1311	211111	PUBLIC SERVICE CO WILLIAMS FORK STATION	NATURAL GAS PROCESSING	SEC 23 T2S R78W	GRAND COUNTY	CO	80468	USA	-106.09	39.8626	13	LATLON
081230141	1311	211111	PUBLIC SERVICE CO YOSEMITE	ICE-NG.			CO		USA	-104.886	40.01472		LATLON
0024	1311	211111	QUESTAR EXPLORATION & PROD -CUTTHROAT A	NATURAL GAS PROCESSING	SE SEC 10 T37N R19W	CORTEZ	CO	81321	USA	-108.927	37.4723	12	LATLON
0132	1311	211111	QUESTAR GAS MANAGEMENT - AVALANCHE	NATURAL GAS GATHERING	LOT 9 SEC 18 T12N R91W	MOFFAT	CO	00000	USA	-107.649	40.993	13	LATLON
0135	1311	211111	QUESTAR GAS MANAGEMENT CO E.HIAWATHA	NATURAL GAS PROCESSING	SEC 23 T 12N R100W	MOFFAT	CO	80000000(	USA	-108.182	40.6116	13	LATLON
0131	1311	211111	QUESTAR GAS MANAGEMENT CO SAND HILL	GLYCOL DEHYDRATOR	BAGGS FIELD	CRAIG	CO	81626	USA	-107.621	40.9514	13	LATLON
0006	1311	211111	QUESTAR GAS MANAGEMENT DOVE CREEK PLT	NATURAL GAS PROCESSING - NOT	SEC 5 T40N R18W	DOVE CREEK	CO	81333	USA	-108.865	37.7857	12	LATLON
080330006	1311	211111	QUESTAR PIPELINE CO DOVE CREEK PLT	ICE-NG.			CO		USA	-108.865	37.78556		LATLON
081030037	1311	211111	ROCKY MOUNTAIN NATURAL GAS CO PICEANCE	ICE-NG.			CO		USA	-108.263	40.04333		LATLON
081130007	1311	211111	ROCKY MOUNTAIN NATURAL GAS CO SLICK ROCK	ICE-NG.			CO		USA	-108.893	38.02056		LATLON
081130016	1311	211111	ROCKY MOUNTAIN NATURAL GAS NICHOLAS DRAW	ICE-NG.			CO		USA	-108.819	38.03083		LATLON
0068	1311	211111	ROCKY MTN NATURAL GAS CO BLACK SULPHUR	NATURAL GAS PROCESSING	SEC 19 T2S R97W	MEEKER	CO	81641	USA	-107.856	40.03395	13	LATLON
0108	1311	211111	ROCKY MTN NATURAL GAS CO DEBEQUE C S	NATURAL GAS PROCESSING	SEC 6 T8S R97W	DE BEQUE	CO	81630	USA	-108.26	39.3885	12	LATLON
0037	1311	211111	ROCKY MTN NATURAL GAS CO PICEANCE	NATURAL GAS PROCESSING	SEC 22 T1N R97W	RIO BLANCO	CO	81602	USA	-108.263	40.0435	12	LATLON
0018	1311	211111	ROCKY MTN NATURAL GAS CO WOLF CREEK	NATURAL GAS_PRODUCTION	VARIOUS LOCATIONS T8N R90W	PITKIN COUNTY	CO	80000	USA	-107.407	39.3202	13	LATLON
080870034	1311	211111	ROGGEN GAS PROCESSING CO SITE NAME UNK	ICE-NG.			CO		USA	-104.05	40.46861		LATLON
0018	1311	211111	SHELL CO2 COMPANY - YELLOW JACKET	NATURAL GAS PROCESSING	NW SEC 13 T37N R18W RD U & 14	CORTEZ	CO	81321	USA	-108.787	37.4715	12	LATLON
0020	1311	211111	SHELL CO2 COMPANY, LTD. - HOVENWEEP CO2 SOURCE FIELD	CO2 SOURCE FIELD FACILITY	SW/4 SEC 16 T37N R18W	CORTEZ	CO	81321	USA	-108.862	37.49	12	LATLON

strStateFacilityIdentifier	strSICPrimary	strNAICSPrimary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXYCoordinateType
081230422	1311	211111	SNYDER OIL CO WEST GAS PLT	ICE-NG.			CO		USA	-104.797	40.23361		LATLON
081230049	1311	211111	SNYDER OIL CORP ROGGEN GAS PLT	ICE-NG.			CO		USA	-104.39	40.11944		LATLON
081230111	1311	211111	SNYDER OIL CORP THOMPSON VALLEY GAS PLA	ICE-NG.			CO		USA	-104.941	40.31472		LATLON
080870012	1311	211111	SNYDER OIL CORP VALLERY GAS PLT	ICE-NG.			CO		USA	-103.966	40.22278		LATLON
0098	1311	211111	SOUTHWESTERN PRODUCTION - GILCREST GAS	NATURAL GAS PROCESSING - FOR	13472 WELD COUNTY RD 40	PLATTEVILLE	CO	80651	USA	-104.806	40.2739	13	LATLON
0018	1311	211111	TBI FIELD SERVICES, INC- N DOUGLAS CREEK	NG PROCESSING (FORMERLY WILL	NE SEC 19 T1S R101W	RANGELY	CO	81648	USA	-108.676	40.1336	12	LATLON
0077	1311	211111	TBI FIELD SERVICES, INC. - CLOUGH COMP.	NATURAL GAS PROCESSING (FORI	NE NE SEC 13 T6S R94W	RIFLE, 2 MI W OF	CO	81601	USA	-107.862	39.527	13	LATLON
0020	1311	211111	TBI FIELD SERVICES, INC. - FOUNDATION CR	NG PROCESSING (FORMERLY WILL	SE NE SEC 25 T4S R102W	DURANGO	CO	81648	USA	-108.803	39.6731	12	LATLON
0004	1311	211111	TBI FIELD SERVICES, INC. - GREASEWOOD	NG PROCESSING - (FORMERLY WII	SEC 5 T2S R96W	RANGELY	CO	84108	USA	-108.189	39.9021	12	LATLON
0010	1311	211111	TEXACO E&P INC WILSON CREEK GAS PLT	NATGAS/OIL PROCESSING	SE SE SEC 27 T3N R94W	MEEKER	CO	81641	USA	-107.917	40.194	13	LATLON
0120	1311	211111	TEXACO EXPLOR & PROD - VAN SCHAIK B-3	OIL & GAS PORDUCTION	NE SEC 24 T12N R101W	HIAWATHA VAN SCHAICK B 3	CO	00000	USA	-108.696	40.9852	12	LATLON
0015	1311	211111	TOM BROWN INC - ANDY'S MESA	NATURAL GAS PROCESSING (WAS	SW NE SEC 28 T44N R16W	SAN MIGUEL	CO	00000	USA	-108.64	38.0441	12	LATLON
0065	1311	211111	TOM BROWN INC TAIGA MTN 1-29	FORMERLY KN ENERGY - GASCO N	SEC 29 T1N R103W	RANGELY	CO	81648	USA	-108.981	40.0258	12	LATLON
0015	1311	211111	UNION PACIFIC RES CO ARAPAHOE PLT	NATURAL GAS PROCESSING	SE SEC 27 T14S R42W	KIT CARSON	CO	80825	USA	-102.795	38.76645	13	LATLON
0010	1311	211111	UNION PACIFIC RES CO BLEDSOE RANCH	NATURAL GAS PROCESSING	SEC 1 T13S R51W	KIT CARSON	CO	80825	USA	-103.059	38.9541	13	LATLON
0008	1311	211111	UNION PACIFIC RES CO MT PEARL PLT	NATURAL GAS PROCESSING	NE SEC 35 T13S R48W	KIT CARSON	CO	80825	USA	-102.752	38.8738	13	LATLON
080170014	1311	211111	UNION PACIFIC RESOURCES FRONTERA PLT	ICE-NG.			CO		USA	-102.041	38.795		LATLON
1274	1311	211111	UNITED STATES EXPLOR.-CARLSON 2 32-33	THIS USED TO BE 001/0703 - THAT	SEC 33 T2S R64W	ADAMS	CO	00000	USA	-104.555	39.8329	13	LATLON
081230119	1311	211111	VESSELS GAS PROC LTD FT LUPTON PROC PLT	ICE-NG.			CO		USA	-104.888	40.01639		LATLON
081230367	1311	211111	VESSELS GAS PROCESSING INC	ICE-NG.			CO		USA	-104.995	40.00056		LATLON
081230148	1311	211111	VESSELS GAS PROCESSING LTD SPACE CITY	ICE-NG.			CO		USA	-104.632	40.08139		LATLON
081230132	1311	211111	VESSELS OIL &GAS FT LUPTON FRACTIONATION	ICE-NG.			CO		USA	-104.887	40.01583		LATLON
0468	1311	211111	WALSH PRODUCTION INC - LILLI GAS PROC.	NATURAL GAS PROCESSING	SEC 4 T8N R58W	RAYMER (5.0 M N OF RAYMER)	CO	80000	USA	-103.888	40.6922	13	LATLON
0128	1311	211111	WEST TEXAS GAS dba DAVIS GAS PROCESSING-PICEANCE CRE	PICEANCE CREEK GAS PROCESSIN	SEC 5 & SEC 8, T2S, R96W	23 MI NW OF RIO BLANCO	CO	00000-000	USA	-108.154	39.8985	12	LATLON
080010228	1311	211111	WESTERN GAS RESOURCES INC CABIN CREEK	ICE-NG.			CO		USA	-104.039	39.75222		LATLON
0115	1311	211111	WILDHORSE ENERGY RIFLE BOULTON COMP	NATURAL GAS PROCESSING - FOR	SW NE SEC 25 T7S R92W	RIFLE	CO	80650	USA	-107.616	39.4166	13	LATLON
081030020	1311	211111	WILLIAMS FIELD SVCS FOUNDATION CREEK				CO		USA	-108.803	39.67306		LATLON
081030018	1311	211111	WILLIAMS FIELD SVCS N DOUGLAS SITE	ICE-NG.			CO		USA	-108.72	39.86		LATLON
0011	1311	211111	WILLIFORD ENERGY CO	NATURAL GAS PROCESSING	NWNW SEC 32 T13S R48W	KIT CARSON_7 MI N OF	CO	80825	USA	-102.821	38.8752	13	LATLON
081230098	1311	211111	WINDSOR GAS PROCESSING INC	ICE-NG.			CO		USA	-104.806	40.27389		LATLON
00099	1311	211111	AMOCO PRODUCTION ULYSSES DEHY	NATURAL GAS - DEHYDRATION	ULYSSES DEHY	S5-T29S-R38W	KS	67880	USA	-101.351	37.57915		LATLON
350150024	1311	211111	AGAVE ENERGY/YATES PLANT____________1M3	ICE-NG.			NM		USA	-104.444	32.71222		LATLON
350150002	1311	211111	AMOCO PROD/EMPIRE ABO GAS PLNT____126M3	ICE-Diesel			NM		USA	-104.263	32.77167		LATLON
350250001	1311	211111	AMOCO PROD/S HOBBS CO2 INJECT STA__79M3	Turbine:			NM		USA	-103.155	32.66056		LATLON
350390028	1311	211111	APACHE CORP/BEAR CANYON_____________814	ICE-NG.			NM		USA	-107.02	36.49		LATLON
350150101	1311	211111	ARCO PERMIAN/EMPIRE ABO INJECTION__12M1	ICE-NG.			NM		USA	-104.259	32.77306		LATLON
350450068	1311	211111	BURLINGTON RES/VALVERDE_______PSDNM728M6	ICE-NG.			NM		USA	-107.956	36.73139		LATLON
350150045	1311	211111	CONOCO/TURKEY TRACK GAS PLANT______457M1	ICE-NG.			NM		USA	-104.04	32.65278		LATLON
350310004	1311	211111	CONOCO/WINGATE FRACTION PLANT_____1313R2	ICE-Diesel			NM		USA	-108.639	35.54278		LATLON
350150102	1311	211111	EL PASO NATL GAS/BURTON FLATS______157M2	ICE-NG.			NM		USA	-104.149	32.56861		LATLON
350250006	1311	211111	EL PASO NATL GAS/JAL #1____________0007	ICE-NG.			NM		USA	-103.21	32.06611		LATLON
350450042	1311	211111	FIVE OAKS/GALLEGOS CANYON__________131M1	ICE-NG.			NM		USA	-107.843	36.40111		LATLON
350450045	1311	211111	GULF ENERGY PROCESSING/GALLUP PLANT__458	ICE-NG.			NM		USA	-108.387	36.7475		LATLON
350410003	1311	211111	H.L.BROWN JR/BLUITT PLANT____________567	ICE-NG.			NM		USA	-103.183	33.635		LATLON
350250007	1311	211111	J.L.DAVIS GAS PROCESS/DENTON________65M2	ICE-NG.			NM		USA	-103.17	33.04611		LATLON
350390071	1311	211111	NIJECT/SAN JUAN 28-7 UNIT NITRO_____1495	ICE-NG.			NM		USA	-107.532	36.65611		LATLON
350150172	1311	211111	PARKER & PARSLEY/LOVING GAS PLNT____1172	ICE-NG.			NM		USA	-104.075	32.24028		LATLON
350250052	1311	211111	TEXACO/EUNICE NORTH GAS PLANT_______57M3	ICE-NG.			NM		USA	-103.163	32.44972		LATLON
350250051	1311	211111	TEXACO/EUNICE SOUTH GAS PLANT______278M4				NM		USA	-103.158	32.36139		LATLON
350410001	1311	211111	WARREN PETROLEUM/BLUITT GAS PLANT____563	ICE-NG.			NM		USA	-103.238	33.62056		LATLON
350150043	1311	211111	WARREN PETROLEUM/SNYDER RANCH FACIL__228	ICE-NG.			NM		USA	-103.869	32.65139		LATLON
350450247	1311	211111	WESTERN GAS RESOURCES/SAN JUAN RVR____GF	ICE-NG.			NM		USA	-108.368	36.75694		LATLON
0004	1311	211111	Wingate Fraction Plant	NMD986679629 Natl Gas Fraction Pla	6 Mi E Of Gallup	Gallup	NM	87301	USA	-108.639	35.5427	12	LATLON
350050050	1311	211111	YATES PETROLEUM/PATHFINDER AMINE___848M1	ICE-NG.			NM		USA	-104.198	33.42861		LATLON
401370203	1311	211111	MOBIL/SHOLEM ALECHEM GAS PLANT	ICE-NG.			OK		USA	-97.605	34.4225		LATLON
2482	1311	211111	Swift Energy Company Weatherford Facility	3900213 Weatherford Facility			OK		USA	-98.728	35.4851	14	LATLON
483230006	1311	211111	ALKEK GAS PLANT	ICE-NG.			TX		USA	-100.389	28.64302		LATLON
481690005	1311	211111	CEDAR HILL GAS PLANT	ICE-NG.			TX		USA	-101.233	33.09556		LATLON
483230002	1311	211111	CRUDE OIL PRODUCTION	ICE-Diesel			TX		USA	-100.389	28.64302		LATLON
48320	1311	211111	DAVIS GAS PROCESSING				TX		USA	-101.396	33.1635	14	LATLON
AG0002Q	1311	211111	EOG RESOURCES INC JOURDANTON GAS SWEETENING FACI		JOURDANTON GAS SWEETENING FACI	JOURDANTON	TX	78026	USA	-98.5944	28.87301	14	LATLON
483230003	1311	211111	FESSMAN PLANT	ICE-NG.			TX		USA	-100.389	28.64302		LATLON
482250002	1311	211111	LAURA LAVELLE SOUTH	ICE-NG.			TX		USA	-95.3658	31.25965		LATLON
481590004	1311	211111	NEW HOPE GAS PLANT	ICE-NG.			TX		USA	-95.0728	33.23194		LATLON
BI0009J	1311	211111	WEST TEXAS GAS PROCESSING LP		1.3 M N ON PLT RD	GAIL	TX	79738	USA	-101.26	32.57091	14	LATLON
BI0011W	1311	211111	WEST TEXAS GAS PROCESSING LP		2 MILES N OF VEALMOOR ON FM 15	GAIL	TX	79738	USA	-101.6	32.61674	14	LATLON
HT0016G	1311	211111	WEST TEXAS GAS PROCESSING LP		VINCENT RT BOX 132 COAHOMA TX	COAHOMA	TX	79511	USA	-101.353	32.49712	14	LATLON
HT0059L	1311	211111	WEST TEXAS GAS PROCESSING LP		FROM VEALMOOR, TX, 1 MI. S. ON	BIG SPRING	TX	79721	USA	-101.523	32.51563	14	LATLON
484930005	1311	211111	WILSON COUNTY PLANT	ICE-NG.			TX		USA	-98.0678	29.1603		LATLON
490139013	1311	211111	ALTONAH GAS PLANT	ICE-NG.			UT		USA	-110.439	40.3199		LATLON
55529	1311	211111	COASTAL FIELD ALTAMONT EAST				UT		USA	-110.439	40.3199	12	LATLON
55530	1311	211111	COASTAL FIELD ALTAMONT SOUTH				UT		USA	-110.439	40.3199	12	LATLON
55531	1311	211111	COASTAL FIELD ALTAMONT WEST				UT		USA	-110.439	40.3199	12	LATLON
490079095	1311	211111	DEW POINT PLANT	ICE-NG.			UT		USA	-110.565	39.64065		LATLON
490070013	1311	211111	DRUNKARDS WASH	ICE-NG.			UT		USA	-110.86	39.58944		LATLON
55552	1311	211111	GARY-WILLIAMS BLUEBELL GAS PLANT				UT		USA	-110.439	40.3199	12	LATLON
10034	1311	211111	Lisbon Plant-Hook & Ladder	Previously owned by Unocal Corp - Oi			UT		USA	-110.227	37.7491		LATLON
560070006	1311	211111	AMOCO BAIROIL CO2	ICE-Diesel			WY		USA	-107.514	42.22917		LATLON
560130008	1311	211111	AMOCO BEAVER CREEK				WY		USA	-108.314	42.84778		LATLON
560290012	1311	211111	AMOCO PROD CO.-ELK BASIN GAS PLANT	ICE-Diesel			WY		USA	-108.854	44.52944		LATLON
560410006	1311	211111	AMOCO PRODUCTION COMPANY - ANSCHUTZ				WY		USA	-111.041	41.07528		LATLON
560070017	1311	211111	AMOCO PRODUCTION COMPANY - WERTZ PL	ICE-NG.			WY		USA	-107	41.71695		LATLON
5604100006	1311	211111	AMOCO PRODUCTION COMPANY _ ANSCHUTZ	NATURAL GAS PROCESSING	17 MI S OF EVANSTON	EVANSTON	WY	82930	USA	-111.04	41.0755	12	LATLON
560410012	1311	211111	AMOCO WHITNEY CANYON	ICE-Diesel			WY		USA	-110.89	41.45444		LATLON
5600300012	1311	22121	BIG HORN GAS PROCESSING-BYRON GAS PLANT	NATURAL GAS PROCESSING	2 MI W OF BYRON_S29,T56N,R97W	BYRON	WY	82412	USA	-108.553	44.8022	12	LATLON
5601300028	1311	211111	BURLINGTON RESOURCES_LOST CABIN	LOST CABIN	1_1/2 S OF LOST CABIN	LOST CABIN	WY	00000	USA	-107.633	43.28651		LATLON
5604100009	1311	211111	CHEVRON CARTER CREEK	NATURAL GAS PROCESSING	30 MI NNE EVANSTON	EVANSTON	WY	82930	USA	-110.912	41.5735	12	LATLON
560410030	1311	211111	CHEVRON USA - PAINTER RESERVOIR EAST	ICE-NG.			WY		USA	-110.868	41.31194		LATLON
5604100030	1311	211111	CHEVRON USA _ PAINTER RESERVOIR EAST	SWEET GAS PLANT	SECTION 5, T15N, R119W	EVANSTON	WY	82930000(	USA	-110.868	41.3116	12	LATLON

strStateFacilityIdentifier	strSIC Primary	strNAICS Primary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXY Coordinate Type
560070019	1311	211111	CIG RAWLINS COMP	ICE-NG.			WY		USA	-107.058	41.75667		LATLON
5603700014	1311	211111	COLORADO INTER GAS_TABLE ROCK GAS PLANT	NATURAL GAS PROCESSING	TABLE ROCK GAS PLANT	ROCK SPRINGS	WY	82901	USA	-108.418	41.6074	12	LATLON
560290006	1311	211111	COLORADO INTERSTATE GAS - ELK BASIN	ICE-NG.			WY		USA	-109.803	44.40953		LATLON
58193	1311	211111	CONOCO - SHERIDAN				WY		USA	-106.975	44.6637	13	LATLON
560250011	1311	211111	EREC-BALCRON OIL DIV -NORTH GRIEVE	ICE-NG.			WY		USA	-106.806	42.96618		LATLON
560350001	1311	211111	EXXON -LABARGE DEHYDRATION FACILITY	ICE-NG.			WY		USA	-110.349	42.3725		LATLON
560230013	1311	211111	EXXON SHUTE CREEK I	NATURAL GAS PROCESSING	13 MI NE OF OPAL	KEMMERER	WY	83101	USA	-110.087	41.8838	12	LATLON
5602900012	1311	211111	HOWELL PET CORP_ELK BASIN GAS PLANT	NATURAL GAS PROCESSING	SECTION 29, T58N, R99W,	POWELL	WY	82435	USA	-108.854	44.5292	12	LATLON
560430003	1311	211111	INTERENERGY CORP.- HILAND GAS PLANT	ICE-NG.			WY		USA	-107.851	44.03056		LATLON
560090021	1311	211111	INTERLINE GAS (LIGHTNING CREEK)	ICE-NG.			WY		USA	-105.211	43.0392	13	LATLON
560090019	1311	211111	INTERLINE GAS (SOUTH WELL DRAW)	ICE-NG.			WY		USA	-111.037	42.9178	12	LATLON
560410022	1311	211111	KERN RIVER GAS - PAINTER RESERVIOR	Turbine:			WY		USA	-110.547	41.28735		LATLON
560230025	1311	211111	KERN RIVER GAS TRANS. - MUDDY CREEK	ICE-NG.			WY		USA	-110.362	41.69111		LATLON
560410001	1311	211111	KERN RIVER GTC-ANSCHUTZ (CT-742)	ICE-NG.			WY		USA	-111.027	41.06278		LATLON
560130027	1311	211111	KN GAS GATHERING - PAVILLION STATION	ICE-NG.			WY		USA	-108.777	43.1348		LATLON
560070026	1311	211111	NORTHERN GAS CO. - OIL SPRINGS	ICE-NG.			WY		USA	-107	41.71695		LATLON
560230023	1311	211111	NORTHWEST PIPELINE-MUDDY CREEK COMP STN				WY		USA	-110.546	42.44677		LATLON
560290007	1311	211111	OREGON BASIN GAS PLANT OP-184	ICE-NG.			WY		USA	-108.903	44.35278		LATLON
560090026	1311	211111	PHILLIPS PETROLEUM (YOSS)	ICE-NG.			WY		USA	-105.259	43.01		LATLON
560350006	1311	211111	QUESTAR PIPELINE - DRY PINEY	ICE-NG.			WY		USA	-109.834	42.86412		LATLON
5603500006	1311	211111	QUESTAR PIPELINE _ DRY PINEY	QUESTAR PIPELINE _ DRY PI	S11 T27N R114W	NONE	WY	99999	USA	-110.344	42.3492	12	LATLON
560410023	1311	211111	QUESTAR PIPELINE-LEROY STORAGE COMP STN	ICE-NG.			WY		USA	-110.616	41.32972		LATLON
560290005	1311	211111	RALSTON PROCESSING ASSOCIATES	ICE-NG.			WY		USA	-108.899	44.40917		LATLON
5601300008	1311	211111	SANTA FE SNYDER_BEAVER CREEK	NATURAL GAS PROCESSING	13 MI SE OF RIVERTON	RIVERTON	WY	82501	USA	-108.314	42.8474	12	LATLON
560130011	1311	211111	SNYDER OIL CORP.-RIVERTON PLANT	ICE-NG.			WY		USA	-108.343	42.94111		LATLON
T$12143	1311	211111	U.S. DOE NAVAL PETROLEUM RESERVE NO. 3		7290 SALT CREEK RTE.	CASPER	WY	82601132(	USA	-106.25	43.31667		LATLON
560410040	1311	211111	UNIVERSAL RESOURCES CORP - CLEAR CREEK	ICE-NG.			WY		USA	-110.839	41.38028		LATLON
560090039	1311	211111	WESTERN GAS RESOURCES - SPEARHEAD	ICE-NG.			WY		USA	-105.485	42.89442		LATLON
560090033	1311	211111	WESTERN GAS RESOURCES-SOUTH SAND DUNES	ICE-NG.			WY		USA	-105.485	42.89442		LATLON
5603700052	1311	22121	WEXPRO CANYON CREEK/VERMILLION	WEXPRO CANYON CREEK/VERM			WY		USA	-108.778	41.634		LATLON
0069	1321	211112	BEAR PAW ENERGY - WIGGINS GAS PLANT	HYDROCARBON LIQUID RECOVERY	SW SEC 3 T3N R59W	WIGGINS, N OF I-76	CO	80202	USA	-103.971	40.2542	13	LATLON
0183	1321	211112	CALPINE NATURAL GAS (WAS VESSELS OIL & G		SEC 29 T6S R91W	GARFIELD	CO	00000	USA	-107.53	39.727		LATLON
0107	1321	211112	DUKE ENERGY FIELD SERVICES - LUCERNE	NATURAL GAS GATHERING AND PF	31495 WCR 43	WELD COUNTY	CO	00000-000	USA	-104.658	40.4502	13	LATLON
0189	1321	211112	DUKE ENERGY FIELD SERVICES - N ARROWHEAD	NATURAL GAS GATHERING (WAS H	8 MILES W OF CHEYENNE WELLS	CHEYENNE WELLS 8 MI W OF	CO	80217	USA	-102.515	38.6699	13	LATLON
080690274	1321	211112	INDUSTRIAL GAS SERVICES INC WELLINGTON	Turbine:			CO		USA	-105.047	40.77639		LATLON
0473	1321	211112	SW PRODUCTION CO (WAS COSTILLA PETRO)	NATURAL GAS PROCESSING	SEC 27 T5N R64W (S WCR 55 & 54	WELD	CO	80000	USA	-104.312	40.50103	13	LATLON
0006	1321	211112	WILLIAMS FIELD SERVICES IGNACIO B PLT	NATURAL GAS PROCESSING	3746 COUNTY RD 307	DURANGO	CO	81301	USA	-107.784	37.1449	13	LATLON
080670006	1321	211112	WILLIAMS FIELD SVCS IGNACIO B PLT				CO		USA	-107.786	37.13889		LATLON
201750038	1321	211112	ANADARKO PETROLEUM CORP.	ICE-NG.			KS		USA	-101.013	37.15528		LATLON
201710011	1321	211112	KN ENERGY, INC. SUNFLOWER HELIUM PLANT	ICE-NG.			KS		USA	-100.982	38.48306		LATLON
00011	1321	211112	ONEOK FIELD SERVICES COMPANY	NATURAL GAS LIQUIDS	S17-T18S-R33W	SCOTT CITY	KS	67871	USA	-100.99	38.48944		LATLON
200070022	1321	211112	TEXACO PRODUCING, INC.	ICE-NG.			KS		USA	-98.5733	37.25528		LATLON
200770017	1321	211112	TRIDENT NGL, INC.	ICE-NG.			KS		USA	-98.2128	37.37667		LATLON
200950002	1321	211112	TRIDENT NGL, INC.	ICE-NG.			KS		USA	-97.8458	37.65		LATLON
350250018	1321	211112	AMERICAN PROCESSING/HOBBS PLANT____320M3	ICE-NG.			NM		USA	-103.358	32.71306		LATLON
0072	1321	211112	Antelope Ridge Gas Plant	NMD986680163 Natural Gas Processi	20 Mi Sw Of Eunice	Eunice	NM	88231	USA	-103.454	32.2996	13	LATLON
350390027	1321	211112	BENSON-MONTIN-GREER/CANADA OJITOS__914M1	ICE-NG.			NM		USA	-106.901	36.39639		LATLON
0140	1321	211112	Carlsbad Gas Plant	NM0001897628 Natl Gas Process & C	2 Mi NE of Loving	Loving	NM	88256	USA	-104.077	32.3184	13	LATLON
350250004	1321	211112	CONOCO/MALJAMAR GAS PLANT__________319M3	ICE-NG.			NM		USA	-103.768	32.8125		LATLON
350450062	1321	211112	CONOCO/SAN JUAN PLANT______________613M2				NM		USA	-107.959	36.73167		LATLON
0285	1321	211112	Dagger Draw Gas Plant	NMD986678019 Natural Gas Processi	9 Mi Ssw Of Artesia	Artesia	NM	88210	USA	-104.445	32.7183	13	LATLON
350450009	1321	211112	EL PASO NATL GAS/CHACO GAS PLANT__1555M1				NM		USA	-108.12	36.48833		LATLON
350150011	1321	211112	GPM GAS/ARTESIA GAS PLANT__________434M5	ICE-NG.			NM		USA	-104.231	32.7625		LATLON
350150169	1321	211112	GPM GAS/AVALON GASOLINE PLNT______1148M1	ICE-NG.			NM		USA	-104.209	32.5025		LATLON
350250044	1321	211112	GPM GAS/EUNICE GAS PLANT____________44M6				NM		USA	-103.299	32.52056		LATLON
350250046	1321	211112	GPM GAS/LEE GAS PLANT______________276M1	ICE-NG.			NM		USA	-103.514	32.80528		LATLON
350250035	1321	211112	GPM GAS/LINAM RANCH GAS PLANT_______39M2				NM		USA	-103.302	32.69833		LATLON
350150140	1321	211112	HIGHLANDS GATHERING/CARLSBAD PLT___927M3	ICE-NG.			NM		USA	-104.077	32.31806		LATLON
350250072	1321	211112	LG&E/HADSON/ANTELOPE RDG GAS PLNT__401M4	ICE-NG.			NM		USA	-103.45	32.29639		LATLON
350250122	1321	211112	LG&E/HADSON/MINERALS PLANT_________166M1	ICE-NG.			NM		USA	-103.325	32.70806		LATLON
350050014	1321	211112	LIQUID ENERGY/WHITE RANCH_______PSD356M1	ICE-NG.			NM		USA	-103.946	33.46361		LATLON
0004	1321	211112	Maljamar Gas Plant	NMD986680742 Natl Gas Processing	3 Mi S Of Maljamar	Maljamar	NM	88264	USA	-103.769	32.8125	13	LATLON
350150008	1321	211112	MARATHON OIL/INDIAN BSN GAS PLT_PSD295M3	Turbine:			NM		USA	-104.574	32.46639		LATLON
350310023	1321	211112	MERRION OIL & GAS/OJO ENCINO_________936	ICE-NG.			NM		USA	-107.327	35.92556		LATLON
350450196	1321	211112	MERRION OIL & GAS/SNAKE EYES PLANT___950	ICE-NG.			NM		USA	-107.631	36.05417		LATLON
350150035	1321	211112	OXY USA/ABO GAS PROCESSING____G__102,256	ICE-NG.			NM		USA	-104.253	32.78472		LATLON
350150138	1321	211112	PAN ENERGY/BURTON FLATS GAS PLT____913M1	ICE-NG.			NM		USA	-103.721	32.40111		LATLON
350150285	1321	211112	PAN ENERGY/DAGGER DRAW GAS PLT__PSD753M2	ICE-NG.			NM		USA	-104.445	32.71833		LATLON
350150095	1321	211112	PAN ENERGY/PECOS DIAMND GAS PLT___PSD389	ICE-NG.			NM		USA	-104.274	32.76861		LATLON
0062	1321	211112	San Juan Gas Plant	NMD986670297 Natural Gas Processi	61 Cnty Rd 4900, 2 Mi Ne Bloom	Bloomfield	NM	87413000(	USA	-107.964	36.7398	13	LATLON
350250008	1321	211112	SID RICHARDSON GASOLINE/JAL #3______1092				NM		USA	-103.176	32.17417		LATLON
350250009	1321	211112	SID RICHARDSON GASOLINE/JAL #4______70M1	ICE-NG.			NM		USA	-103.195	32.25528		LATLON
350250055	1321	211112	TEXACO/BUCKEYE GASOLINE PLANT_________60	ICE-NG.			NM		USA	-103.508	32.78444		LATLON
350250060	1321	211112	WARREN PETROLEUM/EUNICE GAS PLANT___67M3	ICE-NG.			NM		USA	-103.144	32.42583		LATLON
350250061	1321	211112	WARREN PETROLEUM/MONUMENT PLANT____110M3				NM		USA	-103.308	32.61056		LATLON
350250063	1321	211112	WARREN PETROLEUM/SAUNDERS PLANT____315M1	ICE-NG.			NM		USA	-103.61	33.05694		LATLON
350250064	1321	211112	WARREN PETROLEUM/VADA GAS PLANT____203M1	ICE-NG.			NM		USA	-103.544	33.43417		LATLON
350450026	1321	211112	WILLIAMS FIELD SERV/KUTZ GAS PLANT_301M				NM		USA	-107.954	36.66833		LATLON
350390010	1321	211112	WILLIAMS FIELD SERV/LYBROOK PLANT___81M2				NM		USA	-107.545	36.23194		LATLON
1055	1321	211112	Anadarko Gathering Company-Panther Creek Gas Plant	4900356 Panther Creek Gas Plant			OK		USA	-97.4716	34.7079	14	LATLON
400390351	1321	211112	ANR PRODUCTION CO.	Turbine:			OK		USA	-99.0142	35.63556		LATLON
400370204	1321	211112	ASSOCIATED NATURAL GAS/MILFAY GAS PLANT	ICE-NG.			OK		USA	-96.33	35.9		LATLON
2089	1321	211112	Carrera Gas Compranies, LLC Madill Gas Plant	9500200 Madill Gas Plant	6210 S. Yale, Ste. 1640	Tulsa	OK	74136000(	USA	-96.5918	34.0858	14	LATLON
400070231	1321	211112	CIMARRON GAS HOLDING COMPANY	ICE-NG.			OK		USA	-100.943	36.50167		LATLON
400070385	1321	211112	COLORADO INTERSTATE GAS				OK		USA	-100.397	36.89889		LATLON
400510363	1321	211112	CONOCO INC.	ICE-NG.			OK		USA	-97.7633	35.305		LATLON
400870201	1321	211112	CONOCO/GOLDSBY CONTRAL GAS PLANT	ICE-NG.			OK		USA	-97.5067	35.10167		LATLON
2843	1321	211112	Continental Gas, Inc.Eagle Chief Gas Plant	300300 Eagle Chief Gas Plant			OK		USA	-98.5111	36.6109	14	LATLON
1310	1321	211112	Continental Laverne Gas Processing, LLC Laverne Gas Plant	5900200 Laverne Gas Plant	1437 South Boulder	Tulsa	OK	74119362(	USA	-99.9263	36.7117	14	LATLON

strStateFacilityIdentifier	strSIC Primary	strNAICS Primary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXY Coordinate Type
400070361	1321	211112	CONTINENTAL NATURAL GAS INC.(NICOL				OK		USA	-100.293	36.72583		LATLON
1308	1321	211112	Duke Energy Goldsby Gas Plant	8700201 Goldsby Gas Plant			OK		USA	-97.507	35.1032	14	LATLON
2299	1321	211112	Duke Energy Hillsboro Gas Plant	5100360 Hillsboro Gas Plant			OK		USA	-98.0801	34.9567	14	LATLON
2315	1321	211112	Duke Energy Milfay Gas Plant	3700365 Milfay Gas Plant			OK		USA	-96.5674	35.7695	14	LATLON
2365	1321	211112	Duke Energy West Edmond Gas Plant	8300350 West Edmond Gas Plant			OK		USA	-97.622	35.7535	14	LATLON
2366	1321	211112	Duke Energy West Guthrie	8300201 West Guthrie			OK		USA	-97.4529	35.747	14	LATLON
1481	1321	211112	Enerfin Resources Co. Tecumseh Gas Plant	12500355 Tecumseh Gas Plant			OK		USA	-96.9447	35.2088	14	LATLON
401090130	1321	211112	ENOGEX, INC	ICE-NG.			OK		USA	-97.245	35.43556		LATLON
1488	1321	211112	Enogex, Inc. Calumet Gas Processing Plant	1700351 Calumet Gas Processing Pla	515 Central Park Dr. Ste. 600	Oklahoma City	OK	73105000(	USA	-98.1549	35.6665	14	LATLON
2565	1321	211112	Enogex, Inc. Cox City Processing Plant	5100213 Cox City Processing Plant	515 Central Park Dr. Ste. 600	Oklahoma City	OK	73105000(	USA	-97.7923	34.7933	14	LATLON
1079	1321	211112	Enogex, Inc. Custer Gas Plant	3900351 Custer Gas Plant	515 Central Park Dr. Ste. 600	Oklahoma City	OK	73105000(	USA	-99.0144	35.6369	14	LATLON
400730203	1321	211112	EXXON/DOVER-HENNESSEY	ICE-NG.			OK		USA	-97.9028	36.07194		LATLON
1531	1321	211112	ExxonMobile Production Company Dover Hennessey Gas Plant	7300353 Dover Hennessey Gas Plant			OK		USA	-97.904	36.0729	14	LATLON
1042	1321	211112	GPM Gas Company LLC. Mooreland Plant	15300352 Mooreland Plant	210 Park Ave.	Oklahoma City	OK	73102000(	USA	-99.1574	36.4408	14	LATLON
400730220	1321	211112	GPM GAS CORP. KINGFISHER PLANT				OK		USA	-97.7328	35.79083		LATLON
400730224	1321	211112	GPM GAS CORP. OKARCHE PLANT	Turbine:			OK		USA	-98.0856	35.73639		LATLON
400030202	1321	211112	GPM/ALINE BOOSTER	ICE-NG.			OK		USA	-98.3892	36.51444		LATLON
400930218	1321	211112	GPM/CEDAR BOOSTER	ICE-NG.			OK		USA	-98.8214	36.31611		LATLON
400070208	1321	211112	MAPLE GAS CORP.	ICE-NG.			OK		USA	-100.516	36.87306		LATLON
400390358	1321	211112	MOBIL EXPLORATION & PRODUCING U.S.	ICE-NG.			OK		USA	-98.8794	35.82806		LATLON
400190205	1321	211112	MOBIL OIL CO - FOX	ICE-NG.			OK		USA	-97.5094	34.34833		LATLON
401390212	1321	211112	MOBIL OIL CORPORATION WEST HOUGH	ICE-NG.			OK		USA	-101.641	36.90139		LATLON
400030200	1321	211112	NGC ENERGY RESOURCES LIMITED PARTNE	ICE-NG.			OK		USA	-98.2619	36.58194		LATLON
400150205	1321	211112	NGC ENERGY RESOURCES LIMITED PARTNE	ICE-NG.			OK		USA	-98.3267	35.3175		LATLON
400950201	1321	211112	NGC ENERGY RESOURCES LIMITED PARTNE	ICE-NG.			OK		USA	-96.7606	34.11917		LATLON
400470203	1321	211112	NGC ENERGY RESOURCES, L.P.	ICE-NG.			OK		USA	-97.8194	36.42694		LATLON
400950200	1321	211112	NGC ENERGY RESOURCES/MADILL GAS PLANT	ICE-NG.			OK		USA	-96.5903	34.08583		LATLON
400930203	1321	211112	NGC ENERGY, INC/RINGWOOD PLANT	ICE-NG.			OK		USA	-98.2417	36.36556		LATLON
400450201	1321	211112	NORTHERN NATURAL GAS CO.	ICE-NG.			OK		USA	-99.8556	36.45222		LATLON
400070212	1321	211112	NORTHERN NATURAL GAS ELMWOOD	ICE-NG.			OK		USA	-100.523	36.61417		LATLON
401390206	1321	211112	OKLAHOMA GAS PIPELINE CO/TYRONE	ICE-NG.			OK		USA	-101.088	36.99472		LATLON
2523	1321	211112	ONEOK Field Services Co. Antelope Hills Plant	12900203 Antelope Hills Plant			OK		USA	-99.7841	35.8307	14	LATLON
2524	1321	211112	ONEOK Field Services Co. Beaver Gas Plant	700230 Beaver Gas Plant			OK		USA	-100.147	36.5718	14	LATLON
2525	1321	211112	ONEOK Field Services Co. Cimarron Gas Plant	1100208 Cimarron Gas Plant			OK		USA	-98.5417	36.0247	14	LATLON
2526	1321	211112	ONEOK Field Services Co. Custer Gas Plant	3900202 Custer Gas Plant			OK		USA	-98.8918	35.6496	14	LATLON
2527	1321	211112	ONEOK Field Services Co. El Reno Gas Facility	1700203 El Reno Gas Facility			OK		USA	-97.9522	35.6302	14	LATLON
2074	1321	211112	ONEOK Field Services Co. Enid Plant	4700203 Enid Plant			OK		USA	-97.8188	36.4263	14	LATLON
2679	1321	211112	ONEOK Field Services Co. Leedey Plant	12900204 Leedey Plant			OK		USA	-99.4659	35.8092	14	LATLON
2092	1321	211112	ONEOK Field Services Co. Ringwood Gas Plant	9300203 Ringwood Gas Plant			OK		USA	-98.2421	36.3658	14	LATLON
2531	1321	211112	ONEOK Field Services Co. Stephens Plant	13700208 Stephens Plant			OK		USA	-97.7011	34.47	14	LATLON
400530205	1321	211112	ORYX ENERGY	ICE-NG.			OK		USA	-97.9042	36.84639		LATLON
400590200	1321	211112	ORYX ENERGY COMPANY	Turbine:			OK		USA	-99.9256	36.70889		LATLON
401390200	1321	211112	PARKER & PARSLEY				OK		USA	-101.256	36.83417		LATLON
2658	1321	211112	Questar Gas Management Company Beaver Gas Plant	700353 Beaver Gas Plant			OK		USA	-100.953	36.7783	14	LATLON
2509	1321	211112	Spectrum Field Services Velma Gas Plant	13700200 Velma Gas Plant			OK		USA	-97.6919	34.4617	14	LATLON
3082	1321	211112	Superior Pipeline Co. Butler Gas Plant	3903082 Butler Gas Plant			OK		USA	-99.1997	35.6246	14	LATLON
400490219	1321	211112	TEXACO EXPLORATION & PRODUCTION, IN	ICE-NG.			OK		USA	-97.4442	34.81417		LATLON
400850201	1321	211112	TEXACO EXPLORATION & PRODUCTION, IN	ICE-NG.			OK		USA	-97.0281	33.96333		LATLON
2508	1321	211112	Texaco Exploration & Production, Inc. Maysville Gas Plant	4900219 Maysville Gas Plant			OK		USA	-97.4456	34.815	14	LATLON
401370200	1321	211112	TEXACO PRODUCTS - VELMA GAS PLANT	ICE-NG.			OK		USA	-97.6781	34.46083		LATLON
2517	1321	211112	Timberland Gathering & Processing Company Tyrone	13900206 Tyrone			OK		USA	-101.089	36.9973	14	LATLON
400170203	1321	211112	TONKAWA GAS PROCESSING CO.				OK		USA	-97.9517	35.63056		LATLON
401290203	1321	211112	TONKAWA GAS PROCESSING CO.				OK		USA	-99.7833	35.83056		LATLON
401370208	1321	211112	TONKAWA GAS PROCESSING CO.	ICE-NG.			OK		USA	-97.7008	34.46917		LATLON
400390205	1321	211112	TRANSOK, INC.	ICE-NG.			OK		USA	-98.7975	35.73833		LATLON
400630200	1321	211112	TRANSOK, INC.	ICE-NG.			OK		USA	-96.1692	35.1375		LATLON
400830200	1321	211112	TRANSOK, INC.	ICE-NG.			OK		USA	-97.6167	35.89917		LATLON
401290202	1321	211112	TRANSOK, INC.	ICE-NG.			OK		USA	-99.4831	35.74778		LATLON
400470218	1321	211112	TRIDENT NGL, INC.	ICE-NG.			OK		USA	-98.0325	36.17806		LATLON
400470358	1321	211112	TRIDENT NGL, INC.	ICE-NG.			OK		USA	-97.5631	36.36556		LATLON
400730236	1321	211112	TRIDENT NGL, INC.	ICE-NG.			OK		USA	-98.1242	35.79667		LATLON
400710204	1321	211112	TRIDENT NGL, INC/AMBROSE	ICE-NG.			OK		USA	-97.3133	36.82667		LATLON
2946	1321	211112	Tri-Star Energy, LLC Braman Gas Processing Plant	7102946 Braman Gas Processing Plar	101 E. Broadway Ave.	Ponca City	OK	74601430?	USA	-97.2406	36.9863	14	LATLON
400070214	1321	211112	WARREN PERTOLEUM COMPANY MOCANE	ICE-NG.			OK		USA	-100.396	36.89889		LATLON
401290204	1321	211112	WARREN PETROLEUM CO., DIVISION CHEV	ICE-NG.			OK		USA	-99.4656	35.80917		LATLON
2683	1321	211112	Westana Gathering Company Chester Gas Plant	15300201 Chester Gas Plant			OK		USA	-98.9789	36.2474	14	LATLON
400930222	1321	211112	WESTERN GAS RESOURCES/CHANEY DELL				OK		USA	-98.2444	36.43222		LATLON
2928	1321	211112	Williams Field Services Co.Dry Trails Gas Plant	13902928 Dry Trails Gas Plant			OK		USA	-101.616	36.9058	14	LATLON
400530211	1321	211112	WILLIAMS NATURAL GAS CO.	ICE-NG.			OK		USA	-97.4778	36.85306		LATLON
SD0048I	1321	211112	ABRAXAS PETROLEUM CORP		5 MI. N. OF SINTON, TX., THEN	SINTON	TX	78387	USA	-97.1295	28.18036	14	LATLON
MQ0303C	1321	211112	ACACIA NATURAL GAS CORP		SPUR 149 AT FM 149	MAGNOLIA	TX	77355	USA	-95.0916	30.02799	15	LATLON
EA0085H	1321	211112	ALLIANT ENERGY DESDEMONA LP		OFF CR 495, 2.5 MILES NE OF DE	DESDEMONA	TX	76445	USA	-98.5167	32.30843	14	LATLON
CF0017D	1321	211112	AMERICAN GATHERING LP		FRM SKELLYTOWN,APPOX 4.5 MI.E	SKELLYTOWN	TX	79080	USA	-101.121	35.56446	14	LATLON
CF0005K	1321	211112	AMERICAN PROCESSING		FROM SWELLYTOWN APPROX. 2.5 MI	PAMPA	TX	79065	USA	-101.136	35.52877	14	LATLON
HL0019O	1321	211112	AMERICAN PROCESSING LP		APPROX. 10 MI. S. ON HWY. 83;	CANADIAN	TX	79014	USA	-100.476	35.73454	14	LATLON
PG0036K	1321	211112	AMERICAN PROCESSING LP		8 MI. S. OF FRITCH, TX., ON ST	FRITCH	TX	79036	USA	-101.639	35.5433	14	LATLON
MR0026R	1321	211112	ANADARKO GATHERING CO		0.75 MI. S. OF HWY. 1913 & 131	SANFORD	TX	70978	USA	-101.63	35.80891	14	LATLON
WF0098I	1321	211112	APACHE CORPORATION		10 MI. S.E. OF PEIRCE @ INTRSN	EL CAMPO	TX	77437	USA	-96.077	29.14636	14	LATLON
480090001	1321	211112	ARCHER CITY PLT	ICE-NG.			TX		USA	-98.6871	33.6156		LATLON
HL0101F	1321	211112	BP AMOCO		4 MI S. OF CANADIAN, TX	CANADIAN	TX	79014	USA	-100.27	35.84	10	LATLON
EA0007E	1321	211112	CANTERA RESOURCES INC		12 MILES NW OF CISCO OFF HWY 6	CISCO	TX	76437	USA	-99.0927	32.50563	14	LATLON
EA0008C	1321	211112	CANTERA RESOURCES INC		6 MI. W. ON F.M. 101	RANGER	TX	76470	USA	-98.7901	32.46883	14	LATLON
PA0009K	1321	211112	CANTERA RESOURCES INC		2 MI. N. ON HWY. 193 FROM I. 2	GORDON	TX	76453	USA	-98.3389	32.53763	14	LATLON
PC0140M	1321	211112	CANTERA RESOURCES INC		2 MI. N.E. OF HWY. 51 SPRINGTO	SPRINGTOWN	TX	76082	USA	-97.6835	32.98432	14	LATLON
481010001	1321	211112	CHALK PLANT	ICE-NG.			TX		USA	-100.258	34.07462		LATLON
480210001	1321	211112	CHEROKEE GATHERING COMPAN	ICE-NG.			TX		USA	-97.3363	30.1029		LATLON
WJ0002I	1321	211112	CITATION OIL & GAS CORP WILLAMAR PLANT		WILLAMAR PLANT NEAR WILLAMAR	LYFORD	TX	78569	USA	-97.5709	26.40943	14	LATLON
CC0005U	1321	211112	CMS TAURUS FIELD SERVICES LP		8 MI. S. OF PUTNAM ON F.M. 880	PUTNAM	TX	76469	USA	-99.1866	32.27621	14	LATLON
FD0003I	1321	211112	CMS TAURUS FIELD SERVICES LP		ON F.M. 3339, 2 MI. S. OF S.H.	HAMLIN	TX	79520	USA	-100.662	32.96172	14	LATLON

strStateFacilityIdentifier	strSIC Primary	strNAICS Primary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXY Coordinate Type
CI0042R	1321	211112	CONOCO INC		1.5 MILES WEST OF HIGHWAY 146	MONT BELVIEU	TX	77580	USA	-94.9188	29.85177	15	LATLON
IA0001R	1321	211112	CONOCO INCORPORATED		7 MI. W. OF MERTZON ON S.H. 67	MERTZON	TX	76941	USA	-100.908	31.18384	14	LATLON
SF0008V	1321	211112	CONOCO INCORPORATED		10.2 M N ON FM 915 0.7 M W ON	ELDORADO	TX	76936	USA	-100.683	30.9914	14	LATLON
SD0022D	1321	211112	CORPUS CHRISTI NAT GAS GPLP		F.M. 136--2 MI. W. FROM S.H. 3	GREGORY	TX	78359	USA	-97.2633	27.93952	14	LATLON
CZ0011M	1321	211112	CROCKETT GAS PROCESSING CO		3 MI. NW. FROM THE HEADQUARTER	OZONA	TX	76943	USA	-101.237	30.73371	14	LATLON
484510003	1321	211112	DOUBLE A GAS PLANT	Turbine:			TX		USA	-100.41	31.35		LATLON
481770001	1321	211112	DUBOSE PLANT	ICE-NG.			TX		USA	-97.3347	29.09194		LATLON
ML0024S	1321	211112	DUKE ENERGY		12.9 MI SE SH 158 5.1 MI S FM	MIDLAND	TX	79701	USA	-101.794	31.85784	14	LATLON
MF0012R	1321	211112	DUKE ENERGY		13 MI. N.W. OF STANTON, OFF OF	TARZAN	TX	79783	USA	-101.968	32.26804	14	LATLON
PB0067I	1321	211112	DUKE ENERGYFIELD SERVICES		COUNTY RD. 306, 1 MI. E. OF HW	CARTHAGE	TX	75633	USA	-94.3432	32.24294	15	LATLON
PB0002N	1321	211112	DUKE ENERGYFIELD SERVICES INC		5 MI. E. ON U.S. HWY. 79	CARTHAGE	TX	75633	USA	-94.2637	32.18816	15	LATLON
SF0001M	1321	211112	DUKE ENERGYFIELD SERVICES INC		13 MI. S. OF CHRISTOVAL ON U.S	CHRISTOVAL	TX	76935	USA	-100.519	31.00091	14	LATLON
SQ0006B	1321	211112	DUKE ENERGYFIELD SERVICES INC		FROM SONORA, TX., 5.5 MI. S.E.	SONORA	TX	76950	USA	-100.589	30.50798	14	LATLON
LE0012W	1321	211112	DUKE ENERGYFIELD SERVICES INC		FM 2437, 12 MI S OF SHERIDAN	SHERIDAN	TX	77475	USA	-96.9501	29.50857	14	LATLON
NE0028T	1321	211112	DUKE ENERGYFIELD SERVICES INC		13 MI. W. OF BISHOP NEAR F.M.	BISHOP	TX	78343	USA	-97.9016	27.68646	14	LATLON
ML0020D	1321	211112	DUKE ENERGYFIELD SERVICES INC		18 MI. S. OF I. 20 ON F.M. 178	MIDLAND	TX	79701	USA	-102.133	31.66262	13	LATLON
PE0024Q	1321	211112	DUKE ENERGYFIELD SERVICES INC		0.5 MI. S OF FM 1450 ON FM 177	COYANOSA	TX	79730	USA	-103.086	31.26842	13	LATLON
PE0025O	1321	211112	DUKE ENERGYFIELD SERVICES INC		7.2 MI. S. OF F.M. 1450 ON F.M	COYANOSA	TX	79730	USA	-103.037	31.18308	13	LATLON
WF0095O	1321	211112	DUKE ENERGYFIELD SERVICES LLC		WARRIOR GAS CO. WHARTON PLANT	EL CAMPO	TX	77437	USA	-96.2096	29.2059	14	LATLON
HW0020F	1321	211112	DUKE ENERGYFIELD SERVICES LLC		NEAR THE WEST END OF 10TH STRE	BORGER	TX	79007	USA	-101.411	35.67427	14	LATLON
HD0055B	1321	211112	DUKE ENERGYFIELD SERVICES LLC		3.5 MI. S. GRUVER, OFF F.M. 20	GRUVER	TX	79040	USA	-101.388	36.19576	14	LATLON
CI0022A	1321	211112	DYNEGY MIDSTREAM SERVICES LP		10119 HWY. 146 N.	MONT BELVIEU	TX	77580	USA	-94.903	29.84173	15	LATLON
CY0018J	1321	211112	DYNEGY MIDSTREAM SERVICES LP		STAR RT., BOX 18, CRANE, TX.	CRANE	TX	79731	USA	-102.641	31.50153	13	LATLON
GA0011C	1321	211112	DYNEGY MIDSTREAM SERVICES LP		8 MI W ON US 62 AND 180 2.4 MI	SEMINOLE	TX	79360	USA	-102.8	32.76063	13	LATLON
GH0007I	1321	211112	DYNEGY MIDSTREAM SERVICES LP		2.5 MI. E. OF LEFORS, TX. ON H	LEFORS	TX	79054	USA	-100.762	35.43211	14	LATLON
GI0012E	1321	211112	DYNEGY MIDSTREAM SERVICES LP		275 & HWY 82 NW OF SHERMAN	SHERMAN	TX	75090	USA	-96.6344	33.68186	14	LATLON
HH0005S	1321	211112	DYNEGY MIDSTREAM SERVICES LP		SOUTH OF INTERSTATE 20 & WEST	WASKOM	TX	75692	USA	-94.0723	32.46927	15	LATLON
HL0008T	1321	211112	DYNEGY MIDSTREAM SERVICES LP		3 MI. S. ON U.S. 60 FROM CANAD	CANADIAN	TX	79014	USA	-100.402	35.86848	14	LATLON
SH0003J	1321	211112	DYNEGY MIDSTREAM SERVICES LP		9 MI NE OF	ALBANY	TX	76430	USA	-99.2175	32.85847	14	LATLON
WG0011M	1321	211112	DYNEGY MIDSTREAM SERVICES LP		10 MI. N. OF I. 40 ON F.M. 144	MCLEAN	TX	79057	USA	-100.5	35.34575	14	LATLON
WN0005E	1321	211112	DYNEGY MIDSTREAM SERVICES LP		S. OF F.M. 1810, 5 MI. W. OF C	CHICO	TX	76030	USA	-97.8775	33.31185	14	LATLON
WN0045P	1321	211112	DYNEGY MIDSTREAM SERVICES LP		1 MI. S. OF RED BUD CHURCH	CHICO	TX	76030	USA	-97.3959	32.98941	14	LATLON
HE0012I	1321	211112	ECHO PRODUCTION INC		ON F.M. 1167, 1 MI. S. OF U.S.	QUANAH	TX	79252	USA	-99.6469	34.25581	14	LATLON
MC0006W	1321	211112	EGS HYDROCARBONS INC		HWY. 72, 1 MI. S. OF HWY. 99,	TILDEN	TX	78072	USA	-98.4572	28.44476	14	LATLON
CB0063R	1321	211112	EL PASO FIELD SERVICES		CORNER OF SAN ANTONIO & MILAM	PORT LAVACA	TX	77979	USA	-96.63	28.4	14	LATLON
MH0039V	1321	211112	EL PASO FIELD SERVICES		1.5 MI. E. OF HWY. 35 ON F.M.	PALACIOS	TX	77465	USA	-96.1827	28.80017	14	LATLON
MH0057T	1321	211112	EL PASO FIELD SERVICES		OYSTER LAKE	PALACIOS	TX	77465	USA	-96.1337	28.61693	14	LATLON
LK0044R	1321	211112	ENRON PROCESSING PROPERTIES INC		ON HWY. 281 NEAR GEORGE WEST	GEORGE WEST	TX	78022	USA	-98.1206	28.36758	14	LATLON
WB0003U	1321	211112	EXXON COMPANY		AT OR NEAR P.O. BOX 276, KATY,	KATY	TX	77449	USA	-95.8772	29.81367	15	LATLON
WC0010M	1321	211112	EXXON COMPANY USA		3 MI. S. ON F.M. 1927	PYOTE	TX	79777	USA	-103.107	31.4882	13	LATLON
WO0009I	1321	211112	EXXON COMPANY USA		F.M. 1795	HAWKINS	TX	75765	USA	-95.1979	32.61159	15	LATLON
HG0234M	1321	211112	EXXON CORPORATION		51210 RED BLUFF-GENOA RD.	PASADENA	TX	77507	USA	-95.1223	29.63141	15	LATLON
RL0007C	1321	211112	EXXON CORPORATION		2 MI. N. AT THE INTERSECTION O	NEW LONDON	TX	75682	USA	-94.9289	32.27045	15	LATLON
KJ0003N	1321	211112	EXXON USA INC KING RANCH		KING RANCH	KINGSVILLE	TX	78363	USA	-98.0583	27.46553	14	LATLON
CB0053U	1321	211112	FORMOSA HYDROCARBONS CO INC		S. OF S.H. 35, W. OF F.M. 1593	POINT COMFORT	TX	77978	USA	-96.5586	28.66372	14	LATLON
GJ0003W	1321	211112	GAS SOLUTIONS		TO CHEROKEE TRACE 1 MI S & 0.3	WHITE OAK	TX	75693	USA	-94.8664	32.50383	15	LATLON
HD0014P	1321	211112	GPM GAS CORPORATION		20 MI. N. OF GRUVER ON TX. 136	GRUVER	TX	79040	USA	-101.35	36.28	14	LATLON
MR0030D	1321	211112	GPM GAS CORPORATION		4 M SW OF DUMAS ON FM 722	DUMAS	TX	79029	USA	-102.028	35.82075	13	LATLON
FC0033K	1321	211112	GPM GAS SERVICES CO		3 MILES NORTH OF THE CITY OF W	WINCHESTER	TX	78964	USA	-96.9867	30.03686	14	LATLON
FC0049S	1321	211112	GPM GAS SERVICES CO		7 MI. N. OF LAGRANGE ON C.R. 1	GIDDINGS	TX	78942	USA	-96.8919	29.99269	14	LATLON
LF0019U	1321	211112	GPM GAS SERVICES CO		GEORGE B. LOFTIN SURVEY ("A-19	GIDDINGS	TX	78942	USA	-96.8077	30.29071	14	LATLON
LF0022I	1321	211112	GPM GAS SERVICES CO		1 MI. N.E. OF GIDDINGS, TX., O	DIME BOX	TX	77853	USA	-96.7743	30.26542	14	LATLON
LF0024E	1321	211112	GPM GAS SERVICES CO		MATTHEW SPARKS LEAGUE "A-18"	GIDDINGS	TX	78942	USA	-96.8603	30.20506	14	LATLON
482250005	1321	211112	GRAPELAND PLANT	Turbine:			TX		USA	-95.3144	31.30278		LATLON
KA0013M	1321	211112	GULF ENERGYGATHERING PROCESSING		10 MI. S. OF RUNGE, TX., ON F.	RUNGE	TX	78151	USA	-97.6316	28.79102	14	LATLON
RG0069H	1321	211112	H & D OPERATING CO		4 MILES SW OF WOODSBORO ON HWY	WOODSBORO	TX	78393	USA	-97.3884	28.20168	14	LATLON
BL0005M	1321	211112	HILCORP ENERGY CO SWEENY		SWEENY	OLD OCEAN	TX	77463	USA	-95.7502	29.0415	15	LATLON
HM0010V	1321	211112	HUNT OIL CO		1 MI NE ON HWY 315	POYNOR	TX	75782	USA	-95.5822	32.08478	15	LATLON
CA0011B	1321	211112	JL DAVIS		6 MI. N.W. OF LULING ON COUNTY	LULING	TX	78648	USA	-97.7282	29.73106	14	LATLON
FJ0045A	1321	211112	JL DAVIS GAS PROC INC		6 MI SSE OF PEARSALL-14.8 MI N	PEARSALL	TX	78061	USA	-99.0309	28.81301	14	LATLON
IA0009B	1321	211112	JL DAVIS GAS PROCESSING INC		ON S.H. 163 10 MI. N. OF	BARNHART	TX	76930	USA	-101.162	31.28765	14	LATLON
RC0001Q	1321	211112	JL DAVIS GAS PROCESSING INC		6 MI. E. OF BIG LAKE, TX.	BIG LAKE	TX	76932	USA	-101.342	31.16433	14	LATLON
CI0005A	1321	211112	KOCH HYDROCARBON CO		1.2 MI. W. OF THE INTERSECTION	MONT BELVIEU	TX	77580	USA	-94.9087	29.85413	15	LATLON
480710032	1321	211112	KOCH HYDROCARBON COMPANY				TX		USA	-94.5428	29.51167		LATLON
482490001	1321	211112	LA GLORIA GAS PLANT				TX		USA	-98.0914	27.16278		LATLON
483130003	1321	211112	MADISONVILLE GAS PROCESSI	ICE-NG.			TX		USA	-95.9293	30.958		LATLON
484030001	1321	211112	MAGASCO COMPRESSOR STN.	ICE-NG.			TX		USA	-93.5831	31.17139		LATLON
35868	1321	211112	MARATHON OIL COMPANY				TX		USA	-100.301	31.2625	14	LATLON
JE0746E	1321	211112	MARINER ENERGY INC		TRAM RD. BETWEEN SHERWOOD DR.	BEAUMONT	TX	77701	USA	-94.1792	30.16773	15	LATLON
LK0001M	1321	211112	MERIT ENERGY CO		ON F.M. 623 IN LIVE OAK CO. NE	OAKVILLE	TX	78060	USA	-98.0132	28.48416	14	LATLON
483630008	1321	211112	MINERAL WELLS PLANT	ICE-NG.			TX		USA	-98.3157	32.7596		LATLON
MQ0335M	1321	211112	MITCHELL ENERGY CORP		4 MI. E. OF F.M. 149, ON F.M.	MAGNOLIA	TX	77355	USA	-95.6401	30.23659	15	LATLON
WN0021G	1321	211112	MITCHELL GAS SERVCS LMTD PARTNERSHIP		3 1/2 M W OF BRIDGEPORT ON HWY	BRIDGEPORT	TX	76026	USA	-97.8076	33.19607	14	LATLON
CN0003A	1321	211112	MITCHELL GAS SERVICES LP		SILVER	SILVER	TX	76949	USA	-100.68	32.04785	14	LATLON
JA0026U	1321	211112	MITCHELL GAS SERVICES LP		ON F.M. 2210, 1 MI. E. OF F.M.	PERRIN	TX	76075	USA	-98.1883	33.07295	14	LATLON
PA0015P	1321	211112	MITCHELL GAS SERVICES LP		2 MI. W. OF LONE CAMP	PALO PINTO	TX	76072	USA	-98.3116	32.66187	14	LATLON
36659	1321	211112	MOBIL EXPLORATION AND PRODUCING US I				TX		USA	-100.867	33.235	14	LATLON
483390032	1321	211112	N.G.P.L.C.O.A. STN. 302	ICE-NG.			TX		USA	-95.1508	30.12028		LATLON
MQ0064U	1321	211112	NATURAL GASPIPELINE CO OF AMERICA		17057 F. M. 1485	NEW CANEY	TX	77357	USA	-95.2514	30.20271	15	LATLON
CZ0024D	1321	211112	NELEH GAS SYSTEMS				TX		USA	-102.221	31.03878	13	LATLON
HW0035P	1321	211112	NORTHERN NATURAL GAS CO		14.4 MI. S., 207; 10.1 MI. W.,	MORSE	TX	79062	USA	-101.514	36.02208	14	LATLON
HP0005E	1321	211112	OCCIDENTAL PERMIAN LTD		3 MI WEST ON FM 303 ON FM 301	SUNDOWN	TX	79372	USA	-102.559	33.4678	13	LATLON
TC0002Q	1321	211112	OCCIDENTAL PERMIAN LTD		29.5 MI. N. ON S.H. 349; 3 MI.	SHEFFIELD	TX	79781	USA	-101.844	30.37381	14	LATLON
GH0001U	1321	211112	ONEOK FIELDSERVICES CO		5 MI. W. OF PAMPA, & 1 MI. N.	PAMPA	TX	79065	USA	-101.035	35.52066	14	LATLON
MR0023A	1321	211112	ONEOK FIELDSERVICES CO		15 MI. E. OF DUMAS ON HYW. 152	DUMAS	TX	79029	USA	-101.696	35.78764	14	LATLON
38108	1321	211112	ORYX ENERGYCOMPANY				TX		USA	-98.06	27.3285	14	LATLON
38517	1321	211112	PANENERGY FIELDS SERVICES INC				TX		USA	-98.1532	27.2766	14	LATLON
PG0035M	1321	211112	PIONEER NATRESOURCES CO		27 MI. N. OF AMARILLO ON HWY.	AMARILLO	TX	79101	USA	-101.894	35.53807	14	LATLON
BE0013Q	1321	211112	PIONEER NATURAL RESOURCES USA INC		2 MI. S. OF PAWNEE ON F.M. 673	PAWNEE	TX	78145	USA	-97.9929	28.62278	14	LATLON

strStateFacilityIdentifier	strSICPrimary	strNAICSPrimary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXYCoordinateType
481690006	1321	211112	PLEASANT VALLEY PLANT	ICE-NG.			TX		USA	-101.021	33.23444		LATLON
AG0024G	1321	211112	PUEBLO MIDSTREAM GAS CORP		HCO3, FM 2924, FASHING	SAN ANTONIO	TX	78232	USA	-98.1803	28.79523	14	LATLON
MF0001W	1321	211112	RAPTOR FACILITIES INC		RT 1 BOX 142A STANTON TX 79782	STANTON	TX	79782	USA	-101.932	32.21152	14	LATLON
39833	1321	211112	ROCKLAND PIPELINE COMPANY				TX		USA	-100.693	31.5918	14	LATLON
482630002	1321	211112	SALT CREEK FIELD GAS PLT	ICE-NG.			TX		USA	-100.521	33.13972		LATLON
482490006	1321	211112	SEELIGSON GAS PLANT	ICE-NG.			TX		USA	-98.0828	27.24139		LATLON
PE0009M	1321	211112	SID RICHARDSON GASOLINE CO		8 MI. S., S.H. 18	GRANDFALLS	TX	79742	USA	-102.888	31.23951	13	LATLON
PE0042O	1321	211112	SID RICHARDSON GASOLINE COMPANY				TX		USA	-102.986	31.18636	13	LATLON
484510011	1321	211112	STRAWN GAS PLANT	ICE-NG.			TX		USA	-100.689	31.3958		LATLON
CG0012C	1321	211112	SULPHUR RIVER GATHERING LP		2 MI. N. OF HWY. 77 & 6 MI. W.	DOUGLASSVILLE	TX	75560	USA	-94.4598	33.2238	15	LATLON
GJ0005S	1321	211112	SULPHUR RIVER GATHERING LP		ON F.M. 2605, 1.5 MI. W. OF F.	LONGVIEW	TX	75605	USA	-94.8299	32.53675	15	LATLON
HM0014N	1321	211112	SULPHUR RIVER GATHERING LP		0.5 MI. N. ON HWY. 90	EUSTACE	TX	75124	USA	-96.039	32.26805	14	LATLON
VB0004M	1321	211112	SULPHUR RIVER GATHERING LP		NEARBY	CANTON	TX	75103	USA	-95.8981	32.62733	15	LATLON
484510008	1321	211112	SUSAN PEAK GAS PLANT	ICE-NG.			TX		USA	-100.689	31.3958		LATLON
RG0054U	1321	211112	TC OIL COMPANY		19 MI. N.E. OF REFUGIO, TX., O	REFUGIO	TX	78377	USA	-97.046	28.50943	14	LATLON
RG0053W	1321	211112	T-C OIL COMPANY		6 MI. N.E. OF REFUGIO, TX.	REFUGIO	TX	78377	USA	-97.0589	28.40712	14	LATLON
PF0049M	1321	211112	TECO GAS PROCESSING CO		16.2 MI. E. OF LIVINGSTON, TX.	LIVINGSTON	TX	77351	USA	-94.7012	30.75699	15	LATLON
SD0072L	1321	211112	TEJAS CORPUS CHRISTI PROCESSING LP		NEAR THE INTERSECTION OF F. M.	PORTLAND	TX	78374	USA	-97.4104	27.88751	14	LATLON
CZ0027U	1321	211112	TEXACO E &P INC		6.5 MI E. ON I. 10, 4.5 MI. S.	OZONA	TX	76943	USA	-101.071	30.63449	14	LATLON
ML0048E	1321	211112	TEXACO EXPLORATION & PRDCTN INC		3.5 MI. E. ON LEASE ROAD	MIDLAND	TX	79701	USA	-102.016	31.84817	13	LATLON
CZ0014G	1321	211112	TEXACO EXPLORATION & PRODUCTION		2 MI. S., S.H. 163	OZONA	TX	76943	USA	-101.206	30.67269	14	LATLON
SO0003G	1321	211112	TEXACO EXPLORATION & PRODUCTION INC				TX		USA	-101.196	31.74186	14	LATLON
EB0069R	1321	211112	TEXACO EXPLORATION AND PRODUCTION IN		501 SOUTHEAST LOOP 338	ODESSA	TX	79760	USA	-102.313	31.86012	13	LATLON
NE0062T	1321	211112	TEXAS CRUDEENERGY INC		OFF WALDRON RD. BTWN. IT & LAG	CORPUS CHRISTI	TX	78322	USA	-97.2791	27.65474	14	LATLON
44263	1321	211112	THE WISER OIL COMPANY				TX		USA	-103.508	31.8293	13	LATLON
482490007	1321	211112	TIJERINA, CANALES,BLUCHER	ICE-NG.			TX		USA	-97.4714	28.03194		LATLON
44278	1321	211112	TONKAWA GASPROCESSING				TX		USA	-95.5285	31.5084	15	LATLON
LK0027R	1321	211112	TONKAWA GASPROCESSING CO		1.8 MI. E. OF U.S. 281, 4.5 S.	THREE RIVERS	TX	78071	USA	-98.1351	28.40499	14	LATLON
BL0004O	1321	211112	TRI-UNION DEVELOPMENT CORP		HASTINGS PLANT	ALVIN	TX	77512	USA	-95.2439	29.50191	15	LATLON
HM0011T	1321	211112	TXU PROCESSING CO		.25 MI W OF FM 1667	TRINIDAD	TX	75163	USA	-96.0854	32.12701	14	LATLON
483390020	1321	211112	U.P. RESOURCES CONROE	ICE-NG.			TX		USA	-95.4633	30.33665		LATLON
VB0011P	1321	211112	UNION OIL COMPANY OF CALIFORNIA		1 MI N OF THE CITY	VAN	TX	75790	USA	-95.6425	32.59353	15	LATLON
PB0003L	1321	211112	UNION PACIFIC RESOURCES		2 MI. W. OF CARTHAGE ON U.S. H	CARTHAGE	TX	75633	USA	-94.4008	32.16103	15	LATLON
MQ0002T	1321	211112	UNION PACIFIC RESOURCES CO		APPROX 6 MI S ON FM 3083	CONROE	TX	77303	USA	-95.3659	30.27968	15	LATLON
HR0018T	1321	211112	VALENCE OPERATING CO		FM 1567 TO 2948 S 2 MI	SULPHUR SPRINGS	TX	75420	USA	-95.4971	32.98774	15	LATLON
OC0151B	1321	211112	VASTAR RESOURCES INC		OFF OF NORTH TRAM ROAD AT THE	VIDOR	TX	77662	USA	-94.0024	30.19632	15	LATLON
484510004	1321	211112	Veribest Gas Plant	ICE-NG.			TX		USA	-100.689	31.3958		LATLON
SG0031P	1321	211112	WEST TEXAS GAS PROCESSING LP		17 MI. S.S.E. OF SNYDER ON S.H	MIDLAND	TX	79701	USA	-100.931	32.85534	14	LATLON
RC0018W	1321	211112	WESTERN GASRESOURCES INC		6.5 M N ON SH 137 2 M W ON CR5	BIG LAKE	TX	76932	USA	-101.647	31.48897	14	LATLON
UB0009T	1321	211112	WESTERN GASRESOURCES INC		7 MI. N., S.H. 349; 8.5 MI. E.	RANKIN	TX	79778	USA	-101.797	31.3399	14	LATLON
481590003	1321	211112	WESTLAND OIL DEVELOPMENT	ICE-NG.			TX		USA	-95.2168	33.1757		LATLON
WI0016D	1321	211112	WG OPERATING INC		3 MILES WEST OF ELECTRA	ELECTRA	TX	76360	USA	-98.9686	34.0436	14	LATLON
HL0076C	1321	211112	WILLIAMS FIELD SERVICES CO		2 MI. S. ON HWY. 3044 & 83 ON	CANADIAN	TX	79014	USA	-100.389	35.7466	14	LATLON
10679	1321	211112	Bridger Lake Plant	facility sold by Dynergy (prev. Warren	T3N, R14E, Sec. 25	Manila	UT	84046	USA	-110.82	40.91557		LATLON
490131003	1321	211112	KOCH HYDROCARBONS - CEDAR RIM PLANT	ICE-NG.			UT		USA	-110.365	40.20028		LATLON
10683	1321	211112	Pineview Gas Plant	Purchased from Union Pacific Resourc	3604 E Chalk Creek Rd	Coalville	UT	84017	USA	-111.163	40.94026		LATLON
10268	1321	211112	San Arroyo Plant	3/98: Ownership transferred from KN E	SE/4 NW/4 Sec. 23, T16S, R25E	Westwater	UT	84515	USA	-109.634	39.0414		LATLON
5603700036	1321	211112	DUKE ENERGY FLD SVCS _ PATRICK DRAW	NGL RECOVERY	7 MI E OF ROCK SPGS	ROCK SPRINGS	WY	82901	USA	-108.502	41.5899	12	LATLON
5604100015	1321	211112	DUKE ENERGY FLD SVCS_EMIGRANT TRAIL	NATURAL GAS TRANSMISSION	EMIGRANT TRAIL PLANT	EVANSTON	WY	82930	USA	-110.091	41.3991	12	LATLON
5604300003	1321	48621	HILAND PARTNERS, LLC_HILAND GAS PLANT	NATURAL GAS PROCESSING			WY		USA	-107.852	44.0302	13	LATLON
5602500020	1321	211112	KINDER MORGAN, INC _ CASPER EXTRACTION	NATURAL GAS TRANSMISSION	1 MILE E. OF EVANSVILLE HWY 20	CASPER	WY	82601	USA	-106.322	42.84456		LATLON
5600900015	1321	211112	KN GAS GATHERING_DOUGLAS GAS PLANT	NATURAL GAS TRANSMISSION	252 HIGHWAY 59, P.O. DRAWER H	DOUGLAS	WY	82635	USA	-105.359	42.7902	13	LATLON
5602900007	1321	211112	MARATHON OIL CO _ OREGON BASIN GAS PLANT	NATURAL GAS PROCESSING	18 MI SE OF CODY_P O BOX 2690	CODY	WY	82414	USA	-108.903	44.3524	12	LATLON
5603700006	1321	211112	MOUNTAIN GAS RESOURCES_GRANGER GAS PLANT	NATURAL GAS PROCESSING	SEC 16,T18N,R111W	GRANGER	WY	82934	USA	-109.953	41.5385	12	LATLON
560430004	1321	211112	UNION OIL COMPANY-WORLAND PLANT #60	ICE-NG.			WY		USA	-107.906	44.13222		LATLON
560370008	1321	211112	UNION PAC BRADY				WY		USA	-108.746	41.38806		LATLON
560410015	1321	211112	UNION PAC EMIGRANT	ICE-NG.			WY		USA	-110.091	41.39944		LATLON
560370026	1321	211112	UNION PAC RESCRS - NORTH BAXTER COMP STN	ICE-NG.			WY		USA	-108.778	41.634		LATLON
5603700008	1321	211112	UNION PAC_BRADY	NGL RECOVERY	30 MI SE ROCK SPGS	ROCK SPRINGS	WY	82901	USA	-108.746	41.388	12	LATLON
560410018	1321	211112	UPRC - LUCKY DITCH GAS PLANT	ICE-NG.			WY		USA	-110.271	41.01944		LATLON
560370006	1321	211112	WESTERN GAS PROCESSORS-GRANGER GAS PLNT	ICE-NG.			WY		USA	-109.953	41.53861		LATLON
560370011	1321	211112	WESTERN GAS RESOURCES - FONTENELLE	ICE-NG.			WY		USA	-109.975	42.05417		LATLON
560050006	1321	211112	WESTERN GAS RESOURCES - KITTY PLANT	ICE-NG.			WY		USA	-105.546	44.24773		LATLON
560090036	1321	211112	WESTERN GAS RESOURCES - SAND DUNES	ICE-NG.			WY		USA	-105.901	43.09083		LATLON
5600500006	1321	211112	WESTERN GAS RESOURCES _ KITTY PLANT	WESTERN GAS RESOURCES _ K	209 N. WORKS	GILLETTE	WY	82716	USA	-105.486	44.29511		LATLON
5600500003	1321	211112	WESTERN GAS RESOURCES_AMOS DRAW PLANT	NATURAL GAS TRANSMISSION	3108 E. 2ND STREET	GILLETTE	WY	82716	USA	-105.9	44.3558	13	LATLON
5600500049	1321	211112	WESTERN GAS_HILIGHT (MD_124)	WESTERN GAS_HILIGHT (MD_1	NW 1/4,SW1/4,S26,T45N,R71W	WRIGHT	WY	000000000(	USA	-105.357	43.8411	13	LATLON
560050049	1321	211112	WESTERN GAS-HILIGHT (MD-124)	ICE-NG.			WY		USA	-105.546	44.24773		LATLON
560070005	1321	211112	WILLIAMS FIELD SERVICES - ECHO SPRINGS				WY		USA	-107	41.71695		LATLON
560230014	1321	211112	WILLIAMS FIELD SVCS-OPAL PLANT				WY		USA	-110.342	41.76778		LATLON
490390007	1411	212311	BENTONITE PRODUCTION	ICE-Diesel			UT		USA	-111.867	39.055		LATLON
00034	1422	212312	ALLEN COUNTY PUBLIC WORKS	ROCK & AGGREGATE CRUSHING	R. 3	S2-T25S-R19E	KS	66751	USA	-95.2979	37.91552		LATLON
00045	1422	212312	APAC KANSAS, INC., SHEARS DIV DODGE CITY	ROCK & AGGREGATE CRUSHING	S5-T27S-R24W	DODGE CITY	KS	67801	USA	-100.021	37.75704		LATLON
00009	1422	212312	APAC-KANSAS, INC., RENO CONST DIVISION	CRUSHED AND BROKEN LIMEST	7100 WEST 167TH ST.	STANLEY EAST QUARRY	KS	660850000(	USA	-94.6678	38.82556		LATLON
00130	1422	212312	APAC-KANSAS, INC., RENO CONST DIVISION	ROCK & AGGREGATE CRUSHING	10203 WEST 167TH ST.	STANLEY WEST QUARRY	KS	66085	USA	-94.6529	38.79999		LATLON
00131	1422	212312	APAC-KANSAS, INC., RENO CONST DIVISION	ROCK & AGGREGATE CRUSHING	162 & GORDON LAKE ROAD	GARDNER QUARRY	KS	66030	USA	-94.9296	38.81565		LATLON
00023	1422	212312	APAC-KANSAS, INC., RENO CONST. DIVISION	ROCK & AGGREGATE CRUSHING	8811 WEST 247TH ST.	LOUISBURG QUARRY	KS	000000000(	USA	-94.6875	38.67893		LATLON
00016	1422	212312	APAC-KANSAS, INC., SHEARS DIVISION	CRUSHED AND BROKEN LIMEST	WEST HWY 14	QUARTZITE QUARRY	KS	000000000(	USA	-98.2089	39.0451		LATLON
00016	1422	212312	APAC-KANSAS, INC., SHEARS DIVISION	ROCK & AGGREGATE CRUSHING	S2-T28S-R12E	FALL RIVER QUARRY	KS	67047	USA	-96.0279	37.60846		LATLON
00030	1422	212312	APAC-KANSAS, INC., SHEARS DIVISION	ROCK & AGGREGATE CRUSHING	3 1/2 MILES SOUTH OF HARTFORD	HARTFORD QUARRY	KS	66854006	USA	-95.9793	38.27441		LATLON
00019	1422	212312	ASH GROVE AGGREGATES, INC.	ROCK & AGGREGATE CRUSHING	1/2 MI WEST OF AMSTERDAM,MO	LA CYGNE #76	KS	000000000(	USA	-94.733	38.40049		LATLON
00019	1422	212312	ASH GROVE AGGREGATES, INC.	ROCK & AGGREGATE CRUSHING	JCT. 39 & 54	FT. SCOTT EAST #82	KS	000000000(	USA	-94.8509	37.8554		LATLON
00120	1422	212312	ASH GROVE AGGREGATES, INC.	ROCK & AGGREGATE CRUSHING	CEDAR CREEK PARKWAY	CEDAR CREEK #61	KS	000000000(	USA	-94.8317	38.8978		LATLON
00020	1422	212312	BAYER CONSTRUCTION CO., INC.	ROCK & AGGREGATE CRUSHING	7416 TUTTLE CREEK BLVD.	STEVENS QUARRY	KS	66503	USA	-96.7521	39.29102		LATLON
00022	1422	212312	BAYER CONSTRUCTION CO., INC.	ROCK & AGGREGATE CRUSHING	S18&19-T9S-R9E	EBERT QUARRY	KS	000000000(	USA	-96.366	39.3463		LATLON
00024	1422	212312	BAYER CONSTRUCTION CO., INC.	ROCK & AGGREGATE CRUSHING	S4-T9S-R4E	MARTIN QUARRY	KS	67432	USA	-97.1348	39.37493		LATLON
00030	1422	212312	BAYER CONSTRUCTION CO., INC.	ROCK & AGGREGATE CRUSHING	S20-T2S-R9E	SHOTWELL QUARRY	KS	66406	USA	-96.4175	39.8704		LATLON
00007	1422	212312	BYERS & SONS, INC. (HARRY)	CRUSHED AND BROKEN LIMEST	500 N. PLUMMER	CHANUTE	KS	66720	USA	-95.4706	37.68913		LATLON
00043	1422	212312	HARSHMAN CONSTRUCTION L.L.C.	ROCK & AGGRGATE CRUSHING	9423 SW 165TH STREET	SOUTHWEST BUTLER QUARRY	KS	67010	USA	-96.9708	37.67964		LATLON

strStateFacilityIdentifier	strSIC Primary	strNAICS Primary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXY Coordinate Type
00121	1422	212312	HOLLAND CORPORATION, INC.	ROCK & AGGREGATE CRUSHING	23775 W 159TH ST.	OLATHE	KS	66061	USA	-94.8608	38.83988		LATLON
00011	1422	212312	HUNT MIDWEST MINING, INC.	ROCK & AGGREGATE CRUSHING	5 M. WEST ON HWY 166	CEDARVALE	KS	67024	USA	-96.4757	37.12088		LATLON
00020	1422	212312	HUNT MIDWEST MINING, INC.	ROCK & AGGREGATE CRUSHING	18811 W. 271ST ST.	CRAWFORD QUARRY	KS	66071	USA	-94.8032	38.60663		LATLON
00020	1422	212312	HUNT MIDWEST MINING, INC.	ROCK & AGGREGATE CRUSHING	WEST COLONY OFFF K-57 HWY.	SETTLEMYER QUARRY	KS	66015	USA	-95.371	38.07939		LATLON
00021	1422	212312	HUNT MIDWEST MINING, INC.	ROCK & AGGREGATE CRUSHING	SOUTH OF GREELEY ON US HWY 169	SUTTON QUARRY	KS	66033	USA	-95.127	38.36686		LATLON
00022	1422	212312	HUNT MIDWEST MINING, INC.	ROCK & AGGREGATE CRUSHING	WEST OF WELDA	WELDA QUARRY	KS	66091	USA	-95.3527	38.1768		LATLON
00023	1422	212312	HUNT MIDWEST MINING, INC.	ROCK & AGGREGATE CRUSHING	S. OF MOUND CITY ON K-7 HWY.	MOUND CITY QUARRY	KS	66056	USA	-94.814	38.14271		LATLON
00024	1422	212312	HUNT MIDWEST MINING, INC.	ROCK & AGGREGATE CRUSHING	S20-T25S-R24E	FORT SCOTT	KS	000000000(	USA	-94.7015	37.83246		LATLON
00025	1422	212312	HUNT MIDWEST MINING, INC.	ROCK & AGGREGATE CRUSHING	28300 SOUTH US HWY 75	LYNDON QUARRY	KS	66451	USA	-95.6752	38.61903		LATLON
00025	1422	212312	HUNT MIDWEST MINING, INC.	ROCK & AGGREGATE CRUSHING	K-39 HWY	FORT SCOTT-SOUTH	KS	000000000(	USA	-94.7015	37.83246		LATLON
00029	1422	212312	HUNT MIDWEST MINING, INC.	ROCK & AGGREGATE CRUSHING	S. ON U.S. 59 HWY	PRINCETON QUARRY	KS	66078	USA	-95.2677	38.48788		LATLON
00039	1422	212312	HUNT MIDWEST MINING, INC.	ROCK & AGREGATE CRUSHING	1414 EAST 700 ROAD	LAWRENCE	KS	66047	USA	-95.3721	38.9446		LATLON
00040	1422	212312	HUNT MIDWEST MINING, INC.	ROCK & AGGREGATE CRUSHING	80 E. 550 ROAD	GLOBE QUARRY	KS	66524	USA	-95.3989	38.75095		LATLON
00123	1422	212312	HUNT MIDWEST MINING, INC.	ROCK & AGGREGATE CRUSHING	34135 WEST 95TH ST.	SUNFLOWER QUARRY	KS	66018	USA	-94.9804	38.95647		LATLON
00124	1422	212312	JOHNSON COUNTY AGGREGATES	ROCK & AGGREGATE CRUSHING	23555 W. 151ST. ST.	OLATHE QUARRY	KS	66061	USA	-94.8621	38.85451		LATLON
00011	1422	212312	LABETTE COUNTY HIGHWAY DEPT.	CRUSHED AND BROKEN LIMEST	S36-T32S-R19E	OSWEGO	KS	673560000(	USA	-95.1157	37.17144		LATLON
00017	1422	212312	MARTIN MARIETTA MATERIALS, INC	ROCK & AGGREGATE CRUSHING	32306 SOUTH CALIFORNIA	MELVERN QUARRY #349	KS	66510	USA	-95.6374	38.51323		LATLON
00032	1422	212312	MARTIN MARIETTA MATERIALS, INC	ROCK & AGGREGATE CRUSHING	1/2 MI. N. EISENHOWER DR.&US56	NORTH MARION QUARRY #388	KS	66861	USA	-97.0142	38.34863		LATLON
00017	1422	212312	MARTIN MARIETTA MATERIALS, INC.	ROCK & AGGREGATE CRUSHING	HWY 96 EAST	BLAKE QUARRY #328	KS	67137	USA	-96.2274	37.62547		LATLON
00023	1422	212312	MARTIN MARIETTA MATERIALS, INC.	ROCK & AGGREGATE CRUSHING	3000 TABOR VALLEY ROAD	ZEANDALE QUARRY #370	KS	66502	USA	-96.4279	39.1195		LATLON
00023	1422	212312	MARTIN MARIETTA MATERIALS, INC.	ROCK CRUSHER	S13-T16S-R19E	FOGLE QUARRY #376	KS	00000	USA	-95.2825	38.56432		LATLON
00031	1422	212312	MARTIN MARIETTA MATERIALS, INC.	ROCK & CRUSHING EQUIPMENT	2 NORTH 1700 ROAD	BIG SPRINGS QUARRY	KS	660500000(	USA	-95.4821	38.98573		LATLON
00044	1422	212312	MARTIN MARIETTA MATERIALS, INC.	ROCK & AGGREGATE CRUSHING	HWY. K-38	WINFIELD QUARRY #354	KS	67024	USA	-96.8388	37.23763		LATLON
00061	1422	212312	MARTIN MARIETTA MATERIALS, INC.	ROCK & AGGREGATE CRUSHING	1731 UNION ROAD	WOODBINE QUARRY #383	KS	67431	USA	-96.964	38.84736		LATLON
00029	1422	212312	MIDWEST MINERALS, INC.	CRUSHED & BROKEN LIMESTOE	S18-T29S-R16E	ALTOONA QUARRY #24	KS	66710	USA	-95.5903	37.55881		LATLON
00037	1422	212312	MIDWEST MINERALS, INC.	ROCK & AGGREGATE CRUSHING	S30-T30S-R24E	PITTSBURG QUARRY #5	KS	66762	USA	-94.7011	37.40638		LATLON
00049	1422	212312	MIDWEST MINERALS, INC.	ROCK & AGGREGATE CRUSHING	S12-T32S-R19E	PARSONS QUARRY #3	KS	67357	USA	-95.2689	37.34054		LATLON
00071	1422	212312	MIDWEST MINERALS, INC.	ROCK & AGGREGATE CRUSHING	S34-T34S-R17E	COFFEYVILLE QUARRY #16	KS	67337	USA	-95.6253	37.03866		LATLON
00073	1422	212312	MIDWEST MINERALS, INC.	ROCK & AGGREGATE CRUSHING	S9-T32S-R15E	TABLE MOUND QUARRY #26	KS	000000000(	USA	-95.741	37.19285		LATLON
00042	1422	212312	MULBERRY LIMESTONE QUARRY CO.	ROCK & AGGREGATE CRUSHING	S2-T29S-R25E	MULBERRY QUARRY	KS	66756	USA	-94.6419	37.55744		LATLON
00043	1422	212312	MULBERRY LIMESTONE QUARRY CO.	ROCK & AGGREGATE CRUSHING	S25-T28S-R24E	ENGLEVALE QUARRY	KS	000000000(	USA	-94.8525	37.5065		LATLON
00014	1422	212312	N.R. HAMM QUARRY, INC.	ROCK & AGGREGATE CRUSHING	S16-T7S-R12E	HOLTON	KS	000000000(	USA	-95.7314	39.4627		LATLON
00020	1422	212312	N.R. HAMM QUARRY, INC.	ROCK CRUSHING	S32-T7S-R20E	MOONEY CREEK	KS	000000000(	USA	-95.3884	39.2321		LATLON
00022	1422	212312	N.R. HAMM QUARRY, INC.	ROCK CRUSHING	S35&36-T11S-R19E	N. LAWRENCE	KS	000000000(	USA	-95.3884	39.2321		LATLON
00024	1422	212312	N.R. HAMM QUARRY, INC.	ROCK & AGGREGATE CRUSHING	S3&10-T7S-R10E	ONAGA	KS	000000000(	USA	-96.1824	39.47825		LATLON
00027	1422	212312	N.R. HAMM QUARRY, INC.	ROCK & AGGREGATE CRUSHING	S18-T1S-R12E	SENECA	KS	000000000(	USA	-96.0649	39.83569		LATLON
00028	1422	212312	N.R. HAMM QUARRY, INC.	ROCK & AGGREGATE CRUSHING	S36-T5S-R12E	CORNING	KS	000000000(	USA	-96.0703	39.65311		LATLON
00037	1422	212312	N.R. HAMM QUARRY, INC.	ROCK & AGGREGATE CRUSHING	S15-T13S-R21E	EUDORA	KS	000000000(	USA	-95.0851	38.92783		LATLON
00065	1422	212312	N.R. HAMM QUARRY, INC.	ROCK & AGGREGATE CRUSHING	S13-T13S-R3E	CHAPMAN	KS	000000000(	USA	-97.0164	38.96732		LATLON
00034	1422	212312	NELSON QUARRIES, INC.	ROCK & AGGREGATE CRUSHING	S25-T21S-R15E	BURLINGTON QUARRY	KS	000000000(	USA	-95.7468	38.19927		LATLON
00041	1422	212312	NELSON QUARRIES, INC.	ROCK & AGGREGATE CRUSHING	S20-T30S-R24E	PITTSBURG QUARRY	KS	000000000(	USA	-94.8525	37.5065		LATLON
00078	1422	212312	NELSON QUARRIES, INC.	ROCK & AGGREGATE CRUSHING	S15-T31S-R17E	CHERRYVALE QUARRY	KS	000000000(	USA	-95.5438	37.26724		LATLON
00044	1422	212312	NEOSHO COUNTY PUBLIC WORKS DEPT.	ROCK & AGGREGATE CRUSHING	S30-T28S-R19E	NEELY QUARRY	KS	00000	USA	-95.3066	37.55883		LATLON
00033	1422	212312	SCOTT ROCK COMPANY	CRUSHED AND BROKEN LIMEST	1 MI WEST & 1 MI NORTH	SYCAMORE	KS	000000000(	USA	-95.7325	37.33		LATLON
00114	1422	212312	SHAWNEE ROCK COMPANY (PLANT #1)	ROCK & AGGREGATE CRUSHING	151ST STREET	OLATHE	KS	66061	USA	-94.8297	38.89127		LATLON
00231	1422	212312	SHAWNEE ROCK COMPANY (PLANT #3)	ROCK & AGRREGATE CRUSHING	1800 S. 12TH.	BONNER SPRINGS	KS	66012	USA	-94.9075	39.07226		LATLON
00115	1422	212312	SHAWNEE ROCK COMPANY (PLANT #4)	ROCK & AGGREGATE CRUSHING	4875 HOLLIDAY DRIVE	SHAWNEE	KS	66203	USA	-94.7077	39.02012		LATLON
00020	1422	212312	WADE QUARRIES	ROCK & AGGREGATE CRUSHING	S20-T19S-R25E	LA CYGNE	KS	66040	USA	-94.733	38.40049		LATLON
00021	1422	212312	WADE QUARRIES	ROCK & AGGREGATE CRUSHING	S28-T18S-R25E	LOUISBURG	KS	000000000(	USA	-94.6761	38.60332		LATLON
00021	1422	212312	WADE QUARRIES	ROCK & AGGREGATE CRUSHING	S31-T19S-R23E	CADMUS	KS	66026	USA	-94.8631	38.41787		LATLON
490270005	1422	212312	CONTINENTAL LIME				UT		USA	-112.817	38.93972		LATLON
10313	1422	212312	Cricket Mountain Plant	Previous owner: Continental Lime Inc.			UT		USA	-112.586	39.36197		LATLON
0118	1474	212391	AMERICAN SODA LLP - PICEANCE FACILITY	NAHCOLITE SOLUTION MINING	SEC 20 T1S R97W	MEEKER 22 MI WSW OF	CO	00000	USA	-107.856	40.03395	13	LATLON
58196	1474	212391	FMC TRONA				WY		USA	-109.824	41.6013	12	LATLON
5603700010	1474	212391	FMC WYOMING CORP _ SODA ASH PLANT	SODA ASH PRODUCTION	6 MI NE OF GRANGER	GRANGER	WY	82935	USA	-109.899	41.6744	12	LATLON
5603700049	1474	212391	FMC WYOMING CORPORATION-WESTVACO TRONA	FMC WYOMING CORPORATION			WY		USA	-109.466	41.51425		LATLON
5603700002	1474	212391	GENERAL CHEMICAL	SODA ASH PRODUCTION			WY		USA	-109.753	41.5933	12	LATLON
5603700001	1474	212391	OCI (RHONE_POULENC) WYOMING	SODA ASH PRODUCTION			WY		USA	-109.69	41.7141	12	LATLON
5603700005	1474	212391	SOLVAY MINERALS, INC.	SODA ASH PRODUCTION			WY		USA	-109.752	41.531	12	LATLON
490470003	1475	212392	S.F. PHOSPHATES	ICE-Diesel			UT		USA	-109.483	40.59972		LATLON
490570032	1479	212393	GREAT SALT LAKE MINERAL	ICE-Diesel			UT		USA	-112.229	41.23333		LATLON
040250698	1499	2123	CHEMICAL LIME, NELSON PLANT	ICE-Diesel			AZ		USA	-113.311	35.51639		LATLON
0209	2813	325120	DUKE ENERGY - LADDER CREEK HELIUM PLANT	FORMERLY HIGH PLAINS GAS GAT	41707 COUNTY ROAD	CHEYENNE WELLS, 3 MI WSW OF	CO	80000	USA	-102.392	38.7943	13	LATLON
00031	2813	325120	ATOFINA CHEMICALS, INC.	INDUSTRIAL GASES	6040 S. RIDGE ROAD	WICHITA	KS	67202	USA	-97.4252	37.58492		LATLON
201650004	2813	325120	KANSAS REFINED HELIUM COMPANY	ICE-NG.			KS		USA	-99.1067	38.56917		LATLON
200670008	2813	325120	MOBIL EXPLORATION & PRODUCING U.S. INC	ICE-NG.			KS		USA	-101.187	37.57194		LATLON
200670050	2813	325120	PRAXAIR, INC.	ICE-NG.			KS		USA	-101.089	37.64056		LATLON
T$11640	2813	325120	AIR LIQUIDE AMERICA CORP.		11400 BAY AREA BLVD.	PASADENA	TX	77507	USA	-95.05	29.62111		LATLON
T$11721	2813	325120	AIR LIQUIDE AMERICA CORP.		1711 FARM TO MARKET 523	OYSTER CREEK	TX	77541	USA	-95.3333	28.99167		LATLON
HG0010N	2813	325120	AIR PRODUCTS INC		10202 STRANG RD.	LA PORTE	TX	77571	USA	-95.067	29.70155	15	LATLON
MONC4	2813	325120	AIR PRODUCTS, INCORPORATED/HARRIS/HG0011L	Continuous Processes	RTE. 1 10202 STRANG RD.	LA PORTE	TX	77571	USA	-95.44	29.83	0	LATLON
HG1223K	2813	325120	BOC GASES		100 S. AIRHART DRIVE	BAYTOWN	TX	77522	USA	-94.9922	29.74134	15	LATLON
JE0052V	2813	325120	HUNTSMAN CORPORATION		2102 SPUR 136	PORT NECHES	TX	77651	USA	-93.9539	29.84996	15	LATLON
HX2302N	2813	325120	LA PORTE MENTHANOL		11603 STRANG RD	LA PORTE	TX	77572	USA	-95.0619	29.70682	15	LATLON
HX2334A	2813	325120	LINDE GAS INC.		11603 STRANG RD	LA PORTE	TX	77571	USA	-95.0574	29.70675	15	LATLON
T$11739	2813	325120	MATHESON TRI-GAS		1920 W. FAIRMONT PKY.	LA PORTE	TX	77572	USA	-95.0381	29.65333		LATLON
238	2873	325311	KERLEY AG INC.				AZ		USA	-112.107	33.4228	12	LATLON
T$10213	2873	325311	FARMLAND INDS. INC. - LAWRENCE NITROGEN PLANT		1608 N. 1400 RD.	LAWRENCE	KS	660469258	USA	-95.1997	38.95583		LATLON
T$10374	2873	325311	FARMLAND INDS. INC. DODGE CITY NITROGEN PLANT		3 MILES E. OF DODGE CITY ON U.	DODGE CITY	KS	678011337	USA	-99.9292	37.77667		LATLON
00003	2873	325311	FARMLAND INDUSTRIES, INC. (FERTILIZER)	NITROGENOUS FERTILIZERS	E. HWY 56	DODGE CITY	KS	67801	USA	-99.9272	37.74111		LATLON
350430021	2873	325311	AGRONICS, INC/HUMATES PLANT_______1127M1	ICE-Diesel			NM		USA	-106.948	35.89806		LATLON
T$11018	2873	325311	FARMLAND INDS. INC.		5 MILES E. ON HWY. 412 AN D 1	ENID	OK	73701	USA	-97.7628	36.37972		LATLON
1635	2873	325311	Farmland Industries, Inc.-Enid Nitrogen Plant	Enid Nitrogen Plant			OK		USA	-97.7657	36.3751	14	LATLON
401310704	2873	325311	TERRA NITROGEN	Turbine:			OK		USA	-95.7197	36.21972		LATLON
T$11021	2873	325311	TERRA NITROGEN CORP. WOODWARD COMPLEX		1000 TERRA DR.	WOODWARD	OK	73801	USA	-99.4689	36.43528		LATLON
2495	2873	325311	Terra Nitrogen, Limited Partnership Verdigris Plant	13100704 Verdigris Plant	6606 E. 540 Rd.	Claremore	OK	740170000(	USA	-95.7201	36.2203	15	LATLON
HW0004D	2873	325311	AGRIUM US INC		SOMEWHERE NEAR F.M. ROAD 1551	BORGER	TX	79007	USA	-101.425	35.64532	14	LATLON
T$11681	2873	325311	EL DORADO NITROGEN CO.		8490 W. BAY RD.	BAYTOWN	TX	77520	USA	-94.9253	29.75583		LATLON
T$12138	2873	325311	COASTAL CHEM INC.		8305 OTTO RD.	CHEYENNE	WY	82007	USA	-104.904	41.09583		LATLON

strStateFacilityIdentifier	strSIC Primary	strNAICS Primary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXY Coordinate Type
560210002	2873	325311	COASTAL CHEMICAL	ICE-NG.			WY		USA	-104.913	41.09306		LATLON
HG0534U	2874	325312	AGRIFOS FERTILIZER LP		2001 JACKSON ROAD (DAVIDSON)	PASADENA	TX	77501	USA	-95.2571	29.73725	15	LATLON
T$12154	2874	325312	SF PHOSPHATES LTD. CO.		515 S. HWY. 430	ROCK SPRINGS	WY	82901	USA	-109.235	41.59491		LATLON
5603700022	2874	325312	SF PHOSPHATES, INC	PHOSPHATE FERTILIZER PROD	5 MI SE OF ROCK SPGS	ROCK SPRINGS	WY	82902	USA	-109.128	41.538	12	LATLON
0032	2911	324110	BARTKUS OIL CO	PETROLEUM REFINING	3501 PEARL ST	BOULDER	CO	80301	USA	-105.246	40.0243	13	LATLON
0520	2911	324110	CHIEF PETROLEUM	BULK PETROLEUM PLANT	301 S 10TH ST	COLORADO SPRINGS	CO	80000	USA	-104.842	38.8332	13	LATLON
23-E	2911	324110	Colorado Refining Company		5800 Brighton Blvd.	Commerce City	CO	80022	USA	-104.942	39.80481	0	LATLON
55	2911	324110	Conoco Denver Products Terminal		5601 Brighton Blvd.	Commerce City	CO	80022	USA	-104.946	39.80333	0	LATLON
ESD035	2911	324110	Conoco Inc.		5801 BRIGHTON BLVD.	Commerce City	CO	800223696	USA	-104.941	39.80384	13	LATLON
080770001	2911	324110	LANDMARK PETROLEUM INC	ICE-NG. 96NTI was area source.			CO		USA	-108.757	39.16833		LATLON
0063	2911	324110	REX OIL CO	PETROLEUM REFINING	899 DECATUR ST	DENVER	CO	802043724	USA	-105.021	39.7308	13	LATLON
0035	2911	324110	REX OIL CO INC	PETROLEUM REFINING	431 4TH AVE	LYONS	CO	80540	USA	-105.248	40.0234	13	LATLON
0065	2911	324110	SIEGEL OIL CO	BULK PLANT	1380 ZUNI ST	DENVER	CO	80204	USA	-105.015	39.7371	13	LATLON
ESD036	2911	324110	Ultramar Diamond Shamrock (formerly Total Petroleu		5800 BRIGHTON BLVD	Commerce City	CO	800223613	USA	-104.946	39.80495	13	LATLON
201730020	2911	324110	COASTAL DERBY REFINING CO.	Turbine: 96 nti was an area source.			KS		USA	-97.3147	37.72556		LATLON
200150001	2911	324110	COASTAL DERBY REFINING CO.	ICE-NG. 96NTI was area source.			KS		USA	-96.8592	37.8325		LATLON
ESD050	2911	324110	Cooperative Refining (formerly Farmland Industries	PETROLEUM REFINING	S36-T34S-R16E	Coffeyville	KS	67337	USA	-95.6052	37.04822	15	LATLON
ESD051	2911	324110	Cooperative Refining (formerly National Cooperativ		1391 IRON HORSE ROAD	McPherson	KS	674601404	USA	-97.667	38.34928	14	LATLON
201470001	2911	324110	FARMLAND INDUSTRIES, INC.-REFINERY DIV.	ICE-NG. 96NTI was area source.			KS		USA	-99.3714	39.78694		LATLON
ESD052	2911	324110	Frontier Oil Corp. (formerly El Dorado Refining, f		1401 S. DOUGLAS ROAD	El Dorado	KS	67042	USA	-96.8796	37.79681	14	LATLON
200150004	2911	324110	TEXACO REFINING & MARKETING, INC.	ICE-NG. 96NTI was area source.			KS		USA	-96.8667	37.79917		LATLON
200350004	2911	324110	TOTAL PETROLEUM, INC.				KS		USA	-97.1314	37.075		LATLON
0008	2911	324110	Ciniza Refinery	Petroleum Refinery	17 Mi E Of Gallup On I-40	Gallup	NM	87301	USA	-108.425	35.4887	12	LATLON
ESD091	2911	324110	Giant Refining Co.		#50 County Road 4990	Bloomfield	NM	87413	USA	-107.976	36.70039	13	LATLON
ESD092	2911	324110	Giant Refining Co.		17 Mi E Of Gallup On I-40	Gallup	NM	87301	USA	-108.425	35.50724	12	LATLON
T$12478	2911	324110	LEA REFINING CO.		SOUTH OF LOVINGTON	LOVINGTON	NM	88260	USA	-103.3	32.87944		LATLON
T$12476	2911	324110	NAVAJO REFINING CO.		501 E. MAIN ST.	ARTESIA	NM	88210	USA	-104.396	32.85139		LATLON
T$12459	2911	324110	SAN JUAN REFINING CO.		NO. 50 COUNTY RD. 4990	BLOOMFIELD	NM	87413	USA	-107.972	36.69722		LATLON
T$12490	2911	324110	FORELAND REFINING- TONOPAH REFY.		HWY. 6, 6 MILES E. OF TONOPAHA	TONOPAH	NV	89049	USA	-117.1	38.06667		LATLON
400810001	2911	324110	ALLIED MATLS-REFINER	ICE-NG. 96NTI was area source.			OK		USA	-97.0725	35.635		LATLON
T$11123	2911	324110	CONOCO INC. - PONCA CITY REFY.		1000 S. PINE ST.	PONCA CITY	OK	746017501	USA	-97.0869	36.69305		LATLON
2477	2911	324110	Sun Company Inc.	Refinery - 1700 South Union			OK		USA	-96.0249	36.14	14	LATLON
23-D	2911	324110	TRI Petroleum, Inc. Ardmore Refinery	1900509 Ardmore Refinery	825 E. Cameron	Ardmore	OK	73401	USA	-97.1359	34.17472	0	LATLON
ESD103	2911	324110	Ultramar/Diamond Shamrock (formerly Total Petroleu		BYPASS 142	Ardmore	OK	73402	USA	-97.1034	34.20234	14	LATLON
2782	2911	324110	Wynnewood Refining Company	4900507 Wynnewood Refining Facility			OK		USA	-97.1673	34.635	14	LATLON
ESD110	2911	324110	AGE Refining & Manufacturing		7811 S. PRESA	San Antonio	TX	782233547	USA	-98.4601	29.34916	14	LATLON
ESD111	2911	324110	Alon Israel (formerly Fina Oil & Chemical Co.)		I-H 20 AT REFINERY RD.	Big Spring	TX	79720	USA	-101.47	32.24	14	LATLON
HT0011Q	2911	324110	ALON USA LP		ON THE FRONTAGE ROAD OF I20 EA	BIG SPRING	TX	79721	USA	-101.424	32.27038	14	LATLON
JE0005H	2911	324110	ATOFINA PETROCHEMICALS INC		32ND STREET & HWY. 366	PORT ARTHUR	TX	77640	USA	-93.8954	29.95857	15	LATLON
HG0130C	2911	324110	BASIS PETROLEUM INC		9701 MANCHESTER	HOUSTON	TX	77262	USA	-95.2621	29.72616	15	LATLON
481670050	2911	324110	BASIS PETROLEUM, INC.				TX		USA	-94.5439	29.22083		LATLON
10-C	2911	324110	Big Spring Refinery		IH 20 at Refinery Road	Big Spring	TX	79721	USA	-101.415	32.28444	0	LATLON
T$11755	2911	324110	BP AMOCO TEXAS CITY BUSINESS UNIT		2401 5TH AVE. S.	TEXAS CITY	TX	77590	USA	-94.925	29.37444		LATLON
27-H	2911	324110	Chevron El Paso Refinery (North Facility)		6501 Trowbridge	El Paso	TX	79905	USA	-106.402	31.77099	0	LATLON
ESD115	2911	324110	Citgo		1801 NUECES BAY BLVD.	Corpus Christi	TX	78407	USA	-97.4882	27.81323	14	LATLON
T$11904	2911	324110	CITGO REFINING & CHEMICALS CO. L.P. - EAST PLANT		1801 NUECES BAY BLVD.	CORPUS CHRISTI	TX	78407	USA	-97.4278	27.80917		LATLON
ESD116	2911	324110	Coastal Refining & Marketing Inc.		1300 CANTWELL LANE	Corpus Christi	TX	78407	USA	-97.4432	27.81263	14	LATLON
24-C	2911	324110	Corpus Christi East Refinery		1700 Nueces Bay Blvd.	Corpus Christi	TX	78407	USA	-97.4222	27.80611	0	LATLON
24-B	2911	324110	Corpus Christi West Refinery		Suntide and Up River Roads	Corpus Christi	TX	78410	USA	-97.5278	27.83055	0	LATLON
ESD117	2911	324110	Crown Central Petroleum Corp.		111 RED BLUFF RD.	Pasadena	TX	77506	USA	-95.2073	29.72599	15	LATLON
T$11702	2911	324110	DEER PARK REFINING L.P.		5900 HWY. 225	DEER PARK	TX	77536	USA	-95.1292	29.72139		LATLON
MR0008T	2911	324110	DIAMOND SHAMROCK REFINING CO LP		6701 FM 119	SUNRAY	TX	79086	USA	-101.89	35.95423	14	LATLON
LK0009T	2911	324110	DIAMOND SHAMROCK REFINING CO LP		301 LEROY STREET	THREE RIVERS	TX	78071	USA	-98.1843	28.45563	14	LATLON
20-A	2911	324110	Exxon Baytown Refinery		2800 Decker Drive	Baytown	TX	77522	USA	-94.9927	29.75505	0	LATLON
ESD119	2911	324110	ExxonMobil Corp. (formerly Mobil)		E. END OF BURT ST.	Beaumont	TX	77704	USA	-94.0716	30.07583	15	LATLON
26-A	2911	324110	Houston Refinery		9701 Manchester	Houston	TX	77012	USA	-95.2531	29.72333	0	LATLON
NE0122D	2911	324110	KOCH PETROLEUM GROUP LP		SUNTIDE AND UP RIVER ROADS	CORPUS CHRISTI	TX	78322	USA	-97.4418	27.80693	14	LATLON
SK0022A	2911	324110	LA GLORIA OIL AND GAS CO		1702 EAST COMMERCE ST.	TYLER	TX	75701	USA	-95.2693	32.36675	15	LATLON
ESD121	2911	324110	LaGloria Oil & Gas Co.		1702 E. COMMERCE ST.	Tyler	TX	75702	USA	-95.2728	32.36735	15	LATLON
HG0048L	2911	324110	LYONDELL-CITGO REFINING LP		12000 LAWNDALE	HOUSTON	TX	77252	USA	-95.2512	29.70939	15	LATLON
ESD123	2911	324110	Marathon Ashland Petrol. LCC		1320 LOOP 197 S.	Texas City	TX	77590	USA	-94.9066	29.37657	15	LATLON
23-F	2911	324110	McKee Plants		HCR 1, Box 36	Sunray	TX	79086	USA	-101.873	35.95167	0	LATLON
12-D	2911	324110	Mobil Beaumont Refinery		End of Burt Street	Beaumont	TX	77701	USA	-94.0703	30.06389	0	LATLON
ESD124	2911	324110	Motiva Enterprises (formerly Star)		2100 HOUSTON AVE.	Port Arthur	TX	776403399	USA	-93.9582	29.87322	15	LATLON
JE0095D	2911	324110	MOTIVA ENTERPRISES LLC		AT THE NORTH END OF HOUSTON AV	PORT ARTHUR	TX	77640	USA	-93.9527	29.88934	15	LATLON
BL0042G	2911	324110	PHILLIPS 66CO		HWY 35 AND 524 AT OLD OCEAN	SWEENY	TX	77480	USA	-95.7637	29.07126	15	LATLON
16-D	2911	324110	Phillips Borger Refinery & NGL Center		Spur 119 North Borger Refinery	Borger	TX	79007	USA	-101.368	35.69722	0	LATLON
JE0042B	2911	324110	PREMCOR REFINING GROUP		1801 S. GULFWAY DRIVE	PORT ARTHUR	TX	77640	USA	-93.9552	29.85866	15	LATLON
ESD127.5	2911	324110	Pride Refining Inc.		1210 N. 4TH ST	Abilene	TX	79604	USA	-99.7671	32.54485	14	LATLON
27-G	2911	324110	Refinery Holding Co. Refinery (South Facility)		6500 Trowbridfe	El Paso	TX	79905	USA	-106.402	31.7703	0	LATLON
ESD128	2911	324110	Shell -Deer Park Refining Limited Partnership		5900 HWY. 225	Deer Park	TX	77536	USA	-95.1163	29.72406	15	LATLON
HG0659W	2911	324110	SHELL OIL CO		HWY 225 W OF BATTLEGROUND RD	DEER PARK	TX	77536	USA	-95.1155	29.72356	15	LATLON
ESD128.5	2911	324110	Specified Fuels & Chemicals (formerly Howell Hydro		1201 S. SHELDON RD		TX	775300429	USA	-95.1	29.76851	15	LATLON
16-A	2911	324110	Sweeny Refinery and Petrochemical Complex		Hwy 35 and 524 at Old Ocean	Sweeny	TX	77480	USA	-95.7467	29.06889	0	LATLON
21-G	2911	324110	Texas City Refinery		1320 Loop 197 South	Texas City	TX	77590	USA	-94.9114	29.40593	0	LATLON
T$11850	2911	324110	THREE RIVERS REFY.		301 LEROY ST.	THREE RIVERS	TX	78071	USA	-98.1903	28.45667		LATLON
ESD129	2911	324110	Trifinery Petrol. Srvc. (formerly Neste Trifinery)		6600 UP RIVER ROAD	Corpus Christi	TX	78409	USA	-97.4927	27.81925	14	LATLON
ESD131	2911	324110	Ultramar/Diamond Shamrock Corp.		6701 FM 119	Sunray	TX	790869705	USA	-101.882	35.96259	14	LATLON
ESD130	2911	324110	Ultramar/Diamond Shamrock Corp.		301 LEROY ST.	Three Rivers	TX	78071	USA	-98.1884	28.45739	14	LATLON
ESD133	2911	324110	Valero (formerly Basis Petroleum, Inc.)		9701 MANCHESTER	Houston	TX	77012	USA	-95.2372	29.57851	15	LATLON
GB0073P	2911	324110	VALERO REFINING CO - TEXAS		LOOP 197 SOUTH @ 14TH ST.	TEXAS CITY	TX	77590	USA	-94.8944	29.3733	15	LATLON
ESD132	2911	324110	Valero Refining Co.		5900 UP RIVER RD.	Corpus Christi	TX	78407	USA	-97.5265	27.89656	14	LATLON
T$12204	2911	324110	BIGWEST OIL L.L.C.		333 W. CENTER ST.	NORTH SALT LAKE	UT	84054	USA	-111.906	40.86667		LATLON
ESD135	2911	324110	BP (formerly Amoco Oil Co.)		474 W. 900 N.	Salt Lake City	UT	841031494	USA	-111.903	40.79073	12	LATLON
ESD136	2911	324110	Chevron USA		2351 N. 1100 W.	Salt Lake City	UT	84116	USA	-111.924	40.82801	12	LATLON
490470053	2911	324110	CHEVRON USA PRODUCING CO	Turbine: 96 nti was an area source.			UT		USA	-109.302	40.20306		LATLON
490470007	2911	324110	CITATION OIL AND GAS (PREV. EXXON)	ICE-NG. 96NTI was area source.			UT		USA	-109.371	40.30417		LATLON
10122	2911	324110	Flying J Refinery (Big West Oil Co.)	NA	333 W Center St	N Salt Lake	UT	84054	USA	-111.924	40.84199		LATLON
490130100	2911	324110	GARY REFINERY	ICE-NG. 96NTI was area source.			UT		USA	-110.22	40.36056		LATLON

strStateFacilityIdentifier	strSIC Primary	strNAICS Primary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXY Coordinate Type
490430004	2911	324110	NGC ENERGY RESOURCES	ICE-NG. 96NTI was area source.			UT		USA	-111.368	40.90889		LATLON
490470017	2911	324110	NORTHWEST PIPELINE	Turbine: 96 nti was an area source.			UT		USA	-109.333	40.56889		LATLON
490130027	2911	324110	PENNZOIL				UT		USA	-110.018	40.28		LATLON
490130053	2911	324110	PG & E RESOURCES COMPANY	ICE-NG. 96NTI was area source.			UT		USA	-110.02	40.04472		LATLON
490110013	2911	324110	PHILLIPS PETROLEUM	ICE-NG. 96NTI was area source.			UT		USA	-111.908	40.8925		LATLON
ESD139	2911	324110	Phillips Petroleum Co.		393 South 800 West	Woods Cross	UT	84087714:	USA	-111.901	40.88746	12	LATLON
490439078	2911	324110	PINEVIEW FIELD	ICE-NG. 96NTI was area source.			UT		USA	-110.82	40.91557		LATLON
490430010	2911	324110	PINEVIEW GAS PLANT	ICE-NG. 96NTI was area source.			UT		USA	-110.82	40.91557		LATLON
10335	2911	324110	Salt Lake City Refinery	Modify AO DAQE-053-97	474 West 900 North	Salt Lake City	UT	84103	USA	-111.904	40.78906		LATLON
10119	2911	324110	Salt Lake Refinery	NA	2351 N 1100 W	Salt Lake City	UT	84125	USA	-111.921	40.81955		LATLON
ESD137	2911	324110	Silver Eagle Refining Inc. (formerly Inland Refini		2355 S. 1100 W.	Woods Cross	UT	84087	USA	-111.91	40.86698	12	LATLON
490431001	2911	324110	UNION PACIFIC RESOURCES-YELLOW CREEK	ICE-NG. 96NTI was area source.			UT		USA	-111.154	40.94528		LATLON
490070034	2911	324110	US FUEL CO	ICE-Diesel 96 NTI was area source			UT		USA	-111.011	39.49139		LATLON
5602100001	2911	324110	FRONTIER REFINING, INC.	PETROLEUM REFINING	2700 EAST 5TH STREET	CHEYENNE	WY	82007	USA	-104.787	41.128	13	LATLON
ESD150	2911	324110	Little America Refining Co.				WY		USA	-106.264	42.85974	13	LATLON
T$12156	2911	324110	SILVER EAGLE REFINING		2990 COUNTY RD. 180	EVANSTON	WY	82930	USA	-110.807	41.26056		LATLON
60-C	2911	324110	Sinclair, Little America Refinery		5700 East Highway 20-26	Casper	WY	82609	USA	-106.28	42.83902	0	LATLON
60-A	2911	324110	Sinclair, Wyoming Refinery		100 East Lincoln Highway	Sinclair	WY	82334	USA	-107.056	41.78889	0	LATLON
T$12150	2911	324110	WYOMING REFINING CO.		740 W. MAIN ST.	NEWCASTLE	WY	82701	USA	-104.216	43.84972		LATLON
080011182	3211	327211	CAPITOL GLASS & ALUMINUM CORP	ICE-NG. 96NTI was area source.			CO		USA	-104.848	39.76389		LATLON
0008	3221	327213	ROCKY MOUNTAIN BOTTLE CO	GLASS CONTAINERS MFG	10619 W 50TH AVE	WHEAT RIDGE	CO	80033	USA	-105.116	39.7857	13	LATLON
0326	3229	327212	FIBERON INC	FIBERGLASS FABRICATION	337 HICKORY ST	FORT COLLINS	CO	80524-110	USA	-105.083	40.603	13	LATLON
080311259	3229	327212	ROCKY MOUNTAIN SCIENTIFIC GLASS BLOWING	ICE-NG. 96NTI was area source.			CO		USA	-104.929	39.68028		LATLON
0401900310	3241	32731	ARIZONA PORTLAND CEMENT COMPANY	CEMENT PRODUCTION	11115 N.CASA GRANDE HIGHWAY	RILLITO	AZ	85654	USA	-111.149	32.40915	12	LATLON
0003	3241	327310	CEMEX, INC. - LYONS CEMENT PLANT	CEMENT, HYDRAULIC (FORMERLY	5134 UTE HWY	LYONS	CO	00000-000	USA	-105.229	40.209	13	LATLON
0001	3241	327310	HOLNAM INC PORTLAND PLANT	PORTLAND CEMENT MFG	3500 HWY 120	FLORENCE	CO	81226	USA	-105.017	38.3872	13	LATLON
0002	3241	327310	HOLNAM INC_FORT COLLINS PLANT	CEMENT, HYDRAULIC	4629 N OVERLAND TRL	LAPORTE (LA PORTE)	CO	00000-000	USA	-105.141	40.6524	13	LATLON
T$10266	3241	327310	ASH GROVE CEMENT CO.		1801 N. SANTA FE	CHANUTE	KS	66720	USA	-95.4631	37.69778		LATLON
T$10268	3241	327310	LAFARGE CORP. (INCLD SYSTECH ENVIRONMENTAL)		S. CEMENT RD.	FREDONIA	KS	66736	USA	-95.8217	37.50945		LATLON
T$10273	3241	327310	MONARCH CEMENT CO.		449 1200 ST.	HUMBOLDT	KS	66748100(	USA	-95.4417	37.80056		LATLON
T$12442	3241	327310	RIO GRANDE PORTLAND CEMENT CORP.		11783 STATE HWY. 337	TIJERAS	NM	87059	USA	-106.39	35.07222		LATLON
BG0259G	3241	327310	ALAMO CEMENT CO II LTD		6055 W. GREEN MOUNTAIN ROAD	SAN ANTONIO	TX	78201	USA	-98.3756	29.61184	14	LATLON
BG0045E	3241	327310	CAPITOL CEMENT DIV CAPITOL AGGREGATE		11551 NACOGDOCHES ROAD	SAN ANTONIO	TX	78201	USA	-98.4207	29.54637	14	LATLON
T$11980	3241	327310	LONE STAR IND. INC. MARYNEAL PLANT		202 CR 306 FARM RD. 608	MARYNEAL	TX	79535	USA	-100.458	32.25		LATLON
ND0014S	3241	327310	LONE STAR INDUSTRIES INC		0.5 MI. N.W. ON F.M. 608	MARYNEAL	TX	79535	USA	-100.459	32.25113	14	LATLON
T$11385	3241	327310	NORTH TEXAS CEMENT CO. LLP.		900 GIFCO RD.	MIDLOTHIAN	TX	76065052(	USA	-97.0083	32.52083		LATLON
EB0121R	3241	327310	SOUTHDOWN INC		1200 SMITH STREET, SUITE 2400	ODESSA	TX	79761	USA	-102.545	31.74667	13	LATLON
T$12011	3241	327310	SOUTHWESTERN PORTLAND CEMENT		13 MILES W. OF ODESSA I-20 EXI	PENWELL	TX	79776	USA	-102.541	31.75111		LATLON
CS0022K	3241	327310	SUNBELT CEMENT OF TEXAS LP		AT THE INTERSECTION OF WALD &	NEW BRAUNFELS	TX	78130	USA	-98.2524	29.69211	14	LATLON
318	3241	327310	Texas Industries, Inc.	TXD007349327	245 WARD ROAD	Midlothian	TX	76065	USA	-97.0285	32.46378	0	LATLON
T$11924	3241	327310	TEXAS-LEHIGH CEMENT CO.		701 CEMENT PLANT RD.	BUDA	TX	78610061(	USA	-97.8533	30.07111		LATLON
ED0066B	3241	327310	TXI OPERATIONS LIMITED PARTNERSHIP		2.5 MI. W. OF MIDLOTHIAN, TX.,	MIDLOTHIAN	TX	76065	USA	-97.0255	32.46194	14	LATLON
CS0018B	3241	327310	TXI OPERATIONS LP		7781 FM 1102	NEW BRAUNFELS	TX	78132	USA	-98.0412	29.80478	14	LATLON
5600100002	3241	327310	MOUNTAIN CEMENT CO	CEMENT, HYDRAULIC			WY		USA	-105.603	41.2689	13	LATLON
BSCP20	3251	327121	Clinton-Campbell Contractor, Inc	Phoenix Brick Yard	1814 South 7th Ave	Phoenix	AZ	85007	USA	-112.084	33.42083		LATLON
0043	3251	327	DENVER BRICK CO	MANUFACTURE AND SELL FACE BI	401 SANTA FE RD	CASTLE ROCK	CO	80104	USA	-104.867	39.3757	13	LATLON
T$12069	3251	327	ROBINSON BRICK CO.	BRICK MANUFACTURING	1845 W. DARTHMOUTH AVE.	ENGLEWOOD	CO	80110130{	USA	-105.007	39.6625		LATLON
BSCP116	3251	327121	Summit Pressed Brick and Tile Co	Brick Plant and Storange Yard	13 th and Erie St	Pueblo	CO	81001	USA	-104.595	38.28083		LATLON
BSCP39	3251	327121	Summit Pressed Brick and Tile Co	Lakewood Brick and Tile Co	1325 Jay St	Lakewood	CO	80214	USA	-105.064	39.7375		LATLON
BSCP155	3251	327121	The Denver Brick Co	The Denver Brick Co	401 North Santa Fe Rd	Castle Rock	CO	80104	USA	-104.856	39.37889		LATLON
00004	3251	327	ACME BRICK COMPANY	BRICK AND STRUCTURAL CLAY	1915 AVENUE L	KANOPOLIS	KS	67454	USA	-98.1478	38.71083		LATLON
00009	3251	327	CLOUD CERAMICS (DIV. GENERAL FINANCE)	BRICK MANUFACTURING	R. R. 3	CONCORDIA	KS	66901000(	USA	-97.6842	39.59167		LATLON
BSCP158	3251	327121	General Finance, Inc	Cloud Ceramics	RR 3 P.O. Box 369	Concordia	KS	66901	USA	-97.658	39.56749		LATLON
BSCP92	3251	327121	Justin Industries	Acme Brick-Kanopolis Plant	1915 Arenia L	Kanopolis	KS	67454	USA	-98.1506	38.71222		LATLON
BSCP93	3251	327121	Justin Industries	Acme Brick-Weir Plant	South Washington St	Weir	KS	66781	USA	-94.7286	37.28556		LATLON
BSCP175NR	3251	327121	Kansas Brick and Tile Co	Kansas Brick and Tile Co	Highway 281	Hoisington	KS	67544	USA	-98.7842	38.53603		LATLON
BSCP2	3251	327121	American Eagle Brick Co	American Eagle Brick Co	1000 McNutt Rd	Sunland Park	NM	88063	USA	-106.542	31.78889		LATLON
BSCP38	3251	327121	Hoffman Enterprises, Inc	Kinney Brick Co	100 Prosperity SE	Albuquerque	NM	87105	USA	-106.659	35.01473		LATLON
PC0001E	3251	327	ACME BRICK COMPANY		BENNETT PLANT	MILLSAP	TX	76066	USA	-98.0536	32.715	14	LATLON
T$11307	3251	327	BORAL BRICKS INC. HENDERSON PLANT		1309 KILGORE DR.	HENDERSON	TX	75652	USA	-94.8033	32.18083		LATLON
T$11314	3251	327	BORAL BRICKS INC. MARSHALL PLANT		1700 N. FRANKLIN ST.	MARSHALL	TX	75670	USA	-94.3678	32.555		LATLON
BSCP21	3251	327121	D'Hanis Clay Products, Inc	dba D'Hanis Brick and Tile	7734 County Rd No. 429	D'Hanis	TX	78850	USA	-99.2794	29.33028		LATLON
BSCP153	3251	327121	Elgin-Butler Brick Co	Elgin Butler Brick	FM 696 (P.O. Box 546)	Elgin	TX	78621	USA	-97.2894	30.32167		LATLON
BSCP70	3251	327121	Hanson, PLC	US Brick - Mineral Wells Plant	500 N.E. 14th Ave	Mineral Wells	TX	76067	USA	-98.1258	32.81556		LATLON
BSCP77	3251	327121	Hanson, PLC	US Brick-Elgin Plant	Rt.6, Box 338	Elgin	TX	78621	USA	-97.3397	30.31643		LATLON
BSCP118	3251	327121	Justin Industries	Texas Clay	West Bartlett St	Malakoff	TX	75148	USA	-96.0208	32.16555		LATLON
BSCP125	3251	327121	Justin Industries	Acme Brick-Bridgeport Plant	102 Main St	Bridgeport	TX	76426	USA	-97.7744	33.20945		LATLON
BSCP126	3251	327121	Justin Industries	Acme Brick-Garrison Plant	257 Brickyard Rd	Garrison	TX	75946	USA	-94.5089	31.83917		LATLON
BSCP128	3251	327121	Justin Industries	Acme Brick-San Felipe Plant	562 Peter San Felip Rd	Sealy	TX	77474	USA	-96.1397	29.82889		LATLON
BSCP151	3251	327121	Justin Industries	Acme Brick-Bennett Tunnel Plant	2350 Bennett Rd	Milsap	TX	76066	USA	-98.0517	32.68333		LATLON
BSCP97	3251	327121	Justin Industries	Acme Brick-Denton Tunnel Plant	220 E Danels Plant	Denton	TX	76205	USA	-97.1347	33.18639		LATLON
BSCP98	3251	327121	Justin Industries	Acme Brick-Elgin Tunnel Plants	FM Road 696	Elgin	TX	78621	USA	-97.2933	30.31917		LATLON
BSCP99	3251	327121	Justin Industries	Acme Brick-McQueeney Plant	FM I25	McQueeney	TX	78123	USA	-98.0397	29.5725		LATLON
BSCP160NR	3251	327121	Snyder Brick and Tile	Snyder Brick and Tile	901 East US Highway 180	Snyder	TX	79549	USA	-100.906	32.71685		LATLON
BSCP121	3251	327121	Texas Industries	Athens Brick Mineral Wells Plant	7510 Hwy 180 East	Mineral Wells	TX	76080	USA	-97.3502	32.61335		LATLON
HM0003S	3251	327	TEXAS INDUSTRIES INC		FR 31 GO 2495 E.4 & S .4 ON OI	ATHENS	TX	75751	USA	-95.8224	32.20379	15	LATLON
46461	3251	327	WILLIAMSBURG BRICK COMPANY				TX		USA	-95.1039	32.9806	15	LATLON
DB1073N	3253	327122	AMERICAN MARAZZI TILE INC		359 CLAY ROAD	SUNNYVALE	TX	75182	USA	-96.5625	32.76681	14	LATLON
CC48	3253	327122	Dal-Tile Corporation	Tile Plant	10399 Silver Springs Road	Conroe	TX	77303	USA	-95.4672	30.39083		LATLON
CC50	3253	327122	Dal-Tile Corporation	Tile Plant	12001 Railroad Drive	El Paso	TX	79934	USA	-106.355	31.95278		LATLON
DB0242V	3253	327122	DAL-TILE CORPORATION		7834 HAWN FREEWAY	DALLAS	TX	75037	USA	-96.6879	32.71733	14	LATLON
CC72	3253	327122	Huntington/Pacfic Ceramics, Inc.	Tile Plant	3600 Conway	Ft. Worth	TX	76111	USA	-97.2954	32.76771		LATLON
CC73	3253	327122	Huntington/Pacific Ceramics, Inc.	Tile Plant	U.S. Hwy 167 West	Mt. Vernon	TX	75457	USA	-95.2433	33.18528		LATLON
CC205	3253	327122	Lone Star Ceramics Mfg. Co.	Tile Plant	2408 Fruitland Street	Farmers Branch	TX	75234	USA	-96.9092	32.93528		LATLON
9611	3255	327124	ADIENCE INC				CO		USA	-105.23	38.442	13	LATLON
0459	3255	327124	COORSTEK, INC	INDUSTRIAL CERAMIC MANUFACTU	16000 N TABLE MOUNTAIN PKWY	GOLDEN	CO	80403	USA	-105.177	39.7829	13	LATLON
0017	3255	327124	DFC CERAMICS	CLAY REFRACTORIES	515 S NINTH ST	CANON CITY	CO	81212	USA	-105.231	38.4393	13	LATLON
0012	3255	327124	VESUVIUS USA	REFRACTORIES MANUFACTURING	309 S 11TH ST	CANON CITY	CO	81212	USA	-105.23	38.442	13	LATLON
BSCP106	3259	327123	MCP Industries, Inc	Mission Clay Products Phoenix	4850 W. Buckeye Rd	Phoenix	AZ	85043	USA	-112.163	33.43684		LATLON

strStateFacilityIdentifier	strSICPrimary	strNAICSPrimary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXYCoordinateType
BSCP108	3259	327123	MCP Industries, Inc	Mission Clay Products Pittsburg	900 E. 2nd	Pittsburg	KS	66762	USA	-94.6917	37.35833		LATLON
BSCP109	3259	327123	MCP Industries, Inc	Mission Clay Products Saspamco	Old Corpus Christi Rd	Elmendorf	TX	78112	USA	-98.3	29.2375		LATLON
CC15	3261	327111	American Standard, Inc.	Sanitaryware Plant	6615 W. Boston Rd	Chandler	AZ	85226	USA	-111.957	33.30245		LATLON
CC92	3261	327111	Falcon Building Products, Inc. (Mansfield)	Sanitaryware Plant	Highway 259 North	Kilgore	TX	75663	USA	-94.8486	32.40333		LATLON
CC203	3261	327111	Kohler Co	Sanitaryware Plant	4601 Highway 377 South	Brownwood	TX	76801	USA	-98.9972	31.66389		LATLON
CC38	3262	327112	CR/PL, L.L.C.	Sanitaryware Plant	Highway 6 South	Hearne	TX	77859	USA	-96.5943	30.87724		LATLON
0007	3264	327113	COORS CERAMICS CO ELECTRONICS DIV	PORCELAIN ELECTRIC.SUPPLY	17750 W 32ND AVE	GOLDEN	CO	80401	USA	-105.201	39.7649	13	LATLON
0024	3264	327113	COORSTEK GRAND JUNCTION	CERAMIC SUBSTRATE / FURRULE /	2449 RIVER RD	GRAND JUNCTION	CO	81505	USA	-108.596	39.0852	12	LATLON
0437	3264	327113	COORSTEK, INC.	CERAMIC SPECIALITIES (FORMERL	4545 MCINTYRE ST	GOLDEN	CO	80403	USA	-105.174	39.7694	13	LATLON
308	3271	327331	QUALITY BLOCK INC				AZ		USA	-112.225	33.68333		LATLON
490350200	3271	327331	BRICK MANUFACTURING PLANT	ICE-Diesel			UT		USA	-112.014	40.59389		LATLON
490439045	3271	327331	HENIFER MINE	ICE-Diesel			UT		USA	-111.472	41.025		LATLON
490499046	3271	327331	POWELL MINE (UTAH SITE #1)	ICE-Diesel			UT		USA	-111.927	40.33		LATLON
490459043	3271	327331	SMILE MINE	ICE-Diesel			UT		USA	-112.191	40.08889		LATLON
T$12328	3272	327	MONIERLIFETILE L.L.C.		1832 S. 51ST AVE.	PHOENIX	AZ	85043	USA	-112.169	33.43528		LATLON
0411	3272	327	DENVER ARCHITECHURAL PRECAST INC	MFG PRECAST CONCRETE	8200 E 96TH AVE	HENDERSON	CO	80640852	USA	-104.891	39.8704	13	LATLON
0053	3272	327	ROCKY MOUNTAIN PRESTRESS ARCHITECTURAL	ARCHITECTURAL CONCRETE MFG	301 W 60TH PL	DENVER	CO	80216101	USA	-104.982	39.8047	13	LATLON
0081	3272	327	STRESSCON CORP	CONCRETE PRODUCTS, INC.	3210 ASTROZON BLVD	COLORADO SPRINGS	CO	80910	USA	-104.772	38.7808	13	LATLON
00097	3272	327	RICH MIX PRODUCTS, INC.- KANSAS DIVISION	CONSTRUCTION SAND AND GRA	6500 W. 21ST	WICHITA	KS	67212	USA	-97.4181	37.72333		LATLON
DB0374D	3272	327	FRITZ INDUSTRIES INC		500 SAM HOUSTON ROAD	MESQUITE	TX	75149	USA	-96.675	32.75562	14	LATLON
T$11169	3272	327	GIFFORD-HILL AMERICAN		1004 N. MAC ARTHUR BLVD.	GRAND PRAIRIE	TX	75050	USA	-96.9558	32.76639		LATLON
490410012	3272	327	COX ROCK PRODUCTS - AURORA PLANT	ICE-Diesel			UT		USA	-111.908	38.7739		LATLON
490390001	3272	327	COX ROCK PRODUCTS - MT PLEASANT CONCRETE	ICE-Diesel			UT		USA	-111.631	39.42275		LATLON
490350088	3272	327	HOBUSCH PIT	ICE-Diesel			UT		USA	-111.861	40.58111		LATLON
490110049	3272	327	WEBER SAND AND GRAVEL L-6	ICE-Diesel			UT		USA	-112.115	40.9611		LATLON
400	3273	327320	CALMAT OF ARIZONA				AZ		USA	-112.25	33.85556		LATLON
401	3273	327320	CALMAT OF ARIZONA				AZ		USA	-112.072	33.70833		LATLON
403	3273	327320	CALMAT OF AZ PLANT #3				AZ		USA	-112.447	33.78889		LATLON
404	3273	327320	CALMAT OF AZ/SUN CITY PLANT				AZ		USA	-112.517	34.02778		LATLON
411	3273	327320	CENTURY MATERIALS, INC.				AZ		USA	-112.492	33.725		LATLON
413	3273	327320	CHANDLER READY MIX				AZ		USA	-112.381	33.68611		LATLON
304	3273	327320	PHOENIX REDI MIX				AZ		USA	-112.253	33.69167		LATLON
339	3273	327320	SUNWARD MATERIALS				AZ		USA	-112.522	33.82222		LATLON
340	3273	327320	SUNWARD MATERIALS (BCW CEMENT CO.)				AZ		USA	-112.439	33.55556		LATLON
367	3273	327320	UNITED METRO (TANNER)				AZ		USA	-112.661	33.70833		LATLON
0672	3273	327320	KIEWIT WESTERN CO	AGGREGATE STORAGE AND HOT M	2401 PICADILLY RD	AURORA	CO	80019361	USA	-104.734	39.7521	13	LATLON
0103	3273	327320	QUIKRETE OF DENVER HOLDINGS INC	PAVING MIXTURES AND BLOCK	6200 BRYANT ST	DENVER	CO	80221205	USA	-105.019	39.811	13	LATLON
0010	3273	327320	TRANSIT MIX CONCRETE	READY-MIXED CONCRETE	444 E COSTILLA ST	COLORADO SPRINGS	CO	80903	USA	-104.817	38.8278	13	LATLON
0400300176	3274	32741	CHEMICAL LINE COMPANY - DOUGLAS FACILITY	LIME PROCESSING FACILITY	HIGHWAY 80	DOUGLAS	AZ	85607	USA	-109.735	31.36357	12	LATLON
0261	3274	327410	PILOT PEAK		3950 SOUTH 700 EAST SUITE 301	SALT LAKE CITY	NV	84107	USA	-114.22	40.82477	11	LATLON
BJ0001T	3274	327410	CHEMICAL LIME LTD		7 M S.W. OF CLIFTON, TEX., ON	CLIFTON	TX	76634	USA	-97.5973	31.70845	14	LATLON
490450005	3274	327410	GRANTSVILLE PLANT	ICE-Diesel			UT		USA	-112.55	40.685		LATLON
490350373	3274	327410	HERCULES COMPOSITE MATERIALS	ICE-Diesel			UT		USA	-111.906	40.6737		LATLON
490450035	3274	327410	USPCI - MERR	ICE-Diesel			UT		USA	-113.09	40.93056		LATLON
080370029	3275	327420	EAGLE GYPSUM PRODUCTS WALLBOARD PLT				CO		USA	-106.899	39.64583		LATLON
00021	3275	327420	G-P GYPSUM CORPORATION	GYPSUM PRODUCTS	2127 HIGHWAY 77	BLUE RAPIDS	KS	66411	USA	-96.645	39.70444		LATLON
T$10977	3275	327420	UNITED DESIGN CORP. NOBLE FAC.		1600 N. MAIN	NOBLE	OK	73068	USA	-97.4056	35.15694		LATLON
10654	3275	327420	Sigurd Plant	81 North State Street (across the stree	81 N. State Street	Sigurd	UT	84657	USA	-111.967	38.83921		LATLON
5600300001	3275	327420	GEORGIA PACIFIC_GYPSUM PLANT	GYPSUM WALLBOARD MFG	15 MI SE OF LOVELL	LOVELL	WY	82431	USA	-108	44.7529	13	LATLON
T$12314	3281	327991	AVONTI MFG. INC.		941 W. DEER VALLEY RD.	PHOENIX	AZ	85027	USA	-112.126	33.85083		LATLON
T$12342	3281	327991	MESA FULLY FORMED INC.		1111 S. SIRRINE	MESA	AZ	85210878	USA	-111.831	33.39389		LATLON
T$12434	3281	327991	MOUNTAIN MARBLE MFG. INC.		7359 E. SECOND ST.	PRESCOTT VALLEY	AZ	86314735	USA	-112.317	34.58556		LATLON
0131	3281	327991	MANSTONE	MARBLE PRODUCT MFG	105 TALAMINE CT	COLORADO SPRINGS	CO	80907	USA	-104.824	38.8792	13	LATLON
0286	3281	327991	ROCKY MOUNTAIN CULTURED MARBLE INC	MANUFACTURE OF CULTURED MA	832 E LINCOLN AVE	FORT COLLINS	CO	80524	USA	-105.055	40.5885	13	LATLON
T$11300	3281	327991	ALDON MARBLE MFG. CO.		FM 349 & FM 2011	LONGVIEW	TX	75603	USA	-94.7567	32.40417		LATLON
T$11438	3291		NORTON CO.		2770 W. WASHINGTON ST.	STEPHENVILLE	TX	76401	USA	-98.2361	32.20278		LATLON
T$11914	3291		NORTON CO.		1505 MORNINGSIDE RD.	BROWNSVILLE	TX	78521769	USA	-97.4399	25.90414		LATLON
455	3295	2123	HARBORLITE CORP, SUPERIOR PLANT				AZ		USA	-111.128	33.2833	12	LATLON
040271006	3295	2123	YUMA COUNTY DEPT PUBLIC WORKS C&S PLANT				AZ		USA	-114.494	32.75833		LATLON
0004	3295	2123	MWCA INC	SCORIA BRIQ/AQUA PAINT	RD P & RD 12 0.4 MI N OF	SAN ACACIO	CO	81152000	USA	-105.575	37.1907	13	LATLON
00015	3295	2123	MICRO-LITE, L.L.C.	MINERALS, GROUND OR TREAT	WEST MICRO-LITE STREET	BUFFALO	KS	00000	USA	-95.6971	37.70861		LATLON
NB0037F	3295	2123	TXI OPERATIONS LP		2 MI. N. OF STREETMAN, TX., NE	STREETMAN	TX	75859	USA	-96.3488	31.91539	14	LATLON
T$12365	3296	327993	OWENS-CORNING ELOY PLANT		1825 W. BATTAGLIA RD.	ELOY	AZ	85231	USA	-111.628	32.66833		LATLON
0168	3296	327993	MESA FIBERGLASS INC	FIBERGLASS FABRICATION	6471 E 49TH AVE	COMMERCE CITY	CO	80022450	USA	-104.914	39.7857	13	LATLON
00001	3296	327993	CERTAIN TEED CORPORATION	MINERAL WOOL	103 FUNSTON ROAD	KANSAS CITY	KS	00000	USA	-94.6114	39.14305		LATLON
00036	3296	327993	JOHNS MANVILLE	MINERAL WOOL	1465 17TH AVENUE	MCPHERSON	KS	67460	USA	-97.6117	38.38583		LATLON
00010	3296	327993	OWENS CORNING	MINERAL WOOL	300 SUNSHINE ROAD	KANSAS CITY	KS	66115	USA	-94.6156	39.14667		LATLON
34651	3296	327993	SCHULLER INTL. INC.				KS		USA	-97.615	38.38639		LATLON
T$11455	3296	327993	AMERICAN ROCKWOOL INC.		NO. 1 JACKRABBIT RD.	NOLANVILLE	TX	76559	USA	-97.5686	31.075		LATLON
JH0025O	3296	327993	JOHNS MANVILLE INTERNATIONAL INC		200 WEST INDUSTRIAL BLVD.	CLEBURNE	TX	76031	USA	-97.397	32.38778	14	LATLON
AA0044U	3296	327993	OWEN CORNING		5476 S.H. 294	PALESTINE	TX	75801	USA	-95.761	31.65535	15	LATLON
ED0051O	3296	327993	OWENS-CORNING		3700 N.I. 35 E.	WAXAHACHIE	TX	75165	USA	-96.8501	32.43925	14	LATLON
T$11220	3296	327993	OWENS-CORNING		3700 N INTERSTATE HWY. 35E	WAXAHACHIE	TX	75165	USA	-96.85	32.43917		LATLON
HG1766N	3296	327993	ROCK WOOL MANUFACTURING CO		3290 SOUTH LOOP EAST	HOUSTON	TX	77021	USA	-95.3172	29.69829	15	LATLON
BF0107S	3296	327993	THERMAFIBER LLC		1 JACKRABBIT RD.	NOLANVILLE	TX	76558	USA	-97.5695	31.07524	14	LATLON
0106	3299	327	VISICOM LABORATORIES DBA MICROLITHICS CO	CIRCUIT BOARD MANUFACTURING	17301 W COLFAX AVE STE 100 152	GOLDEN	CO	80401	USA	-105.166	39.7316	13	LATLON
T$11847	3299	327	KAMAL INC. VENETIAN MARBLE (DBA)		13310 WESTERN OAK	HELOTES	TX	78023410	USA	-98.6619	29.56556		LATLON
BM0026Q	3299	327	NORTON CHEMICAL PROCESS PRODUCTS COR		BRAZOS COUNTY INDUSTRIAL PARK	BRYAN	TX	77801	USA	-96.4086	30.66233	14	LATLON
MQ0106G	3299	327	SCAN-PAC MFG INC		31502 SUGAR BEND DRIVE	MAGNOLIA	TX	77355	USA	-95.46	30.34	15	LATLON
RL0086D	3299	327	TROY MFG TEXAS INC		200 PRESTON ROAD-PRESTON INDUS	HENDERSON	TX	75652	USA	-94.8182	32.19677	15	LATLON
0401501232	3312	331111	NORTH STAR STEEL ARIZONA	STEEL MILL	3000 HWY 66 SOUTH	KINGMAN	AZ	86413	USA	-114.091	35.13795	11	LATLON
0048	3312	331	CF&I STEEL L P DBA ROCKY MTN STEEL MILLS	BLAST FURNACES AND STEEL	2100 S. FREEWAY	PUEBLO	CO	81004	USA	-104.613	38.237	13	LATLON
1144	3312	331	CONSOLIDATED STEEL SVC	STEEL FABRICATOR	3700 S WINDERMERE ST	ENGLEWOOD	CO	80110	USA	-105.002	39.6479	13	LATLON
T$11138	3312	331	ACKER INDS. INC.		301 N WEWOKA AVE.	WEWOKA	OK	74884222	USA	-96.4911	35.16028		LATLON
2453	3312	331	Sheffield Steel	14300010 2300 South Highway 97			OK		USA	-96.1185	36.1324	14	LATLON
T$11048	3312	331	SHEFFIELD STEEL CORP.		2300 S. HWY. 97	SAND SPRINGS	OK	74063	USA	-96.1186	36.11861		LATLON
EE0011P	3312	331	BORDER STEEL INC		IH-10 & VINTON ROAD	EL PASO	TX	79901	USA	-106.584	31.96589	13	LATLON
T$11384	3312	331	CHAPARRAL STEEL MIDLOTHIAN L.P.		300 WARD RD.	MIDLOTHIAN	TX	76065965	USA	-97.0417	32.46389		LATLON
ED0011D	3312	331	CHAPARRAL STEEL MIDLOTHIAN LP		U.S. HWY. 67 @ WARD RD., IN MI	MIDLOTHIAN	TX	76065	USA	-97.0375	32.45792	14	LATLON

strStateFacilityIdentifier	strSIC Primary	strNAICS Primary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXY Coordinate Type
CI0170H	3312	331	JINDAL UNITED STEEL CORP		5200 E. MCKINNEY ROAD, SUITE 1	BAYTOWN	TX	77520	USA	-94.8956	29.68826	15	LATLON
MS0008I	3312	331	LONE STAR STEEL CO		HIGHWAY 259 SOUTH	LONE STAR	TX	75668	USA	-94.74	33.12	15	LATLON
T$11311	3312	331	LONE STAR STEEL CO.		HWY. 259 S.	LONE STAR	TX	75668100(	USA	-94.7167	32.9		LATLON
55404	3312	331	LONE STAR STEEL COMPANY				TX		USA	-94.718	32.9142	15	LATLON
OC0011S	3312	331	NORTH STAR STEEL OF TEXAS		OLD HIGHWAY 90	ROSE CITY	TX	77662	USA	-94.0786	30.08556	15	LATLON
GL0028H	3312	331	STRUCTURAL METALS INC		STEEL MILL ROAD	SEGUIN	TX	78155	USA	-98.0328	29.57685	14	LATLON
T$12209	3312	331	GENEVA STEEL		10 S. GENEVA RD. BIN 10	VINEYARD	UT	84058	USA	-111.74	40.29639		LATLON
T$12268	3312	331	NUCOR STEEL - A DIV. OF NUCOR CORP.		7825 W. 21200 N.	PLYMOUTH	UT	84330	USA	-112.189	41.87695		LATLON
5603700003	3312	331	P4 PRODUCTION_ROCK SPRINGS FACILITY	ROTARY COKING			WY		USA	-109.22	41.5241	12	LATLON
T$12467	3331	331411	PHELPS DODGE HIDALGO INC.		9 MILES S. OF HWY. 9 ALONG SME	PLAYAS	NM	88009	USA	-108.543	31.77111		LATLON
350230003	3331	331411	PHELPS DODGE/HIDALGO SMELTER________59M1	Turbine:			NM		USA	-108.529	31.77528		LATLON
T$11966	3331	331411	ASARCO INC. AMARILLO COPPER REFY.		7901 N. HWY. 136	AMARILLO	TX	79107020(	USA	-101.734	35.28528		LATLON
EE0007G	3331	331411	ASARCO INCORPORATED		2301 WEST PAISANO DRIVE	EL PASO	TX	79901	USA	-106.523	31.78263	13	LATLON
PG0005V	3331	331411	ASARCO INCORPORATED		8 MI. N.E. OF AMARILLO, TX., O	AMARILLO	TX	79101	USA	-101.733	35.28257	14	LATLON
EE0067L	3331	331411	PHELPS DODGE EL PASO OPERATIONS		6999 NORTH LOOP ROAD	EL PASO	TX	79998	USA	-106.392	31.76683	13	LATLON
15076	3331	331411	KENNECOTT - UTAH POWER PLANT AND				UT		USA	-112.117	40.7		LATLON
T$12197	3331	331411	KENNECOTT UTAH COPPER SMELTER & REFY.		12000 W. 2100 S., & 11500 W. 2	MAGNA	UT	84044	USA	-112.197	40.72167		LATLON
10346	3331	331411	Smelter, Refinery	Refinery precious metals facility, smelt	12000 West 2100 South	Magna	UT	84044	USA	-112.083	40.70026		LATLON
T$11456	3334	331312	ALCOA		FM 1786 OFF RTE. 79	ROCKDALE	TX	76567	USA	-97.0886	30.63417		LATLON
MM0001T	3334	331312	ALUMINUM COMPANY OF AMERICA		5 MI. S. OF U.S. HWY. 79 AT IN	ROCKDALE	TX	76567	USA	-97.0729	30.56841	14	LATLON
00002	3341	331	TOWER METAL PRODUCTS	SECONDARY NONFERROUS META	301 NORTH HILL	FORT SCOTT	KS	66701	USA	-94.6988	37.8389		LATLON
T$11049	3341	331	IMCO RECYCLING INC.		1508 N. 8TH ST.	SAPULPA	OK	74066	USA	-96.1317	36.01694		LATLON
T$11114	3341	331	WABASH ALLOYS L.L.C.		100 E. APEX RD.	CHECOTAH	OK	74426	USA	-95.5417	35.4		LATLON
T$11028	3341	331	ZINC CORP. OF AMERICA		HWY. 123 & ELEVENTH ST.	BARTLESVILLE	OK	74003	USA	-95.9936	36.74167		LATLON
T$11852	3341	331	ALCOA INC. SAN ANTONIO WORKS		14555 OLD CORPUS CHRISTI RD.	ELMENDORF	TX	78112	USA	-98.3789	29.2775		LATLON
T$11283	3341	331	ALUMAX MILL PRODS. INC.		300 ALUMAX DR.	TEXARKANA	TX	75501	USA	-94.1422	33.45139		LATLON
47835	3341	331	COLUMBIA ALUMINUM PROCESSORS				TX		USA	-96.4494	32.925	14	LATLON
T$11212	3341	331	ECS REFINING TEXAS L.L.C.		106 TEJAS DR.	TERRELL	TX	75160	USA	-96.3133	32.72585		LATLON
CP0029G	3341	331	EXIDE CORPORATION		SOUTH FIFTH STREET	FRISCO	TX	75034	USA	-96.8335	33.13477	14	LATLON
T$11520	3341	331	FABRICATED PRODS./LONE STAR		9200 MARKET ST. RD.	HOUSTON	TX	77029	USA	-95.2637	29.76901		LATLON
BL0029V	3341	331	GULF CHEMICAL & METALLURGICAL CORP		302 MIDWAY ROAD	FREEPORT	TX	77541	USA	-95.3382	28.95808	15	LATLON
T$11469	3341	331	GULF REDUCTION CORP. - ESPERSON DIV. OF U.S. ZINC		6020 ESPERSON ST.	HOUSTON	TX	77010	USA	-95.3125	29.74333		LATLON
T$11478	3341	331	GULF REDUCTION CORP. - GREENWOOD METAL DIV. OF U.S		310 N. GREENWOOD	HOUSTON	TX	77011	USA	-95.3125	29.74694		LATLON
490350006	3341	331	UTAH METAL WORKS	ICE-NG.			UT		USA	-111.769	40.79944		LATLON
13374	4911	2211	AGUA FRIA				AZ		USA	-112.217	33.55667		LATLON
13068-A	4911	2211	Apache Station	0079600000-0	10 Miles South of Interst	Cochise	AZ		USA	-109.926	32.03034		LATLON
040131025	4911	2211	APS-CC PLANT PHOENIX	Turbine:			AZ		USA	-112.157	33.44444		LATLON
040131507	4911	2211	APS-OCOTILLO POWER PLANT	Turbine:			AZ		USA	-111.912	33.42222		LATLON
313	4911	2211	APS-OCOTILLO POWER PLANT				AZ		USA	-111.912	33.4225	12	LATLON
324	4911	2211	APS-WEST PHOENIX POWER PLANT				AZ		USA	-112.158	33.4447	12	LATLON
T$12400	4911	2211	ARIZONA ELECTRIC POWER COOPERATIVE INC.		HWY. 191 4 MILES S.	COCHISE	AZ	85606	USA	-109.892	32.06167		LATLON
040030037	4911	2211	ARIZONA ELECTRIC POWER COOPERATIVE, INC.	Turbine:			AZ		USA	-109.893	32.06167		LATLON
040131009	4911	2211	ARIZONA NUCLEAR POWER PROJECT	ICE-Diesel			AZ		USA	-113.433	33.65		LATLON
040030123	4911	2211	ARIZONA PUBLIC SERVICE COMPANY (APS)	Turbine:			AZ		USA	-109.552	31.36333		LATLON
040270331	4911	2211	ARIZONA PUBLIC SERVICE COMPANY (APS)	Turbine:			AZ		USA	-114.709	32.72139		LATLON
040210033	4911	2211	ARIZONA PUBLIC SERVICE, SAGUARO PLANT	ICE-NG.			AZ		USA	-111.3	32.55167		LATLON
0400300037	4911	221112	AZ ELECTRIC POWER COOPERATIVE INC	APACHE GENERATING STATION	3525 NORTH HIGHWAY 191	COCHISE	AZ	85606	USA	-109.89	32.06176	12	LATLON
13700-A	4911	2211	Cholla Power Plant	0008030000-0	Cholla Power Plant I-40 F	Joseph City	AZ	86032	USA	-110.364	35.1869		LATLON
13712	4911	2211	CORONADO				AZ		USA	-109.272	34.57778		LATLON
13712-A	4911	2211	Coronado	0615720000-0	10 Miles NorthEast of Str	Saint John's	AZ	85936	USA	-109.377	34.50642		LATLON
040131007	4911	2211	GROVE COGENERATION PROJECT	ICE-NG.			AZ		USA	-112.116	33.58389		LATLON
13135	4911	2211	IRVINGTON				AZ		USA	-110.904	32.15972		LATLON
13135-A	4911	2211	Irvington	0242110000-0	3950 East Irvington Rd	Tuscon	AZ	85714	USA	-110.907	32.16294		LATLON
13160	4911	2211	KYRENE				AZ		USA	-111.936	33.35444		LATLON
13568	4911	2211	NAVAJO				AZ		USA	-111.392	37.52361		LATLON
13568-A	4911	2211	Navajo	0165720000-0	Highway 98; 5 Miles East	Page	AZ	86040	USA	-111.46	36.91629		LATLON
13248	4911	2211	OCOTILLO				AZ		USA	-111.942	33.44667		LATLON
98	4911	221113	PALO VERDE NUCLEAR GENERATING STATION	FORMERLY AZ NUCLEAR POWER, !	5801 S WINTERSBURG RD	TONOPAH	AZ	85354-752	USA	-112.875	33.39567	12	LATLON
040190076	4911	2211	PIMA CO. WASTE WATER	ICE-NG.			AZ		USA	-110.869	32.15111		LATLON
13308	4911	2211	SAGUARO				AZ		USA	-111.299	32.55194		LATLON
040131500	4911	2211	SANTAN GENERATING PLANT_(SRP)	Turbine:			AZ		USA	-111.748	33.33028		LATLON
318	4911	2211	SANTAN GENERATING PLANT_(SRP)				AZ		USA	-111.748	33.3306	12	LATLON
040131006	4911	2211	SCOTTSDALE PRINCESS RESORT HOTEL	ICE-NG.			AZ		USA	-111.908	33.64806		LATLON
322	4911	2211	SCOTTSDALE PRINCESS RESORT HOTEL				AZ		USA	-112.522	34.08889		LATLON
13638	4911	2211	SPRINGERVILLE				AZ		USA	-109.163	34.31833		LATLON
13638-A	4911	2211	Springerville	0242110000-0	12 Miles North of Springe	Tuscon	AZ	85714	USA	-109.522	35.24095		LATLON
3316	4911	221112	SRP AGUA FRIA	FORMER SITE ID 1215	7302 W NORTHERN AVE	GLENDALE	AZ	85303-	USA	-112.216	33.55593	12	LATLON
040131215	4911	2211	SRP-AGUA FRIA PWR PL	Turbine:			AZ		USA	-112.216	33.55389		LATLON
0400100060	4911	22111	TUCSON ELECTRIC POWER CO-SPRINGERVILLE	TUCSON ELECTRIC POWER CO-	OFF RTE191,APP.15 MI SPRINGER	SPRINGERVILLE	AZ	85938	USA	-109.164	34.31857	12	LATLON
13387	4911	2211	YUMA AXIS				AZ		USA	-113.94	33.21972		LATLON
080450057	4911	2211	AMERICAN ATLAS NO 1				CO		USA	-107.708	39.51917		LATLON
13079	4911	2211	Arapahoe	0154660000-0	2601 South Platte River D	Denver	CO	80223-	USA	-105.001	39.66833		LATLON
13391	4911	2211	Cameo	0154660000-0	NW 1/4 SEC34 T10D R98W	Palisade	CO	81526-	USA	-108.317	39.13306		LATLON
13400	4911	2211	CHEROKEE	0154660000-0	6198 Franklin Street	Denver	CO	80216-	USA	-105.966	39.80806		LATLON
080410030	4911	2211	COLORADO SPRINGS NIXON	Turbine:			CO		USA	-104.709	38.63306		LATLON
0030	4911	2211	COLORADO SPRINGS UTILITIES - NIXON PLT	ELECTRICAL POWER	FOUNTAIN BLVD & US HWY I25	COLORADO SPRINGS	CO	80817000(	USA	-104.706	38.6329	13	LATLON
0004	4911	2211	COLORADO SPRINGS UTILITIES-DRAKE PLT	ELECTRICAL POWER	700 S CONEJOS ST	COLORADO SPRINGS	CO	809470001	USA	-104.831	38.8242	13	LATLON
13410	4911	2211	Comanche	0154660000-0	2005 Lime Road	Pueblo	CO	81006-	USA	-104.574	38.20806		LATLON
13418-A	4911	2211	Craig	0301510000-0	2101 South Ranney	Craig	CO	81626	USA	-107.772	40.6362		LATLON
13091	4911	2211	GEORGE BIRDSALL				CO		USA	-104.52	38.82972		LATLON
13112	4911	2211	Hayden	0154660000-0	12795 East Ute	Hayden	CO	81639-	USA	-107.258	40.49484		LATLON
1238	4911	2211	KN SERVICES - LAKEWOOD GENERATION FACILI	RECIPROCATING COMPRESSOR EI	143 UNION BLVD	LAKEWOOD	CO	80228-182	USA	-105.133	39.7154	13	LATLON
13168	4911	2211	LAMAR				CO		USA	-102.401	37.95028		LATLON
080990006	4911	2211	LAMAR UTILITIES BOARD	ICE-Diesel			CO		USA	-102.615	38.09028		LATLON
13194	4911	2211	Martin Drake	0039890000-0	700 South Conejos Street	Colorado Springs	CO	80903	USA	-104.833	38.82417		LATLON
11589-A	4911	2211	Nucla		30799 DD 30 Road	Nucla	CO	81424	USA	-108.506	38.24238		LATLON
13259	4911	2211	Pawnee	0154660000-0	14940 County Rd 24	Brush	CO	80723-	USA	-103.693	40.26917		LATLON
081230321	4911	2211	PHOENIX POWER PARTNERS	Turbine:			CO		USA	-104.686	40.40972		LATLON
11170	4911	2211	PLATTE RIVER POWER AUTH RAWHIDE	0151430000-0	2700 E RD 82	LARIMER CNTY	CO	80549	USA	-105.047	40.8408	13	LATLON

strStateFacilityIdentifier	strSICPrimary	strNAICSPrimary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXYCoordinateType
0053	4911	2211	PLATTE RIVER POWER AUTHORITY - RAWHIDE	ELECTRICAL POWER	2700 E RD 82	WELLINGTON	CO	00000-000	USA	-105.047	40.8408	13	LATLON
0008	4911	2211	PUBLIC SERVICE CO - ARAPAHOE	ELECTRICAL GENERATION	2601 S PLATTE RIVER DR	DENVER	CO	80223421(	USA	-105	39.6695	13	LATLON
0001	4911	2211	PUBLIC SERVICE CO - VALMONT	ELECTRICAL GENERATION	1800 N 63RD ST	BOULDER	CO	80301	USA	-105.206	40.0162	13	LATLON
0007	4911	2211	PUBLIC SERVICE CO ALAMOSA PLT	ELECTRICAL POWER	400 WASHINGTON ST	ALAMOSA	CO	81101	USA	-105.883	37.4655	13	LATLON
080030007	4911	2211	PUBLIC SERVICE CO ALAMOSA STA	Turbine:			CO		USA	-105.883	37.46556		LATLON
080310008	4911	2211	PUBLIC SERVICE CO ARAPAHOE	ICE-Diesel			CO		USA	-104.999	39.66972		LATLON
080770002	4911	2211	PUBLIC SERVICE CO CAMEO	ICE-Diesel			CO		USA	-108.315	39.14861		LATLON
0002	4911	2211	PUBLIC SERVICE CO CAMEO PLT	ELECTRICAL POWER	NW SEC 34 T10S R98W	PALISADE	CO	81526	USA	-108.315	39.1484	12	LATLON
8653	4911	2211	PUBLIC SERVICE CO CHEROKEE PLANT				CO		USA	-104.968	39.8056	13	LATLON
0001	4911	2211	PUBLIC SERVICE CO CHEROKEE PLT	ELECTRICAL GENERATION	6198 FRANKLIN ST	DENVER	CO	80216121	USA	-104.968	39.8056	13	LATLON
081010003	4911	2211	PUBLIC SERVICE CO COMANCHE	ICE-Diesel			CO		USA	-104.571	38.21111		LATLON
0003	4911	2211	PUBLIC SERVICE CO COMANCHE PLT	ELECTRICAL POWER	2005 LIME RD	PUEBLO	CO	81006	USA	-104.571	38.2107	13	LATLON
0023	4911	2211	PUBLIC SERVICE CO FORT SAINT VRAIN PLT	ELECTRICAL POWER	16805 19.5 RD	WELD CNTY	CO	80651	USA	-104.874	40.2434	13	LATLON
080770035	4911	2211	PUBLIC SERVICE CO FRUITA	Turbine:			CO		USA	-108.732	39.15972		LATLON
0035	4911	2211	PUBLIC SERVICE CO FRUITA STA	ELECTRICAL POWER	158 N MESA AVE	FRUITA	CO	81521000(	USA	-108.733	39.16	12	LATLON
081230014	4911	2211	PUBLIC SERVICE CO FT LUPTON	Turbine:			CO		USA	-104.772	40.10028		LATLON
0014	4911	2211	PUBLIC SERVICE CO FT LUPTON STATION	ELECTRICAL POWER	SEC 33 T2N R66W	FORT LUPTON	CO	80621	USA	-104.772	40.1	13	LATLON
081230023	4911	2211	PUBLIC SERVICE CO FT ST VRAIN				CO		USA	-104.874	40.24333		LATLON
11193	4911	2211	PUBLIC SERVICE CO HAYDEN				CO		USA	-107.185	40.4858	13	LATLON
0001	4911	2211	PUBLIC SERVICE CO HAYDEN PLT	ELECTRICAL POWER	US HWY 40 - 12795 E YUTE	HAYDEN	CO	81639	USA	-107.185	40.4858	13	LATLON
080590059	4911	2211	PUBLIC SERVICE CO LOOKOUT CTR	ICE-Diesel			CO		USA	-105.202	39.73361		LATLON
080870011	4911	2211	PUBLIC SERVICE CO PAWNEE	ICE-Diesel			CO		USA	-103.683	40.21889		LATLON
0011	4911	2211	PUBLIC SERVICE CO PAWNEE PLT	ELECTRICAL POWER	14940 RD 24	BRUSH	CO	80723	USA	-103.684	40.2189	13	LATLON
8661	4911	2211	PUBLIC SERVICE CO VALMONT				CO		USA	-105.206	40.0162	13	LATLON
8662	4911	2211	PUBLIC SERVICE CO ZUNI				CO		USA	-105.015	39.7362	13	LATLON
T$12092	4911	2211	RAWHIDE ENERGY STATION		2700 E. COUNTY RD. 82	WELLINGTON	CO	80549210	USA	-105.024	40.85944		LATLON
9748-A	4911	2211	Ray D. Nixon	0039890000-0	14020 Ray Nixon Rd exit 1	Fountain	CO	80817	USA	-104.691	38.64485		LATLON
0250	4911	2211	THERMO COGEN PARTNERSHIP FT LUPTON	ELECTRICAL AND STEAM GENERA	6501 ROAD 31	FORT LUPTON	CO	80621	USA	-104.772	40.1063	13	LATLON
0412	4911	2211	THERMO GREELEY INC	ELECTRIC POWER GENERATION	846 N SIXTH AVE	GREELEY	CO	80621-018	USA	-104.686	40.443	13	LATLON
0126	4911	2211	THERMO POWER & ELEC INC	COGENERATION ELECTRICITY - sa	510 18TH ST	GREELEY	CO	80631	USA	-104.687	40.4097	13	LATLON
081250001	4911	2211	TRI STATE GENERATION & TRANSMISSION ASSN	Turbine:			CO		USA	-102.242	40.07917		LATLON
0003	4911	2211	TRI STATE GENERATION BURLINGTON	ELECTRICAL POWER PLANT	ROAD 50 & 21889 ROAD Z	BURLINGTON	CO	80807	USA	-102.241	39.3286	13	LATLON
0018	4911	2211	TRI STATE GENERATION CRAIG	COAL FIRED ELECTRICAL POWER (	2101 S RANNEY	CRAIG	CO	81626	USA	-107.591	40.4639	13	LATLON
0001	4911	2211	TRI STATE GENERATION NUCLA	COAL FIRED ELECTRIC GENERATI(	30739 DD 30 RD	MONTROSE CNTY	CO	81424	USA	-108.517	38.2474	12	LATLON
T$12135	4911	2211	TRI-STATE GENERATION & TRANSMISSION - CRAIG STATIO		2201 RANNEY ST.	CRAIG	CO	81626	USA	-107.59	40.46444		LATLON
T$12125	4911	2211	TRI-STATE GENERATION & TRANSMISSION - NUCLA STATIO		30739 DD 30 RD.	NUCLA	CO	81424	USA	-108.506	38.24238		LATLON
13363	4911	2211	Valmont	0154660000-0	1800 North 63rd Street	Boulder	CO	80301-	USA	-105.206	40.01735		LATLON
081010008	4911	2211	WEST PLAINS ENERGY PUEBLO	ICE-Diesel			CO		USA	-104.614	38.26528		LATLON
0003	4911	2211	WEST PLAINS ENERGY - W.N. CLARK STATION	ELECTRICAL POWER	550 W US HWY 50	CANON CITY	CO	81212	USA	-105.238	38.4393	13	LATLON
080890004	4911	2211	WEST PLAINS ENERGY ROCKY FORD PLT	ICE-Diesel			CO		USA	-103.713	38.04917		LATLON
13388	4911	2211	ZUNI				CO		USA	-105.018	39.73722		LATLON
200330001	4911	2211	ANR PIPELINE CO.				KS		USA	-99.3772	37.47806		LATLON
200770002	4911	2211	ANTHONY-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-98.0894	37.17306		LATLON
13110	4911	2211	ARTHUR MULLERGREN				KS		USA	-98.8692	38.40528		LATLON
200250001	4911	2211	ASHLAND-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-99.8114	37.21722		LATLON
200770013	4911	2211	ATTICA-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-98.2881	37.27667		LATLON
200150009	4911	2211	AUGUSTA-MUNICIPAL POWER PLANT (#1)	ICE-NG.			KS		USA	-97.0419	37.69694		LATLON
200150010	4911	2211	AUGUSTA-MUNICIPAL POWER PLANT (#2)	ICE-NG.			KS		USA	-97.0419	37.69667		LATLON
200450011	4911	2211	BALDWIN-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-95.1783	38.79556		LATLON
201570016	4911	2211	BELLEVILLE-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-97.6603	39.85167		LATLON
201230012	4911	2211	BELOIT-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-98.1531	39.49444		LATLON
00008	4911	2211	BOARD OF PUBLIC UTILITIES - NEARMAN	ELECTRICAL SERVICES	4240 N. 55TH	KANSAS CITY	KS	00000	USA	-94.7056	39.15639		LATLON
00048	4911	2211	BOARD OF PUBLIC UTILITIES - QUINDARO	ELECTRICAL SERVICES	3601 N. 12TH	KANSAS CITY	KS	00000	USA	-94.6414	39.14833		LATLON
202090048	4911	2211	BOARD OF PUBLIC UTILITIES - QUINDARO	Turbine:			KS		USA	-94.6406	39.14972		LATLON
201390012	4911	2211	BURLINGAME-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-95.8064	38.75222		LATLON
200310006	4911	2211	BURLINGTON-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-95.7117	38.18972		LATLON
13404	4911	2211	CIMARRON RIVER				KS		USA	-100.932	37.05917		LATLON
201330030	4911	2211	CITY OF CHANUTE ELEC. DEPT.- N. GARFIELD	ICE-NG.			KS		USA	-95.4508	37.67389		LATLON
201330028	4911	2211	CITY OF CHANUTE ELEC. DEPT.- S. PLUMMER	ICE-NG.			KS		USA	-95.4006	37.68833		LATLON
201330002	4911	2211	CITY OF CHANUTE ELEC. DEPT.-S. SANTA FE	ICE-Diesel			KS		USA	-95.4006	37.68833		LATLON
200930019	4911	2211	CITY OF LAKIN	ICE-NG.			KS		USA	-101.285	37.95222		LATLON
201910055	4911	2211	CITY OF OXFORD, MUNICIPAL POWER PLANT	ICE-Diesel			KS		USA	-97.1731	37.26806		LATLON
200270007	4911	2211	CLAY CENTER-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-97.1456	39.39556		LATLON
13406	4911	2211	COFFEYVILLE		7TH & SANTA FE	COFFEYVILLE	KS	67337	USA	-95.5433	37.04722		LATLON
201930007	4911	2211	COLBY-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-101.127	39.40583		LATLON
13446	4911	2211	EAST 12TH STREET PLA				KS		USA	-97.0717	37.26306		LATLON
200090025	4911	2211	ELLINWOOD-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-98.6278	38.39528		LATLON
00002	4911	2211	EMPIRE DISTRICT ELECTRIC COMPANY (THE)	ELECTRICAL SERVICES	R. R. 1	RIVERTON	KS	66770	USA	-94.6986	37.07167		LATLON
202050018	4911	2211	FREDONIA-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-95.76	37.53556		LATLON
200910065	4911	2211	GARDNER ENERGY CENTER	Turbine:			KS		USA	-94.9256	38.80833		LATLON
200030001	4911	2211	GARNETT-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-95.2481	38.26917		LATLON
200370006	4911	2211	GIRARD-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-94.7947	37.52528		LATLON
201810005	4911	2211	GOODLAND-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-101.797	39.34778		LATLON
13098	4911	2211	GORDON EVANS				KS		USA	-97.5217	37.79028		LATLON
200970007	4911	2211	GREENSBURG-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-99.3242	37.64056		LATLON
200410034	4911	2211	HERINGTON-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-96.9969	38.68306		LATLON
201530011	4911	2211	HERNDON-MUNICIPAL POWER PLANT	ICE-Diesel			KS		USA	-100.871	39.91667		LATLON
200650009	4911	2211	HILL CITY-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-99.9117	39.39194		LATLON
200090026	4911	2211	HOISINGTON-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-98.7764	38.51528		LATLON
13121	4911	2211	HOLCOMB				KS		USA	-100.972	37.93167		LATLON
13121-A	4911	2211	Holcomb	0183150000-0	2440 Holcomb Lane	Holcomb	KS	67851-043	USA	-100.992	37.92702		LATLON
200850011	4911	2211	HOLTON-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-95.7417	39.465		LATLON
201890020	4911	2211	HUGOTON-MUNICIPAL POWER PLANT (#1)	ICE-NG.			KS		USA	-101.352	37.18194		LATLON
201890021	4911	2211	HUGOTON-MUNICIPAL POWER PLANT (#2)	ICE-NG.			KS		USA	-101.352	37.18194		LATLON
13132	4911	2211	HUTCHINSON				KS		USA	-97.8694	38.09417		LATLON
13134	4911	2211	IOLA				KS		USA	-95.3542	37.93667		LATLON
200010011	4911	2211	IOLA-MUNICIPAL POWER PLANT (#1)				KS		USA	-95.3542	37.93639		LATLON
200010019	4911	2211	IOLA-MUNICIPAL POWER PLANT (#2)	ICE-Diesel			KS		USA	-95.4225	37.93056		LATLON
13509	4911	2211	JEFFREY ENERGY CENTE				KS		USA	-96.1083	39.28528		LATLON

strStateFacilityIdentifier	strSIC Primary	strNAICS Primary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXY Coordinate Type
13509-A	4911	2211	Jeffrey Energy Center	0002250000-0	25905 Jeffrey Rd	Saint Marys	KS	66536	USA	-96.1128	39.28223		LATLON
200830005	4911	2211	JETMORE-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-99.9317	38.11583		LATLON
201870009	4911	2211	JOHNSON CITY MUN. POWER PLANT	ICE-NG.			KS		USA	-101.764	37.56556		LATLON
13153	4911	2211	JUDSON LARGE		E. HWY 154	DODGE CITY	KS	67801	USA	-99.9492	37.73278		LATLON
201070005	4911	2211	KANSAS CITY POWER & LIGHT CO.	ICE-Diesel			KS		USA	-94.6431	38.34667		LATLON
201730079	4911	2211	KANSAS GAS AND ELECTRIC CO.-WICHITA STA.	Turbine:			KS		USA	-97.2808	37.66389		LATLON
00007	4911	2211	KANSAS STATE UNIVERSITY	COLLEGES AND UNIVERSITIES	109 DYKSTRA HALL	MANHATTAN	KS	66502	USA	-96.5825	39.19417		LATLON
13154	4911	2211	KAW				KS		USA	-94.6517	39.08639		LATLON
200950004	4911	2211	KINGMAN-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-98.1742	37.68139		LATLON
200410017	4911	2211	KPL GAS SERVICE (AEC)	Turbine:			KS		USA	-97.2494	38.93306		LATLON
201550033	4911	2211	KPL GAS SERVICE (HEC)	Turbine:			KS		USA	-97.8694	38.09417		LATLON
201770030	4911	2211	KPL GAS SERVICE (TEC)	Turbine:			KS		USA	-95.5689	39.05444		LATLON
13526	4911	2211	LA CYGNE				KS		USA	-94.6456	38.34806		LATLON
13526-A	4911	2211	La Cygne	0100000000-0	RR 1	LaCygne	KS	66040-980	USA	-94.845	38.2133		LATLON
201650001	4911	2211	LACROSSE MUNICIPAL POWER PLANT				KS		USA	-99.3647	38.56889		LATLON
13172	4911	2211	LARNED				KS		USA	-99.1428	38.20694		LATLON
201450010	4911	2211	LARNED-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-99.1428	38.20694		LATLON
13174	4911	2211	LAWRENCE				KS		USA	-95.2681	39.00778		LATLON
13174-A	4911	2211	Lawrence	0002250000-0	1250 North 1800 Rd	Lawrence	KS	66044	USA	-95.2708	39.00079		LATLON
201050013	4911	2211	LINCOLN-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-98.1953	39.07417		LATLON
13198	4911	2211	MCPHERSON 2				KS		USA	-97.6867	38.37167		LATLON
201130014	4911	2211	MCPHERSON BOARD OF PUBLIC UTILITIES #2	Turbine:			KS		USA	-97.6867	38.37167		LATLON
201190013	4911	2211	MEADE-MUNICIPAL POWER PLANT				KS		USA	-100.359	37.38639		LATLON
200090001	4911	2211	MIDWEST ENERGY, INC.	ICE-NG.			KS		USA	-98.8108	38.39556		LATLON
200230008	4911	2211	MIDWEST ENERGY, INC.	ICE-Diesel			KS		USA	-101.644	39.75722		LATLON
200510012	4911	2211	MIDWEST ENERGY, INC.	ICE-NG.			KS		USA	-99.3181	38.86694		LATLON
201930001	4911	2211	MIDWEST ENERGY, INC.				KS		USA	-101.127	39.40583		LATLON
201430013	4911	2211	MINNEAPOLIS-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-97.7478	39.1575		LATLON
201910025	4911	2211	MULVANE-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-97.2369	37.45917		LATLON
13563	4911	2211	MURRAY GILL				KS		USA	-97.4133	37.42806		LATLON
23422-A	4911	2211	Nearman Creek	0099960000-0	4240 North 55th Street	Kansas City	KS	66104-127	USA	-94.7057	39.15488		LATLON
202050014	4911	2211	NEODESHA-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-95.6103	37.42333		LATLON
201370005	4911	2211	NORTON-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-99.955	39.85556		LATLON
201090009	4911	2211	OAKLEY-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-100.942	39.11917		LATLON
200390009	4911	2211	OBERLIN-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-100.613	39.83417		LATLON
201390014	4911	2211	OSAGE CITY-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-95.8019	38.6375		LATLON
201210001	4911	2211	OSAWATOMIE-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-94.9117	38.52444		LATLON
201410009	4911	2211	OSBORNE-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-98.7525	39.46833		LATLON
200590006	4911	2211	OTTAWA-MUNICIPAL POWER PLANT				KS		USA	-95.2481	38.63833		LATLON
13276	4911	2211	PRATT				KS		USA	-98.7944	37.68417		LATLON
201510005	4911	2211	PRATT-MUNICIPAL POWER PLANT	ICE-Diesel			KS		USA	-98.7944	37.68417		LATLON
13278-A	4911	2211	Quindaro	0099960000-0	3601 North 12th Street	Kansas City	KS	66104-510	USA	-94.6411	39.14855		LATLON
201730128	4911	2211	RITCHIE SAND, INC.	ICE-NG.			KS		USA	-97.4614	37.77528		LATLON
13299	4911	2211	RIVERTON				KS		USA	-94.6983	37.07167		LATLON
13299-A	4911	2211	Riverton	0058600000-0	Highway 66	Riverton	KS	66713	USA	-94.7353	37.02401		LATLON
201670005	4911	2211	RUSSELL-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-98.9031	38.91722		LATLON
201310009	4911	2211	SABETHA-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-95.8342	39.89778		LATLON
201990005	4911	2211	SHARON SPRINGS-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-101.815	38.88306		LATLON
200230009	4911	2211	ST. FRANCIS-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-101.908	39.76556		LATLON
201850015	4911	2211	ST. JOHN-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-98.8117	38.03194		LATLON
201850017	4911	2211	STAFFORD-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-98.6467	38.00306		LATLON
201590024	4911	2211	STERLING MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-98.2592	38.24806		LATLON
201630014	4911	2211	STOCKTON-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-99.3322	39.46806		LATLON
200550026	4911	2211	SUNFLOWER ELECTRIC POWER CORPORATION	Turbine:			KS		USA	-100.894	37.96917		LATLON
13347	4911	2211	TECUMSEH				KS		USA	-95.5689	39.05444		LATLON
13347-A	4911	2211	Tecumseh	0002250000-0	2nd and Dupont Rd	Tecumseh	KS	66542	USA	-95.5663	39.0516		LATLON
201490012	4911	2211	WAMEGO-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-96.3069	39.19722		LATLON
202010024	4911	2211	WASHINGTON-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-97.0778	39.82917		LATLON
13376	4911	2211	WELLINGTON				KS		USA	-97.4703	37.28306		LATLON
201910056	4911	2211	WELLINGTON CITY POWER PLANT, GAS TURBINE	Turbine:			KS		USA	-97.3644	37.27139		LATLON
201910019	4911	2211	WELLINGTON-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-97.4703	37.28306		LATLON
201750001	4911	2211	WEST PLAINS ENERGY	Turbine:			KS		USA	-100.932	37.05917		LATLON
202010012	4911	2211	WEST PLAINS ENERGY				KS		USA	-97.3092	39.58694		LATLON
23413	4911	2211	WEST PLAINS ENERGY				KS		USA	-98.8694	38.4052	14	LATLON
00014	4911	2211	WESTERN RESOURCES, INC.	ELECTRICAL SERVICES	1250 N. 1800 RD.	LAWRENCE	KS	66044	USA	-95.2836	39.00056		LATLON
00033	4911	2211	WESTERN RESOURCES, INC. (HEC)	ELECTRICAL SERVICES	3200 E. 30TH	HUTCHINSON	KS	00000	USA	-97.8764	38.08639		LATLON
200350006	4911	2211	WINFIELD MUNICIPAL POWER PLANT (OLD)	Turbine:			KS		USA	-97.0717	37.26306		LATLON
13438	4911	2211	ANIMAS				NM		USA	-108.33	36.50972		LATLON
350450029	4911	2211	CITY OF FARMINGTON/ANIMAS PLANT___1061R1	Turbine:			NM		USA	-108.193	36.72806		LATLON
13423	4911	2211	CUNNINGHAM				NM		USA	-103.353	32.71306		LATLON
0032	4911	2211	Escalante	NMD980335624 233mw Coal-fired Ge	4 Mi N Of Prewitt	Prewitt	NM	87045	USA	-108.081	35.416	12	LATLON
13086	4911	2211	FOUR CORNERS				NM		USA	-108.482	36.69056		LATLON
13086-A	4911	2211	Four Corners	0008030000-0	End of County Road 6675	Fruitland	NM	87416-035	USA	-108.436	36.75341		LATLON
T$12460	4911	2211	FOUR CORNERS STEAM ELECTRIC STATION		COUNTY RD. 6675	FRUITLAND	NM	87416	USA	-108.482	36.69139		LATLON
350250028	4911	2211	LEA COUNTY ELEC COOP/CUNNINGHAM_______GF	Turbine:			NM		USA	-103.32	32.97833		LATLON
350230001	4911	2211	LORDSBURG LTD/REPOWERING PRJCT___PSD90M1	Turbine:			NM		USA	-108.694	32.33778		LATLON
13189	4911	2211	MADDOX				NM		USA	-103.302	32.71306		LATLON
350310027	4911	2211	MERRION OIL & GAS/PAPERS WASH ELEC_949M1	ICE-NG.			NM		USA	-107.325	35.85333		LATLON
350130025	4911	2211	NMSU/PHYSICAL PLANT BOILERS_________1640	Turbine:			NM		USA	-106.753	32.27944		LATLON
0025	4911	2211	Physical Plant Boilers	NM0001424126 Electric & Steam Gen	Nmsu Campus	Las Cruces	NM	88003	USA	-106.753	32.2798	13	LATLON
350470004	4911	2211	PUBLIC SERV CO NM/LAS VEGAS GEN STA___GF	Turbine:			NM		USA	-105.232	35.60528		LATLON
12917	4911	2211	RATON				NM		USA	-104.651	36.60139		LATLON
13288	4911	2211	REEVES				NM		USA	-106.5	36.33306		LATLON
13603	4911	2211	RIO GRANDE				NM		USA	-106.547	31.80444		LATLON
0002	4911	2211	Rio Grande Generating Station	NMD980622971 Electric Power Gener	3501 Doniphan Road	Sunland Park	NM	88063	USA	-106.546	31.8017	13	LATLON
13618	4911	2211	SAN JUAN				NM		USA	-108.483	36.88306		LATLON
13618-A	4911	2211	San Juan	0154730000-0	County Road 6800 - 1.5 Mi	Waterflow	NM	87421	USA	-108.482	36.7616		LATLON
350490017	4911	2211	SANTA FE COGEN ASSOC___________________620	ICE-NG.			NM		USA	-106.048	35.55583		LATLON
350250054	4911	2211	SOUTHWESTERN PUBL SERV/CUNNINGH PSD622M1				NM		USA	-103.356	32.7175		LATLON

strStateFacilityIdentifier	strSICPrimary	strNAICSPrimary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXY Coordinate Type
350250034	4911	2211	SOUTHWESTERN PUBL SERV/MADDOX STN____747	Turbine:			NM		USA	-103.303	32.71694		LATLON
350370002	4911	2211	SOUTHWESTERN PUBL SERV/TUCUMCARI___586M1	ICE-Diesel			NM		USA	-103.737	35.175		LATLON
1011	4911	2211	AES Shady Point, Inc.	7900701 Cogeneration Plant			OK		USA	-94.6466	35.1972	15	LATLON
13427	4911	2211	ANADARKO				OK		USA	-98.2256	35.08417		LATLON
13313	4911	2211	BOOMER LAKE				OK		USA	-96.9872	36.09389		LATLON
400310703	4911	2211	CENTRAL AND SOUTH WEST SERVICES, IN	ICE-NG.			OK		USA	-98.3242	34.54306		LATLON
1211	4911	2211	Central and South West Services, Inc. - Comanche Power Station	3100703 PSO - Comanche Power Sta			OK		USA	-98.3246	34.5435	14	LATLON
1212	4911	2211	Central and South West Services, Inc. - Northeastern Power Statio	13100705 PSO - Northeastern Power			OK		USA	-95.6992	36.426	15	LATLON
1213	4911	2211	Central and South West Services, Inc. - Riverside/Jenks Power Sta	14300036 PSO - Riverside/Jenks Pow			OK		USA	-95.9566	35.9995	15	LATLON
1214	4911	2211	Central and South West Services, Inc. - Southwestern Power Station	1500703 PSO - Southwestern Power S			OK		USA	-98.3523	35.1009	14	LATLON
1215	4911	2211	Central and South West Services, Inc. - Tulsa Power Station	14300009 PSO - Tulsa Power Station			OK		USA	-95.9903	36.1159	15	LATLON
1216	4911	2211	Central and South West Services, Inc. - Weleetka Power Station	10700700 PSO - Weleetka Power Stat			OK		USA	-96.1357	35.3261	14	LATLON
13411	4911	2211	COMANCHE				OK		USA	-98.3242	34.54306		LATLON
1799	4911	2211	Grand River Dam Authority	9700710 Chouteau - Coal Fired Comp			OK		USA	-95.2898	36.1913	15	LATLON
13103	4911	2211	GRDA				OK		USA	-95.2892	36.18889		LATLON
13103-A	4911	2211	GRDA	0074900000-0	4 Miles East on State Hig	Chouteau	OK	74337	USA	-95.3303	36.19272		LATLON
13488	4911	2211	HORSESHOE LAKE				OK		USA	-97.1794	35.50222		LATLON
13492-A	4911	2211	Hugo	0204470000-0	4 Miles West of Ft.	Towson	OK		USA	-95.3167	34.0292		LATLON
13213	4911	2211	MOORELAND				OK		USA	-99.2206	36.7375		LATLON
13224	4911	2211	MUSKOGEE				OK		USA	-95.2953	35.76722		LATLON
13566-A	4911	2211	Muskogee	0140630000-0	5501 Three Forks Road	Muskogee	OK	74434	USA	-95.2961	35.7713		LATLON
13225	4911	2211	MUSTANG				OK		USA	-97.6747	35.48139		LATLON
13241	4911	2211	NORTHEASTERN				OK		USA	-95.6981	36.43194		LATLON
13241-A	4911	2211	Northeastern	0154740000-0	Jct. Highway US 169 / O	Oologah	OK	74053	USA	-95.7118	36.43913		LATLON
T$11045	4911	2211	NORTHEASTERN STATION		JCT. HWY. US 169/OK 88	OOLOGAH	OK	74053	USA	-95.7008	36.43167		LATLON
401090052	4911	2211	OG & E TINKER	Turbine:			OK		USA	-97.9006	35.24		LATLON
400470702	4911	2211	OG&E	Turbine:			OK		USA	-97.8742	36.36917		LATLON
401090010	4911	2211	OG&E-HORSESHOE PLANT	ICE-NG.			OK		USA	-97.1792	35.50833		LATLON
401330702	4911	2211	OG&E-SEMINOLE POWER PLANT	Turbine:			OK		USA	-96.7247	34.96556		LATLON
2209	4911	2211	Oklahoma Gas & Electric	10100704 Muskogee			OK		USA	-95.2869	35.7619	15	LATLON
2211	4911	2211	Oklahoma Gas & Electric	10300700 Sooner			OK		USA	-97.0517	36.4542	14	LATLON
13269	4911	2211	PONCA				OK		USA	-97.1506	36.82		LATLON
401070700	4911	2211	PUBLIC SERVICE CO.				OK		USA	-96.1308	35.32583		LATLON
13297	4911	2211	RIVERSIDE				OK		USA	-95.9517	35.98556		LATLON
13624	4911	2211	SEMINOLE				OK		USA	-96.7256	34.96639		LATLON
13637	4911	2211	SOONER				OK		USA	-97.0497	36.45417		LATLON
13637-A	4911	2211	Sooner	0140630000-0	Intersection of Highway 1	Red Rock	OK	74651	USA	-97.1214	36.46992		LATLON
13331	4911	2211	SOUTHWESTERN				OK		USA	-98.3531	35.10139		LATLON
13356	4911	2211	TULSA				OK		USA	-95.9906	36.11639		LATLON
2700	4911	2211	Western Farmers Electric Coop Hugo	2300702 Hugo			OK		USA	-95.3197	34.0136	15	LATLON
13244-A	4911	2211	Big Brown	0443720000-0	FM 2570 11 Miles NE of F	Fairfield	TX	75840-	USA	-96.1494	31.72349		LATLON
481610004	4911	2211	BIG BROWN STATION	ICE-Diesel			TX		USA	-96.1418	31.712		LATLON
T$11331	4911	2211	BIG BROWN STEAM ELECTRIC STATION & LIGNITE MINE		11 MI E. OF FAIRFIELD ON FM 25	FAIRFIELD	TX	75840	USA	-96.0561	31.82056		LATLON
PA0003W	4911	2211	BRAZOS ELECTRIC POWER COOPERATIVE IN		PALO PINTO	PALO PINTO	TX	76072	USA	-98.3085	32.65814	14	LATLON
HG1169O	4911	2211	CALPINE CORPORATION		9602 BAYPORT RD.	PASADENA	TX	77507	USA	-95.0653	29.62571	15	LATLON
GF0002R	4911	2211	CENTRAL SOUTH WEST SERVICES INC		SCHROEDER ROAD (FM 2987)	FANNIN	TX	77960	USA	-97.2142	28.7129	14	LATLON
480830002	4911	2211	CITY OF COLEMAN	ICE-NG.			TX		USA	-99.4588	31.76063		LATLON
BG0057U	4911	2211	CITY PUBLICSERVICE		9599 GARDNER ROAD	SAN ANTONIO	TX	78201	USA	-98.3203	29.30802	14	LATLON
13705	4911	2211	COLETO CREEK				TX		USA	-97.2142	28.71278		LATLON
13705-A	4911	2211	Coleto Creek	0032780000-0	FM 2987	Fannin	TX	77960	USA	-97.2163	28.73652		LATLON
484250001	4911	2211	COMANCHE PEAK POWER PLANT	ICE-Diesel			TX		USA	-97.4714	32.17528		LATLON
13456	4911	2211	GIBBONS CREEK				TX		USA	-96.1375	30.61667		LATLON
13456-A	4911	2211	Gibbons Creek	0187150000-0	2-1/2 Miles North of Carl		TX		USA	-96.0778	30.6167		LATLON
T$11304	4911	2211	H.W. PIRKEY POWER PLANT		2400 FM RD. 3251	HALLSVILLE	TX	75650	USA	-94.4828	32.4625		LATLON
13157	4911	2211	KNOX LEE				TX		USA	-94.6431	32.37417		LATLON
T$11951	4911	2211	L.C.R.A. FAYETTE POWER PROJECT		6549 POWER PLANT RD.	LA GRANGE	TX	78945	USA	-96.7531	29.91917		LATLON
13178	4911	2211	LIMESTONE				TX		USA	-96.2553	31.42306		LATLON
T$11333	4911	2211	LIMESTONE ELECTRIC GENERATING STATION		FM39 AT FM80	JEWETT	TX	75846	USA	-96.2617	31.41083		LATLON
55505	4911	2211	LOWER COLORADO RIVER AUTHORITY		FOUR MIES NORTHEAST OF BASTROP	BASTROP	TX	78602	USA	-97.2723	30.0616	14	LATLON
FC0018G	4911	2211	LOWER COLORADO RIVER AUTHORITY		7 MI. E. OF LA GRANGE, TX., ON	LA GRANGE	TX	78945	USA	-96.7506	29.91745	14	LATLON
T$11320	4911	2211	MARTIN LAKE STEAM ELECTRIC STATION & LIGNITE		8850 FM 2658 N.	TATUM	TX	75691	USA	-94.5758	32.26111		LATLON
484490004	4911	2211	MONTICELLO STATION	ICE-Diesel			TX		USA	-95.02	33.05444		LATLON
T$11277	4911	2211	MONTICELLO STEAM ELECTRIC STATION & LIGNITE MINE		OFF FM 127 8MI.S.W. OF MT. P	MOUNT PLEASANT	TX	75455	USA	-95.0417	33.09167		LATLON
13232	4911	2211	NEWMAN				TX		USA	-106.431	31.98306		LATLON
T$12027	4911	2211	NEWMAN POWER STATION		4900 STAN ROBERTS SR. BLVD.	EL PASO	TX	79934	USA	-106.395	31.93399		LATLON
481410028	4911	2211	NEWMAN STATION	Turbine:			TX		USA	-106.223	31.45306		LATLON
T$11892	4911	2211	O.W. SOMMERS/J.T. DEELY/J.K. SPRUCE GENERATING COM		9599 GARDNER RD.	SAN ANTONIO	TX	78263	USA	-98.3358	29.32028		LATLON
13580	4911	2211	OKLAUNION				TX		USA	-99.1753	34.14028		LATLON
13580-A	4911	2211	Oklaunion	0204040000-0	12567 FM Road 3430	Vernon	TX	76384-	USA	-99.3004	34.15378		LATLON
T$11436	4911	2211	OKLAUNION POWER STATION		12567 FM RD. 3430	VERNON	TX	76384	USA	-99.1769	34.08333		LATLON
13257	4911	2211	PAINT CREEK				TX		USA	-99.5778	33.08083		LATLON
13265	4911	2211	PIRKEY				TX		USA	-94.4678	32.44556		LATLON
13265-A	4911	2211	Pirkey	0176980000-0	2400 Farm Road 3251	Hallsville	TX	75650	USA	-94.5817	32.53524		LATLON
HT0065Q	4911	2211	POWER RESOURCES LTD		3 MI. E. ON I. 20 FROM BIG SPR	BIG SPRING	TX	79721	USA	-101.422	32.27277	14	LATLON
FG0020V	4911	2211	RELIANT ENERGY INC		NEAR Y.U. JONES ROAD	FRESNO	TX	77545	USA	-95.6341	29.47652	15	LATLON
LI0027L	4911	2211	RELIANT ENERGY INC		9 MI. N. OF JEWETT, TX., ON F.	JEWETT	TX	75846	USA	-96.2534	31.42341	14	LATLON
13616	4911	2211	SAM SEYMOUR				TX		USA	-96.7542	29.925		LATLON
13616-A	4911	2211	Sam Seymour	0112690000-0	6549 Power Plant Rd	La Grange	TX	78945	USA	-96.8755	29.91007		LATLON
13617	4911	2211	SAN ANGELO				TX		USA	-100.492	31.39306		LATLON
484510007	4911	2211	SAN ANGELO POWER STATION	Turbine:			TX		USA	-100.064	31.42167		LATLON
13619	4911	2211	SAN MIGUEL				TX		USA	-98.4719	28.70889		LATLON
13619-A	4911	2211	San Miguel	0166240000-0		Jourdanton	TX	78026-	USA	-98.4722	28.7089		LATLON
AG0007G	4911	2211	SAN MIGUEL ELCTRC COOPERATIVE INC		11 MI. S., S.H. 16; 6 MI. E.,	CHRISTINE	TX	78012	USA	-98.4723	28.70915	14	LATLON
483310002	4911	2211	SANDOW STATION	ICE-Diesel			TX		USA	-96.9655	30.78385		LATLON
T$11457	4911	2211	SANDOW STEAM ELECTRIC STATION		7 MI S.W. OF ROCKDALE OFF FM	ROCKDALE	TX	76567	USA	-97.012	30.65274		LATLON
13325	4911	2211	SIM GIDEON				TX		USA	-97.2708	30.06056		LATLON
VC0026O	4911	2211	SOUTH TEXASELECTRIC COOPERATIVE INC		FM 447, 3 M W OF NURSERY	NURSERY	TX	77976	USA	-97.1359	28.89386	14	LATLON
GJ0043K	4911	2211	SOUTHWESTERN ELECTRIC POWER CO		KNOX LEE POWER PLT.	LONGVIEW	TX	75601	USA	-94.6422	32.37419	15	LATLON
HH0037F	4911	2211	SOUTHWESTERN ELECTRIC POWER CO		RT 2 BOX 165	HALLSVILLE	TX	75650	USA	-94.4679	32.44564	15	LATLON

strStateFacilityIdentifier	strSIC Primary	strNAICS Primary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXY Coordinate Type
ME0006A	4911	2211	SOUTHWESTERN ELECTRIC POWER CO		12 MI W OF AVINGER	AVINGER	TX	75630	USA	-94.5468	32.84868	15	LATLON
TF0012D	4911	2211	SOUTHWESTERN ELECTRIC POWER CO		NORTH TWO MILES ON AN OILED CO	MOUNT PLEASANT	TX	75455	USA	-94.8457	33.05838	15	LATLON
LB0047N	4911	2211	SOUTHWESTERN PUBLIC SERVICE CO		N. OF SUDAN, TEXAS	MULESHOE	TX	79347	USA	-102.575	34.18164	13	LATLON
PG0041R	4911	2211	SOUTHWESTERN PUBLIC SERVICE CO		2.7 MI. N. ON LAKESIDE DR. FRO	AMARILLO	TX	79101	USA	-101.746	35.29962	14	LATLON
T$11964	4911	2211	SOUTHWESTERN PUBLIC SERVICE CO. HARRINGTON STATI		N. LAKESIDE & HWY. 136	AMARILLO	TX	79108	USA	-101.747	35.29944		LATLON
T$11974	4911	2211	SOUTHWESTERN PUBLIC SERVICE CO. - TOLK STATION		8 MI S.W. EARTH	SUDAN	TX	79371	USA	-102.569	34.18472		LATLON
13343	4911	2211	T C FERGUSON				TX		USA	-98.3692	30.55639		LATLON
GB0153Q	4911	2211	TEXAS CITY COGENERATION LP		CRNR OF 5TH AVE S AND GRANT AV	TEXAS CITY	TX	77590	USA	-94.9416	29.37886	15	LATLON
RI0035C	4911	2211	TEXAS NEW MEXICO POWER CO		8 MILES N OF CALVERT ON HWY 6	CALVERT	TX	77837	USA	-96.6956	31.09322	14	LATLON
13351	4911	2211	TOLK STATION				TX		USA	-102.574	34.18139		LATLON
FB0025U	4911	2211	TX UTILITIES ELECTRIC CO		ON HWY. 1752 N. OF SAVOY, TX.	SAVOY	TX	75479	USA	-96.3673	33.63033	14	LATLON
HQ0012T	4911	2211	TXU ELECTRIC CO				TX		USA	-97.688	32.40537	14	LATLON
CP0065C	4911	2211	TXU ELECTRIC CO		APP 3M N OF FRISCO OFF US HWY	FRISCO	TX	75034	USA	-96.8133	33.19956	14	LATLON
DB0249H	4911	2211	TXU ELECTRIC CO		555 BARNES BRIDGE ROAD	DALLAS	TX	75037	USA	-96.5454	32.83763	14	LATLON
HM0017H	4911	2211	TXU ELECTRIC CO		1 MI S FM 764 0.5 MI W	TRINIDAD	TX	75163	USA	-96.1011	32.12639	14	LATLON
DB0251U	4911	2211	TXU ELECTRIC CO		14901 NORTHLAKE RD.	DALLAS	TX	75201	USA	-96.9746	32.95025	14	LATLON
DB0252S	4911	2211	TXU ELECTRIC CO		2233 MOUNTAIN CREEK PARKWAY	DALLAS	TX	75201	USA	-96.936	32.72499	14	LATLON
DB0253Q	4911	2211	TXU ELECTRIC CO		5770 PARKDALE DRIVE	DALLAS	TX	75201	USA	-96.7227	32.77844	14	LATLON
CJ0026J	4911	2211	TXU ELECTRIC CO		LOCATED ON THE W SHORE OF STRY	DALLAS	TX	75201	USA	-94.9895	31.94187	15	LATLON
RE0012M	4911	2211	TXU ELECTRIC CO		APPROX 5.4 M SE ON US HWY 271	BOGATA	TX	75417	USA	-95.1549	33.40181	15	LATLON
TF0013B	4911	2211	TXU ELECTRIC CO		7 MI. S.W. OF MT. PLEASANT OFF	MOUNT PLEASANT	TX	75455	USA	-95.0374	33.09243	15	LATLON
RL0020K	4911	2211	TXU ELECTRIC CO		6 MI SW OF TATUM NEAR FM 2658	TATUM	TX	75691	USA	-94.5702	32.26071	15	LATLON
FI0020W	4911	2211	TXU ELECTRIC CO		9 MI. N.E. OF FAIRFIELD, TX.	FAIRFIELD	TX	75840	USA	-96.0549	31.82158	14	LATLON
TA0352I	4911	2211	TXU ELECTRIC CO		10 MI. N.W. ON FM 1220	FORT WORTH	TX	76002	USA	-97.4794	32.90547	14	LATLON
TA0354E	4911	2211	TXU ELECTRIC CO		AT 4TH AND NORTH HOUSTON STREE	FORT WORTH	TX	76002	USA	-97.3365	32.76111	14	LATLON
TA0353G	4911	2211	TXU ELECTRIC CO		6604 EAST ROSEDALE	FORT WORTH	TX	76002	USA	-97.222	32.72918	14	LATLON
YB0017V	4911	2211	TXU ELECTRIC CO		3 MI. NW OF GRAHAM	GRAHAM	TX	76046	USA	-98.6123	33.13643	14	LATLON
MM0023J	4911	2211	TXU ELECTRIC CO		7 MI SW OF ROCKDALE	ROCKDALE	TX	76567	USA	-97.0581	30.5681	14	LATLON
MB0117A	4911	2211	TXU ELECTRIC CO		APPROX. 4.3 MI. S.W., OFF F.M.	WACO	TX	76701	USA	-96.9853	31.46673	14	LATLON
MO0014L	4911	2211	TXU ELECTRIC CO		5 MI. S.W. OF COLORADO CITY, T	COLORADO CITY	TX	79512	USA	-100.916	32.3346	14	LATLON
WC0028Q	4911	2211	TXU ELECTRIC CO		600 YUCCA DR., MONAHANS, TX.:	MONAHANS	TX	79756	USA	-102.957	31.58346	13	LATLON
13368	4911	2211	W A PARISH				TX		USA	-95.6317	29.48389		LATLON
13368-A	4911	2211	W A Parish	0089010000-0	2500 Y.U. Jones Road	Thompsons	TX	77481-	USA	-95.7641	29.5695		LATLON
481570011	4911	2211	W. A. PARISH STATION	Turbine:			TX		USA	-95.2514	29.47167		LATLON
T$11617	4911	2211	W.A. PARISH ELECTRIC GENERATING STATION		Y.U. JONES RD.	THOMPSON	TX	77481	USA	-95.6342	29.47528		LATLON
13675	4911	2211	WELSH				TX		USA	-94.8456	33.05806		LATLON
WI0025C	4911	2211	WEST TEXAS UTILITIES CO		3.5 MI. S.S.W. OF OKLAUNION, T	OKLAUNION	TX	76373	USA	-99.1802	34.083	14	LATLON
13379	4911	2211	WILKES		TWELVE MI. W. OF AVINGER	AVINGER	TX	75630	USA	-94.5467	32.84833		LATLON
12922	4911	2211	Bonanza	0402300000-0	12500 East 25500 South	Vernal	UT	84078	USA	-109.283	40.08306		LATLON
T$12223	4911	2211	BONANZA POWER PLANT		12500 E. 25500 S.	VERNAL	UT	84078	USA	-109.284	40.08639		LATLON
12997	4911	2211	Carbon	0143540000-0	Highway 6 & 91 3 Miles No	Price	UT	84526	USA	-110.864	39.72639		LATLON
10081	4911	2211	Carbon Power Plant	two fossil fuel fired electric	NA	Helper	UT	84526	USA	-110.852	39.66883		LATLON
490470001	4911	2211	DESERET - BONANZA	ICE-Diesel			UT		USA	-109.317	40.1177	0	LATLON
490350044	4911	2211	ELECTRICAL GENERATION PLANT	ICE-NG.			UT		USA	-111.906	40.6737		LATLON
10355	4911	2211	Gadsby Power Plant	three natural gas fired electr	1407 West North Temple (rear)	Salt Lake City	UT	84116	USA	-111.93	40.77138		LATLON
11539	4911	2211	Hildale City Cogeneration Facility	As of 11/15/95 not yet operating	1325 West Utah Ave.	Hildale	UT	84784	USA	-113.14	37.2278		LATLON
12799	4911	2211	Hunter	0143540000-0	Utah Highway 10 3 Miles S	Castledale	UT	84513	USA	-111.019	39.21085		LATLON
10237	4911	2211	Hunter Power Plant	Hunter thermal electric genera			UT		USA	-111.019	39.21085		LATLON
12800	4911	2211	Huntington	0143540000-0	Highway 31 10 Miles West	Huntington	UT	84528	USA	-111.075	39.37917		LATLON
10238	4911	2211	Huntington Power Plant	Huntington thermal electric ge			UT		USA	-110.963	39.32856		LATLON
10327	4911	2211	Intermountain Generation Station	8 miles north of Delta on Hwy 6, then 8	850 W Brush Wellman Rd	Delta	UT	84624	USA	-112.568	39.49323		LATLON
490579088	4911	2211	LITTLE MOUNTAIN COGENERATION FACILITY	Turbine:			UT		USA	-111.956	41.24985		LATLON
13088	4911	2211	PACIFCORP GADSBY				UT		USA	-111.929	40.76667		LATLON
10120	4911	2211	Power Plant	ICE-NG.	253 S 200 W	Bountiful	UT	84010	USA	-111.885	40.88658		LATLON
490490018	4911	2211	PROVO CITY POWER CO.	ICE-NG.			UT		USA	-111.666	40.2625		LATLON
490530011	4911	2211	ST GEORGE POWER	ICE-Diesel			UT		USA	-113.66	37.12861		LATLON
10892	4911	2211	St. George City Power Plant	diesel powered electrical plant	795 E. Skyline Dr.	St. George	UT	84770	USA	-113.565	37.11274		LATLON
T$12281	4911	2211	SUNNYSIDE COGENERATION ASSOCIATES	50951	ONE POWER PLANT RD.	SUNNYSIDE	UT	84539	USA	-110.392	39.54722		LATLON
490490072	4911	2211	WHITEHEAD POWER PLANT	ICE-NG.			UT		USA	-111.619	40.17611		LATLON
5603100001	4911	2211	BASIN ELECTRIC_LARAMIE RIVER STATION	POWER PLANT	LARAMIE RIVER PLANT	WHEATLAND	WY	82201	USA	-104.877	42.1119	13	LATLON
T$12151	4911	2211	BHPL-OSAGE POWER PLANT		3363 HWY. 16	OSAGE	WY	82723	USA	-104.41	43.97167		LATLON
5604500005	4911	2211	BLACK HILLS OSAGE	POWER PLANT	OSAGE POWER PLANT	OSAGE	WY	82723	USA	-104.408	43.9672	13	LATLON
5600500002	4911	2211	BLACK HILLS POWER & LGHT SIMPSON 1	POWER PLANT	3 MI NE OF GILLETTE	GILLETTE	WY	82718971(	USA	-105.387	44.2867	13	LATLON
58184-A	4911	2211	BLACK HILLS POWER & LGT-SIMPSON 2	0195450000-0	13151 Highway 51 HCR # 81	Gillette	WY	82718-971	USA	-105.499	44.25329		LATLON
13722	4911	2211	DAVE JOHNSTON				WY		USA	-105.767	42.83306		LATLON
13722-A	4911	2211	Dave Johnston	0143540000-0	1951 Tank Farm Road Coal	Glenrock	WY	82637	USA	-105.848	42.87368		LATLON
T$12140	4911	2211	LARAMIE RIVER STATION		347 GRAYROCKS RD.	WHEATLAND	WY	82201134(	USA	-104.881	42.10833		LATLON
58145-A	4911	2211	Laramie River Station	0013070000-0	347 Grayrocks Rd	Wheatland	WY	82201	USA	-104.882	42.10436		LATLON
13228	4911	2211	Naughton	0143540000-0	7 Miles SouthWest of Kemm	Kemmerer	WY	83101	USA	-110.543	41.79367		LATLON
T$12159	4911	2211	PACIFICORP, NAUGHTON POWER PLANT		5 MI. SO., HWY. 189`	KEMMERER	WY	83101	USA	-110.599	41.75722		LATLON
5600900001	4911	2211	PACIFICORP_DAVE JOHNSTON	POWER PLANT	1591 TANK FARM ROAD	GLENROCK	WY	82637	USA	-105.775	42.843	13	LATLON
5603701002	4911	2211	PACIFICORP_JIM BRIDGER	POWER PLANT			WY		USA	-108.795	41.7375	12	LATLON
5602300004	4911	221112	PACIFICORP_NAUGHTON POWER PLANT	POWER PLANT	6.5 MI SW OF KEMMERER, HWY 189	KEMMERER	WY	83101	USA	-110.596	42.8489	12	LATLON
5600500046	4911	2211	PACIFICORP_WYODAK	POWER PLANT	3 MI E OF GILLETTE	GILLETTE	WY	82716	USA	-105.386	44.2903	13	LATLON
58233-A	4911	2211	PACIFICORP-JIM BRIDGER	0143540000-0	35 Miles East of Rock Spr	Point of Rocks	WY	82942	USA	-108.957	41.6029	12	LATLON
58137-A	4911	2211	Wyodak	0143540000-0	48 Wyodak Road (Garner La	Gillette	WY	82716	USA	-105.385	44.28926		LATLON
T$12153	4911	2211	WYODAK PLANT		48 WYODAK RD.	GILLETTE	WY	82718	USA	-105.385	44.28926		LATLON
1639	3211	327211	Visteon	14300035 Tulsa Glass Plant	5555 S. 129th	Tulsa	OK	74134000(	USA	-95.8318	36.0835	15	LATLON
1057	3221	327213	Anchor Glass Container Corporation	11100703 Henryetta (Plant #15)			OK		USA	-95.9694	35.4476	15	LATLON
1144	3221	327213	Bartlett-Collins Glass Company	3700700 Sapulpa	620 S Linden PO Box 1288	Sapulpa	OK	74067000(	USA	-96.1037	35.9929	14	LATLON
1826	3241	327310	Holnam, Inc.	12300701 Ada Plant	1100 West 18th Street	Ada	OK	74820000(	USA	-96.6933	34.773	14	LATLON
401310703	3241	327310	BLUE CIRCLE CEMENT (LaFarge?)	ICE-Diesel 96 NTI was area source		Tulsa	OK		USA	-95.8131	36.19417		LATLON
T$11100	3241	327310	LONE STAR IND. INC. PRYOR CEMENT PLANT		5 MILES E. HWY. 20 & 2 MILES S	PRYOR	OK	74361	USA	-95.2217	36.27194		LATLON
BSCP134	3251	327121	Commercial Brick Corp	Commercial Brick Corp	Old Hwy 270	Wewoka	OK	74884	USA	-96.5458	35.175		LATLON
BSCP76	3251	327121	Scott Jewett Truck Line, Inc	Mangum Brick	2316 N Louis Tittle Ave	Mangum	OK	73554	USA	-99.5	34.9		LATLON
BSCP95	3251	327121	Justin Industries	Acme Brick-Oklahoma City Plant	500 E. Memorial Rd	Oklahoma City	OK	73114	USA	-97.6336	35.6025		LATLON
BSCP96	3251	327121	Justin Industries	Acme Brick-Tulsa Plant	4103 Dawson Rd	Tulsa	OK	74115	USA	-95.93	36.18		LATLON
T$11108	3251	327	BORAL BRICKS INC. - MUSKOGEE PLANT		3101 W. 53RD ST. S.	MUSKOGEE	OK	74401	USA	-95.4	35.69167		LATLON
CC87	3253	327122	Laufen International	Tile Plant	4942 E. 66th Street, N.	Tulsa	OK	74117-180	USA	-95.9218	36.24933		LATLON

strStateFacilityIdentifier	strSICPrimary	strNAICSPrimary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXYCoordinateType
T$10977	3275	327420	UNITED DESIGN CORP. NOBLE FAC.		1600 N. MAIN	NOBLE	OK	73068	USA	-97.4056	35.15694		LATLON
1219	3295	2123	Chandler Materials Co.	14300900 2100 N. 145th E Ave (Aggre	5805 E. 15th St.	Tulsa	OK	74112000(	USA	-95.8206	36.1853	15	LATLON
10303	3241	327310	Ash Grove Leamington Cement Plant	Subject to MACT (40 CFR 63 Subpart	Hwy 132	Leamington	UT	84638	USA	-112.815	39.6627		LATLON
490290001	3241	327310	HOLNAM INC.-Devil Slide Plant	ICE-Diesel 96 NTI was area source	6055 E. Croydon Rd	Morgan	UT	84050	USA	-111.514	41.06778		LATLON
BSCP154	3251	327121	Pacific Coast Building Products	Interstate Brick Co	9780 South 5200 West	West Jordan	UT	84088	USA	-112.061	40.59444		LATLON
BSCP71	3251	327121	Interpace Industries Inc	Interpace Industries Inc	736 W. Harrisville Rd	Ogden	UT	84412	USA	-111.994	41.28388		LATLON
490450051	3255	327124	A.P.GREEN REFRACTORIES - SILICA STONE QU	ICE-Diesel 96 NTI was area source			UT		USA	-113.106	40.49005		LATLON
490490007	3255	327124	A.P.GREEN REFRACTORIES - LEHI PLANT	ICE-NG. 96NTI was area source.			UT		USA	-111.524	40.1895		LATLON

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117	AZ-0040	APS WEST PHOENIX	Arizona Public Service	MARICOPA	CHAS SPELL	P.O. BOX 53933, MAIL STATION 4120	PHOENIX	AZ	85072	602-750-1383		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		8604356 S99-023	4911
117	AZ-0040	APS WEST PHOENIX	Arizona Public Service	MARICOPA	CHAS SPELL	P.O. BOX 53933, MAIL STATION 4120	PHOENIX	AZ	85072	602-750-1383		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		8604356 S99-023	4911
117	AZ-0040	APS WEST PHOENIX	Arizona Public Service	MARICOPA	CHAS SPELL	P.O. BOX 53933, MAIL STATION 4120	PHOENIX	AZ	85072	602-750-1383		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		8604356 S99-023	4911
117	AZ-0040	APS WEST PHOENIX	Arizona Public Service	MARICOPA	CHAS SPELL	P.O. BOX 53933, MAIL STATION 4120	PHOENIX	AZ	85072	602-750-1383		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		8604356 S99-023	4911
117	AZ-0040	APS WEST PHOENIX	Arizona Public Service	MARICOPA	CHAS SPELL	P.O. BOX 53933, MAIL STATION 4120	PHOENIX	AZ	85072	602-750-1383		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		8604356 S99-023	4911
117	AZ-0040	APS WEST PHOENIX	Arizona Public Service	MARICOPA	CHAS SPELL	P.O. BOX 53933, MAIL STATION 4120	PHOENIX	AZ	85072	602-750-1383		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		8604356 S99-023	4911
55282	AZ-0035	DUKE ENERGY ARLINGTON VALLEY	DUKE ENERGY ARLINGTON VALLEY	MARICOPA	RUFUS KELLAM	P.O. BOX 26	ARLINGTON	AZ	85322	623-882-2223		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE LIEB	(602) 506-6738		V99-014	4911
55282	AZ-0035	DUKE ENERGY ARLINGTON VALLEY	DUKE ENERGY ARLINGTON VALLEY	MARICOPA	RUFUS KELLAM	P.O. BOX 26	ARLINGTON	AZ	85322	623-882-2223		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE LIEB	(602) 506-6738		V99-014	4911
55282	AZ-0035	DUKE ENERGY ARLINGTON VALLEY	DUKE ENERGY ARLINGTON VALLEY	MARICOPA	RUFUS KELLAM	P.O. BOX 26	ARLINGTON	AZ	85322	623-882-2223		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE LIEB	(602) 506-6738		V99-014	4911
55282	AZ-0035	DUKE ENERGY ARLINGTON VALLEY	DUKE ENERGY ARLINGTON VALLEY	MARICOPA	RUFUS KELLAM	P.O. BOX 26	ARLINGTON	AZ	85322	623-882-2223		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE LIEB	(602) 506-6738		V99-014	4911
55282	AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	DUKE ENERGY ARLINGTON VALLEY	MARICOPA	RUFUS KELLAM	P.O. BOX 27	ARLINGTON	AZ	85322	623-882-2223		9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		S01-004	4911
55282	AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	DUKE ENERGY ARLINGTON VALLEY	MARICOPA	RUFUS KELLAM	P.O. BOX 27	ARLINGTON	AZ	85322	623-882-2223		9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		S01-004	4911
55282	AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	DUKE ENERGY ARLINGTON VALLEY	MARICOPA	RUFUS KELLAM	P.O. BOX 27	ARLINGTON	AZ	85322	623-882-2223		9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		S01-004	4911
55282	AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	DUKE ENERGY ARLINGTON VALLEY	MARICOPA	RUFUS KELLAM	P.O. BOX 27	ARLINGTON	AZ	85322	623-882-2223		9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		S01-004	4911
55282	AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	DUKE ENERGY ARLINGTON VALLEY	MARICOPA	RUFUS KELLAM	P.O. BOX 27	ARLINGTON	AZ	85322	623-882-2223		9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		S01-004	4911
55282	AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	DUKE ENERGY ARLINGTON VALLEY	MARICOPA	RUFUS KELLAM	P.O. BOX 27	ARLINGTON	AZ	85322	623-882-2223		9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		S01-004	4911
55282	AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	DUKE ENERGY ARLINGTON VALLEY	MARICOPA	RUFUS KELLAM	P.O. BOX 27	ARLINGTON	AZ	85322	623-882-2223		9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		S01-004	4911
55282	AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	DUKE ENERGY ARLINGTON VALLEY	MARICOPA	RUFUS KELLAM	P.O. BOX 27	ARLINGTON	AZ	85322	623-882-2223		9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		S01-004	4911
55507	AZ-0038	GILA BEND POWER GENERATING STATION	GILA BEND POWER GENERATING STATION	MARICOPA	JOHN WASHBURN	5949 SHERRY LANE, SUITE 1900	DALLAS	TX	75225	214 210 5000		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A. LIEB	(602) 506-6738		V00-001	4911
55507	AZ-0038	GILA BEND POWER GENERATING STATION	GILA BEND POWER GENERATING STATION	MARICOPA	JOHN WASHBURN	5949 SHERRY LANE, SUITE 1900	DALLAS	TX	75225	214 210 5000		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A. LIEB	(602) 506-6738		V00-001	4911
55507	AZ-0038	GILA BEND POWER GENERATING STATION	GILA BEND POWER GENERATING STATION	MARICOPA	JOHN WASHBURN	5949 SHERRY LANE, SUITE 1900	DALLAS	TX	75225	214 210 5000		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A. LIEB	(602) 506-6738		V00-001	4911
55507	AZ-0038	GILA BEND POWER GENERATING STATION	GILA BEND POWER GENERATING STATION	MARICOPA	JOHN WASHBURN	5949 SHERRY LANE, SUITE 1900	DALLAS	TX	75225	214 210 5000		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A. LIEB	(602) 506-6738		V00-001	4911
55372	AZ-0034	HARQUAHALA GENERATING PROJECT	HARQUAHALA GENERATING CO.	MARICOPA		HARQUAHALA VALLEY ROAD	TONOPAH	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		V99-015	
55372	AZ-0034	HARQUAHALA GENERATING PROJECT	HARQUAHALA GENERATING CO.	MARICOPA		HARQUAHALA VALLEY ROAD	TONOPAH	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		V99-015	
55372	AZ-0034	HARQUAHALA GENERATING PROJECT	HARQUAHALA GENERATING CO.	MARICOPA		HARQUAHALA VALLEY ROAD	TONOPAH	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		V99-015	
55372	AZ-0034	HARQUAHALA GENERATING PROJECT	HARQUAHALA GENERATING CO.	MARICOPA		HARQUAHALA VALLEY ROAD	TONOPAH	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		V99-015	
55372	AZ-0034	HARQUAHALA GENERATING PROJECT	HARQUAHALA GENERATING CO.	MARICOPA		HARQUAHALA VALLEY ROAD	TONOPAH	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		V99-015	
	AZ-0022	INTEL CORPORATION	INTEL CORPORATION			OLD PRICE RD ALIGNMENT	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		93-0046	3674
	AZ-0022	INTEL CORPORATION	INTEL CORPORATION			OLD PRICE RD ALIGNMENT	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		93-0046	3674
	AZ-0022	INTEL CORPORATION	INTEL CORPORATION			OLD PRICE RD ALIGNMENT	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		93-0046	3674
	AZ-0022	INTEL CORPORATION	INTEL CORPORATION			OLD PRICE RD ALIGNMENT	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		93-0046	3674
	AZ-0022	INTEL CORPORATION	INTEL CORPORATION			OLD PRICE RD ALIGNMENT	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		93-0046	3674
	AZ-0032	INTEL CORPORATION	INTEL CORPORATION			4500 S. DOBSON RD	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE LIEB	(602) 506-6738		96-0743	3674
	AZ-0032	INTEL CORPORATION	INTEL CORPORATION			4500 S. DOBSON RD	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE LIEB	(602) 506-6738		96-0743	3674
	AZ-0032	INTEL CORPORATION	INTEL CORPORATION			4500 S. DOBSON RD	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE LIEB	(602) 506-6738		96-0743	3674

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147	AZ-0041	KYRENE GENERATING STATION, SALT RIVER PROJECT	KYRENE GENERATING STATION	MARICOPA	CHRIS JANICK	P.O.BOX 5205, MAIL STATION PAB352	PHOENIX	AZ	85072	602-236-5374		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V95-009	4911
147	AZ-0041	KYRENE GENERATING STATION, SALT RIVER PROJECT	KYRENE GENERATING STATION	MARICOPA	CHRIS JANICK	P.O.BOX 5205, MAIL STATION PAB352	PHOENIX	AZ	85072	602-236-5374		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V95-009	4911
147	AZ-0041	KYRENE GENERATING STATION, SALT RIVER PROJECT	KYRENE GENERATING STATION	MARICOPA	CHRIS JANICK	P.O.BOX 5205, MAIL STATION PAB352	PHOENIX	AZ	85072	602-236-5374		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V95-009	4911
55481	AZ-0033	MESQUITE GENERATING STATION	MESQUITE POWER LLC	MARICOPA		37600 WEST ELLIOT ROAD	ARLINGTON	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE LIEB	(602) 506-6738		V99-017	4911
55481	AZ-0033	MESQUITE GENERATING STATION	MESQUITE POWER LLC	MARICOPA		37600 WEST ELLIOT ROAD	ARLINGTON	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE LIEB	(602) 506-6738		V99-017	4911
55481	AZ-0033	MESQUITE GENERATING STATION	MESQUITE POWER LLC	MARICOPA		37600 WEST ELLIOT ROAD	ARLINGTON	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE LIEB	(602) 506-6738		V99-017	4911
55481	AZ-0033	MESQUITE GENERATING STATION	MESQUITE POWER LLC	MARICOPA		37600 WEST ELLIOT ROAD	ARLINGTON	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE LIEB	(602) 506-6738		V99-017	4911
55481	AZ-0033	MESQUITE GENERATING STATION	MESQUITE POWER LLC	MARICOPA		37600 WEST ELLIOT ROAD	ARLINGTON	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE LIEB	(602) 506-6738		V99-017	4911
	AZ-0027	MINNESOTA METHANE	MINNESOTA METHANE	MARICOPA		2800 S. 27TH AVE.	PHOENIX	AZ	-85009			9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	LYNN APOSTLE	(602) 506-6760		95-0241	4959
	AZ-0027	MINNESOTA METHANE	MINNESOTA METHANE	MARICOPA		2800 S. 27TH AVE.	PHOENIX	AZ	-85009			9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	LYNN APOSTLE	(602) 506-6760		95-0241	4959
	AZ-0042	NORTHWEST REGIONAL LANDFILL	NORTHWEST REGIONAL LANDFILL	MARICOPA	DAVE BEARDEN	19401 WEST DEER VALLEY	SURPRISE	AZ	85374	602-708-9815		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V97016	4953
	AZ-0042	NORTHWEST REGIONAL LANDFILL	NORTHWEST REGIONAL LANDFILL	MARICOPA	DAVE BEARDEN	19401 WEST DEER VALLEY	SURPRISE	AZ	85374	602-708-9815		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V97016	4953
	AZ-0042	NORTHWEST REGIONAL LANDFILL	NORTHWEST REGIONAL LANDFILL	MARICOPA	DAVE BEARDEN	19401 WEST DEER VALLEY	SURPRISE	AZ	85374	602-708-9815		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V97016	4953
	AZ-0042	NORTHWEST REGIONAL LANDFILL	NORTHWEST REGIONAL LANDFILL	MARICOPA	DAVE BEARDEN	19401 WEST DEER VALLEY	SURPRISE	AZ	85374	602-708-9815		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V97016	4953
55306	AZ-0037	PANDA GILA RIVER	TPS Arizona Operations, PANDA GILA RIVER	MARICOPA	DAN BAERMAN	P.O. BOX 798	GILA BEND	AZ	85337	928-683-0111		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V99-018	4911
55306	AZ-0037	PANDA GILA RIVER	TPS Arizona Operations, PANDA GILA RIVER	MARICOPA	DAN BAERMAN	P.O. BOX 798	GILA BEND	AZ	85337	928-683-0111		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V99-018	4911
55306	AZ-0037	PANDA GILA RIVER	TPS Arizona Operations, PANDA GILA RIVER	MARICOPA	DAN BAERMAN	P.O. BOX 798	GILA BEND	AZ	85337	928-683-0111		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V99-018	4911
55306	AZ-0037	PANDA GILA RIVER	TPS Arizona Operations, PANDA GILA RIVER	MARICOPA	DAN BAERMAN	P.O. BOX 798	GILA BEND	AZ	85337	928-683-0111		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V99-018	4911
55455	AZ-0036	PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	PINNACLE WEST ENERGY CORP.	MARICOPA	CHRIS CHITTESLER	400 N. 5TH ST.	PHOENIX	AZ	85004	602-407-7807		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V99-013	4911
55455	AZ-0036	PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	PINNACLE WEST ENERGY CORP.	MARICOPA	CHRIS CHITTESLER	400 N. 5TH ST.	PHOENIX	AZ	85004	602-407-7807		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V99-013	4911
55455	AZ-0036	PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	PINNACLE WEST ENERGY CORP.	MARICOPA	CHRIS CHITTESLER	400 N. 5TH ST.	PHOENIX	AZ	85004	602-407-7807		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V99-013	4911
55455	AZ-0036	PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	PINNACLE WEST ENERGY CORP.	MARICOPA	CHRIS CHITTESLER	400 N. 5TH ST.	PHOENIX	AZ	85004	602-407-7807		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V99-013	4911

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55455	AZ-0036	PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	PINNACLE WEST ENERGY CORP.	MARICOPA	CHRIS CHITTESLER	400 N. 5TH ST.	PHOENIX	AZ	85004	602-407-7807		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V99-013	4911
55522	AZ-0045	PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	PPL SUNDANCE ENERGY, LLC	PINAL	PAT THEMIG	P.O. BOX 38	COLSTRIP	MT	59323	303-237-6943	PJTHEMIG@PPLMT.COM	9	AZ004	PINAL CO AIR QUALITY CONTROL DIST, AZ	DONALD GABRIELSON	520-866-6929		V20613.000	4911
55522	AZ-0045	PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	PPL SUNDANCE ENERGY, LLC	PINAL	PAT THEMIG	P.O. BOX 38	COLSTRIP	MT	59323	303-237-6943	PJTHEMIG@PPLMT.COM	9	AZ004	PINAL CO AIR QUALITY CONTROL DIST, AZ	DONALD GABRIELSON	520-866-6929		V20613.000	4911
55522	AZ-0045	PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	PPL SUNDANCE ENERGY, LLC	PINAL	PAT THEMIG	P.O. BOX 38	COLSTRIP	MT	59323	303-237-6943	PJTHEMIG@PPLMT.COM	9	AZ004	PINAL CO AIR QUALITY CONTROL DIST, AZ	DONALD GABRIELSON	520-866-6929		V20613.000	4911
55522	AZ-0045	PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	PPL SUNDANCE ENERGY, LLC	PINAL	PAT THEMIG	P.O. BOX 38	COLSTRIP	MT	59323	303-237-6943	PJTHEMIG@PPLMT.COM	9	AZ004	PINAL CO AIR QUALITY CONTROL DIST, AZ	DONALD GABRIELSON	520-866-6929		V20613.000	4911
55129	AZ-0044	SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	SALT RIVER PROJECT	PINAL	CHRIS JANICK	P.O. BOX 52025, PAB 352	PHOENIX	AZ	85072	602-236-3407		9	AZ004	PINAL CO AIR QUALITY CONTROL DIST, AZ	DALE A LIEB	(602) 506-6738		V20610.000	4911
55129	AZ-0044	SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	SALT RIVER PROJECT	PINAL	CHRIS JANICK	P.O. BOX 52025, PAB 352	PHOENIX	AZ	85072	602-236-3407		9	AZ004	PINAL CO AIR QUALITY CONTROL DIST, AZ	DALE A LIEB	(602) 506-6738		V20610.000	4911
55129	AZ-0044	SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	SALT RIVER PROJECT	PINAL	CHRIS JANICK	P.O. BOX 52025, PAB 352	PHOENIX	AZ	85072	602-236-3407		9	AZ004	PINAL CO AIR QUALITY CONTROL DIST, AZ	DALE A LIEB	(602) 506-6738		V20610.000	4911
55129	AZ-0044	SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	SALT RIVER PROJECT	PINAL	CHRIS JANICK	P.O. BOX 52025, PAB 352	PHOENIX	AZ	85072	602-236-3407		9	AZ004	PINAL CO AIR QUALITY CONTROL DIST, AZ	DALE A LIEB	(602) 506-6738		V20610.000	4911
55129	AZ-0044	SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	SALT RIVER PROJECT	PINAL	CHRIS JANICK	P.O. BOX 52025, PAB 352	PHOENIX	AZ	85072	602-236-3407		9	AZ004	PINAL CO AIR QUALITY CONTROL DIST, AZ	DALE A LIEB	(602) 506-6738		V20610.000	4911

FACILITY	NAICS	AIRSID	EPAID	UTMZONE	XCOORD	YCOORD	RCVD DATE	PERMIT DATE	STARTUP DATE	VERIFY DATE	ENTRY DATE	LAST UPDATE	NEW_ MOD	PUBLIC HEAR	FUEL	EMISSSOURCES	ABATEMENT
APS WEST PHOENIX	221112	3313					9/15/1999	5/26/2000	3/15/2003		11/10/2003	11/21/2003	M	Y	NATURAL GAS	COMBINED CYCLE UNITS	OXIDATION CATALYST
APS WEST PHOENIX	221112	3313					9/15/1999	5/26/2000	3/15/2003		11/10/2003	11/21/2003	M	Y	NATURAL GAS	COMBINED CYCLE UNITS	OXIDATION CATALYST
APS WEST PHOENIX	221112	3313					9/15/1999	5/26/2000	3/15/2003		11/10/2003	11/21/2003	M	Y	NATURAL GAS	COMBINED CYCLE UNITS	OXIDATION CATALYST
APS WEST PHOENIX	221112	3313					9/15/1999	5/26/2000	3/15/2003		11/10/2003	11/21/2003	M	Y	NATURAL GAS	COMBINED CYCLE UNITS	OXIDATION CATALYST
APS WEST PHOENIX	221112	3313					9/15/1999	5/26/2000	3/15/2003		11/10/2003	11/21/2003	M	Y	NATURAL GAS	COMBINED CYCLE UNITS	OXIDATION CATALYST
APS WEST PHOENIX	221112	3313					9/15/1999	5/26/2000	3/15/2003		11/10/2003	11/21/2003	M	Y	NATURAL GAS	COMBINED CYCLE UNITS	OXIDATION CATALYST
DUKE ENERGY ARLINGTON VALLEY	21112						7/27/1999	12/14/2000	3/19/2002		11/10/2003	11/21/2003	N	Y	NATURAL GAS	COMBINED CYCLE UNITS	SCR
DUKE ENERGY ARLINGTON VALLEY	21112						7/27/1999	12/14/2000	3/19/2002		11/10/2003	11/21/2003	N	Y	NATURAL GAS	COMBINED CYCLE UNITS	SCR
DUKE ENERGY ARLINGTON VALLEY	21112						7/27/1999	12/14/2000	3/19/2002		11/10/2003	11/21/2003	N	Y	NATURAL GAS	COMBINED CYCLE UNITS	SCR
DUKE ENERGY ARLINGTON VALLEY	21112						7/27/1999	12/14/2000	3/19/2002		11/10/2003	11/21/2003	N	Y	NATURAL GAS	COMBINED CYCLE UNITS	SCR
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	221112	43063		12	323852	3690212	9/1/2001	11/12/2003			1/8/2004	1/29/2004	M	N	NATURAL GAS	COMBINED CYCLE UNITS	SCR & OXIDATION CATALYST
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	221112	43063		12	323852	3690212	9/1/2001	11/12/2003			1/8/2004	1/29/2004	M	N	NATURAL GAS	COMBINED CYCLE UNITS	SCR & OXIDATION CATALYST
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	221112	43063		12	323852	3690212	9/1/2001	11/12/2003			1/8/2004	1/29/2004	M	N	NATURAL GAS	COMBINED CYCLE UNITS	SCR & OXIDATION CATALYST
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	221112	43063		12	323852	3690212	9/1/2001	11/12/2003			1/8/2004	1/29/2004	M	N	NATURAL GAS	COMBINED CYCLE UNITS	SCR & OXIDATION CATALYST
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	221112	43063		12	323852	3690212	9/1/2001	11/12/2003			1/8/2004	1/29/2004	M	N	NATURAL GAS	COMBINED CYCLE UNITS	SCR & OXIDATION CATALYST
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	221112	43063		12	323852	3690212	9/1/2001	11/12/2003			1/8/2004	1/29/2004	M	N	NATURAL GAS	COMBINED CYCLE UNITS	SCR & OXIDATION CATALYST
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	221112	43063		12	323852	3690212	9/1/2001	11/12/2003			1/8/2004	1/29/2004	M	N	NATURAL GAS	COMBINED CYCLE UNITS	SCR & OXIDATION CATALYST
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	221112	43063		12	323852	3690212	9/1/2001	11/12/2003			1/8/2004	1/29/2004	M	N	NATURAL GAS	COMBINED CYCLE UNITS	SCR & OXIDATION CATALYST
GILA BEND POWER GENERATING STATION	221112						2/29/2000	5/15/2002			11/10/2003	11/21/2003	N		NATURAL GAS	COMBINED CYCLE COMBUSTION TURBINE (3)/ STEAM TURBINE (1)	SELECTIVE CATALYTIC REDUCTION (SCR), OXIDATION CATALYST
GILA BEND POWER GENERATING STATION	221112						2/29/2000	5/15/2002			11/10/2003	11/21/2003	N		NATURAL GAS	COMBINED CYCLE COMBUSTION TURBINE (3)/ STEAM TURBINE (1)	SELECTIVE CATALYTIC REDUCTION (SCR), OXIDATION CATALYST
GILA BEND POWER GENERATING STATION	221112						2/29/2000	5/15/2002			11/10/2003	11/21/2003	N		NATURAL GAS	COMBINED CYCLE COMBUSTION TURBINE (3)/ STEAM TURBINE (1)	SELECTIVE CATALYTIC REDUCTION (SCR), OXIDATION CATALYST
GILA BEND POWER GENERATING STATION	221112						2/29/2000	5/15/2002			11/10/2003	11/21/2003	N		NATURAL GAS	COMBINED CYCLE COMBUSTION TURBINE (3)/ STEAM TURBINE (1)	SELECTIVE CATALYTIC REDUCTION (SCR), OXIDATION CATALYST
HARQUAHALA GENERATING PROJECT				12	303.6	3705.8	9/8/1999	2/15/2001	11/30/2002		4/19/2001	4/23/2002	N				
HARQUAHALA GENERATING PROJECT				12	303.6	3705.8	9/8/1999	2/15/2001	11/30/2002		4/19/2001	4/23/2002	N				
HARQUAHALA GENERATING PROJECT				12	303.6	3705.8	9/8/1999	2/15/2001	11/30/2002		4/19/2001	4/23/2002	N				
HARQUAHALA GENERATING PROJECT				12	303.6	3705.8	9/8/1999	2/15/2001	11/30/2002		4/19/2001	4/23/2002	N				
HARQUAHALA GENERATING PROJECT				12	303.6	3705.8	9/8/1999	2/15/2001	11/30/2002		4/19/2001	4/23/2002	N				
INTEL CORPORATION	334413							4/10/1994	4/1/1995		5/16/1994	12/18/2001					
INTEL CORPORATION	334413							4/10/1994	4/1/1995		5/16/1994	12/18/2001					
INTEL CORPORATION	334413							4/10/1994	4/1/1995		5/16/1994	12/18/2001					
INTEL CORPORATION	334413							4/10/1994	4/1/1995		5/16/1994	12/18/2001					
INTEL CORPORATION	334413							4/10/1994	4/1/1995		5/16/1994	12/18/2001					
INTEL CORPORATION	334413							9/1/1996			10/21/1996	12/18/2001					
INTEL CORPORATION	334413							9/1/1996			10/21/1996	12/18/2001					
INTEL CORPORATION	334413							9/1/1996			10/21/1996	12/18/2001					

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KYRENE GENERATING STATION, SALT RIVER PROJECT	221112	3317					8/15/2000	3/14/2001	4/16/2002		11/10/2003	11/26/2003	N	Y	NATURAL GAS	COMBINED CYCLE SYSTEM	SCR, OXIDATION CATALYST
KYRENE GENERATING STATION, SALT RIVER PROJECT	221112	3317					8/15/2000	3/14/2001	4/16/2002		11/10/2003	11/26/2003	N	Y	NATURAL GAS	COMBINED CYCLE SYSTEM	SCR, OXIDATION CATALYST
KYRENE GENERATING STATION, SALT RIVER PROJECT	221112	3317					8/15/2000	3/14/2001	4/16/2002		11/10/2003	11/26/2003	N	Y	NATURAL GAS	COMBINED CYCLE SYSTEM	SCR, OXIDATION CATALYST
MESQUITE GENERATING STATION	221111, 221112, 221113, 221119, 221121, 221122			12	326.6	369	11/24/1999	3/22/2001	6/1/2003		4/16/2001	8/20/2002	N				
MESQUITE GENERATING STATION	221111, 221112, 221113, 221119, 221121, 221122			12	326.6	369	11/24/1999	3/22/2001	6/1/2003		4/16/2001	8/20/2002	N				
MESQUITE GENERATING STATION	221111, 221112, 221113, 221119, 221121, 221122			12	326.6	369	11/24/1999	3/22/2001	6/1/2003		4/16/2001	8/20/2002	N				
MESQUITE GENERATING STATION	221111, 221112, 221113, 221119, 221121, 221122			12	326.6	369	11/24/1999	3/22/2001	6/1/2003		4/16/2001	8/20/2002	N				
MESQUITE GENERATING STATION	221111, 221112, 221113, 221119, 221121, 221122			12	326.6	369	11/24/1999	3/22/2001	6/1/2003		4/16/2001	8/20/2002	N				
MINNESOTA METHANE	488119, 56291, 56171, 562998							11/12/1995	12/15/1995		10/31/1995	12/18/2001					
MINNESOTA METHANE	488119, 56291, 56171, 562998							11/12/1995	12/15/1995		10/31/1995	12/18/2001					
NORTHWEST REGIONAL LANDFILL	562212	1879					6/15/1997	10/27/2003	6/15/1988		11/18/2003	12/4/2003	M	N	LANDFILL GAS	ENCLOSED FLARE, INTERNAL COMBUSTION ENGINE	
NORTHWEST REGIONAL LANDFILL	562212	1879					6/15/1997	10/27/2003	6/15/1988		11/18/2003	12/4/2003	M	N	LANDFILL GAS	ENCLOSED FLARE, INTERNAL COMBUSTION ENGINE	
NORTHWEST REGIONAL LANDFILL	562212	1879					6/15/1997	10/27/2003	6/15/1988		11/18/2003	12/4/2003	M	N	LANDFILL GAS	ENCLOSED FLARE, INTERNAL COMBUSTION ENGINE	
NORTHWEST REGIONAL LANDFILL	562212	1879					6/15/1997	10/27/2003	6/15/1988		11/18/2003	12/4/2003	M	N	LANDFILL GAS	ENCLOSED FLARE, INTERNAL COMBUSTION ENGINE	
PANDA GILA RIVER	221112	444439					12/29/1999	2/23/2001	3/7/2003		11/10/2003	11/21/2003	N		NATURAL GAS	COMBINED CYCLE UNITS	SCR AND CATALYTIC OXIDATION
PANDA GILA RIVER	221112	444439					12/29/1999	2/23/2001	3/7/2003		11/10/2003	11/21/2003	N		NATURAL GAS	COMBINED CYCLE UNITS	SCR AND CATALYTIC OXIDATION
PANDA GILA RIVER	221112	444439					12/29/1999	2/23/2001	3/7/2003		11/10/2003	11/21/2003	N		NATURAL GAS	COMBINED CYCLE UNITS	SCR AND CATALYTIC OXIDATION
PANDA GILA RIVER	221112	444439					12/29/1999	2/23/2001	3/7/2003		11/10/2003	11/21/2003	N		NATURAL GAS	COMBINED CYCLE UNITS	SCR AND CATALYTIC OXIDATION
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	221112	42956					7/14/1999	12/2/2000	4/9/2002		11/10/2003	11/21/2003	N	Y	NATURAL GAS	COMBINED CYCLE UNITS	SCR
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	221112	42956					7/14/1999	12/2/2000	4/9/2002		11/10/2003	11/21/2003	N	Y	NATURAL GAS	COMBINED CYCLE UNITS	SCR
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	221112	42956					7/14/1999	12/2/2000	4/9/2002		11/10/2003	11/21/2003	N	Y	NATURAL GAS	COMBINED CYCLE UNITS	SCR
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	221112	42956					7/14/1999	12/2/2000	4/9/2002		11/10/2003	11/21/2003	N	Y	NATURAL GAS	COMBINED CYCLE UNITS	SCR

FACILITY	NAICS	AIRSID	EPAID	UTMZONE	XCOORD	YCOORD	RCVD DATE	PERMIT DATE	STARTUP DATE	VERIFY DATE	ENTRY DATE	LAST UPDATE	NEW_ MOD	PUBLIC HEAR	FUEL	EMISSSOURCES	ABATEMENT
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	221112	42956					7/14/1999	12/2/2000	4/9/2002		11/10/2003	11/21/2003	N	Y	NATURAL GAS	COMBINED CYCLE UNITS	SCR
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	221112	4.02E+08					10/4/2000	7/25/2001	7/17/2002	10/9/2002	4/5/2004	4/15/2004	N	Y	NATURAL GAS	SIMPLE CYCLE COMBUSTION TURBINES	SELECTIVE CATALYTIC REDUCTION (SCR) WITH AMMONIA INJECTION, CATALYTIC OXIDIZER.
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	221112	4.02E+08					10/4/2000	7/25/2001	7/17/2002	10/9/2002	4/5/2004	4/15/2004	N	Y	NATURAL GAS	SIMPLE CYCLE COMBUSTION TURBINES	SELECTIVE CATALYTIC REDUCTION (SCR) WITH AMMONIA INJECTION, CATALYTIC OXIDIZER.
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	221112	4.02E+08					10/4/2000	7/25/2001	7/17/2002	10/9/2002	4/5/2004	4/15/2004	N	Y	NATURAL GAS	SIMPLE CYCLE COMBUSTION TURBINES	SELECTIVE CATALYTIC REDUCTION (SCR) WITH AMMONIA INJECTION, CATALYTIC OXIDIZER.
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	221112	4.02E+08					10/4/2000	7/25/2001	7/17/2002	10/9/2002	4/5/2004	4/15/2004	N	Y	NATURAL GAS	SIMPLE CYCLE COMBUSTION TURBINES	SELECTIVE CATALYTIC REDUCTION (SCR) WITH AMMONIA INJECTION, CATALYTIC OXIDIZER.
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	221112	4.02E+08					2/18/1999	9/10/1999	4/7/2001		4/5/2004	4/19/2004	N	Y	NATURAL GAS	COMBUSTION TURBINES WITH DUCT BURNERS	SELECTIVE CATALYTIC REDUCTION
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	221112	4.02E+08					2/18/1999	9/10/1999	4/7/2001		4/5/2004	4/19/2004	N	Y	NATURAL GAS	COMBUSTION TURBINES WITH DUCT BURNERS	SELECTIVE CATALYTIC REDUCTION
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	221112	4.02E+08					2/18/1999	9/10/1999	4/7/2001		4/5/2004	4/19/2004	N	Y	NATURAL GAS	COMBUSTION TURBINES WITH DUCT BURNERS	SELECTIVE CATALYTIC REDUCTION
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	221112	4.02E+08					2/18/1999	9/10/1999	4/7/2001		4/5/2004	4/19/2004	N	Y	NATURAL GAS	COMBUSTION TURBINES WITH DUCT BURNERS	SELECTIVE CATALYTIC REDUCTION
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	221112	4.02E+08					2/18/1999	9/10/1999	4/7/2001		4/5/2004	4/19/2004	N	Y	NATURAL GAS	COMBUSTION TURBINES WITH DUCT BURNERS	SELECTIVE CATALYTIC REDUCTION

FACILITY	NARRATIVE	NOTES	PROCESS	PROC TYPE	SCC	FUEL	THRUPUT	THRUPUT UNIT	COMP VERIFY	STACK TEST	INSPECTION	CALCULATED
APS WEST PHOENIX	POWER PLANT	Major modification. BACT/LAER required for PM, VOC and CO. NOx netted out.	TURBINE, COMBINED CYCLE, DUCT BURNER, NAT GAS, CC4	15.21	20100201	NATURAL GAS	130	MW	Y	Y	N	N
APS WEST PHOENIX	POWER PLANT	Major modification. BACT/LAER required for PM, VOC and CO. NOx netted out.	TURBINE, COMBINED CYCLE, DUCT BURNER, NAT GAS, CC4	15.21	20100201	NATURAL GAS	130	MW	Y	Y	N	N
APS WEST PHOENIX	POWER PLANT	Major modification. BACT/LAER required for PM, VOC and CO. NOx netted out.	TURBINE, COMBINED CYCLE, DUCT BURNER, NAT GAS, CC4	15.21	20100201	NATURAL GAS	130	MW	Y	Y	N	N
APS WEST PHOENIX	POWER PLANT	Major modification. BACT/LAER required for PM, VOC and CO. NOx netted out.	TURBINE, COMBINED CYCLE, DUCT BURNER, NAT GAS, CC5	15.21	20100201	NATURAL GAS	530	MW	Y	Y	N	N
APS WEST PHOENIX	POWER PLANT	Major modification. BACT/LAER required for PM, VOC and CO. NOx netted out.	TURBINE, COMBINED CYCLE, DUCT BURNER, NAT GAS, CC5	15.21	20100201	NATURAL GAS	530	MW	Y	Y	N	N
APS WEST PHOENIX	POWER PLANT	Major modification. BACT/LAER required for PM, VOC and CO. NOx netted out.	TURBINE, COMBINED CYCLE, DUCT BURNER, NAT GAS, CC5	15.21	20100201	NATURAL GAS	530	MW	Y	Y	N	N
DUKE ENERGY ARLINGTON VALLEY	POWER PLANT		TURBINE, COMBINED CYCLE	15.21	20100201	NATURAL GAS	255	MW	Y	Y	N	Y
DUKE ENERGY ARLINGTON VALLEY	POWER PLANT		TURBINE, COMBINED CYCLE	15.21	20100201	NATURAL GAS	255	MW	Y	Y	N	Y
DUKE ENERGY ARLINGTON VALLEY	POWER PLANT		TURBINE, COMBINED CYCLE	15.21	20100201	NATURAL GAS	255	MW	Y	Y	N	Y
DUKE ENERGY ARLINGTON VALLEY	POWER PLANT		TURBINE, COMBINED CYCLE	15.21	20100201	NATURAL GAS	255	MW	Y	Y	N	Y
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	POWER PLANT		TURBINE, COMBINED CYCLE & DUCT BURNER	15.21	20100201	NATURAL GAS	325	MW	N	N	N	N
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	POWER PLANT		TURBINE, COMBINED CYCLE & DUCT BURNER	15.21	20100201	NATURAL GAS	325	MW	N	N	N	N
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	POWER PLANT		TURBINE, COMBINED CYCLE & DUCT BURNER	15.21	20100201	NATURAL GAS	325	MW	N	N	N	N
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	POWER PLANT		TURBINE, COMBINED CYCLE & DUCT BURNER	15.21	20100201	NATURAL GAS	325	MW	N	N	N	N
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	POWER PLANT		TURBINE, COMBINED CYCLE	15.21	20100201	NATURAL GAS	325	MW	N	N	N	N
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	POWER PLANT		TURBINE, COMBINED CYCLE	15.21	20100201	NATURAL GAS	325	MW	N	N	N	N
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	POWER PLANT		TURBINE, COMBINED CYCLE	15.21	20100201	NATURAL GAS	325	MW	N	N	N	N
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	POWER PLANT		TURBINE, COMBINED CYCLE	15.21	20100201	NATURAL GAS	325	MW	N	N	N	N
GILA BEND POWER GENERATING STATION	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER, NATURAL GAS	15.21	20100201	NATURAL GAS	170	MW	Y	N	N	Y
GILA BEND POWER GENERATING STATION	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER, NATURAL GAS	15.21	20100201	NATURAL GAS	170	MW	Y	N	N	Y
GILA BEND POWER GENERATING STATION	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER, NATURAL GAS	15.21	20100201	NATURAL GAS	170	MW	Y	N	N	Y
GILA BEND POWER GENERATING STATION	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER, NATURAL GAS	15.21	20100201	NATURAL GAS	170	MW	Y	N	N	Y
HARQUAHALA GENERATING PROJECT		THERE ARE 3 NATURAL GAS FIRED TURBINES, SEIMENS-WESTINGHOUSE SW501G (240 MW EACH) AND THREE STEAM TURBINES (121 MW EACH). THERE IS NO SUPPLEMENTARY DUCT FIRING. SCR AND OXIDATION CATALYSTS FOR EMISSION CONTROLS	COMBINED CYCLE, NATURAL GAS	15.21	2-01-002-01	NATURAL GAS	2362	MMBTU/H	N	N	N	N
HARQUAHALA GENERATING PROJECT		THERE ARE 3 NATURAL GAS FIRED TURBINES, SEIMENS-WESTINGHOUSE SW501G (240 MW EACH) AND THREE STEAM TURBINES (121 MW EACH). THERE IS NO SUPPLEMENTARY DUCT FIRING. SCR AND OXIDATION CATALYSTS FOR EMISSION CONTROLS	COMBINED CYCLE, NATURAL GAS	15.21	2-01-002-01	NATURAL GAS	2362	MMBTU/H	N	N	N	N
HARQUAHALA GENERATING PROJECT		THERE ARE 3 NATURAL GAS FIRED TURBINES, SEIMENS-WESTINGHOUSE SW501G (240 MW EACH) AND THREE STEAM TURBINES (121 MW EACH). THERE IS NO SUPPLEMENTARY DUCT FIRING. SCR AND OXIDATION CATALYSTS FOR EMISSION CONTROLS	COMBINED CYCLE, NATURAL GAS	15.21	2-01-002-01	NATURAL GAS	2362	MMBTU/H	N	N	N	N
HARQUAHALA GENERATING PROJECT		THERE ARE 3 NATURAL GAS FIRED TURBINES, SEIMENS-WESTINGHOUSE SW501G (240 MW EACH) AND THREE STEAM TURBINES (121 MW EACH). THERE IS NO SUPPLEMENTARY DUCT FIRING. SCR AND OXIDATION CATALYSTS FOR EMISSION CONTROLS	COMBINED CYCLE, NATURAL GAS	15.21	2-01-002-01	NATURAL GAS	2362	MMBTU/H	N	N	N	N
HARQUAHALA GENERATING PROJECT		THERE ARE 3 NATURAL GAS FIRED TURBINES, SEIMENS-WESTINGHOUSE SW501G (240 MW EACH) AND THREE STEAM TURBINES (121 MW EACH). THERE IS NO SUPPLEMENTARY DUCT FIRING. SCR AND OXIDATION CATALYSTS FOR EMISSION CONTROLS	COMBINED CYCLE, NATURAL GAS	15.21	2-01-002-01	NATURAL GAS	2362	MMBTU/H	N	N	N	N
INTEL CORPORATION			BOILERS, 5	13.31	10200602	NATURAL GAS	50	MMBTU/HR	F	F	F	F
INTEL CORPORATION			BOILERS, 5	13.31	10200602	NATURAL GAS	50	MMBTU/HR	F	F	F	F
INTEL CORPORATION			PHOTORESIST OPERATIONS	99.011	40100399		0		F	F	F	F
INTEL CORPORATION			GENERATORS, BACKUP, 5	17.13	20200202	NATURAL GAS	2220	BHP	F	F	F	F
INTEL CORPORATION			GENERATORS, BACKUP, 5	17.13	20200202	NATURAL GAS	2220	BHP	F	F	F	F
INTEL CORPORATION		PROJECT XL PERMIT	SEMICONDUCTOR MANUFACTURING	99.011	3-13-999-99		0		F	F	F	F
INTEL CORPORATION		PROJECT XL PERMIT	BOILERS, GENERATORS	16.11	1-02-005-02		0		F	F	F	F
INTEL CORPORATION		PROJECT XL PERMIT	BOILERS (10)	13.31	1-02-005-02		54	MMBTU	F	F	F	F

FACILITY	NARRATIVE	NOTES	PROCESS	PROC TYPE	SCC	FUEL	THRUPUT	THRUPUT UNIT	COMP VERIFY	STACK TEST	INSPECTION	CALCULATED
KYRENE GENERATING STATION, SALT RIVER PROJECT	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER, NAT GAS	15.21	20100201	NATURAL GAS	175	MW	Y	Y	N	N
KYRENE GENERATING STATION, SALT RIVER PROJECT	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER, NAT GAS	15.21	20100201	NATURAL GAS	175	MW	Y	Y	N	N
KYRENE GENERATING STATION, SALT RIVER PROJECT	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER, NAT GAS	15.21	20100201	NATURAL GAS	175	MW	Y	Y	N	N
MESQUITE GENERATING STATION		FACILITY WILL HAVE FOUR GE 7FA TURBINES - 180 MW EA. (WITH POWER AUGMENTATION). EACH TURBINE HAS A HEAT RECOVERY STEAM GENERATOR (HRSG) WITH DUCT BURNER. EACH DUCT BURNER HAS A MAX. HEAT INPUT OF 592.6 MMBTU/H (HHV). STEAM FROM THE FOUR HRSGS IS ROUTED TO TWO STEAM TURBINES (290 MW EACH.) TOTAL NOMINAL OUTPUT FOR THE FACILITY IS 1300 MW.	TURBINE, COMBINED CYCLE, NATURAL GAS	15.21	20100201	NATURAL GAS	1923	MMBTU/H	N	N	N	N
MESQUITE GENERATING STATION		FACILITY WILL HAVE FOUR GE 7FA TURBINES - 180 MW EA. (WITH POWER AUGMENTATION). EACH TURBINE HAS A HEAT RECOVERY STEAM GENERATOR (HRSG) WITH DUCT BURNER. EACH DUCT BURNER HAS A MAX. HEAT INPUT OF 592.6 MMBTU/H (HHV). STEAM FROM THE FOUR HRSGS IS ROUTED TO TWO STEAM TURBINES (290 MW EACH.) TOTAL NOMINAL OUTPUT FOR THE FACILITY IS 1300 MW.	TURBINE, COMBINED CYCLE, NATURAL GAS	15.21	20100201	NATURAL GAS	1923	MMBTU/H	N	N	N	N
MESQUITE GENERATING STATION		FACILITY WILL HAVE FOUR GE 7FA TURBINES - 180 MW EA. (WITH POWER AUGMENTATION). EACH TURBINE HAS A HEAT RECOVERY STEAM GENERATOR (HRSG) WITH DUCT BURNER. EACH DUCT BURNER HAS A MAX. HEAT INPUT OF 592.6 MMBTU/H (HHV). STEAM FROM THE FOUR HRSGS IS ROUTED TO TWO STEAM TURBINES (290 MW EACH.) TOTAL NOMINAL OUTPUT FOR THE FACILITY IS 1300 MW.	TURBINE, COMBINED CYCLE, NATURAL GAS	15.21	20100201	NATURAL GAS	1923	MMBTU/H	N	N	N	N
MESQUITE GENERATING STATION		FACILITY WILL HAVE FOUR GE 7FA TURBINES - 180 MW EA. (WITH POWER AUGMENTATION). EACH TURBINE HAS A HEAT RECOVERY STEAM GENERATOR (HRSG) WITH DUCT BURNER. EACH DUCT BURNER HAS A MAX. HEAT INPUT OF 592.6 MMBTU/H (HHV). STEAM FROM THE FOUR HRSGS IS ROUTED TO TWO STEAM TURBINES (290 MW EACH.) TOTAL NOMINAL OUTPUT FOR THE FACILITY IS 1300 MW.	TURBINE, COMBINED CYCLE, NATURAL GAS	15.21	20100201	NATURAL GAS	1923	MMBTU/H	N	N	N	N
MESQUITE GENERATING STATION		FACILITY WILL HAVE FOUR GE 7FA TURBINES - 180 MW EA. (WITH POWER AUGMENTATION). EACH TURBINE HAS A HEAT RECOVERY STEAM GENERATOR (HRSG) WITH DUCT BURNER. EACH DUCT BURNER HAS A MAX. HEAT INPUT OF 592.6 MMBTU/H (HHV). STEAM FROM THE FOUR HRSGS IS ROUTED TO TWO STEAM TURBINES (290 MW EACH.) TOTAL NOMINAL OUTPUT FOR THE FACILITY IS 1300 MW.	TURBINE, COMBINED CYCLE, NATURAL GAS	15.21	20100201	NATURAL GAS	1923	MMBTU/H	N	N	N	N
MINNESOTA METHANE		COMPANY SELLS ENGINES TO MUNICIPAL LANDFILLS TO DESTROY LANDFILL GAS VIA COGENERATION.	ENGINES, COGENERATION (4)	17.15	2-01-008-02	LANDFILL GAS	800	KW	F	F	F	F
MINNESOTA METHANE		COMPANY SELLS ENGINES TO MUNICIPAL LANDFILLS TO DESTROY LANDFILL GAS VIA COGENERATION.	ENGINES, COGENERATION (4)	17.15	2-01-008-02	LANDFILL GAS	800	KW	F	F	F	F
NORTHWEST REGIONAL LANDFILL	MUNICIPAL LANDFILL		FLARE, ENCLOSED	19.32	50100410	LANDFILL GAS			N	N	N	N
NORTHWEST REGIONAL LANDFILL	MUNICIPAL LANDFILL		FLARE, ENCLOSED	19.32	50100410	LANDFILL GAS			N	N	N	N
NORTHWEST REGIONAL LANDFILL	MUNICIPAL LANDFILL		INTERNAL COMBUSTION ENGINE	17.15	20100802	LANDFILL GAS	1410	HP	N	N	N	N
NORTHWEST REGIONAL LANDFILL	MUNICIPAL LANDFILL		INTERNAL COMBUSTION ENGINE	17.15	20100802	LANDFILL GAS	1410	HP	N	N	N	N
PANDA GILA RIVER	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER	15.21	20100201	NATURAL GAS	170	MW	Y	Y	N	Y
PANDA GILA RIVER	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER	15.21	20100201	NATURAL GAS	170	MW	Y	Y	N	Y
PANDA GILA RIVER	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER	15.21	20100201	NATURAL GAS	170	MW	Y	Y	N	Y
PANDA GILA RIVER	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER	15.21	20100201	NATURAL GAS	170	MW	Y	Y	N	Y
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER	15.21	20100201	NATURAL GAS	175	MW	Y	Y	N	Y
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER	15.21	20100201	NATURAL GAS	175	MW	Y	Y	N	Y
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER	15.21	20100201	NATURAL GAS	175	MW	Y	Y	N	Y
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER	15.21	20100201	NATURAL GAS	175	MW	Y	Y	N	Y

FACILITY	NARRATIVE	NOTES	PROCESS	PROC TYPE	SCC	FUEL	THRUPUT	THRUPUT UNIT	COMP VERIFY	STACK TEST	INSPECTION	CALCULATED
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	POWER PLANT		TURBINE, COMBINED CYCLE, NO DUCT BURNER	15.21	20100201	NATURAL GAS	175	MW	Y	Y	N	Y
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	POWER PLANT		TURBINE, SIMPLE CYCLE, (12)	15.11	20100201	NATURAL GAS	450	MW	N	N	N	N
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	POWER PLANT		TURBINE, SIMPLE CYCLE, (12)	15.11	20100201	NATURAL GAS	450	MW	N	N	N	N
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	POWER PLANT		TURBINE, SIMPLE CYCLE, (12)	15.11	20100201	NATURAL GAS	450	MW	N	N	N	N
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	POWER PLANT		TURBINE, SIMPLE CYCLE, (12)	15.11	20100201	NATURAL GAS	450	MW	N	N	N	N
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	POWER PLANT		TURBINE, COMBINED CYCLE	15.21	20100201	NATURAL GAS	290	MW	Y	Y	Y	N
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	POWER PLANT		TURBINE, COMBINED CYCLE	15.21	20100201	NATURAL GAS	290	MW	Y	Y	Y	N
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	POWER PLANT		TURBINE, COMBINED CYCLE	15.21	20100201	NATURAL GAS	290	MW	Y	Y	Y	N
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	POWER PLANT		TURBINE, COMBINED CYCLE	15.21	20100201	NATURAL GAS	290	MW	Y	Y	Y	N
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	POWER PLANT		TURBINE, COMB'D CYCLE WITH DUCT BURNERS	15.21	20100201	NATURAL GAS	290	MW	Y	Y	Y	N

FACILITY	OTHER TEST	OTHER METHD	PRNOTES	POLLUTANT	CAS	CONTROLCOD	CTRLDESC	RANK OPTS	RANK SEL	EMIS LIMIT1	EMIS LIMIT1 UNIT	EMISLIMIT1 CONDITION	BASIS
APS WEST PHOENIX	N			PM10	PM	P	USE OF NATURAL GAS AND GOOD COMBUSTION PRACTICES	4	3	0.0055	LB/MMBTU		LAER
APS WEST PHOENIX	N			VOC	VOC	A	OXIDATION CATALYST			0.0016	LB/MMBTU		LAER
APS WEST PHOENIX	N			CO	630-08-0	A	OXIDATION CATALYST			6	PPM @ 15% O2		LAER
APS WEST PHOENIX	N			PM10	PM	P	USE OF NATURAL GAS AND GOOD COMBUSTION	4	3	0.0051	LB/MMBTU	3 h avg	LAER
APS WEST PHOENIX	N			VOC	VOC	A	OXIDATION CATALYST	3	3	0.0025	LB/MMBTU	3 h avg	BACT-OTHER
APS WEST PHOENIX	N			CO	630-08-0	A	OXIDATION CATALYST			6	PPM @ 15% O2		LAER
DUKE ENERGY ARLINGTON VALLEY	N			NOX	10102	A	SCR	4	3	2.5	PPM @ 15% O2	3 hr avg	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY	N			CO	630-08-0	N				20	PPM @ 15% O2	3 hr avg	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY	N			PM10	PM	N				27	LB/H		BACT-PSD
DUKE ENERGY ARLINGTON VALLEY	N			VOC	VOC	N				1.4	PPM @ 15% O2	3 hr avg	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	N			NOX	10102	A	SCR			2	PPM @ 15% O2	1 hr avg	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	N			CO	630-08-0	A	CATALYTIC OXIDIZER			3	PPM @ 15% O2	3 hr avg	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	N			PM10	PM	N				25	LB/H		BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	N			VOC	VOC	N				4	PPM	3 hr avg	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	N		This process entry provides emission limits for the combined cycl turbine without the duct burner.	NOX	10102	A	SCR			2	PPM @ 15% O2	1 hr avg	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	N		This process entry provides emission limits for the combined cycl turbine without the duct burner.	CO	630-08-0	A	CATALYTIC OXIDIZER			2	PPM @ 15% O2	3 hr avg	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	N		This process entry provides emission limits for the combined cycl turbine without the duct burner.	PM10	PM	N				18	LB/H		BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	N		This process entry provides emission limits for the combined cycl turbine without the duct burner.	VOC	VOC	N				1	PPM	3 hr avg	BACT-PSD
GILA BEND POWER GENERATING STATION	N			NOX	10102	B	SCR AND LOW NOX COMBUSTORS	3		2	PPM @ 15% O2	1-hr avg	BACT-PSD
GILA BEND POWER GENERATING STATION	N			CO	630-08-0	A	OXIDATION CATALYST	3	2	4	PPM @ 15% O2	3 h avg	BACT-PSD
GILA BEND POWER GENERATING STATION	N			VOC	VOC	B	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICE	2	1	1.4	PPM @ 15% O2		BACT-PSD
GILA BEND POWER GENERATING STATION	N			PM10	PM	N				0.014	LB/MMBTU	3 h avg	BACT-PSD
HARQUAHALA GENERATING PROJECT	N		THERE ARE 3 NATURAL GAS FIRED TURBINES (240 MW EACH) AND THREE STEAM TURBINES (121 MW EACH). THERE IS NO SUPPLEMENTARY DUCT FIRING. THROUGHPUT LISTED IS PER TURBINE.	NOX	10102	A	SCR. EMISSIONS IN THE LB/H ARE FOR EACH COMBINED CYCLE UNIT.			2.5	PPM		BACT-OTHER
HARQUAHALA GENERATING PROJECT	N		THERE ARE 3 NATURAL GAS FIRED TURBINES (240 MW EACH) AND THREE STEAM TURBINES (121 MW EACH). THERE IS NO SUPPLEMENTARY DUCT FIRING. THROUGHPUT LISTED IS PER TURBINE.	SO2	9/5/7446	P	USE OF PIPELINE QUALITY NATURAL GAS ONLY. EMISSIONS IN THE LB/H ARE FOR EACH COMBINED CYCLE UNIT . PPM FOR SO2 NOT AVAILABLE.			5.8	LB/H		BACT-OTHER
HARQUAHALA GENERATING PROJECT	N		THERE ARE 3 NATURAL GAS FIRED TURBINES (240 MW EACH) AND THREE STEAM TURBINES (121 MW EACH). THERE IS NO SUPPLEMENTARY DUCT FIRING. THROUGHPUT LISTED IS PER TURBINE.	PM10	PM	P	GOOD COMBUSTION CONTROL. EMISSIONS IN THE LB/H ARE FOR EACH COMBINED CYCLE UNIT.			24	LB/H		BACT-OTHER
HARQUAHALA GENERATING PROJECT	N		THERE ARE 3 NATURAL GAS FIRED TURBINES (240 MW EACH) AND THREE STEAM TURBINES (121 MW EACH). THERE IS NO SUPPLEMENTARY DUCT FIRING. THROUGHPUT LISTED IS PER TURBINE.	CO	630-08-0	A	OXIDATION CATALYST. EMISSIONS IN THE LB/H ARE FOR EACH COMBINED CYCLE UNIT .			37	LB/H		BACT-OTHER
HARQUAHALA GENERATING PROJECT	N		THERE ARE 3 NATURAL GAS FIRED TURBINES (240 MW EACH) AND THREE STEAM TURBINES (121 MW EACH). THERE IS NO SUPPLEMENTARY DUCT FIRING. THROUGHPUT LISTED IS PER TURBINE.	VOC	VOC	P	COMBUSTION CONTROL AND USE OF NATURAL GAS. EMISSIONS IN THE LB/H ARE FOR EACH COMBINED CYCLE UNIT.			2.8	PPM		BACT-OTHER
INTEL CORPORATION	F			NOX	10102	P	LOW NOX BURNERS	0	0	0			BACT
INTEL CORPORATION	F			SOX/PM10	7446	P	FUEL SPEC: NATURAL GAS PRIMARY, .055 WT % S FUEL OIL BACKUP ONLY	0	0	0			BACT
INTEL CORPORATION	F			VOC	VOC	A	AFTERBURNERS	0	0	0			BACT
INTEL CORPORATION	F			NOX/PM10	10102	A	CYANURIC ACID INJECTION TAILPIPE CONTROL	0	0	0			BACT
INTEL CORPORATION	F			SOX	7446	P	FUEL SPEC: .055 WT % S FUEL OIL	0	0	0			BACT
INTEL CORPORATION	F			VOC	VOC	A	CARBON ADSORPTION KREHA CONTINUOUSLY DESORBED WITH CHILLER	0	0	40	TPY		BACT-OTHER
INTEL CORPORATION	F			SOX	7446	P	FUEL SPEC: 0.055 WT% S OIL	0	0	5	TPY		BACT-OTHER
INTEL CORPORATION	F			NOX	10102	P	LOW NOX BURNERS < 50 PPM NOX	0	0	49	TPY		BACT-OTHER

FACILITY	OTHER TEST	OTHER METHD	PRNOTES	POLLUTANT	CAS	CONTROLCOD	CTRLDESC	RANK OPTS	RANK SEL	EMIS LIMIT1	EMIS LIMIT1 UNIT	EMISLIMIT1 CONDITION	BASIS
KYRENE GENERATING STATION, SALT RIVER PROJECT	N			NOX	10102	A	SCR			2.5	PPM @ 15% O2	3 H avg	LAER
KYRENE GENERATING STATION, SALT RIVER PROJECT	N			CO	630-08-0	A	OXIDATION CATALYST			3.9	PPM @ 15% O2	3 H avg	LAER
KYRENE GENERATING STATION, SALT RIVER PROJECT	N			PM10	PM	N				0.0072	LB/MMBTU		LAER
MESQUITE GENERATING STATION	N		FOUR GE 7FA TURBINES - COMBINED CYCLE 180 MW (WITH POWER AUGMENTATION) TWO 290 MW STEAM TURBINES. THROUGHPUT LISTED PER TURBINE.	VOC	VOC	A	OXIDATION CATALYST. EMISSIONS IN LB/H ARE COMBINED FOR EACH COMBINED CYCLE UNIT (TURBINE AND DUCT BURNER)			16.6	LB/H		BACT-PSD
MESQUITE GENERATING STATION	N		FOUR GE 7FA TURBINES - COMBINED CYCLE 180 MW (WITH POWER AUGMENTATION) TWO 290 MW STEAM TURBINES. THROUGHPUT LISTED PER TURBINE.	SO2	9/5/7446	P	PIPELINE QUALITY NATURAL GAS. EMISSIONS IN LB/H ARE COMBINED FOR EACH COMBINED CYCLE UNIT (TURBINE AND DUCT BURNER). PPM FOR SO2 NOT AVAILABLE.			2.1	LB/H		BACT-OTHER
MESQUITE GENERATING STATION	N		FOUR GE 7FA TURBINES - COMBINED CYCLE 180 MW (WITH POWER AUGMENTATION) TWO 290 MW STEAM TURBINES. THROUGHPUT LISTED PER TURBINE.	PM10	PM	N	EMISSIONS IN LB/H ARE COMBINED FOR EACH COMBINED CYCLE UNIT (TURBINE AND DUCT BURNER)			30.4	LB/H		BACT-PSD
MESQUITE GENERATING STATION	N		FOUR GE 7FA TURBINES - COMBINED CYCLE 180 MW (WITH POWER AUGMENTATION) TWO 290 MW STEAM TURBINES. THROUGHPUT LISTED PER TURBINE.	NOX	10102	A	SCR. EMISSIONS IN LB/H ARE COMBINED FOR EACH COMBINED CYCLE UNIT (TURBINE AND DUCT BURNER)			2.5	PPM @ 15% O2		BACT-PSD
MESQUITE GENERATING STATION	N		FOUR GE 7FA TURBINES - COMBINED CYCLE 180 MW (WITH POWER AUGMENTATION) TWO 290 MW STEAM TURBINES. THROUGHPUT LISTED PER TURBINE.	CO	630-08-0	A	OXIDATION CATALYST. EMISSIONS IN LB/H ARE COMBINED FOR EACH COMBINED CYCLE UNIT (TURBINE AND DUCT BURNER)			4	PPM @ 15% O2		BACT-PSD
MINNESOTA METHANE	F			NOX	10102	P	AIR/FUEL CONTROLLER ADJUSTED TO OBTAIN LOW NOX	0	0	99	TPY		BACT
MINNESOTA METHANE	F			CO	630-08-0	P	AIR/FUEL CONTROLLER	0	0	99.9	TPY		BACT
NORTHWEST REGIONAL LANDFILL	N			NOX	10102	N				0.041	LB/MMBTU		BACT-OTHER
NORTHWEST REGIONAL LANDFILL	N			CO	630-08-0	N				0.13	LB/MMBTU		BACT-OTHER
NORTHWEST REGIONAL LANDFILL	N			NOX	10102	N				0.6	G/B-HP-H		BACT-OTHER
NORTHWEST REGIONAL LANDFILL	N			CO	630-08-0	N				2.5	G/B-HP-H		BACT-OTHER
PANDA GILA RIVER	N			NOX	10102	A	SCR			3	PPM @ 15% O2	3 hr avg	BACT-PSD
PANDA GILA RIVER	N			CO	630-08-0	A	OXIDATION CATALYST			2.8	PPM @ 15% O2	24 hr avg	BACT-PSD
PANDA GILA RIVER	N			PM10	PM	N				0.0056	LB/MMBTU	3 hr avg	BACT-PSD
PANDA GILA RIVER	N			VOC	VOC	N				2.8	PPM @ 15% O2	3 hr avg	BACT-PSD
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	N			NOX	10102	B	SCR AND LOW-NOX BURNERS	4		2.5	PPM @ 15% O2		BACT-PSD
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	N			CO	630-08-0	P	GOOD COMBUSTION	2	2	23	PPM @ 15% O2		BACT-PSD
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	N			VOC	VOC	P	GOOD COMBUSTION	2	2	0.0036	LB/MMBTU		BACT-PSD
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	N			PM10	PM	N				0.0101	LB/MMBTU		BACT-PSD

FACILITY	OTHER TEST	OTHER METHD	PRNOTES	POLLUTANT	CAS	CONTROLCOD	CTRLDESC	RANK OPTS	RANK SEL	EMIS LIMIT1	EMIS LIMIT1 UNIT	EMISLIMIT1 CONDITION	BASIS
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	N		All limits the same as those for power generation with duct burner, except for limits for CO.	CO	630-08-0	P	GOOD COMBUSTION	2	2	14	PPM @ 15% O2		BACT-PSD
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	N		twelve 45 MW simple cycle natural gas fired turbines, with a nominal generating capacity of 540 MW, combined.	NOX	10102	A	SCR			5	PPM @ 15% O2	3-h avg	BACT-PSD
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	N		twelve 45 MW simple cycle natural gas fired turbines, with a nominal generating capacity of 540 MW, combined.	CO	630-08-0	A	OXIDATION CATALYST			7.5	PPM @ 15% O2	>59 degrees F, 3-h avg	BACT-PSD
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	N		twelve 45 MW simple cycle natural gas fired turbines, with a nominal generating capacity of 540 MW, combined.	PM10	PM	P	GOOD COMBUSTION PRACTICE			7	LB/H		BACT-PSD
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	N		twelve 45 MW simple cycle natural gas fired turbines, with a nominal generating capacity of 540 MW, combined.	VOC	VOC	A	CATALYTIC OXIDIZER			4.5	LB/H		BACT-PSD
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	N			NOX	10102	A	SCR			3	PPM @ 15% O2	3-h avg	BACT-PSD
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	N			CO	630-08-0	P	GOOD COMBUSTION PRACTICE			15.3	PPM @ 15% O2	3-h avg	BACT-PSD
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	N			PM10	PM	P	GOOD COMBUSTION PRACTICE			15.3	LB/H	3-h avg	BACT-PSD
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	N			VOC	VOC	P	GOOD COMBUSTION PRACTICE			8.2	LB/H	3-h avg	BACT-PSD
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	N			NOX	10102	A	SCR			3	PPM @ 15% O2		BACT-PSD

FACILITY	PCTEFFIC	EMIS LIMIT2	EMISLIMIT2 UNIT	EMISLIMIT2 CONDITION	STDEMISS	STDUNIT	STOTHER CONDITIONS	EMISSTYPE	CAPCOST	ANNUALCOST	OMCOST	COSTEFFECT	COSTVERIFY	DOLLARYEAR	POLNOTES
APS WEST PHOENIX								P					N		
APS WEST PHOENIX								P					N		
APS WEST PHOENIX					6	PPM @ 15% O2		P					N		
APS WEST PHOENIX								P					N		
APS WEST PHOENIX								P					N		
APS WEST PHOENIX					6	PPM @ 15% O2		P					N		
DUKE ENERGY ARLINGTON VALLEY					2.5	PPM @ 15% O2		P					N		
DUKE ENERGY ARLINGTON VALLEY					20	PPM @ 15% O2		P					N		
DUKE ENERGY ARLINGTON VALLEY								P					N		
DUKE ENERGY ARLINGTON VALLEY		3	LB/H					P					N		
DUKE ENERGY ARLINGTON VALLEY (AVEFII)					2	PPM @ 15% O2		P					N		Limit achieved after 2 yr demonstratior period
DUKE ENERGY ARLINGTON VALLEY (AVEFII)					3	PPM @ 15% O2		P					N		
DUKE ENERGY ARLINGTON VALLEY (AVEFII)								P					N		
DUKE ENERGY ARLINGTON VALLEY (AVEFII)								P					N		
DUKE ENERGY ARLINGTON VALLEY (AVEFII)					2	PPM @ 15% O2		P					N		Limit achieved after 2 yr demonstratior period
DUKE ENERGY ARLINGTON VALLEY (AVEFII)					2	PPM @ 15% O2		P					N		
DUKE ENERGY ARLINGTON VALLEY (AVEFII)								P					N		
DUKE ENERGY ARLINGTON VALLEY (AVEFII)								P					N		
GILA BEND POWER GENERATING STATION	78				2	PPM @ 15% O2		P				148288	N		
GILA BEND POWER GENERATING STATION	67				4	PPM @ 15% O2		P				9638	N		
GILA BEND POWER GENERATING STATION	50							P				142238	N		
GILA BEND POWER GENERATING STATION		26.02	LB/H	3 h avg				P					N		
HARQUAHALA GENERATING PROJECT		25	LB/H		2.5	PPM @ 15% O2		P					N		
HARQUAHALA GENERATING PROJECT								P					N		
HARQUAHALA GENERATING PROJECT								P					N		
HARQUAHALA GENERATING PROJECT		10	PPM		10	PPM @ 15% O2		P					N		
HARQUAHALA GENERATING PROJECT		7.8	LB/H		2.8	PPM @ 15% O2		P					N		
INTEL CORPORATION	0	0			0			P	0	0	0		N		
INTEL CORPORATION	0	0			0			P	0	0	0		N		
INTEL CORPORATION	90	0			0			P	0	0	0		N		
INTEL CORPORATION	80	0			0			P	0	0	0		N		
INTEL CORPORATION	0	0			0			P	0	0	0		N		
INTEL CORPORATION	90	0			0			P	0	0	0		N		
INTEL CORPORATION	0	0			0			P	0	0	0		N		
INTEL CORPORATION	0	0			0			P	0	0	0		N		

FACILITY	PCTEFFIC	EMIS LIMIT2	EMISLIMIT2 UNIT	EMISLIMIT2 CONDITION	STDEMISS	STDUNIT	STOTHER CONDITIONS	EMISSTYPE	CAPCOST	ANNUALCOST	OMCOST	COSTEFFECT	COSTVERIFY	DOLLARYEAR	POLNOTES
KYRENE GENERATING STATION, SALT RIVER PROJECT					2.5	PPM @ 15% O2	3 H avg	P					N		
KYRENE GENERATING STATION, SALT RIVER PROJECT					3.9	PPM @ 15% O2	3 H avg	P					N		
KYRENE GENERATING STATION, SALT RIVER PROJECT								P					N		
MESQUITE GENERATING STATION		5.2	PPM @ 15% O2		5.2	PPM @ 15% O2		P					N		
MESQUITE GENERATING STATION								P					N		
MESQUITE GENERATING STATION		0.0128	LB/MMBTU					P					N		
MESQUITE GENERATING STATION		22.2	LB/H		2.5	PPM @ 15% O2		P					N		
MESQUITE GENERATING STATION		21.6	LB/H		4	PPM @ 15% O2		P					N		
MINNESOTA METHANE	0	0			0			P	0	0	0		N		
MINNESOTA METHANE	0	0			0			P	0	0	0		N		
NORTHWEST REGIONAL LANDFILL					0.041	LB/MMBTU		P					N		
NORTHWEST REGIONAL LANDFILL					0.13	LB/MMBTU		P					N		
NORTHWEST REGIONAL LANDFILL		4500	PPM		0.6	G/B-HP-H		P					N		
NORTHWEST REGIONAL LANDFILL		280	PPM		2.5	G/B-HP-H		P					N		
PANDA GILA RIVER					3	PPM @ 15% O2		P					N		
PANDA GILA RIVER					2.8	PPM @ 15% O2		P					N		
PANDA GILA RIVER		12.5	LB/H					P					N		
PANDA GILA RIVER								P					N		
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY					2.5	PPM @ 15% O2		P					N		
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY					23	PPM @ 15% O2		P					N		
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY								P					N		
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY		22.2	LB/H					P					N		

FACILITY	PCTEFFIC	EMIS LIMIT2	EMISLIMIT2 UNIT	EMISLIMIT2 CONDITION	STDEMISS	STDUNIT	STOTHER CONDITIONS	EMISSTYPE	CAPCOST	ANNUALCOST	OMCOST	COSTEFFECT	COSTVERIFY	DOLLARYEAR	POLNOTES
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY					14	PPM @ 15% O2		P					N		
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY					5	PPM @ 15% O2		P					N		
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY		15	PPM @ 15% O2	<59 degrees F, 3-h avg	7.5	PPM @ 15% O2		P					N		
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY								P					N		
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY								P					N		
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC					3	PPM @ 15% O2		P					N		
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC					15.3	PPM @ 15% O2		P					N		
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC								P					N		
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC								P					N		
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC					3	PPM @ 15% O2		P					N		

RBLCID	ORIS_CODE	FACILITY_NAME
	50805	ABITIBI CONSOLIDATED SNOWFLAKE DIVISION
	141	Agua Fria Generating Station
	160	Apache Station
	118	APS Saguaro Power Plant
	54594	BIOSPHERE 2 CENTER INC
	55780	Bowie Power Station
	112	CHILDS
	113	Cholla
	6177	Coronado Generating Station
	143	Crosscut
	152	DAVIS
	124	De Moss Petrie Generating Station
AZ-0044	55129	Desert Basin Generating Station
	114	DOUGLAS
AZ-0035	55282	Duke Energy Arlington Valley
	923	Gila Bend
AZ-0038	55507	Gila Bend Power Generation Station
AZ-0037	55306	Gila River Power Station
	153	GLEN CANYON
	54838	GOULD ELECTRONICS FOIL DIVISION
	55124	Griffith Energy LLC
AZ-0034	55372	Harquahala Generating Project
	8902	HOOVER
	145	HORSE MESA
	55257	INA ROAD WATER POLLUTION CONTROL FACILITY
	10564	INTERMOUNTAIN REFINING COMPANY, INC
	115	IRVING
	126	Irvington Generating Station
AZ-0041	147	Kyrene Generating Station
	55711	La Paz Generating Facility
AZ-0033	55481	Mesquite Generating Station
	148	MORMON FLAT
	4941	Navajo Generating Station
	54245	NELSON PLANT GENERATORS
	50738	NEW CORNELIA BRANCH POWER PLANT
	54949	NORDIC POWER OF SOUTH POINT I

RBLCID	ORIS_CODE	FACILITY_NAME
	6088	NORTH LOOP
	116	Ocotillo Power Plant
	6008	PALO VERDE
AZ-0045	55522	PPL Sundance Energy, LLC
AZ-0036	55455	Redhawk Generating Facility
	149	ROOSEVELT
AZ-0039	8068	Santan
	55692	Signal Peak Generating Facility
	100	SOUTH CONSOLIDATED
	55177	South Point Energy Center, LLC
	8223	Springerville Generating Station
	50238	STARWOOD HOTELS RESORTS
	150	STEWART MTN
	6515	VALENCIA
AZ-0040	117	West Phoenix Power Plant
	120	Yuma Axis
	54694	YUMA COGENERATION ASSOCIATES
	464	Alamosa
	10755	AMERICAN ATLAS 1 COGENERATION PLANT
	54630	AMERICAN GYPSUM COGENERATION
	6207	AMES
	465	Arapahoe
CO-0049	55200	Arapahoe Combustion Turbine
	54680	BETASSO HYDROELECTRIC PLANT
	515	BIG THOMPSON
	512	BLUE MESA
	55645	Blue Spruce Energy Center
	466	BOULDER
	10682	Brush 3
	55209	Brush 4
CO-0027 & C(	10683	BRUSH COGEN PROJECT PHASE 2 BCP
	6619	BURLINGTON
	467	CABIN CREEK
	468	Cameo
	469	Cherokee
	54679	CITY OF BOULDER - LAKEWOOD HYDROELECTRIC PLT

RBLCID	ORIS_CODE	FACILITY_NAME
	470	Comanche (470)
	6021	Craig
	6159	CRYSTAL
	496	DELTA
	10421	DILLON HYDRO PLANT
	54671	DRAGON TRAIL GAS PROCESSING PLANT
	513	ESTES
	54973	FAA AIR ROUTE TRAFFIC CONTROL CENTER
	518	FLATIRON
	10070	FOOTHILLS HYDRO PLANT
	8067	FORT LUPTON
CO-0024 & CO	6112	Fort St. Vrain
	55453	Fountain Valley Combustion Turbine
	55505	Frank Knutson Station
CO-0042	55283	Front Range Power Plant
	471	FRUITA
	493	George Birdsall
	472	GEORGETOWN
	54413	GLENWOOD SPRINGS SALT PROJECT
	6708	GR JUNCTION
	516	GREEN MOUNTAIN
	10424	GROSS HYDRO PLANT
	525	Hayden
	54142	HILLCREST POWERPLANT
	502	Holly
	50205	IGNACIO GASOLINE PLANT
	54596	JOHNSTOWN COGENERATION
	55191	KQ1
	506	LA JUNTA
	508	Lamar
	507	LAS ANIMAS
CO-0050	55504	Limon Generating Station
	509	LONGMONT
	520	LOWER MOLINA
CO-0039	55127	Manchief Station
	494	MANITOU

RBLCID	ORIS_CODE	FACILITY_NAME
	492	Martin Drake
	517	MARYS LAKE
	7372	MCPHEE
	10180	METRO WASTEWATER RECLAMATION DISTRICT
	50899	MONTROSE PARTNERS
	514	MORROW POINT
	6208	MOUNT ELBERT
	10423	NORTH FORK HYDRO PLANT
	527	Nucla
	473	PALISADE
	6248	Pawnee
	55650	Plains End Generating Station
	519	POLE HILL
	460	Pueblo
	7995	Pueblo Airport Industrial Park
CO-0053	6761	Rawhide Energy Station
CO-0025 & C(	8219	Ray D Nixon
	50267	REDLANDS WATER & POWER CO
	6516	Rocky Ford
CO-0052	55835	Rocky Mountain Energy Center
	495	RUXTON
	474	SALIDA 1
	475	SALIDA 2
	476	SHOSHONE
	55621	SOUTH BEAR CREEK
	10081	STRONTIA SPRINGS HYDRO PLANT
	50435	SUGARLOAF HYDRO PLANT
	6206	TACOMA
	54729	TAYLOR DRAW HYDROELECTRIC FACILITY
	50707	TCP 122
	50708	TCP 150
	7233	TESLA
	50709	THERMO GREELEY INC
	50676	THERMO POWER ELECTRIC INC
	7373	TOWAOC
	10003	TRIGEN COLORADO ENERGY CORP

USGS for 2002

NONFUEL RAW MINERAL PRODUCTION IN SW REGION

(Thousand metric tons unless otherwise specified)

Mineral		AZ	CO	WY	TX	NV	KS	OK	UT	NM
Beryllium concentrates									2,500	
Cement:										
Masonry					290		30			
Portland					10,700		2,310			
Clays:									W	
Bentonite				3,400		34	647		454	
Common		42	295	41	2,240			735		30
Fuller's earth					29	--				
Kaolin					40					
Copper[3]		760								113
Gemstones		NA	NA	NA	NA				NA	NA
Gold[3]	kilograms	129	W			242,000				
Gypsum, crude					W			2,570		
Helium, crude	n cubic meters				8		32			
Grade-A	n cubic meters						86			
Iodine, crude	metric tons							1,700		
Lime			32		1,560				2,590	
Salt					9,390		3,060			
Sand and gravel:									30,300	
Construction		49,200	40,700	8,300	78,700	33,200	9,600	10,700		10,900
Industrial			W		1,770	608		1,360		
Silver[3]	metric tons	W	W			449				
Stone:									7,800	
Crushed		8,200	16,000	5,400	128,000	9,700	22,000	40,700		5,900
Dimension			10,200		88,100		12,600	16,500		26,100
Talc, crude	metric tons				233,000					
Tripoli	metric tons							11,700		

[e]Estimated. [p]Preliminary. [r]Revised. NA Not available. W Withheld to avoid disclosing company proprietary data; values included with "Combined values" data. XX Not applicable.

[1]Production as measured by mine shipments, sales, or marketable production (including consumption by producers).

[2]Data are rounded to no more than three significant digits; may not add to totals shown.

[3]Recoverable content of ores, etc.

[4]Withheld to avoid disclosing company proprietary data.

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for
eGRID2002yr00_plant.xls, Version 2.01
Year 2000 eGRID Plant, Boiler, and Generator Data Files

eGRID2002 Version 2.01 Plant File (Year 2000 Data)

SEQPLT00 eGRID2002 2000 file plant sequence number	SEQPLT99 eGRID2002 1999 file plant sequence number	PSTATABB State abbreviation	PNAME Plant name	ORISPL DOE/EIA ORIS plant or facility code	PLTYPE Plant type	PREVUTIL Previously a utility plant flag	CHANGE Change? – If Y, go to EGRDPLCH file	OPRNAME Plant operator name
248	243	AZ	ABITIBI CONSOLIDATED SNOWFLA	50805.0	NU	0	N	Abitibi Consolidated
249	244	AZ	AGUA FRIA	141.0	UT	0	N	Salt River Proj Ag I & P Dist
250	245	AZ	APACHE STATION	160.0	UT	0	N	Arizona Electric Pwr Coop Inc
251	246	AZ	BIOSPHERE 2 CENTER INC	54594.0	NU	0	N	Biosphere 2 Center Inc
252	247	AZ	CHILDS	112.0	UT	0	N	Arizona Public Service Co
253	248	AZ	CHOLLA	113.0	UT	0	N	Arizona Public Service Co
254	249	AZ	CORONADO	6177.0	UT	0	N	Salt River Proj Ag I & P Dist
255	250	AZ	CROSSCUT	143.0	UT	0	N	Salt River Proj Ag I & P Dist
256	251	AZ	DAVIS	152.0	UT	0	N	USBR-Lower Colorado Region
257	252	AZ	DOUGLAS	114.0	UT	0	N	Arizona Public Service Co
258	253	AZ	GLEN CANYON	153.0	UT	0	N	USBR-Upper Colorado Region
259	254	AZ	GOULD ELECTRONICS FOIL DIVISI	54838.0	NU	0	N	Japan Energy Corp Ltd
260	255	AZ	HOOVER	8902.0	UT	0	N	USBR-Lower Colorado Region
261	256	AZ	HORSE MESA	145.0	UT	0	N	Salt River Proj Ag I & P Dist
262	257	AZ	INA ROAD WATER POLLUTION CON	55257.0	NU	0	N	PIMA County Wastewater Manage
263	258	AZ	IRVING	115.0	UT	0	N	Arizona Public Service Co
264	259	AZ	IRVINGTON	126.0	UT	0	N	Tucson Electric Power Co
265	260	AZ	KYRENE	147.0	UT	0	N	Salt River Proj Ag I & P Dist
266	261	AZ	MORMON FLAT	148.0	UT	0	N	Salt River Proj Ag I & P Dist
267	262	AZ	NAVAJO	4941.0	UT	0	N	Salt River Proj Ag I & P Dist
268	263	AZ	NELSON PLANT GENERATORS	54245.0	NU	0	N	Chemical Lime Co
269	N/A	AZ	NEW CORNELIA BRANCH POWER I	50738.0	NU	0	N	Phelps Dodge Corp
270	264	AZ	NORTH LOOP	6088.0	UT	0	N	Tucson Electric Power Co
271	265	AZ	OCOTILLO	116.0	UT	0	N	Arizona Public Service Co
272	266	AZ	PALO VERDE	6008.0	UT	0	N	Arizona Public Service Co
273	267	AZ	ROOSEVELT	149.0	UT	0	N	Salt River Proj Ag I & P Dist
274	268	AZ	SAGUARO	118.0	UT	0	N	Arizona Public Service Co
275	269	AZ	SANTAN	8068.0	UT	0	N	Salt River Proj Ag I & P Dist
276	270	AZ	SOUTH CONSOLIDATED	100.0	UT	0	N	Salt River Proj Ag I & P Dist
277	271	AZ	SPRINGERVILLE	8223.0	UT	0	N	Tucson Electric Power Co

)00 Data)

PNAME Plant name	OPRCODE Plant operator ID	UTLSRVNM Nonutility's service area name	UTLSRVID Nonutility's service area ID	OPPRNUM Location (operator)-based parent company ID	OPPRNAME Location (operator)-based parent company name
ABITIBI CONSOLIDATED SNOWFLA	-1245.0	Arizona Public Service Co	803.0	0.0	
AGUA FRIA	16572.0		0.0	0.0	
APACHE STATION	796.0		0.0	0.0	
BIOSPHERE 2 CENTER INC	-2018.0	USBIA-San Carlos Project	19604.0	0.0	
CHILDS	803.0		0.0	-7042.0	Pinnacle West Capital Corporation
CHOLLA	803.0		0.0	-7042.0	Pinnacle West Capital Corporation
CORONADO	16572.0		0.0	0.0	
CROSSCUT	16572.0		0.0	0.0	
DAVIS	19580.0		0.0	-7061.0	US Bureau Of Reclamation
DOUGLAS	803.0		0.0	-7042.0	Pinnacle West Capital Corporation
GLEN CANYON	25472.0		0.0	-7061.0	US Bureau Of Reclamation
GOULD ELECTRONICS FOIL DIVISI(	9669.0	Salt River Proj Ag I & P Dist	16572.0	0.0	
HOOVER	19580.0		0.0	-7061.0	US Bureau Of Reclamation
HORSE MESA	16572.0		0.0	0.0	
INA ROAD WATER POLLUTION CON	15090.0	Tucson Electric Power Co	24211.0	0.0	
IRVING	803.0		0.0	-7042.0	Pinnacle West Capital Corporation
IRVINGTON	24211.0		0.0	-7058.0	UniSource Energy Corporation
KYRENE	16572.0		0.0	0.0	
MORMON FLAT	16572.0		0.0	0.0	
NAVAJO	16572.0		0.0	0.0	
NELSON PLANT GENERATORS	3468.0	Mohave Electric Coop Inc	21538.0	0.0	
NEW CORNELIA BRANCH POWER I	-1118.0	Ajo Improvement Co	176.0	0.0	
NORTH LOOP	24211.0		0.0	-7058.0	UniSource Energy Corporation
OCOTILLO	803.0		0.0	-7042.0	Pinnacle West Capital Corporation
PALO VERDE	803.0		0.0	-7042.0	Pinnacle West Capital Corporation
ROOSEVELT	16572.0		0.0	0.0	
SAGUARO	803.0		0.0	-7042.0	Pinnacle West Capital Corporation
SANTAN	16572.0		0.0	0.0	
SOUTH CONSOLIDATED	16572.0		0.0	0.0	
SPRINGERVILLE	24211.0		0.0	-7058.0	UniSource Energy Corporation

)00 Data)

PNAME Plant name	PCANAME Location (operator)-based power control area name	PCAID Location (operator)-based power control area ID	NERC Location (operator)-based NERC region acronym	NERCNUM NERC number associated with NERC region	SUBRGN eGRID subregion acronym
ABITIBI CONSOLIDATED SNOWFLA	Arizona Public Service Co/PCA	803.0	WECC	9	WSSW
AGUA FRIA	Salt River Proj Ag I & P Dist/PCA	16572.0	WECC	9	WSSW
APACHE STATION	WAPA - Phoenix (LC)/PCA	19610.0	WECC	9	WSSW
BIOSPHERE 2 CENTER INC	WAPA - Phoenix (LC)/PCA	19610.0	WECC	9	WSSW
CHILDS	Arizona Public Service Co/PCA	803.0	WECC	9	WSSW
CHOLLA	Arizona Public Service Co/PCA	803.0	WECC	9	WSSW
CORONADO	Salt River Proj Ag I & P Dist/PCA	16572.0	WECC	9	WSSW
CROSSCUT	Salt River Proj Ag I & P Dist/PCA	16572.0	WECC	9	WSSW
DAVIS	WAPA - Phoenix (LC)/PCA	19610.0	WECC	9	WSSW
DOUGLAS	Arizona Public Service Co/PCA	803.0	WECC	9	WSSW
GLEN CANYON	WAPA - Rocky Mountains/PCA	28503.0	WECC	9	ROCK
GOULD ELECTRONICS FOIL DIVISI	Salt River Proj Ag I & P Dist/PCA	16572.0	WECC	9	WSSW
HOOVER	WAPA - Phoenix (LC)/PCA	19610.0	WECC	9	WSSW
HORSE MESA	Salt River Proj Ag I & P Dist/PCA	16572.0	WECC	9	WSSW
INA ROAD WATER POLLUTION CON	Tucson Electric Power Co/PCA	24211.0	WECC	9	WSSW
IRVING	Arizona Public Service Co/PCA	803.0	WECC	9	WSSW
IRVINGTON	Tucson Electric Power Co/PCA	24211.0	WECC	9	WSSW
KYRENE	Salt River Proj Ag I & P Dist/PCA	16572.0	WECC	9	WSSW
MORMON FLAT	Salt River Proj Ag I & P Dist/PCA	16572.0	WECC	9	WSSW
NAVAJO	Salt River Proj Ag I & P Dist/PCA	16572.0	WECC	9	WSSW
NELSON PLANT GENERATORS	WAPA - Phoenix (LC)/PCA	19610.0	WECC	9	WSSW
NEW CORNELIA BRANCH POWER I	Arizona Public Service Co/PCA	803.0	WECC	9	WSSW
NORTH LOOP	Tucson Electric Power Co/PCA	24211.0	WECC	9	WSSW
OCOTILLO	Arizona Public Service Co/PCA	803.0	WECC	9	WSSW
PALO VERDE	Arizona Public Service Co/PCA	803.0	WECC	9	WSSW
ROOSEVELT	Salt River Proj Ag I & P Dist/PCA	16572.0	WECC	9	WSSW
SAGUARO	Arizona Public Service Co/PCA	803.0	WECC	9	WSSW
SANTAN	Salt River Proj Ag I & P Dist/PCA	16572.0	WECC	9	WSSW
SOUTH CONSOLIDATED	Salt River Proj Ag I & P Dist/PCA	16572.0	WECC	9	WSSW
SPRINGERVILLE	Tucson Electric Power Co/PCA	24211.0	WECC	9	WSSW

)00 Data)

PNAME Plant name	SRNAME eGRID subregion name	FIPST Plant FIPS State code	FIPSCNY Plant FIPS county code	CNTYNAME Plant county name	LAT Plant latitude	LON Plant longitude	NUMBLR Number of utility boilers
ABITIBI CONSOLIDATED SNOWFLA	WECC Southwest	4	17	NAVAJO	35.2863	110.2885	N/A
AGUA FRIA	WECC Southwest	4	13	MARICOPA	33.5569	112.2175	3
APACHE STATION	WECC Southwest	4	3	COCHISE	32.0556	109.8861	3
BIOSPHERE 2 CENTER INC	WECC Southwest	4	21	PINAL	32.9836	111.3255	N/A
CHILDS	WECC Southwest	4	25	YAVAPAI	34.7053	112.4042	N/A
CHOLLA	WECC Southwest	4	17	NAVAJO	34.9414	110.3003	4
CORONADO	WECC Southwest	4	1	APACHE	34.5778	109.2717	2
CROSSCUT	WECC Southwest	4	13	MARICOPA	33.3500	112.4900	N/A
DAVIS	WECC Southwest	4	15	MOHAVE	35.6134	113.6474	N/A
DOUGLAS	WECC Southwest	4	3	COCHISE	31.8799	109.7540	N/A
GLEN CANYON	WECC Rockies	4	5	COCONINO	35.6337	112.0444	N/A
GOULD ELECTRONICS FOIL DIVISI(	WECC Southwest	4	13	MARICOPA	33.3500	112.4900	N/A
HOOVER	WECC Southwest	4	15	MOHAVE	35.6134	113.6474	N/A
HORSE MESA	WECC Southwest	4	13	MARICOPA	33.3500	112.4900	N/A
INA ROAD WATER POLLUTION COI	WECC Southwest	4	19	PIMA	31.9699	111.8899	N/A
IRVING	WECC Southwest	4	25	YAVAPAI	34.7053	112.4042	N/A
IRVINGTON	WECC Southwest	4	19	PIMA	32.1600	110.9044	4
KYRENE	WECC Southwest	4	13	MARICOPA	33.3547	111.9364	2
MORMON FLAT	WECC Southwest	4	13	MARICOPA	33.3500	112.4900	N/A
NAVAJO	WECC Southwest	4	5	COCONINO	36.9125	111.3917	3
NELSON PLANT GENERATORS	WECC Southwest	4	15	MOHAVE	35.6134	113.6474	N/A
NEW CORNELIA BRANCH POWER I	WECC Southwest	4	19	PIMA	31.9699	111.8899	N/A
NORTH LOOP	WECC Southwest	4	19	PIMA	31.9699	111.8899	N/A
OCOTILLO	WECC Southwest	4	13	MARICOPA	33.4467	111.9417	2
PALO VERDE	WECC Southwest	4	13	MARICOPA	33.3500	112.4900	N/A
ROOSEVELT	WECC Southwest	4	13	MARICOPA	33.3500	112.4900	N/A
SAGUARO	WECC Southwest	4	21	PINAL	32.5522	111.2992	2
SANTAN	WECC Southwest	4	13	MARICOPA	33.3500	112.4900	N/A
SOUTH CONSOLIDATED	WECC Southwest	4	13	MARICOPA	33.3500	112.4900	N/A
SPRINGERVILLE	WECC Southwest	4	1	APACHE	34.3186	109.1636	2

)00 Data)

PNAME Plant name	NUMGEN Number of generators	SOURCEM Plant emissions source(s)	PLPRIMFL Plant primary fuel	PLFFLCTG Plant fossil fuel category	CAPFAC Plant capacity factor	BOILCAP Utility plant boiler capacity (MMBtu/hr)	NAMEPCAP Plant generator capacity (MW)	CHPFLAG Combined heat and power (CHP) (cogenerator) 2000 plant flag	USETHRMO CHP plant 2000 useful thermal output (MMBtu)
ABITIBI CONSOLIDATED SNOWFLA	2	E	SUB	C	0.5541	N/A	70.55	U	3155479
AGUA FRIA	6	T,E	GAS	G	0.3803	3672.00	613.42		0
APACHE STATION	6	T	COL	C	0.7062	4515.20	559.14		0
BIOSPHERE 2 CENTER INC	2	E	NG	G	0.0932	N/A	3.05	U	2590
CHILDS	1	Z	WT		0.4414	N/A	5.40		0
CHOLLA	4	T	COL	C	0.7017	10506.00	1105.44		0
CORONADO	2	T	COL	C	0.8717	7471.84	821.88		0
CROSSCUT	5	Z	WT		0.0181	N/A	33.00		0
DAVIS	1	Z	WT		0.5911	N/A	240.00		0
DOUGLAS	1	E	OIL	O	0.0196	N/A	21.40		0
GLEN CANYON	1	Z	WT		0.3642	N/A	1296.00		0
GOULD ELECTRONICS FOIL DIVISI(	2	E	NG	G	0.0599	N/A	1.05	U	818
HOOVER	1	Z	WT		0.3148	N/A	1039.40		0
HORSE MESA	2	Z	WT		0.1957	N/A	129.58		0
INA ROAD WATER POLLUTION CON	7	E	NG	G	0.4703	N/A	4.54	U	70733
IRVING	1	Z	WT		0.8549	N/A	1.60		0
IRVINGTON	6	T,E	COL	C	0.3352	3633.92	558.50		0
KYRENE	6	T,E	GAS	G	0.1345	1349.12	334.85		0
MORMON FLAT	2	Z	WT		0.1598	N/A	57.85		0
NAVAJO	3	T	COL	C	0.8574	22072.80	2409.48		0
NELSON PLANT GENERATORS	1	E	DFO	O	0.0237	N/A	2.27		0
NEW CORNELIA BRANCH POWER F	2	E	NG	G	0.0350	N/A	10.50		0
NORTH LOOP	3	E	GAS	G	0.0700	N/A	81.00		0
OCOTILLO	5	T,E	GAS	G	0.2561	2176.00	333.90		0
PALO VERDE	1	Z	UR		0.8239	N/A	4209.57		0
ROOSEVELT	1	Z	WT		0.1130	N/A	36.02		0
SAGUARO	4	T,E	GAS	G	0.2126	2448.00	356.25		0
SANTAN	4	E	GAS	G	0.4091	N/A	414.00		0
SOUTH CONSOLIDATED	1	Z	WT		0.0882	N/A	1.40		0
SPRINGERVILLE	2	T	COL	C	0.7896	7656.80	849.60		0

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PNAME Plant name	PWRTOHT CHP plant 2000 power to heat ratio	ELCALLOC CHP plant 2000 electric allocation factor	PLNUCONN Nonutility plant connected to grid flag	PSFLG Plant pumped storage flag	ARDBNU ARD nonutility flag	LMSWFLG Nonutility plant landfill methane or solid waste flag	PLNUCMBS Plant nonutility combustion flag	PLNUCOAL Plant nonutility coal flag	UTNOWNU Now nonutility flag
ABITIBI CONSOLIDATED SNOWFLA	0.3703	0.4255	Y	0	N/A	N/A	N/A	N/A	N/A
AGUA FRIA	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
APACHE STATION	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
BIOSPHERE 2 CENTER INC	3.2787	0.8677	Y	0	N/A	N/A	N/A	N/A	N/A
CHILDS	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
CHOLLA	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
CORONADO	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
CROSSCUT	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
DAVIS	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
DOUGLAS	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
GLEN CANYON	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
GOULD ELECTRONICS FOIL DIVISI(	2.2967	0.8212	Y	0	N/A	N/A	N/A	N/A	N/A
HOOVER	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
HORSE MESA	N/A	N/A		1	N/A	N/A	N/A	N/A	N/A
INA ROAD WATER POLLUTION COI	0.9022	0.6434	Y	0	N/A	N/A	N/A	N/A	N/A
IRVING	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
IRVINGTON	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
KYRENE	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
MORMON FLAT	N/A	N/A		1	N/A	N/A	N/A	N/A	N/A
NAVAJO	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
NELSON PLANT GENERATORS	N/A	N/A	Y	0	N/A	N/A	N/A	N/A	N/A
NEW CORNELIA BRANCH POWER I	N/A	N/A	Y	0	N/A	N/A	N/A	N/A	N/A
NORTH LOOP	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
OCOTILLO	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
PALO VERDE	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
ROOSEVELT	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
SAGUARO	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
SANTAN	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
SOUTH CONSOLIDATED	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
SPRINGERVILLE	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A

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PNAME Plant name	GENERVAL Generation value source	EMISVAL Emission value source	RESMXVAL Resource mix value source	PLHTIAN Plant 2000 annual heat input (MMBtu)	PLHTIOZ Plant 2000 ozone season heat input (MMBtu)	PLGGENAN Plant 2000 annual gross generation (MWh)	PLNGENAN Plant 2000 annual net generation (MWh)	PLNGENOZ Plant 2000 ozone season net generation (MWh)	PLNOXAN Plant 2000 annual NOx emissions (tons)
ABITIBI CONSOLIDATED SNOWFLA	N/A	N/A	N/A	3086048.8	1285853.7	N/A	342452.4	142688.5	722.74
AGUA FRIA	N/A	N/A	N/A	22470746.6	11170252.9	N/A	2043449.0	1131526.0	6103.47
APACHE STATION	N/A	N/A	N/A	37032772.0	16502992.0	N/A	3459141.0	1570982.0	7781.45
BIOSPHERE 2 CENTER INC	N/A	N/A	N/A	27022.7	11259.5	N/A	2488.8	1037.0	2.50
CHILDS	N/A	N/A	N/A	0.0	0.0	N/A	20879.0	8833.0	0.00
CHOLLA	N/A	N/A	N/A	82362288.0	35757011.0	N/A	6795289.0	2920529.0	13780.99
CORONADO	N/A	N/A	N/A	69344438.0	29514079.0	N/A	6276187.0	2691266.0	14271.79
CROSSCUT	N/A	N/A	N/A	0.0	0.0	N/A	5236.0	5053.0	0.00
DAVIS	N/A	N/A	N/A	0.0	0.0	N/A	1242714.0	573382.0	0.00
DOUGLAS	N/A	N/A	N/A	72745.9	30310.8	N/A	3672.0	1431.0	32.10
GLEN CANYON	N/A	N/A	N/A	0.0	0.0	N/A	4134622.0	1589468.0	0.00
GOULD ELECTRONICS FOIL DIVISI(	N/A	N/A	N/A	6668.3	2778.5	N/A	550.6	229.4	0.63
HOOVER	N/A	N/A	N/A	0.0	0.0	N/A	2865991.0	1213516.0	0.00
HORSE MESA	N/A	N/A	N/A	0.0	0.0	N/A	222126.0	130262.0	0.00
INA ROAD WATER POLLUTION CON	N/A	N/A	N/A	167667.2	69861.3	N/A	18702.9	7792.9	16.20
IRVING	N/A	N/A	N/A	0.0	0.0	N/A	11982.0	5114.0	0.00
IRVINGTON	N/A	N/A	N/A	18316851.6	9628483.4	N/A	1639965.0	876354.0	2884.34
KYRENE	N/A	N/A	N/A	7916713.6	5002054.6	N/A	394424.0	251668.0	2762.78
MORMON FLAT	N/A	N/A	N/A	0.0	0.0	N/A	80958.0	50221.0	0.00
NAVAJO	N/A	N/A	N/A	196273976.0	84036483.0	N/A	18096243.0	7623743.0	37267.01
NELSON PLANT GENERATORS	N/A	N/A	N/A	3822.0	1592.5	N/A	471.2	196.3	0.35
NEW CORNELIA BRANCH POWER I	N/A	N/A	N/A	38141.9	15892.5	N/A	3221.2	1342.2	3.79
NORTH LOOP	N/A	N/A	N/A	831481.6	346450.7	N/A	49686.0	34023.0	133.59
OCOTILLO	N/A	N/A	N/A	8435320.4	4236604.5	N/A	749070.0	414904.0	701.54
PALO VERDE	N/A	N/A	N/A	0.0	0.0	N/A	30380571.0	13435250.0	0.00
ROOSEVELT	N/A	N/A	N/A	0.0	0.0	N/A	35643.0	29375.0	0.00
SAGUARO	N/A	N/A	N/A	8191494.3	4013723.5	N/A	663616.0	346773.0	678.92
SANTAN	N/A	N/A	N/A	13056927.2	5440386.3	N/A	1483808.0	773607.0	2151.86
SOUTH CONSOLIDATED	N/A	N/A	N/A	0.0	0.0	N/A	1082.0	861.0	0.00
SPRINGERVILLE	N/A	N/A	N/A	60872540.0	25745307.0	N/A	5876943.0	2559848.0	11715.30

)00 Data)

PNAME Plant name	PLNOXOZ Plant 2000 ozone season NOx emissions (tons)	PLSO2AN Plant 2000 annual SO2 emissions (tons)	PLCO2AN Plant 2000 annual CO2 emissions (tons)	PLHGAN Plant 2000 annual mercury emissions (lbs)	PLNOXRTA Plant 2000 annual NOx output emission rate (lbs/MWh)	PLNOXRTO Plant 2000 ozone season NOx output emission rate (lbs/MWh)	PLSO2RTA Plant 2000 annual SO2 output emission rate (lbs/MWh)	PLCO2RTA Plant 2000 annual CO2 output emission rate (lbs/MWh)	PLHGRTA Plant 2000 annual mercury output emission rate (lbs/GWh)
ABITIBI CONSOLIDATED SNOWFLA	301.14	733.44	313283.88	N/A	4.221	4.221	4.283	1829.649	N/A
AGUA FRIA	3024.54	82.02	1333531.54	N/A	5.974	5.346	0.080	1305.177	N/A
APACHE STATION	3540.10	6568.90	3597609.90	130.09	4.499	4.507	3.798	2080.060	0.0376
BIOSPHERE 2 CENTER INC	1.04	0.02	1596.87	N/A	2.006	2.006	0.020	1283.242	N/A
CHILDS	0.00	0.00	0.00	N/A	0.000	0.000	0.000	0.000	N/A
CHOLLA	6071.50	17896.80	8441969.40	351.41	4.056	4.158	5.267	2484.654	0.0517
CORONADO	5932.80	19459.90	7113186.50	298.99	4.548	4.409	6.201	2266.722	0.0476
CROSSCUT	0.00	0.00	0.00	N/A	0.000	0.000	0.000	0.000	N/A
DAVIS	0.00	0.00	0.00	N/A	0.000	0.000	0.000	0.000	N/A
DOUGLAS	13.37	2.78	5807.08	N/A	17.483	18.692	1.513	3162.898	N/A
GLEN CANYON	0.00	0.00	0.00	N/A	0.000	0.000	0.000	0.000	N/A
GOULD ELECTRONICS FOIL DIVISI(	0.26	0.00	386.09	N/A	2.301	2.301	0.004	1402.402	N/A
HOOVER	0.00	0.00	0.00	N/A	0.000	0.000	0.000	0.000	N/A
HORSE MESA	0.00	0.00	0.00	N/A	0.000	0.000	0.000	0.000	N/A
INA ROAD WATER POLLUTION CON	6.75	0.25	5532.85	N/A	1.732	1.732	0.027	591.657	N/A
IRVING	0.00	0.00	0.00	N/A	0.000	0.000	0.000	0.000	N/A
IRVINGTON	1413.40	3419.00	1455423.61	3.14	3.518	3.226	4.170	1774.945	0.0019
KYRENE	2053.45	95.32	472553.85	N/A	14.009	16.319	0.483	2396.172	N/A
MORMON FLAT	0.00	0.00	0.00	N/A	0.000	0.000	0.000	0.000	N/A
NAVAJO	16184.00	4837.10	20137720.90	321.36	4.119	4.246	0.535	2225.625	0.0178
NELSON PLANT GENERATORS	0.15	0.50	305.10	N/A	1.498	1.498	2.135	1295.067	N/A
NEW CORNELIA BRANCH POWER I	1.58	0.10	2219.04	N/A	2.354	2.354	0.064	1377.749	N/A
NORTH LOOP	55.66	1.44	48392.20	N/A	5.377	3.272	0.058	1947.921	N/A
OCOTILLO	343.99	7.66	504972.50	N/A	1.873	1.658	0.020	1348.265	N/A
PALO VERDE	0.00	0.00	0.00	N/A	0.000	0.000	0.000	0.000	N/A
ROOSEVELT	0.00	0.00	0.00	N/A	0.000	0.000	0.000	0.000	N/A
SAGUARO	306.85	154.00	495723.06	N/A	2.046	1.770	0.464	1494.006	N/A
SANTAN	896.61	30.43	764564.40	N/A	2.900	2.318	0.041	1030.544	N/A
SOUTH CONSOLIDATED	0.00	0.00	0.00	N/A	0.000	0.000	0.000	0.000	N/A
SPRINGERVILLE	4891.10	19048.40	6245526.40	326.68	3.987	3.821	6.482	2125.434	0.0556

)00 Data)

PNAME Plant name	PLNOXRA Plant 2000 annual NOx input emission rate (lbs/MMBtu)	PLNOXRO Plant 2000 ozone season NOx input emission rate (lbs/MMBtu)	PLSO2RA Plant 2000 annual SO2 input emission rate (lbs/MMBtu)	PLCO2RA Plant 2000 annual CO2 input emission rate (lbs/MMBtu)	PLHGRA Plant 2000 annual mercury input emission rate (lbs/BBtu)	PLHTRT Plant 2000 nominal heat rate (Btu/kWh)	PLGENACL Plant 2000 annual coal net generation (MWh)	PLGENAOL Plant 2000 annual oil net generation (MWh)
ABITIBI CONSOLIDATED SNOWFLA	0.468	0.468	0.475	203.032	N/A	9011.614	330502.4	278.6
AGUA FRIA	0.543	0.542	0.007	118.690	N/A	10996.480	0.0	32226.0
APACHE STATION	0.420	0.429	0.355	194.293	0.0035	10705.771	2862418.0	0.0
BIOSPHERE 2 CENTER INC	0.185	0.185	0.002	118.187	N/A	10857.703	0.0	135.5
CHILDS	0.000	0.000	0.000	0.000	N/A	0.000	0.0	0.0
CHOLLA	0.335	0.340	0.435	204.996	0.0043	12120.498	6787337.0	6576.0
CORONADO	0.412	0.402	0.561	205.155	0.0043	11048.816	6272316.0	3871.0
CROSSCUT	0.000	0.000	0.000	0.000	N/A	0.000	0.0	0.0
DAVIS	0.000	0.000	0.000	0.000	N/A	0.000	0.0	0.0
DOUGLAS	0.882	0.882	0.076	159.654	N/A	19810.974	0.0	3672.0
GLEN CANYON	0.000	0.000	0.000	0.000	N/A	0.000	0.0	0.0
GOULD ELECTRONICS FOIL DIVISI	0.190	0.190	0.000	115.799	N/A	12110.654	0.0	0.0
HOOVER	0.000	0.000	0.000	0.000	N/A	0.000	0.0	0.0
HORSE MESA	0.000	0.000	0.000	0.000	N/A	0.000	0.0	0.0
INA ROAD WATER POLLUTION CON	0.193	0.193	0.003	65.998	N/A	8964.768	0.0	0.0
IRVING	0.000	0.000	0.000	0.000	N/A	0.000	0.0	0.0
IRVINGTON	0.315	0.294	0.373	158.916	0.0002	11169.050	789923.0	320.0
KYRENE	0.698	0.821	0.024	119.381	N/A	20071.582	0.0	15357.0
MORMON FLAT	0.000	0.000	0.000	0.000	N/A	0.000	0.0	0.0
NAVAJO	0.380	0.385	0.049	205.200	0.0016	10846.117	18076057.0	20186.0
NELSON PLANT GENERATORS	0.185	0.185	0.263	159.654	N/A	8111.717	0.0	471.2
NEW CORNELIA BRANCH POWER I	0.199	0.199	0.005	116.357	N/A	11840.724	0.0	41.0
NORTH LOOP	0.321	0.321	0.003	116.400	N/A	16734.726	0.0	25.0
OCOTILLO	0.166	0.162	0.002	119.728	N/A	11261.058	0.0	0.0
PALO VERDE	0.000	0.000	0.000	0.000	N/A	0.000	0.0	0.0
ROOSEVELT	0.000	0.000	0.000	0.000	N/A	0.000	0.0	0.0
SAGUARO	0.166	0.153	0.038	121.034	N/A	12343.726	0.0	30784.0
SANTAN	0.330	0.330	0.005	117.112	N/A	8799.607	0.0	25262.0
SOUTH CONSOLIDATED	0.000	0.000	0.000	0.000	N/A	0.000	0.0	0.0
SPRINGERVILLE	0.385	0.380	0.626	205.200	0.0054	10357.858	5874576.0	2367.0

)00 Data)

PNAME Plant name	PLGENAGS Plant 2000 annual gas net generation (MWh)	PLGENANC Plant 2000 annual nuclear net generation (MWh)	PLGENAHY Plant 2000 annual hydro net generation (MWh)	PLGENABM Plant 2000 annual biomass/ wood net generation (MWh)	PLGENAWI Plant 2000 annual wind net generation (MWh)	PLGENASO Plant 2000 annual solar net generation (MWh)	PLGENAGT Plant 2000 annual geothermal net generation (MWh)	PLGENAOF Plant 2000 annual other fossil (tires, batteries, chemicals, etc.) net generation (MWh)	PLGENASW Plant 2000 annual solid waste net generation (MWh)
ABITIBI CONSOLIDATED SNOWFLA	11671.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AGUA FRIA	2011223.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
APACHE STATION	596723.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BIOSPHERE 2 CENTER INC	2353.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CHILDS	0.0	0.0	20879.0	0.0	0.0	0.0	0.0	0.0	0.0
CHOLLA	1376.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CORONADO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CROSSCUT	0.0	0.0	5236.0	0.0	0.0	0.0	0.0	0.0	0.0
DAVIS	0.0	0.0	1242714.0	0.0	0.0	0.0	0.0	0.0	0.0
DOUGLAS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GLEN CANYON	0.0	0.0	4134622.0	0.0	0.0	0.0	0.0	0.0	0.0
GOULD ELECTRONICS FOIL DIVISI(	550.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HOOVER	0.0	0.0	2865991.0	0.0	0.0	0.0	0.0	0.0	0.0
HORSE MESA	0.0	0.0	222126.0	0.0	0.0	0.0	0.0	0.0	0.0
INA ROAD WATER POLLUTION COI	14119.6	0.0	0.0	4583.3	0.0	0.0	0.0	0.0	0.0
IRVING	0.0	0.0	11982.0	0.0	0.0	0.0	0.0	0.0	0.0
IRVINGTON	849722.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
KYRENE	379067.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MORMON FLAT	0.0	0.0	80958.0	0.0	0.0	0.0	0.0	0.0	0.0
NAVAJO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NELSON PLANT GENERATORS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NEW CORNELIA BRANCH POWER I	3180.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NORTH LOOP	49661.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OCOTILLO	749070.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PALO VERDE	0.0	30380571.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ROOSEVELT	0.0	0.0	35643.0	0.0	0.0	0.0	0.0	0.0	0.0
SAGUARO	632832.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SANTAN	1458546.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTH CONSOLIDATED	0.0	0.0	1082.0	0.0	0.0	0.0	0.0	0.0	0.0
SPRINGERVILLE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

)00 Data)

PNAME Plant name	PLGENATN Plant 2000 annual total nonrenewables net generation (MWh)	PLGENATR Plant 2000 annual total renewables net generation (MWh)	PLGENATH Plant 2000 annual total nonhydro renewables net generation (MWh)	PLCLPR Plant 2000 coal generation percent (resource mix)	PLOLPR Plant 2000 oil generation percent (resource mix)	PLGSPR Plant 2000 gas generation percent (resource mix)	PLNCPR Plant 2000 nuclear generation percent (resource mix)	PLHYPR Plant 2000 hydro generation percent (resource mix)	PLBMPR Plant 2000 biomass/ wood generation percent (resource mix)
ABITIBI CONSOLIDATED SNOWFLA	342452.4	0.0	0.0	96.5105	0.0813	3.4082	0.0000	0.0000	0.0000
AGUA FRIA	2043449.0	0.0	0.0	0.0000	1.5770	98.4230	0.0000	0.0000	0.0000
APACHE STATION	3459141.0	0.0	0.0	82.7494	0.0000	17.2506	0.0000	0.0000	0.0000
BIOSPHERE 2 CENTER INC	2488.8	0.0	0.0	0.0000	5.4457	94.5543	0.0000	0.0000	0.0000
CHILDS	0.0	20879.0	0.0	0.0000	0.0000	0.0000	0.0000	100.0000	0.0000
CHOLLA	6795289.0	0.0	0.0	99.8830	0.0968	0.0202	0.0000	0.0000	0.0000
CORONADO	6276187.0	0.0	0.0	99.9383	0.0617	0.0000	0.0000	0.0000	0.0000
CROSSCUT	0.0	5236.0	0.0	0.0000	0.0000	0.0000	0.0000	100.0000	0.0000
DAVIS	0.0	1242714.0	0.0	0.0000	0.0000	0.0000	0.0000	100.0000	0.0000
DOUGLAS	3672.0	0.0	0.0	0.0000	100.0000	0.0000	0.0000	0.0000	0.0000
GLEN CANYON	0.0	4134622.0	0.0	0.0000	0.0000	0.0000	0.0000	100.0000	0.0000
GOULD ELECTRONICS FOIL DIVISI(	550.6	0.0	0.0	0.0000	0.0000	100.0000	0.0000	0.0000	0.0000
HOOVER	0.0	2865991.0	0.0	0.0000	0.0000	0.0000	0.0000	100.0000	0.0000
HORSE MESA	0.0	222126.0	0.0	0.0000	0.0000	0.0000	0.0000	100.0000	0.0000
INA ROAD WATER POLLUTION CON	14119.6	4583.3	4583.3	0.0000	0.0000	75.4941	0.0000	0.0000	24.5059
IRVING	0.0	11982.0	0.0	0.0000	0.0000	0.0000	0.0000	100.0000	0.0000
IRVINGTON	1639965.0	0.0	0.0	48.1671	0.0195	51.8134	0.0000	0.0000	0.0000
KYRENE	394424.0	0.0	0.0	0.0000	3.8935	96.1065	0.0000	0.0000	0.0000
MORMON FLAT	0.0	80958.0	0.0	0.0000	0.0000	0.0000	0.0000	100.0000	0.0000
NAVAJO	18096243.0	0.0	0.0	99.8885	0.1115	0.0000	0.0000	0.0000	0.0000
NELSON PLANT GENERATORS	471.2	0.0	0.0	0.0000	100.0000	0.0000	0.0000	0.0000	0.0000
NEW CORNELIA BRANCH POWER I	3221.2	0.0	0.0	0.0000	1.2718	98.7282	0.0000	0.0000	0.0000
NORTH LOOP	49686.0	0.0	0.0	0.0000	0.0503	99.9497	0.0000	0.0000	0.0000
OCOTILLO	749070.0	0.0	0.0	0.0000	0.0000	100.0000	0.0000	0.0000	0.0000
PALO VERDE	30380571.0	0.0	0.0	0.0000	0.0000	0.0000	100.0000	0.0000	0.0000
ROOSEVELT	0.0	35643.0	0.0	0.0000	0.0000	0.0000	0.0000	100.0000	0.0000
SAGUARO	663616.0	0.0	0.0	0.0000	4.6388	95.3612	0.0000	0.0000	0.0000
SANTAN	1483808.0	0.0	0.0	0.0000	1.7025	98.2975	0.0000	0.0000	0.0000
SOUTH CONSOLIDATED	0.0	1082.0	0.0	0.0000	0.0000	0.0000	0.0000	100.0000	0.0000
SPRINGERVILLE	5876943.0	0.0	0.0	99.9597	0.0403	0.0000	0.0000	0.0000	0.0000

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PNAME Plant name	PLWIPR Plant 2000 wind generation percent (resource mix)	PLSOPR Plant 2000 solar generation percent (resource mix)	PLGTPR Plant 2000 geothermal generation percent (resource mix)	PLOFPR Plant 2000 other fossil (tires, batteries, chemicals, etc.) generation percent (resource mix)	PLSWPR Plant 2000 solid waste generation percent (resource mix)	PLTNPR Plant 2000 total nonrenewables generation percent (resource mix)	PLTRPR Plant 2000 total renewables generation percent (resource mix)	PLTHPR Plant 2000 total nonhydro renewables generation percent (resource mix)
ABITIBI CONSOLIDATED SNOWFLA	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
AGUA FRIA	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
APACHE STATION	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
BIOSPHERE 2 CENTER INC	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
CHILDS	0.0000	0.0000	0.0000	0.0000	N/A	0.0000	100.0000	0.0000
CHOLLA	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
CORONADO	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
CROSSCUT	0.0000	0.0000	0.0000	0.0000	N/A	0.0000	100.0000	0.0000
DAVIS	0.0000	0.0000	0.0000	0.0000	N/A	0.0000	100.0000	0.0000
DOUGLAS	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
GLEN CANYON	0.0000	0.0000	0.0000	0.0000	N/A	0.0000	100.0000	0.0000
GOULD ELECTRONICS FOIL DIVISI(	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
HOOVER	0.0000	0.0000	0.0000	0.0000	N/A	0.0000	100.0000	0.0000
HORSE MESA	0.0000	0.0000	0.0000	0.0000	N/A	0.0000	100.0000	0.0000
INA ROAD WATER POLLUTION COI	0.0000	0.0000	0.0000	0.0000	N/A	75.4941	24.5059	24.5059
IRVING	0.0000	0.0000	0.0000	0.0000	N/A	0.0000	100.0000	0.0000
IRVINGTON	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
KYRENE	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
MORMON FLAT	0.0000	0.0000	0.0000	0.0000	N/A	0.0000	100.0000	0.0000
NAVAJO	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
NELSON PLANT GENERATORS	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
NEW CORNELIA BRANCH POWER I	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
NORTH LOOP	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
OCOTILLO	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
PALO VERDE	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
ROOSEVELT	0.0000	0.0000	0.0000	0.0000	N/A	0.0000	100.0000	0.0000
SAGUARO	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
SANTAN	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
SOUTH CONSOLIDATED	0.0000	0.0000	0.0000	0.0000	N/A	0.0000	100.0000	0.0000
SPRINGERVILLE	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000

)00 Data)

PNAME Plant name	OWNRNM01 Plant 2000 owner name (first)	OWNRUC01 Plant 2000 owner code (first)	OWNRPR01 Plant 2000 owner percent (first)	OWNRTY01 Plant 2000 owner type (first)	OWNRNM02 Plant 2000 owner name (second)
ABITIBI CONSOLIDATED SNOWFLA	Abitibi Consolidated	-1245.0	100.0000	NU	
AGUA FRIA	Salt River Proj Ag I & P Dist	16572.0	100.0000	UT	
APACHE STATION	Arizona Electric Pwr Coop Inc	796.0	100.0000	UT	
BIOSPHERE 2 CENTER INC	Decisions Investments Corp	4831.0	100.0000	NU	
CHILDS	Arizona Public Service Co	803.0	100.0000	UT	
CHOLLA	Arizona Public Service Co	803.0	62.5487	UT	PacifiCorp-East
CORONADO	Salt River Proj Ag I & P Dist	16572.0	100.0000	UT	
CROSSCUT	Salt River Proj Ag I & P Dist	16572.0	100.0000	UT	
DAVIS	USBR-Lower Colorado Region	19580.0	100.0000	UT	
DOUGLAS	Arizona Public Service Co	803.0	100.0000	UT	
GLEN CANYON	USBR-Upper Colorado Region	25472.0	100.0000	UT	
GOULD ELECTRONICS FOIL DIVISI(	Japan Energy Corp Ltd	9669.0	100.0000	NU	
HOOVER	USBR-Lower Colorado Region	19580.0	100.0000	UT	
HORSE MESA	Salt River Proj Ag I & P Dist	16572.0	100.0000	UT	
INA ROAD WATER POLLUTION CON	PIMA County Wastewater Manage	15090.0	100.0000	NU	
IRVING	Arizona Public Service Co	803.0	100.0000	UT	
IRVINGTON	Tucson Electric Power Co	24211.0	100.0000	UT	
KYRENE	Salt River Proj Ag I & P Dist	16572.0	100.0000	UT	
MORMON FLAT	Salt River Proj Ag I & P Dist	16572.0	100.0000	UT	
NAVAJO	USBR-Upper Colorado Region	25472.0	24.3000	UT	Salt River Proj Ag I & P Dist
NELSON PLANT GENERATORS	Chemical Lime Co	3468.0	100.0000	NU	
NEW CORNELIA BRANCH POWER I	Phelps Dodge Corp	-1118.0	100.0000	NU	
NORTH LOOP	Tucson Electric Power Co	24211.0	100.0000	UT	
OCOTILLO	Arizona Public Service Co	803.0	100.0000	UT	
PALO VERDE	Arizona Public Service Co	803.0	29.1000	UT	Salt River Proj Ag I & P Dist
ROOSEVELT	Salt River Proj Ag I & P Dist	16572.0	100.0000	UT	
SAGUARO	Arizona Public Service Co	803.0	100.0000	UT	
SANTAN	Salt River Proj Ag I & P Dist	16572.0	100.0000	UT	
SOUTH CONSOLIDATED	Salt River Proj Ag I & P Dist	16572.0	100.0000	UT	
SPRINGERVILLE	Tucson Electric Power Co	24211.0	100.0000	UT	

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PNAME Plant name	OWNRUC02 Plant 2000 owner code (second)	OWNRPR02 Plant 2000 owner percent (second)	OWNRTY02 Plant 2000 owner type (second)	OWNRNM03 Plant 2000 owner name (third)	OWNRUC03 Plant 2000 owner code (third)	OWNRPR03 Plant 2000 owner percent (third)	OWNRTY03 Plant 2000 owner type (third)
ABITIBI CONSOLIDATED SNOWFLA	0.0	0.0000			0.0	0.0000	
AGUA FRIA	0.0	0.0000			0.0	0.0000	
APACHE STATION	0.0	0.0000			0.0	0.0000	
BIOSPHERE 2 CENTER INC	0.0	0.0000			0.0	0.0000	
CHILDS	0.0	0.0000			0.0	0.0000	
CHOLLA	14354.1	37.4513	UT		0.0	0.0000	
CORONADO	0.0	0.0000			0.0	0.0000	
CROSSCUT	0.0	0.0000			0.0	0.0000	
DAVIS	0.0	0.0000			0.0	0.0000	
DOUGLAS	0.0	0.0000			0.0	0.0000	
GLEN CANYON	0.0	0.0000			0.0	0.0000	
GOULD ELECTRONICS FOIL DIVISI	0.0	0.0000			0.0	0.0000	
HOOVER	0.0	0.0000			0.0	0.0000	
HORSE MESA	0.0	0.0000			0.0	0.0000	
INA ROAD WATER POLLUTION CON	0.0	0.0000			0.0	0.0000	
IRVING	0.0	0.0000			0.0	0.0000	
IRVINGTON	0.0	0.0000			0.0	0.0000	
KYRENE	0.0	0.0000			0.0	0.0000	
MORMON FLAT	0.0	0.0000			0.0	0.0000	
NAVAJO	16572.0	21.7000	UT	Los Angeles City of	11208.0	21.2000	UT
NELSON PLANT GENERATORS	0.0	0.0000			0.0	0.0000	
NEW CORNELIA BRANCH POWER I	0.0	0.0000			0.0	0.0000	
NORTH LOOP	0.0	0.0000			0.0	0.0000	
OCOTILLO	0.0	0.0000			0.0	0.0000	
PALO VERDE	16572.0	17.4900	UT	El Paso Electric Co	5701.0	15.8000	UT
ROOSEVELT	0.0	0.0000			0.0	0.0000	
SAGUARO	0.0	0.0000			0.0	0.0000	
SANTAN	0.0	0.0000			0.0	0.0000	
SOUTH CONSOLIDATED	0.0	0.0000			0.0	0.0000	
SPRINGERVILLE	0.0	0.0000			0.0	0.0000	

)00 Data)

PNAME Plant name	OWNRNM04 Plant 2000 owner name (fourth)	OWNRUC04 Plant 2000 owner code (fourth)	OWNRPR04 Plant 2000 owner percent (fourth)	OWNRTY04 Plant 2000 owner type (fourth)	OWNRNM05 Plant 2000 owner name (fifth)	OWNRUC05 Plant 2000 owner code (fifth)
ABITIBI CONSOLIDATED SNOWFLA		0.0	0.0000			0.0
AGUA FRIA		0.0	0.0000			0.0
APACHE STATION		0.0	0.0000			0.0
BIOSPHERE 2 CENTER INC		0.0	0.0000			0.0
CHILDS		0.0	0.0000			0.0
CHOLLA		0.0	0.0000			0.0
CORONADO		0.0	0.0000			0.0
CROSSCUT		0.0	0.0000			0.0
DAVIS		0.0	0.0000			0.0
DOUGLAS		0.0	0.0000			0.0
GLEN CANYON		0.0	0.0000			0.0
GOULD ELECTRONICS FOIL DIVISI(		0.0	0.0000			0.0
HOOVER		0.0	0.0000			0.0
HORSE MESA		0.0	0.0000			0.0
INA ROAD WATER POLLUTION COI		0.0	0.0000			0.0
IRVING		0.0	0.0000			0.0
IRVINGTON		0.0	0.0000			0.0
KYRENE		0.0	0.0000			0.0
MORMON FLAT		0.0	0.0000			0.0
NAVAJO	Arizona Public Service Co	803.0	14.0000	UT	Nevada Power Co	13407.0
NELSON PLANT GENERATORS		0.0	0.0000			0.0
NEW CORNELIA BRANCH POWER I		0.0	0.0000			0.0
NORTH LOOP		0.0	0.0000			0.0
OCOTILLO		0.0	0.0000			0.0
PALO VERDE	Southern California Edison Co	17609.0	15.8000	UT	Public Service Co of NM	15473.0
ROOSEVELT		0.0	0.0000			0.0
SAGUARO		0.0	0.0000			0.0
SANTAN		0.0	0.0000			0.0
SOUTH CONSOLIDATED		0.0	0.0000			0.0
SPRINGERVILLE		0.0	0.0000			0.0

)00 Data)

PNAME Plant name	OWNRPR05 Plant 2000 owner percent (fifth)	OWNRTY05 Plant 2000 owner type (fifth)	OWNRNM06 Plant 2000 owner name (sixth)	OWNRUC06 Plant 2000 owner code (sixth)	OWNRPR06 Plant 2000 owner percent (sixth)	OWNRTY06 Plant 2000 owner type (sixth)	OWNRNM07 Plant 2000 owner name (seventh)
ABITIBI CONSOLIDATED SNOWFLA	0.0000			0.0	0.0000		
AGUA FRIA	0.0000			0.0	0.0000		
APACHE STATION	0.0000			0.0	0.0000		
BIOSPHERE 2 CENTER INC	0.0000			0.0	0.0000		
CHILDS	0.0000			0.0	0.0000		
CHOLLA	0.0000			0.0	0.0000		
CORONADO	0.0000			0.0	0.0000		
CROSSCUT	0.0000			0.0	0.0000		
DAVIS	0.0000			0.0	0.0000		
DOUGLAS	0.0000			0.0	0.0000		
GLEN CANYON	0.0000			0.0	0.0000		
GOULD ELECTRONICS FOIL DIVISI(	0.0000			0.0	0.0000		
HOOVER	0.0000			0.0	0.0000		
HORSE MESA	0.0000			0.0	0.0000		
INA ROAD WATER POLLUTION COI	0.0000			0.0	0.0000		
IRVING	0.0000			0.0	0.0000		
IRVINGTON	0.0000			0.0	0.0000		
KYRENE	0.0000			0.0	0.0000		
MORMON FLAT	0.0000			0.0	0.0000		
NAVAJO	11.3000	UT	Tucson Electric Power Co	24211.0	7.5000	UT	
NELSON PLANT GENERATORS	0.0000			0.0	0.0000		
NEW CORNELIA BRANCH POWER I	0.0000			0.0	0.0000		
NORTH LOOP	0.0000			0.0	0.0000		
OCOTILLO	0.0000			0.0	0.0000		
PALO VERDE	10.2000	UT	Southern California P P A	17513.0	5.9100	UT	Los Angeles City of
ROOSEVELT	0.0000			0.0	0.0000		
SAGUARO	0.0000			0.0	0.0000		
SANTAN	0.0000			0.0	0.0000		
SOUTH CONSOLIDATED	0.0000			0.0	0.0000		
SPRINGERVILLE	0.0000			0.0	0.0000		

)00 Data)

PNAME Plant name	OWNRUC07 Plant 2000 owner code (seventh)	OWNRPR07 Plant 2000 owner percent (seventh)	OWNRTY07 Plant 2000 owner type (seventh)	OWNRNM08 Plant 2000 owner name (eighth)	OWNRUC08 Plant 2000 owner code (eighth)	OWNRPR08 Plant 2000 owner percent (eighth)	OWNRTY08 Plant 2000 owner type (eighth)
ABITIBI CONSOLIDATED SNOWFLA	0.0	0.0000			0.0	0.0000	
AGUA FRIA	0.0	0.0000			0.0	0.0000	
APACHE STATION	0.0	0.0000			0.0	0.0000	
BIOSPHERE 2 CENTER INC	0.0	0.0000			0.0	0.0000	
CHILDS	0.0	0.0000			0.0	0.0000	
CHOLLA	0.0	0.0000			0.0	0.0000	
CORONADO	0.0	0.0000			0.0	0.0000	
CROSSCUT	0.0	0.0000			0.0	0.0000	
DAVIS	0.0	0.0000			0.0	0.0000	
DOUGLAS	0.0	0.0000			0.0	0.0000	
GLEN CANYON	0.0	0.0000			0.0	0.0000	
GOULD ELECTRONICS FOIL DIVISI	0.0	0.0000			0.0	0.0000	
HOOVER	0.0	0.0000			0.0	0.0000	
HORSE MESA	0.0	0.0000			0.0	0.0000	
INA ROAD WATER POLLUTION CON	0.0	0.0000			0.0	0.0000	
IRVING	0.0	0.0000			0.0	0.0000	
IRVINGTON	0.0	0.0000			0.0	0.0000	
KYRENE	0.0	0.0000			0.0	0.0000	
MORMON FLAT	0.0	0.0000			0.0	0.0000	
NAVAJO	0.0	0.0000			0.0	0.0000	
NELSON PLANT GENERATORS	0.0	0.0000			0.0	0.0000	
NEW CORNELIA BRANCH POWER I	0.0	0.0000			0.0	0.0000	
NORTH LOOP	0.0	0.0000			0.0	0.0000	
OCOTILLO	0.0	0.0000			0.0	0.0000	
PALO VERDE	11208.0	5.7000	UT		0.0	0.0000	
ROOSEVELT	0.0	0.0000			0.0	0.0000	
SAGUARO	0.0	0.0000			0.0	0.0000	
SANTAN	0.0	0.0000			0.0	0.0000	
SOUTH CONSOLIDATED	0.0	0.0000			0.0	0.0000	
SPRINGERVILLE	0.0	0.0000			0.0	0.0000	

)00 Data)

PNAME Plant name	OWNRNM09 Plant 2000 owner name (ninth)	OWNRUC09 Plant 2000 owner code (ninth)	OWNRPR09 Plant 2000 owner percent (ninth)	OWNRTY09 Plant 2000 owner type (ninth)	OWNRNM10 Plant 2000 owner name (tenth)	OWNRUC10 Plant 2000 owner code (tenth)
ABITIBI CONSOLIDATED SNOWFLA		0.0	0.0000			0.0
AGUA FRIA		0.0	0.0000			0.0
APACHE STATION		0.0	0.0000			0.0
BIOSPHERE 2 CENTER INC		0.0	0.0000			0.0
CHILDS		0.0	0.0000			0.0
CHOLLA		0.0	0.0000			0.0
CORONADO		0.0	0.0000			0.0
CROSSCUT		0.0	0.0000			0.0
DAVIS		0.0	0.0000			0.0
DOUGLAS		0.0	0.0000			0.0
GLEN CANYON		0.0	0.0000			0.0
GOULD ELECTRONICS FOIL DIVISI(		0.0	0.0000			0.0
HOOVER		0.0	0.0000			0.0
HORSE MESA		0.0	0.0000			0.0
INA ROAD WATER POLLUTION CON		0.0	0.0000			0.0
IRVING		0.0	0.0000			0.0
IRVINGTON		0.0	0.0000			0.0
KYRENE		0.0	0.0000			0.0
MORMON FLAT		0.0	0.0000			0.0
NAVAJO		0.0	0.0000			0.0
NELSON PLANT GENERATORS		0.0	0.0000			0.0
NEW CORNELIA BRANCH POWER I		0.0	0.0000			0.0
NORTH LOOP		0.0	0.0000			0.0
OCOTILLO		0.0	0.0000			0.0
PALO VERDE		0.0	0.0000			0.0
ROOSEVELT		0.0	0.0000			0.0
SAGUARO		0.0	0.0000			0.0
SANTAN		0.0	0.0000			0.0
SOUTH CONSOLIDATED		0.0	0.0000			0.0
SPRINGERVILLE		0.0	0.0000			0.0

)00 Data)

PNAME Plant name	OWNRPR10 Plant 2000 owner percent (tenth)	OWNRTY10 Plant 2000 owner type (tenth)	OWNRNM11 Plant 2000 owner name (eleventh)	OWNRUC11 Plant 2000 owner code (eleventh)	OWNRPR11 Plant 2000 owner percent (eleventh)
ABITIBI CONSOLIDATED SNOWFLA	0.0000			0.0	0.0000
AGUA FRIA	0.0000			0.0	0.0000
APACHE STATION	0.0000			0.0	0.0000
BIOSPHERE 2 CENTER INC	0.0000			0.0	0.0000
CHILDS	0.0000			0.0	0.0000
CHOLLA	0.0000			0.0	0.0000
CORONADO	0.0000			0.0	0.0000
CROSSCUT	0.0000			0.0	0.0000
DAVIS	0.0000			0.0	0.0000
DOUGLAS	0.0000			0.0	0.0000
GLEN CANYON	0.0000			0.0	0.0000
GOULD ELECTRONICS FOIL DIVISI	0.0000			0.0	0.0000
HOOVER	0.0000			0.0	0.0000
HORSE MESA	0.0000			0.0	0.0000
INA ROAD WATER POLLUTION CON	0.0000			0.0	0.0000
IRVING	0.0000			0.0	0.0000
IRVINGTON	0.0000			0.0	0.0000
KYRENE	0.0000			0.0	0.0000
MORMON FLAT	0.0000			0.0	0.0000
NAVAJO	0.0000			0.0	0.0000
NELSON PLANT GENERATORS	0.0000			0.0	0.0000
NEW CORNELIA BRANCH POWER I	0.0000			0.0	0.0000
NORTH LOOP	0.0000			0.0	0.0000
OCOTILLO	0.0000			0.0	0.0000
PALO VERDE	0.0000			0.0	0.0000
ROOSEVELT	0.0000			0.0	0.0000
SAGUARO	0.0000			0.0	0.0000
SANTAN	0.0000			0.0	0.0000
SOUTH CONSOLIDATED	0.0000			0.0	0.0000
SPRINGERVILLE	0.0000			0.0	0.0000

)00 Data)

PNAME Plant name	OWNRTY11 Plant 2000 owner type (eleventh)	OWNRNM12 Plant 2000 owner name (twelfth)	OWNRUC12 Plant 2000 owner code (twelfth)	OWNRPR12 Plant 2000 owner percent (twelfth)	OWNRTY12 Plant 2000 owner type (twelfth)
ABITIBI CONSOLIDATED SNOWFLA			0.0	0.0000	
AGUA FRIA			0.0	0.0000	
APACHE STATION			0.0	0.0000	
BIOSPHERE 2 CENTER INC			0.0	0.0000	
CHILDS			0.0	0.0000	
CHOLLA			0.0	0.0000	
CORONADO			0.0	0.0000	
CROSSCUT			0.0	0.0000	
DAVIS			0.0	0.0000	
DOUGLAS			0.0	0.0000	
GLEN CANYON			0.0	0.0000	
GOULD ELECTRONICS FOIL DIVISI(			0.0	0.0000	
HOOVER			0.0	0.0000	
HORSE MESA			0.0	0.0000	
INA ROAD WATER POLLUTION CON			0.0	0.0000	
IRVING			0.0	0.0000	
IRVINGTON			0.0	0.0000	
KYRENE			0.0	0.0000	
MORMON FLAT			0.0	0.0000	
NAVAJO			0.0	0.0000	
NELSON PLANT GENERATORS			0.0	0.0000	
NEW CORNELIA BRANCH POWER F			0.0	0.0000	
NORTH LOOP			0.0	0.0000	
OCOTILLO			0.0	0.0000	
PALO VERDE			0.0	0.0000	
ROOSEVELT			0.0	0.0000	
SAGUARO			0.0	0.0000	
SANTAN			0.0	0.0000	
SOUTH CONSOLIDATED			0.0	0.0000	
SPRINGERVILLE			0.0	0.0000	

)00 Data)

PNAME Plant name	OWNRNM13 Plant 2000 owner name (thirteenth)	OWNRUC13 Plant 2000 owner code (thirteenth)	OWNRPR13 Plant 2000 owner percent (thirteenth)	OWNRTY13 Plant 2000 owner type (thirteenth)	OWNRNM14 Plant 2000 owner name (fourteenth)
ABITIBI CONSOLIDATED SNOWFLA		0.0	0.0000		
AGUA FRIA		0.0	0.0000		
APACHE STATION		0.0	0.0000		
BIOSPHERE 2 CENTER INC		0.0	0.0000		
CHILDS		0.0	0.0000		
CHOLLA		0.0	0.0000		
CORONADO		0.0	0.0000		
CROSSCUT		0.0	0.0000		
DAVIS		0.0	0.0000		
DOUGLAS		0.0	0.0000		
GLEN CANYON		0.0	0.0000		
GOULD ELECTRONICS FOIL DIVISI(		0.0	0.0000		
HOOVER		0.0	0.0000		
HORSE MESA		0.0	0.0000		
INA ROAD WATER POLLUTION CON		0.0	0.0000		
IRVING		0.0	0.0000		
IRVINGTON		0.0	0.0000		
KYRENE		0.0	0.0000		
MORMON FLAT		0.0	0.0000		
NAVAJO		0.0	0.0000		
NELSON PLANT GENERATORS		0.0	0.0000		
NEW CORNELIA BRANCH POWER I		0.0	0.0000		
NORTH LOOP		0.0	0.0000		
OCOTILLO		0.0	0.0000		
PALO VERDE		0.0	0.0000		
ROOSEVELT		0.0	0.0000		
SAGUARO		0.0	0.0000		
SANTAN		0.0	0.0000		
SOUTH CONSOLIDATED		0.0	0.0000		
SPRINGERVILLE		0.0	0.0000		

)00 Data)

PNAME Plant name	OWNRUC14 Plant 2000 owner code (fourteenth)	OWNRPR14 Plant 2000 owner percent (fourteenth)	OWNRTY14 Plant 2000 owner type (fourteenth)	SEQPLT eGRID96 1996 file plant sequence number	SEQPLT97 eGRID97 1997 file plant sequence number	SEQPLT98 eGRID2000 1998 file plant sequence number
ABITIBI CONSOLIDATED SNOWFLA	0.0	0.0000		281	280	244
AGUA FRIA	0.0	0.0000		249	248	245
APACHE STATION	0.0	0.0000		250	249	246
BIOSPHERE 2 CENTER INC	0.0	0.0000		251	250	247
CHILDS	0.0	0.0000		252	251	248
CHOLLA	0.0	0.0000		253	252	249
CORONADO	0.0	0.0000		254	253	250
CROSSCUT	0.0	0.0000		255	254	251
DAVIS	0.0	0.0000		256	255	252
DOUGLAS	0.0	0.0000		258	257	254
GLEN CANYON	0.0	0.0000		259	258	255
GOULD ELECTRONICS FOIL DIVISI(	0.0	0.0000		260	259	256
HOOVER	0.0	0.0000		261	260	257
HORSE MESA	0.0	0.0000		262	261	258
INA ROAD WATER POLLUTION CON	0.0	0.0000		N/A	N/A	N/A
IRVING	0.0	0.0000		264	263	259
IRVINGTON	0.0	0.0000		265	264	260
KYRENE	0.0	0.0000		266	265	261
MORMON FLAT	0.0	0.0000		267	266	262
NAVAJO	0.0	0.0000		268	267	263
NELSON PLANT GENERATORS	0.0	0.0000		269	268	264
NEW CORNELIA BRANCH POWER I	0.0	0.0000		270	269	N/A
NORTH LOOP	0.0	0.0000		272	271	265
OCOTILLO	0.0	0.0000		273	272	266
PALO VERDE	0.0	0.0000		274	273	267
ROOSEVELT	0.0	0.0000		275	274	268
SAGUARO	0.0	0.0000		276	275	269
SANTAN	0.0	0.0000		277	276	270
SOUTH CONSOLIDATED	0.0	0.0000		278	277	271
SPRINGERVILLE	0.0	0.0000		279	278	272

eGRID2002 Version 2.01 Boiler File (Year 2000 Data)

SEQBLR00 eGRID2002 2000 file boiler sequence number	SEQBLR99 eGRID2002 1999 file boiler sequence number	PSTATABB State abbreviation	PNAME Plant name	ORISPL DOE/EIA ORIS plant or facility code	BLRID Boiler ID	AFFECTED Affected flag	BOTFIRTY Boiler bottom and firing types	BOILCAP Boiler capacity (MMBtu/hr)
82	78	AZ	AGUA FRIA	141.0	1	Y	DBFF	1020.00
83	79	AZ	AGUA FRIA	141.0	2	Y	DBFF	1020.00
84	80	AZ	AGUA FRIA	141.0	3	Y	DBOT	1632.00
85	81	AZ	APACHE STATION	160.0	1	Y	DBFF	829.60
86	82	AZ	APACHE STATION	160.0	2	Y	DBOF	1842.80
87	83	AZ	APACHE STATION	160.0	3	Y	DBOF	1842.80
88	84	AZ	CHOLLA	113.0	1	Y	DBTF	1176.40
89	85	AZ	CHOLLA	113.0	2	Y	DBTF	2740.40
90	86	AZ	CHOLLA	113.0	3	Y	DBTF	2740.40
91	87	AZ	CHOLLA	113.0	4	Y	DBTF	3848.80
92	88	AZ	CORONADO	6177.0	U1B	Y	DBOF	3735.92
93	89	AZ	CORONADO	6177.0	U2B	Y	DBOF	3735.92
94	90	AZ	IRVINGTON	126.0	1	Y	DBTF	782.00
95	91	AZ	IRVINGTON	126.0	2	Y	DBTF	782.00
96	92	AZ	IRVINGTON	126.0	3	Y	DBTF	1088.00
97	93	AZ	IRVINGTON	126.0	4	Y	DBFF	981.92
98	94	AZ	KYRENE	147.0	K-1	Y	DBFF	476.00
99	95	AZ	KYRENE	147.0	K-2	Y	DBFF	873.12
100	96	AZ	NAVAJO	4941.0	1	Y	DBTF	7357.60
101	97	AZ	NAVAJO	4941.0	2	Y	DBTF	7357.60
102	98	AZ	NAVAJO	4941.0	3	Y	DBTF	7357.60
103	99	AZ	OCOTILLO	116.0	1	Y	DBTF	1088.00
104	100	AZ	OCOTILLO	116.0	2	Y	DBTF	1088.00
105	101	AZ	SAGUARO	118.0	1	Y	DBTF	1224.00
106	102	AZ	SAGUARO	118.0	2	Y	DBTF	1224.00

SEQBLR00 eGRID2002 2000 file boiler sequence number	SEQBLR99 eGRID2002 1999 file boiler sequence number	PSTATABB State abbreviation	PNAME Plant name	ORISPL DOE/EIA ORIS plant or facility code	BLRID Boiler ID	AFFECTED Affected flag	BOTFIRTY Boiler bottom and firing types	BOILCAP Boiler capacity (MMBtu/hr)
107	103	AZ	SPRINGERVILLE	8223.0	1	Y	DBTF	3828.40
108	104	AZ	SPRINGERVILLE	8223.0	2	Y	DBTF	3828.40
109	105	AZ	YUCCA	120.0	1	Y	DBFF	N/A
212	207	CO	ARAPAHOE	465.0	1	Y	DBVF	612.00
213	208	CO	ARAPAHOE	465.0	2	Y	DBVF	612.00
214	209	CO	ARAPAHOE	465.0	3	Y	DBVF	612.00
215	210	CO	ARAPAHOE	465.0	4	Y	DBVF	1264.80
216	N/A	CO	ARAPAHOE COMBUSTION TURBINI	55200.0	CT5	Y		N/A
217	N/A	CO	ARAPAHOE COMBUSTION TURBINI	55200.0	CT6	Y		N/A
218	211	CO	CAMEO	468.0	1	N	DBFF	N/A
219	212	CO	CAMEO	468.0	2	Y	DBFF	N/A
220	213	CO	CHEROKEE	469.0	1	Y	DBVF	1158.72
221	214	CO	CHEROKEE	469.0	2	Y	DBVF	1158.72
222	215	CO	CHEROKEE	469.0	3	Y	DBFF	1550.40
223	216	CO	CHEROKEE	469.0	4	Y	DBTF	3518.32
224	217	CO	COMANCHE	470.0	1	Y	DBTF	3446.24
225	218	CO	COMANCHE	470.0	2	Y	DBOF	3446.24
226	219	CO	CRAIG	6021.0	C1	Y	DBOF	4127.60
227	220	CO	CRAIG	6021.0	C2	Y	DBOF	4127.60
228	221	CO	CRAIG	6021.0	C3	Y	DBOF	4148.00
229	222	CO	FORT ST VRAIN	6112.0	2	Y	DBOT	938.40
230	223	CO	FORT ST VRAIN	6112.0	3	Y	DBOT	938.40
231	224	CO	GEORGE BIRDSALL	493.0	1	N	DBFF	N/A
232	225	CO	GEORGE BIRDSALL	493.0	2	N	DBFF	N/A
233	226	CO	GEORGE BIRDSALL	493.0	3	N	DBFF	N/A
234	227	CO	HAYDEN	525.0	H1	Y	DBFF	1632.00

2000 Data)

PNAME Plant name	NUMGEN Number of associated generators	FUELB1 Primary boiler fuel	LOADHRS Hours connected to load	HTIEAN Boiler 2000 annual ETS/CEM heat input (MMBtu)	HTIEOZ Boiler 2000 ozone season ETS/CEM heat input (MMBtu)	HTIFAN Boiler 2000 annual total EIA-based calculated heat input (MMBtu)	HTIFOZ Boiler 2000 ozone season EIA-based calculated heat input (MMBtu)	HTICL Boiler 2000 annual EIA-based calculated coal heat input (MMBtu)
AGUA FRIA	1	G	4884	4749733.0	2545490.0	4666025.3	2497259.1	0.0
AGUA FRIA	1	G	4705	4426448.0	2044063.0	4665896.0	2428561.3	0.0
AGUA FRIA	1	G	5452	9071394.0	4821045.0	8809257.3	4609684.9	0.0
APACHE STATION	1	G	7331	4595848.0	2352325.0	3579906.5	1767378.6	0.0
APACHE STATION	1	C	8646	17151222.0	7112977.0	15599086.3	6510969.4	15563247.2
APACHE STATION	1	C	8186	15285702.0	7037690.0	14421579.3	6317091.5	14386302.8
CHOLLA	1	C	8292	9431578.0	4265475.0	8585833.5	3807466.3	8568126.0
CHOLLA	1	C	8494	25087567.0	10331574.0	21499508.0	8700190.1	21491864.6
CHOLLA	1	C	7216	20767690.0	10165881.0	18756802.0	9247592.2	18740326.8
CHOLLA	1	C	7336	27075453.0	10994081.0	24735618.8	9580740.3	24687948.8
CORONADO	1	C	8351	34681360.0	15448886.0	31563327.2	13639171.5	31532469.2
CORONADO	1	C	8687	34663078.0	14065193.0	32993429.2	14166480.9	32982379.2
IRVINGTON	1	G	4168	2549079.0	1555852.0	2707141.2	1656153.9	0.0
IRVINGTON	1	G	4260	2820425.0	1666890.0	2944894.2	1762968.1	0.0
IRVINGTON	1	G	3452	3547241.0	2334671.0	3397082.0	2255132.6	0.0
IRVINGTON	1	C	8351	8902912.0	3863906.0	8086117.9	3495936.0	7955107.8
KYRENE	1	G	2061	1064408.0	603597.0	818637.4	493877.8	0.0
KYRENE	1	G	3181	4758957.0	3526229.0	2304917.0	1354391.5	0.0
NAVAJO	1	C	8541	63503234.0	26651681.0	62104129.2	25690198.8	62057402.0
NAVAJO	1	C	7963	62748887.0	27265272.0	58957274.7	25718230.8	58859674.8
NAVAJO	1	C	8375	70021855.0	30119530.0	62322743.4	26627291.2	62233405.4
OCOTILLO	1	G	6131	3798195.0	1919839.0	3619867.5	1923963.4	0.0
OCOTILLO	1	G	5953	3493553.0	1840277.0	3627184.0	1878352.2	0.0
SAGUARO	1	G	4554	3211899.0	1558964.0	3187992.1	1554678.3	0.0
SAGUARO	1	G	4856	3122995.0	1681176.0	3168324.8	1677794.3	0.0

PNAME Plant name	NUMGEN Number of associated generators	FUELB1 Primary boiler fuel	LOADHRS Hours connected to load	HTIEAN Boiler 2000 annual ETS/CEM heat input (MMBtu)	HTIEOZ Boiler 2000 ozone season ETS/CEM heat input (MMBtu)	HTIFAN Boiler 2000 annual total EIA-based calculated heat input (MMBtu)	HTIFOZ Boiler 2000 ozone season EIA-based calculated heat input (MMBtu)	HTICL Boiler 2000 annual EIA-based calculated coal heat input (MMBtu)
SPRINGERVILLE	1	C	7451	28736736.0	12548228.0	27428007.0	12040965.2	27404487.0
SPRINGERVILLE	1	C	8709	32135804.0	13197079.0	30190504.2	12560976.6	30186388.2
YUCCA	1	G	6534	3038057.0	1822943.0	3023164.6	1774895.4	0.0
ARAPAHOE	1	C	7947	3593472.4	1625399.0	3451132.5	1528190.2	3412723.2
ARAPAHOE	1	C	5791	2463698.6	1340916.0	2338451.4	1418460.7	1601877.4
ARAPAHOE	1	C	8118	4336365.0	1759674.0	3401858.6	1372743.6	3373144.0
ARAPAHOE	1	C	8273	8668123.0	3588212.0	8190205.0	3460017.3	7501643.4
ARAPAHOE COMBUSTION TURBINI	N/A	G	N/A	172848.0	56247.0	0.0	0.0	0.0
ARAPAHOE COMBUSTION TURBINI	N/A	G	N/A	151942.0	55564.0	0.0	0.0	0.0
CAMEO	1	C	7881	0.0	0.0	2374993.3	1084577.4	2359738.6
CAMEO	1	C	8519	4434395.0	1970557.0	4775522.5	2177962.5	4766264.0
CHEROKEE	1	C	7974	8984969.0	3950360.0	7879886.8	3448464.5	7477869.6
CHEROKEE	1	C	8356	11608612.0	4632458.0	8615533.0	3664283.4	8311229.0
CHEROKEE	1	C	8369	11824012.0	5235036.0	11334163.8	4925383.8	10995773.8
CHEROKEE	1	C	7016	20736114.0	11465305.0	20792247.2	11163717.8	20531810.4
COMANCHE	1	C	6625	20074913.0	8611915.0	20050163.1	8703756.3	20001485.8
COMANCHE	1	C	8316	27676003.0	11392694.0	24595224.5	9826419.8	24553236.2
CRAIG	1	C	8482	34304580.0	13938281.0	33983748.4	14420713.9	33929637.2
CRAIG	1	C	8506	34111517.0	13227958.0	34471387.3	13468357.0	34435179.6
CRAIG	1	C	8710	33928905.0	14236458.0	33110757.4	13908835.4	33074265.6
FORT ST VRAIN	1	G	7589	11286681.0	5625851.0	1025436.3	678571.8	0.0
FORT ST VRAIN	1	G	7809	11694948.0	5588743.0	1067526.2	653758.0	0.0
GEORGE BIRDSALL	1	G	4452	0.0	0.0	555822.1	361222.8	0.0
GEORGE BIRDSALL	1	G	4249	0.0	0.0	524738.4	296814.3	0.0
GEORGE BIRDSALL	1	G	3648	0.0	0.0	509291.9	336397.7	0.0
HAYDEN	1	C	5456	12131871.0	2444139.0	10093234.0	2009653.0	10067686.4

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PNAME Plant name	HTIOL Boiler 2000 annual EIA-based calculated oil heat input (MMBtu)	HTIGS Boiler 2000 annual EIA-based calculated gas heat input (MMBtu)	HTIBM Boiler 2000 annual EIA-based calculated biomass/ wood heat input (MMBtu)	HTISW Boiler 2000 annual EIA-based calculated solid waste heat input (MMBtu)	HTIOT Boiler 2000 annual EIA-based calculated other fuel heat input (MMBtu)	HTIBAN Boiler 2000 annual best heat input (MMBtu)	HTIBOZ Boiler 2000 ozone season best heat input (MMBtu)	NOXEAN Boiler 2000 annual ETS/CEM NOx emissions (tons)
AGUA FRIA	75703.2	4590322.1	0.0	N/A	0.0	4749733.0	2545490.0	772.39
AGUA FRIA	81017.0	4584879.0	0.0	N/A	0.0	4426448.0	2044063.0	835.93
AGUA FRIA	158931.8	8650325.5	0.0	N/A	0.0	9071394.0	4821045.0	3805.52
APACHE STATION	0.0	3579906.5	0.0	N/A	0.0	4595848.0	2352325.0	355.39
APACHE STATION	0.0	35839.1	0.0	N/A	0.0	17151222.0	7112977.0	4142.17
APACHE STATION	0.0	35276.5	0.0	N/A	0.0	15285702.0	7037690.0	3283.89
CHOLLA	0.0	17707.5	0.0	N/A	0.0	9431578.0	4265475.0	1890.46
CHOLLA	7643.4	0.0	0.0	N/A	0.0	25087567.0	10331574.0	4611.64
CHOLLA	16475.2	0.0	0.0	N/A	0.0	20767690.0	10165881.0	3410.27
CHOLLA	47670.0	0.0	0.0	N/A	0.0	27075453.0	10994081.0	3868.62
CORONADO	30858.0	0.0	0.0	N/A	0.0	34681360.0	15448886.0	7300.18
CORONADO	11050.0	0.0	0.0	N/A	0.0	34663078.0	14065193.0	6971.61
IRVINGTON	0.0	2707141.2	0.0	N/A	0.0	2549079.0	1555852.0	246.62
IRVINGTON	0.0	2944894.2	0.0	N/A	0.0	2820425.0	1666890.0	340.11
IRVINGTON	0.0	3397082.0	0.0	N/A	0.0	3547241.0	2334671.0	307.02
IRVINGTON	0.0	131010.1	0.0	N/A	0.0	8902912.0	3863906.0	1909.47
KYRENE	53298.9	765338.5	0.0	N/A	0.0	1064408.0	603597.0	280.99
KYRENE	122907.0	2182010.0	0.0	N/A	0.0	4758957.0	3526229.0	2144.71
NAVAJO	46727.2	0.0	0.0	N/A	0.0	63503234.0	26651681.0	13004.99
NAVAJO	97599.9	0.0	0.0	N/A	0.0	62748887.0	27265272.0	11090.36
NAVAJO	89338.0	0.0	0.0	N/A	0.0	70021855.0	30119530.0	13171.65
OCOTILLO	0.0	3619867.5	0.0	N/A	0.0	3798195.0	1919839.0	291.06
OCOTILLO	0.0	3627184.0	0.0	N/A	0.0	3493553.0	1840277.0	227.62
SAGUARO	346921.0	2841071.1	0.0	N/A	0.0	3211899.0	1558964.0	191.84
SAGUARO	0.0	3168324.8	0.0	N/A	0.0	3122995.0	1681176.0	148.80

PNAME Plant name	HTIOL Boiler 2000 annual EIA-based calculated oil heat input (MMBtu)	HTIGS Boiler 2000 annual EIA-based calculated gas heat input (MMBtu)	HTIBM Boiler 2000 annual EIA-based calculated biomass/ wood heat input (MMBtu)	HTISW Boiler 2000 annual EIA-based calculated solid waste heat input (MMBtu)	HTIOT Boiler 2000 annual EIA-based calculated other fuel heat input (MMBtu)	HTIBAN Boiler 2000 annual best heat input (MMBtu)	HTIBOZ Boiler 2000 ozone season best heat input (MMBtu)	NOXEAN Boiler 2000 annual ETS/CEM NOx emissions (tons)
SPRINGERVILLE	23520.0	0.0	0.0	N/A	0.0	28736736.0	12548228.0	5556.92
SPRINGERVILLE	4116.0	0.0	0.0	N/A	0.0	32135804.0	13197079.0	6158.39
YUCCA	0.0	3023164.6	0.0	N/A	0.0	3038057.0	1822943.0	178.77
ARAPAHOE	0.0	38409.3	0.0	N/A	0.0	3593472.4	1625399.0	1307.43
ARAPAHOE	0.0	736574.0	0.0	N/A	0.0	2463698.6	1340916.0	896.38
ARAPAHOE	0.0	28714.6	0.0	N/A	0.0	4336365.0	1759674.0	1439.66
ARAPAHOE	0.0	688561.6	0.0	N/A	0.0	8668123.0	3588212.0	1086.34
ARAPAHOE COMBUSTION TURBINI	0.0	0.0	0.0	N/A	0.0	172848.0	56247.0	7.76
ARAPAHOE COMBUSTION TURBINI	0.0	0.0	0.0	N/A	0.0	151942.0	55564.0	6.98
CAMEO	0.0	15254.7	0.0	N/A	0.0	2374993.3	1084577.4	0.00
CAMEO	0.0	9258.5	0.0	N/A	0.0	4434395.0	1970557.0	905.59
CHEROKEE	0.0	402017.2	0.0	N/A	0.0	8984969.0	3950360.0	1538.83
CHEROKEE	0.0	304304.0	0.0	N/A	0.0	11608612.0	4632458.0	4658.23
CHEROKEE	0.0	338390.0	0.0	N/A	0.0	11824012.0	5235036.0	2270.56
CHEROKEE	0.0	260436.8	0.0	N/A	0.0	20736114.0	11465305.0	3493.38
COMANCHE	0.0	48677.3	0.0	N/A	0.0	20074913.0	8611915.0	2520.42
COMANCHE	0.0	41988.3	0.0	N/A	0.0	27676003.0	11392694.0	4457.93
CRAIG	5139.1	48972.1	0.0	N/A	0.0	34304580.0	13938281.0	6196.02
CRAIG	4111.3	32096.4	0.0	N/A	0.0	34111517.0	13227958.0	7303.56
CRAIG	6680.9	29810.9	0.0	N/A	0.0	33928905.0	14236458.0	6064.50
FORT ST VRAIN	0.0	1025436.3	0.0	N/A	0.0	11286681.0	5625851.0	216.32
FORT ST VRAIN	0.0	1067526.2	0.0	N/A	0.0	11694948.0	5588743.0	188.70
GEORGE BIRDSALL	34055.9	521766.2	0.0	N/A	0.0	555822.1	361222.8	0.00
GEORGE BIRDSALL	577.0	524161.4	0.0	N/A	0.0	524738.4	296814.3	0.00
GEORGE BIRDSALL	569.3	508722.6	0.0	N/A	0.0	509291.9	336397.7	0.00
HAYDEN	556.9	24990.7	0.0	N/A	0.0	12131871.0	2444139.0	2450.99

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PNAME Plant name	NOXEOZ Boiler 2000 ozone season ETS/CEM NOx emissions (tons)	NOXFAN Boiler 2000 annual EIA-based calculated NOx emissions (tons)	NOXFOZ Boiler 2000 ozone season EIA-based calculated NOx emissions (tons)	SO2EAN Boiler 2000 annual ETS/CEM SO2 emissions (tons)	SO2FAN Boiler 2000 annual EIA-based calculated SO2 emissions (tons)	CO2EAN Boiler 2000 annual ETS/CEM CO2 emissions (tons)	CO2FAN Boiler 2000 annual EIA-based calculated CO2 emissions (tons)	SRCBEST Source of "best" 2000 heat input, NOx, SO2, and CO2 data
AGUA FRIA	395.90	650.73	347.70	18.10	17.02	282523.80	273629.39	E
AGUA FRIA	376.50	650.90	338.11	21.70	17.53	264212.60	273769.58	E
AGUA FRIA	1964.80	1229.01	641.64	33.20	33.10	540620.60	517045.62	E
APACHE STATION	165.20	489.54	241.68	1.30	6.12	273126.40	208321.71	E
APACHE STATION	1796.80	5459.68	2279.98	3410.70	1117.50	1757801.40	1606263.37	E
APACHE STATION	1578.10	5047.55	2212.95	3156.90	1043.16	1566682.10	1484917.38	E
CHOLLA	866.40	1931.81	857.42	859.10	844.63	967513.20	884187.88	E
CHOLLA	1839.20	4837.39	1957.47	1389.40	1210.37	2572425.90	2215878.72	E
CHOLLA	1704.30	4220.28	2081.50	8378.20	7337.35	2128413.50	1932969.67	E
CHOLLA	1661.60	5565.51	2153.36	7270.10	11188.66	2773616.80	2548509.51	E
CORONADO	3100.50	9696.27	4191.11	10051.40	2239.81	3557628.20	3252664.68	E
CORONADO	2832.30	10340.16	4439.80	9408.50	2422.90	3555558.30	3400532.59	E
IRVINGTON	147.20	224.99	137.64	0.70	4.63	151487.80	157533.80	E
IRVINGTON	205.90	244.74	146.52	1.30	5.04	167733.30	171369.11	E
IRVINGTON	203.20	282.06	187.25	1.10	5.81	210801.60	197682.80	E
IRVINGTON	823.30	2830.14	1220.46	3414.90	3273.43	896387.20	827594.48	E
KYRENE	149.90	113.34	67.40	45.30	10.01	64862.50	49119.65	E
KYRENE	1763.10	318.07	185.63	45.90	31.03	285549.50	137544.05	E
NAVAJO	5597.10	13973.43	5780.21	1206.00	1134.81	6515438.70	6400281.30	E
NAVAJO	4874.30	13265.39	5784.91	1687.40	1075.85	6438039.70	6074737.38	E
NAVAJO	5712.60	14022.62	5991.77	1943.70	1139.72	7184242.50	6421824.29	E
OCOTILLO	145.30	301.54	160.27	4.60	6.21	230763.90	210647.12	E
OCOTILLO	122.50	301.84	156.31	1.10	6.21	207661.90	211072.88	E
SAGUARO	85.00	273.85	132.49	144.40	149.88	198772.20	195158.83	E
SAGUARO	80.90	262.89	139.21	0.90	5.41	185634.50	184370.97	E

PNAME Plant name	NOXEOZ Boiler 2000 ozone season ETS/CEM NOx emissions (tons)	NOXFAN Boiler 2000 annual EIA-based calculated NOx emissions (tons)	NOXFOZ Boiler 2000 ozone season EIA-based calculated NOx emissions (tons)	SO2EAN Boiler 2000 annual ETS/CEM SO2 emissions (tons)	SO2FAN Boiler 2000 annual EIA-based calculated SO2 emissions (tons)	CO2EAN Boiler 2000 annual ETS/CEM CO2 emissions (tons)	CO2FAN Boiler 2000 annual EIA-based calculated CO2 emissions (tons)	SRCBEST Source of "best" 2000 heat input, NOx, SO2, and CO2 data
SPRINGERVILLE	2448.50	9558.66	4196.21	9035.50	7637.88	2948392.80	2826588.18	E
SPRINGERVILLE	2442.60	10521.39	4377.00	10012.90	8422.16	3297133.60	3111782.99	E
YUCCA	117.60	418.00	245.41	12.30	5.23	181134.60	175923.82	E
ARAPAHOE	589.40	1154.45	510.16	844.27	839.67	368716.93	354000.70	E
ARAPAHOE	507.90	638.30	389.65	578.83	390.38	252793.77	207975.78	E
ARAPAHOE	565.10	1140.46	458.02	1078.80	830.67	444909.80	349356.93	E
ARAPAHOE	470.30	2623.73	1066.23	1664.80	1433.38	888367.50	813298.76	E
ARAPAHOE COMBUSTION TURBINI	2.40	0.00	0.00	0.00	0.00	10272.70	0.00	E
ARAPAHOE COMBUSTION TURBINI	2.30	0.00	0.00	0.00	0.00	9029.60	0.00	E
CAMEO	0.00	1189.03	543.99	0.00	1030.53	0.00	244117.17	F
CAMEO	368.80	2401.49	1095.13	2288.40	2083.04	454741.90	491820.24	E
CHEROKEE	676.40	3151.96	1368.03	2622.40	2319.48	915938.40	794173.70	E
CHEROKEE	1788.80	3446.21	1448.33	4560.50	3315.64	1185501.50	874385.89	E
CHEROKEE	1046.90	2833.54	1224.64	5012.80	4377.23	1205689.80	1153078.21	E
CHEROKEE	1875.10	4678.26	2519.45	6949.00	6684.53	2117548.70	2131466.55	E
COMANCHE	1054.00	4511.29	1958.39	5956.30	6216.79	2055774.30	2064480.78	E
COMANCHE	2048.80	6148.81	2456.44	8404.80	7689.08	2836431.90	2533262.07	E
CRAIG	2414.70	8495.94	3605.67	4203.80	3653.07	3511949.20	3500548.90	E
CRAIG	2788.40	8617.85	3366.00	4059.20	3590.13	3478470.10	3551593.48	E
CRAIG	2491.70	8277.69	3477.77	1802.30	1550.60	3476245.80	3411389.73	E
FORT ST VRAIN	111.60	0.73	0.48	3.40	1.74	670752.30	59672.13	E
FORT ST VRAIN	94.10	0.76	0.47	3.50	1.81	695004.90	62121.42	E
GEORGE BIRDSALL	0.00	96.10	62.50	0.00	11.56	0.00	33291.02	F
GEORGE BIRDSALL	0.00	90.74	51.32	0.00	1.32	0.00	30551.58	F
GEORGE BIRDSALL	0.00	88.13	58.21	0.00	1.24	0.00	29652.51	F
HAYDEN	501.50	2321.44	461.11	694.60	502.31	1240852.20	1039222.98	E

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PNAME Plant name	NOXBAN Boiler 2000 annual best NOx emissions (tons)	NOXBOZ Boiler 2000 ozone season best NOx emissions (tons)	SO2BAN Boiler 2000 annual best SO2 emissions (tons)	CO2BAN Boiler 2000 annual best CO2 emissions (tons)	SO2CTLDV 2000 SO2 (scrubber) control device for utilities	NOXCTLDV 2000 NOx control device for utilities	T4A00 Year 2000 Title IV SO2 1998 reallocation plus repowering allowance (tons)	T4A10 Year 2010 Title IV SO2 1998 reallocation plus repowering allowance (tons)
AGUA FRIA	772.39	395.90	18.10	282523.80		NA	54	34
AGUA FRIA	835.93	376.50	21.70	264212.60		NA	65	39
AGUA FRIA	3805.52	1964.80	33.20	540620.60		NA	77	67
APACHE STATION	355.39	165.20	1.30	273126.40		NA	331	332
APACHE STATION	4142.17	1796.80	3410.70	1757801.40	PA	OV	1609	1420
APACHE STATION	3283.89	1578.10	3156.90	1566682.10	PA	OV	3011	2836
CHOLLA	1890.46	866.40	859.10	967513.20	VE	NA	2223	2034
CHOLLA	4611.64	1839.20	1389.40	2572425.90	VE	OV	5443	5067
CHOLLA	3410.27	1704.30	8378.20	2128413.50		OV	5147	4858
CHOLLA	3868.62	1661.60	7270.10	2773616.80	PA	OV	8334	7784
CORONADO	7300.18	3100.50	10051.40	3557628.20	SP	OV	5733	5199
CORONADO	6971.61	2832.30	9408.50	3555558.30	SP	OV	5903	5465
IRVINGTON	246.62	147.20	0.70	151487.80		NA	16	14
IRVINGTON	340.11	205.90	1.30	167733.30		NA	28	40
IRVINGTON	307.02	203.20	1.10	210801.60		NA	0	2
IRVINGTON	1909.47	823.30	3414.90	896387.20		LN	2854	2805
KYRENE	280.99	149.90	45.30	64862.50		NA	7	7
KYRENE	2144.71	1763.10	45.90	285549.50		NA	18	16
NAVAJO	13004.99	5597.10	1206.00	6515438.70	SP	OT	26220	24949
NAVAJO	11090.36	4874.30	1687.40	6438039.70	SP	OT	24262	23354
NAVAJO	13171.65	5712.60	1943.70	7184242.50	SP	OT	25042	23693
OCOTILLO	291.06	145.30	4.60	230763.90		NA	56	40
OCOTILLO	227.62	122.50	1.10	207661.90		NA	132	129
SAGUARO	191.84	85.00	144.40	198772.20		NA	204	189
SAGUARO	148.80	80.90	0.90	185634.50		NA	25	22

PNAME Plant name	NOXBAN Boiler 2000 annual best NOx emissions (tons)	NOXBOZ Boiler 2000 ozone season best NOx emissions (tons)	SO2BAN Boiler 2000 annual best SO2 emissions (tons)	CO2BAN Boiler 2000 annual best CO2 emissions (tons)	SO2CTLDV 2000 SO2 (scrubber) control device for utilities	NOXCTLDV 2000 NOx control device for utilities	T4A00 Year 2000 Title IV SO2 1998 reallocation plus repowering allowance (tons)	T4A10 Year 2010 Title IV SO2 1998 reallocation plus repowering allowance (tons)
SPRINGERVILLE	5556.92	2448.50	9035.50	2948392.80	SD	LN	6566	6099
SPRINGERVILLE	6158.39	2442.60	10012.90	3297133.60	SD	LN	5756	5765
YUCCA	178.77	117.60	12.30	181134.60			42	40
ARAPAHOE	1307.43	589.40	844.27	368716.93		NA	221	208
ARAPAHOE	896.38	507.90	578.83	252793.77		NA	247	229
ARAPAHOE	1439.66	565.10	1078.80	444909.80		NA	181	172
ARAPAHOE	1086.34	470.30	1664.80	888367.50	OT	LN	1927	1829
ARAPAHOE COMBUSTION TURBINI	7.76	2.40	0.00	10272.70			0	0
ARAPAHOE COMBUSTION TURBINI	6.98	2.30	0.00	9029.60			0	0
CAMEO	1189.03	543.99	1030.53	244117.17			0	0
CAMEO	905.59	368.80	2288.40	454741.90			904	852
CHEROKEE	1538.83	676.40	2622.40	915938.40	OT	LN	2138	2035
CHEROKEE	4658.23	1788.80	4560.50	1185501.50		OV	2838	2722
CHEROKEE	2270.56	1046.90	5012.80	1205689.80		LN	3761	3562
CHEROKEE	3493.38	1875.10	6949.00	2117548.70	SD	LN	7535	7132
COMANCHE	2520.42	1054.00	5956.30	2055774.30		NA	7698	7363
COMANCHE	4457.93	2048.80	8404.80	2836431.90		OV	6914	6450
CRAIG	6196.02	2414.70	4203.80	3511949.20	SP	LN	8218	7678
CRAIG	7303.56	2788.40	4059.20	3478470.10	SP	LN	7845	7352
CRAIG	6064.50	2491.70	1802.30	3476245.80	SD	LN	2602	2149
FORT ST VRAIN	216.32	111.60	3.40	670752.30		LN	0	0
FORT ST VRAIN	188.70	94.10	3.50	695004.90		LN	0	0
GEORGE BIRDSALL	96.10	62.50	11.56	33291.02			0	0
GEORGE BIRDSALL	90.74	51.32	1.32	30551.58			0	0
GEORGE BIRDSALL	88.13	58.21	1.24	29652.51			0	0
HAYDEN	2450.99	501.50	694.60	1240852.20	SD	LN	6063	5776

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PNAME Plant name	BLRYRONL Boiler year on-line	BLRSEQ Unique boiler identifier originating in NADB, and continuing in ARDB and IMDB data files	SEQBLR eGRID96 1996 file boiler sequence number	SEQBLR97 eGRID97 1997 file boiler sequence number	SEQBLR98 eGRID2000 1998 file boiler sequence number
AGUA FRIA	1958	52	81	71	71
AGUA FRIA	1957	53	82	72	72
AGUA FRIA	1961	54	83	73	73
APACHE STATION	1964	55	84	74	74
APACHE STATION	1979	56	85	75	75
APACHE STATION	1979	57	86	76	76
CHOLLA	1962	58	87	77	77
CHOLLA	1978	59	88	78	78
CHOLLA	1980	60	89	79	79
CHOLLA	1981	61	90	80	80
CORONADO	1979	63	91	81	81
CORONADO	1980	64	92	82	82
IRVINGTON	1958	79	102	83	83
IRVINGTON	1960	80	103	84	84
IRVINGTON	1962	81	104	85	85
IRVINGTON	1967	82	105	86	86
KYRENE	1952	83	106	87	87
KYRENE	1954	84	107	88	88
NAVAJO	1974	85	108	89	89
NAVAJO	1975	86	109	90	90
NAVAJO	1976	87	110	91	91
OCOTILLO	1960	88	111	92	92
OCOTILLO	1960	89	112	93	93
SAGUARO	1954	90	113	94	94
SAGUARO	1955	91	114	95	95

PNAME Plant name	BLRYRONL Boiler year on-line	BLRSEQ Unique boiler identifier originating in NADB, and continuing in ARDB and IMDB data files	SEQBLR eGRID96 1996 file boiler sequence number	SEQBLR97 eGRID97 1997 file boiler sequence number	SEQBLR98 eGRID2000 1998 file boiler sequence number
SPRINGERVILLE	1985	92	115	96	96
SPRINGERVILLE	1990	93	116	97	97
YUCCA	N/A	98	120	98	98
ARAPAHOE	1950	276	256	194	187
ARAPAHOE	1951	277	257	195	188
ARAPAHOE	1951	278	258	196	189
ARAPAHOE	1955	279	259	197	190
ARAPAHOE COMBUSTION TURBINI	N/A	4188	N/A	N/A	N/A
ARAPAHOE COMBUSTION TURBINI	N/A	4189	N/A	N/A	N/A
CAMEO	N/A	280	260	198	191
CAMEO	N/A	281	261	199	192
CHEROKEE	1957	282	262	200	193
CHEROKEE	1959	283	263	201	194
CHEROKEE	1962	284	264	202	195
CHEROKEE	1968	285	265	203	196
COMANCHE	1973	286	266	204	197
COMANCHE	1975	287	267	205	198
CRAIG	1980	288	268	206	199
CRAIG	1979	289	269	207	200
CRAIG	1984	290	270	208	201
FORT ST VRAIN	1998	3187	271	209	202
FORT ST VRAIN	1999	3469	N/A	N/A	N/A
GEORGE BIRDSALL	N/A	291	272	210	203
GEORGE BIRDSALL	N/A	292	273	211	204
GEORGE BIRDSALL	N/A	293	274	212	205
HAYDEN	1965	294	275	213	206

eGRID2002 Version 2.01 Generator File (Year 2000 Data)

SEQGEN00 eGRID2002 2000 file generator sequence number	SEQGEN99 eGRID2002 1999 file generator sequence number	PSTATABB State abbreviation	PNAME Plant name	ORISPL DOE/EIA ORIS plant or facility code	GENID Generator ID or grouped identifier	GENTYPE Generator type	NUMBLR Number of associated boilers	GENSTAT Generator 2000 status
764	766	AZ	ABITIBI CONSOLIDATED SNOWFLA	50805.0	GEN1	NU	N/A	OP
765	767	AZ	ABITIBI CONSOLIDATED SNOWFLA	50805.0	GEN2	NU	N/A	OP
766	768	AZ	AGUA FRIA	141.0	AF1	UT	1	OP
767	769	AZ	AGUA FRIA	141.0	AF2	UT	1	OP
768	770	AZ	AGUA FRIA	141.0	AF3	UT	1	OP
769	771	AZ	AGUA FRIA	141.0	AF4	UT	N/A	OP
770	772	AZ	AGUA FRIA	141.0	AF5	UT	N/A	OP
771	773	AZ	AGUA FRIA	141.0	AF6	UT	N/A	OP
772	774	AZ	APACHE STATION	160.0	GT1	UT	N/A	OP
773	775	AZ	APACHE STATION	160.0	GT2	UT	N/A	OP
774	776	AZ	APACHE STATION	160.0	GT3	UT	N/A	OP
775	777	AZ	APACHE STATION	160.0	ST1	UT	1	OP
776	778	AZ	APACHE STATION	160.0	ST2	UT	1	OP
777	779	AZ	APACHE STATION	160.0	ST3	UT	1	OP
778	780	AZ	BIOSPHERE 2 CENTER INC	54594.0	G-1	NU	N/A	CS
779	N/A	AZ	BIOSPHERE 2 CENTER INC	54594.0	G-4	NU	N/A	SB
780	782	AZ	CHILDS	112.0	HY#	UT	N/A	OP
781	783	AZ	CHOLLA	113.0	1	UT	1	OP
782	784	AZ	CHOLLA	113.0	2	UT	1	OP
783	785	AZ	CHOLLA	113.0	3	UT	1	OP
784	786	AZ	CHOLLA	113.0	4	UT	1	OP
785	787	AZ	CORONADO	6177.0	CO1	UT	1	OP
786	788	AZ	CORONADO	6177.0	CO2	UT	1	OP
787	789	AZ	CROSSCUT	143.0	CC1	UT	1	SB
788	790	AZ	CROSSCUT	143.0	CC2	UT	1	SB
789	791	AZ	CROSSCUT	143.0	CC3	UT	1	SB
790	792	AZ	CROSSCUT	143.0	CC4	UT	3	SB
791	793	AZ	CROSSCUT	143.0	HY#	UT	N/A	OP
792	794	AZ	DAVIS	152.0	HY#	UT	N/A	OP

SEQGEN00 eGRID2002 2000 file generator sequence number	SEQGEN99 eGRID2002 1999 file generator sequence number	PSTATABB State abbreviation	PNAME Plant name	ORISPL DOE/EIA ORIS plant or facility code	GENID Generator ID or grouped identifier	GENTYPE Generator type	NUMBLR Number of associated boilers	GENSTAT Generator 2000 status
793	795	AZ	DOUGLAS	114.0	1	UT	N/A	OP
794	796	AZ	GLEN CANYON	153.0	HY#	UT	N/A	OP
795	797	AZ	GOULD ELECTRONICS FOIL DIVISI	54838.0	G1	NU	N/A	CS
796	798	AZ	GOULD ELECTRONICS FOIL DIVISI	54838.0	G2	NU	N/A	CS
797	799	AZ	HOOVER	8902.0	HY#	UT	N/A	OP
798	800	AZ	HORSE MESA	145.0	HY#	UT	N/A	OP
799	801	AZ	HORSE MESA	145.0	PS#	UT	N/A	OP
800	802	AZ	INA ROAD WATER POLLUTION CON	55257.0	1	NU	N/A	OP
801	803	AZ	INA ROAD WATER POLLUTION CON	55257.0	2	NU	N/A	OP
802	804	AZ	INA ROAD WATER POLLUTION CON	55257.0	3	NU	N/A	SB
803	805	AZ	INA ROAD WATER POLLUTION CON	55257.0	4	NU	N/A	OP
804	806	AZ	INA ROAD WATER POLLUTION CON	55257.0	5	NU	N/A	OP
805	807	AZ	INA ROAD WATER POLLUTION CON	55257.0	6	NU	N/A	OP
806	808	AZ	INA ROAD WATER POLLUTION CON	55257.0	7	NU	N/A	OP
807	809	AZ	IRVING	115.0	HY#	UT	N/A	OP
808	810	AZ	IRVINGTON	126.0	4	UT	1	OP
809	811	AZ	IRVINGTON	126.0	GT1	UT	N/A	OP
810	812	AZ	IRVINGTON	126.0	GT2	UT	N/A	OP
811	813	AZ	IRVINGTON	126.0	ST1	UT	1	OP
812	814	AZ	IRVINGTON	126.0	ST2	UT	1	OP
813	815	AZ	IRVINGTON	126.0	ST3	UT	1	OP
814	816	AZ	KYRENE	147.0	KY1	UT	1	OP
815	817	AZ	KYRENE	147.0	KY2	UT	1	OP
816	818	AZ	KYRENE	147.0	KY3	UT	N/A	SD
817	819	AZ	KYRENE	147.0	KY4	UT	N/A	OP
818	820	AZ	KYRENE	147.0	KY5	UT	N/A	OP
819	821	AZ	KYRENE	147.0	KY6	UT	N/A	OP
820	822	AZ	MORMON FLAT	148.0	HY#	UT	N/A	OP
821	823	AZ	MORMON FLAT	148.0	PS#	UT	N/A	OP
822	824	AZ	NAVAJO	4941.0	NAV1	UT	1	OP

'ear 2000 Data)

PNAME Plant name	PRMVR Prime mover type	FUELG1 Primary generator fuel	NAMEPCAP Generator nameplate capacity (MW)	CFACT Generator 2000 capacity factor	GENNTAN Generator 2000 annual net generation (MWh)	GENNTOZ Generator 2000 ozone season net generation (MWh)	GENYRONL Generator year on-line	SEQGEN eGRID96 1996 file generator sequence number
ABITIBI CONSOLIDATED SNOWFLA	ST	SUB	27.20	0.5319	126747.0	52811.3	1961	N/A
ABITIBI CONSOLIDATED SNOWFLA	ST	SUB	43.35	0.5680	215705.4	89877.2	1974	N/A
AGUA FRIA	ST	NG	113.64	0.4391	437140.0	182141.7	1958	303
AGUA FRIA	ST	NG	113.64	0.4347	432757.0	180315.4	1957	304
AGUA FRIA	ST	NG	163.20	0.5848	836014.0	348339.2	1961	305
AGUA FRIA	GT	NG	80.55	N/A	N/A	N/A	1975	N/A
AGUA FRIA	GT	NG	71.20	N/A	N/A	N/A	1974	N/A
AGUA FRIA	GT	NG	71.20	N/A	N/A	N/A	1974	N/A
APACHE STATION	CT	NG	10.05	N/A	N/A	N/A	1965	307
APACHE STATION	GT	DFO	19.80	N/A	N/A	N/A	1972	N/A
APACHE STATION	GT	DFO	64.89	N/A	N/A	N/A	1974	N/A
APACHE STATION	CA	RFO	75.00	0.5651	371281.0	154700.4	1965	309
APACHE STATION	ST	SUB	194.70	0.8680	1480476.7	616865.3	1979	310
APACHE STATION	ST	SUB	194.70	0.8140	1388425.1	578510.5	1979	311
BIOSPHERE 2 CENTER INC	IC	DFO	1.47	0.0143	183.8	76.6	1990	N/A
BIOSPHERE 2 CENTER INC	IC	NG	1.58	0.1666	2305.0	960.4	2000	N/A
CHILDS	HY	WAT	5.40	N/A	N/A	N/A	N/A	312
CHOLLA	ST	SUB	113.64	0.7997	796037.9	331682.5	1962	313
CHOLLA	ST	SUB	288.90	0.7671	1941407.5	808919.8	1978	314
CHOLLA	ST	SUB	288.90	0.6857	1735247.1	723019.6	1980	315
CHOLLA	ST	SUB	414.00	0.6404	2322439.5	967683.1	1981	316
CORONADO	ST	SUB	410.94	0.8527	3069595.0	1278997.9	1979	318
CORONADO	ST	SUB	410.94	0.8908	3206765.0	1336152.1	1980	319
CROSSCUT	ST	NG	7.50	N/A	N/A	N/A	1942	320
CROSSCUT	ST	NG	7.50	N/A	N/A	N/A	1942	321
CROSSCUT	ST	NG	7.50	N/A	N/A	N/A	1942	322
CROSSCUT	ST	NG	7.50	N/A	N/A	N/A	1949	323
CROSSCUT	HY	WAT	3.00	N/A	N/A	N/A	N/A	324
DAVIS	HY	WAT	240.00	N/A	N/A	N/A	N/A	325

PNAME Plant name	PRMVR Prime mover type	FUELG1 Primary generator fuel	NAMEPCAP Generator nameplate capacity (MW)	CFACT Generator 2000 capacity factor	GENNTAN Generator 2000 annual net generation (MWh)	GENNTOZ Generator 2000 ozone season net generation (MWh)	GENYRONL Generator year on-line	SEQGEN eGRID96 1996 file generator sequence number
DOUGLAS	GT	DFO	21.40	N/A	N/A	N/A	1972	N/A
GLEN CANYON	HY	WAT	1296.00	N/A	N/A	N/A	N/A	328
GOULD ELECTRONICS FOIL DIVISI(	IC	NG	0.53	0.0621	285.4	118.9	1994	N/A
GOULD ELECTRONICS FOIL DIVISI(	IC	NG	0.53	0.0577	265.2	110.5	1994	N/A
HOOVER	HY	WAT	1039.40	N/A	N/A	N/A	N/A	330
HORSE MESA	HY	WAT	29.70	N/A	N/A	N/A	N/A	331
HORSE MESA	PS	WAT	99.88	N/A	N/A	N/A	N/A	332
INA ROAD WATER POLLUTION CON	IC	NG	0.65	0.3707	2110.9	879.6	1977	N/A
INA ROAD WATER POLLUTION CON	IC	NG	0.65	0.6190	3524.5	1468.5	1977	N/A
INA ROAD WATER POLLUTION CON	IC	NG	0.65	0.1480	842.6	351.1	1977	N/A
INA ROAD WATER POLLUTION CON	IC	NG	0.65	0.5767	3283.9	1368.3	1977	N/A
INA ROAD WATER POLLUTION CON	IC	NG	0.65	0.6187	3522.8	1467.8	1977	N/A
INA ROAD WATER POLLUTION CON	IC	NG	0.64	0.4104	2300.8	958.7	1977	N/A
INA ROAD WATER POLLUTION CON	IC	NG	0.65	0.5475	3117.4	1298.9	1977	N/A
IRVING	HY	WAT	1.60	N/A	N/A	N/A	N/A	333
IRVINGTON	ST	SUB	173.30	0.5224	792994.0	330414.2	1967	338
IRVINGTON	GT	NG	27.00	N/A	N/A	N/A	1972	N/A
IRVINGTON	GT	NG	27.00	N/A	N/A	N/A	1972	N/A
IRVINGTON	ST	NG	108.80	0.2439	232422.3	96842.6	1958	335
IRVINGTON	ST	NG	108.80	0.2773	264337.6	110140.7	1960	336
IRVINGTON	ST	NG	113.60	0.3123	310780.8	129492.0	1962	337
KYRENE	ST	NG	34.50	0.1888	57069.0	23778.8	1952	340
KYRENE	ST	NG	73.50	0.2921	188043.0	78351.3	1954	341
KYRENE	GT	NG	53.13	N/A	N/A	N/A	1972	N/A
KYRENE	GT	NG	53.13	N/A	N/A	N/A	1971	N/A
KYRENE	GT	NG	60.30	N/A	N/A	N/A	1973	N/A
KYRENE	GT	NG	60.30	N/A	N/A	N/A	1973	N/A
MORMON FLAT	HY	WAT	9.20	N/A	N/A	N/A	N/A	342
MORMON FLAT	PS	WAT	48.65	N/A	N/A	N/A	N/A	343
NAVAJO	ST	SUB	803.16	0.8849	6225990.0	2594162.5	1974	344

'ear 2000 Data)

PNAME Plant name	SEQGEN97 eGRID97 1997 file generator sequence number	SEQGEN98 eGRID2000 1998 file generator sequence number
ABITIBI CONSOLIDATED SNOWFLA	N/A	524
ABITIBI CONSOLIDATED SNOWFLA	N/A	525
AGUA FRIA	248	526
AGUA FRIA	249	527
AGUA FRIA	250	528
AGUA FRIA	N/A	N/A
AGUA FRIA	N/A	N/A
AGUA FRIA	N/A	N/A
APACHE STATION	252	531
APACHE STATION	N/A	N/A
APACHE STATION	N/A	N/A
APACHE STATION	254	532
APACHE STATION	255	533
APACHE STATION	256	534
BIOSPHERE 2 CENTER INC	N/A	535
BIOSPHERE 2 CENTER INC	N/A	N/A
CHILDS	257	537
CHOLLA	258	538
CHOLLA	259	539
CHOLLA	260	540
CHOLLA	261	541
CORONADO	262	543
CORONADO	263	544
CROSSCUT	264	545
CROSSCUT	265	546
CROSSCUT	266	547
CROSSCUT	267	548
CROSSCUT	268	549
DAVIS	269	550

PNAME Plant name	SEQGEN97 eGRID97 1997 file generator sequence number	SEQGEN98 eGRID2000 1998 file generator sequence number
DOUGLAS	N/A	N/A
GLEN CANYON	272	554
GOULD ELECTRONICS FOIL DIVISI(	N/A	556
GOULD ELECTRONICS FOIL DIVISI(	N/A	557
HOOVER	273	559
HORSE MESA	274	560
HORSE MESA	275	561
INA ROAD WATER POLLUTION CON	N/A	N/A
INA ROAD WATER POLLUTION CON	N/A	N/A
INA ROAD WATER POLLUTION CON	N/A	N/A
INA ROAD WATER POLLUTION CON	N/A	N/A
INA ROAD WATER POLLUTION CON	N/A	N/A
INA ROAD WATER POLLUTION CON	N/A	N/A
INA ROAD WATER POLLUTION CON	N/A	N/A
IRVING	276	562
IRVINGTON	281	563
IRVINGTON	N/A	N/A
IRVINGTON	N/A	N/A
IRVINGTON	278	565
IRVINGTON	279	566
IRVINGTON	280	567
KYRENE	283	569
KYRENE	284	570
KYRENE	N/A	N/A
KYRENE	N/A	N/A
KYRENE	N/A	N/A
KYRENE	N/A	N/A
MORMON FLAT	285	571
MORMON FLAT	286	572
NAVAJO	287	573

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SEQPLCH eGRID2002 plant change sequence number	SEQPLT00 eGRID2002 2000 file plant sequence number	SEQPLT98 eGRID2002 1998 file plant sequence number	PNAME Plant name	ORISPL DOE/EIA ORIS plant or facility code	CHTYPE Type of note	CHDATE Change date (yymm)
1	3909	3866	Abilene	3517.0	OPR	0201
2	3909	3866	Abilene	3517.0	OWN	0201
3	288	284	Alamitos	315.0	OPR	9805
4	288	284	Alamitos	315.0	OWN	9805
5	3112	3067	Albany	2539.0	OPR	0005
6	3112	3067	Albany	2539.0	OWN	0005
7	3116	3070	Allens Falls	2540.0	OPR	9907
8	3116	3070	Allens Falls	2540.0	OWN	9907
9	3703	3578	Allentown	3139.0	OPR	0007
10	3703	3578	Allentown	3139.0	OWN	0007
11	0	2124	Androscog Mill Lower	7047.0	OPR	99xx
12	0	2124	Androscog Mill Lower	7047.0	OWN	99xx
13	2151	2126	Androscoggin 3	1480.0	OPR	99xx
14	2151	2126	Androscoggin 3	1480.0	OWN	99xx
15	3622	3581	Armstrong	3178.0	OPR	0001
16	3622	3581	Armstrong	3178.0	OWN	0001
17	2154	0	Aroostook Valley	7513.0	OPR	9904
18	2154	0	Aroostook Valley	7513.0	OWN	9904
19	4489	4435	Arpin Dam	3995.0	OPR	0104
20	4489	4435	Arpin Dam	3995.0	OWN	0104
21	3119	3073	Arthur Kill	2490.0	OPR	9906
22	3119	3073	Arthur Kill	2490.0	OWN	9906
23	3122	3075	Astoria	8906.0	SPL	9908
24	3121	3076	Astoria (GT)	55243.0	OPR	9906
25	3121	3076	Astoria (GT)	55243.0	OWN	9906
26	3122	3075	Astoria (ST)	8906.0	OPR	9908
27	3122	3075	Astoria (ST)	8906.0	OWN	9908
28	3416	3383	Avon Lake	2836.0	OPR	0004
29	3416	3383	Avon Lake	2836.0	OWN	0004
30	1583	1578	Baldwin	889.0	OPR	9910

SEQPLCH eGRID2002 plant change sequence number	SEQPLT00 eGRID2002 2000 file plant sequence number	SEQPLT98 eGRID2002 1998 file plant sequence number	PNAME Plant name	ORISPL DOE/EIA ORIS plant or facility code	CHTYPE Type of note	CHDATE Change date (yymm)
31	1583	1578	Baldwin	889.0	OWN	9910
32	0	3078	Baldwinsville	2542.0	OPR	9907
33	0	3078	Baldwinsville	2542.0	OWN	9907
34	1044	1041	Bantam	6457.0	OPR	0003
35	1044	1041	Bantam	6457.0	OWN	0003
36	2157	2132	Bar Mills	1481.0	OPR	9904
37	2157	2132	Bar Mills	1481.0	OWN	9904
38	3914	3872	Barney M Davis	4939.0	OPR	0201
39	3914	3872	Barney M Davis	4939.0	OWN	0201
40	0	0	Bates Mill Lower	7045.0	OPR	9904
41	0	0	Bates Mill Lower	7045.0	OWN	9904
42	2160	2135	Bates Mill Upper	7044.0	OPR	9904
43	2160	2135	Bates Mill Upper	7044.0	OWN	9904
44	2961	2921	Bayonne	2397.0	OPR	0008
45	2961	2921	Bayonne	2397.0	OWN	0008
46	4233	4174	Bayview	3782.0	OPR	0007
47	4233	4174	Bayview	3782.0	OWN	0007
48	2011	1986	Bear Swamp	8005.0	OPR	9809
49	2011	1986	Bear Swamp	8005.0	OWN	9809
50	3126	3080	Beardslee	2543.0	OPR	9907
51	3126	3080	Beardslee	2543.0	OWN	9907
52	3130	3083	Beebee Island	10531.0	OPR	9907
53	3130	3083	Beebee Island	10531.0	OWN	9907
54	3131	3084	Belfort	2544.0	OPR	9907
55	3131	3084	Belfort	2544.0	OWN	9907
56	4325	4265	Bellows Falls	3745.0	OPR	9809
57	4325	4265	Bellows Falls	3745.0	OWN	9809
58	3132	3085	Bennetts Bridge	2545.0	OPR	9907
59	3132	3085	Bennetts Bridge	2545.0	OWN	9907
60	1094	1093	Benning	603.0	OPR	0012
61	1094	1093	Benning	603.0	OWN	0012

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PNAME	OLDNAME	OLDID
Plant name	Old name	Old ID
Abilene	West Texas Utilities Co	20404.0
Abilene	West Texas Utilities Co	20404.0
Alamitos	Southern California Edison Co	17609.0
Alamitos	Southern California Edison Co	17609.0
Albany	Niagara Mohawk Power Corp	13573.0
Albany	Niagara Mohawk Power Corp	13573.0
Allens Falls	Niagara Mohawk Power Corp	13573.0
Allens Falls	Niagara Mohawk Power Corp	13573.0
Allentown	PPL Utilities	14715.0
Allentown	PPL Utilities	14715.0
Androscog Mill Lower	Central Maine Power Co	3266.0
Androscog Mill Lower	Central Maine Power Co	3266.0
Androscoggin 3	Central Maine Power Co	3266.0
Androscoggin 3	Central Maine Power Co	3266.0
Armstrong	West Penn Power Co	20387.0
Armstrong	West Penn Power Co	20387.0
Aroostook Valley	Central Maine Power Co	3266.0
Aroostook Valley	Central Maine Power Co	3266.0
Arpin Dam	North Central Power Co Inc	13697.0
Arpin Dam	North Central Power Co Inc	13697.0
Arthur Kill	Consolidated Edison Co-NY Inc	4226.0
Arthur Kill	Consolidated Edison Co-NY Inc	4226.0
Astoria		0.0
Astoria (GT)	Consolidated Edison Co-NY Inc	4226.0
Astoria (GT)	Consolidated Edison Co-NY Inc	4226.0
Astoria (ST)	Consolidated Edison Co-NY Inc	4226.0
Astoria (ST)	Consolidated Edison Co-NY Inc	4226.0
Avon Lake	Duquesne Light Co	5487.0
Avon Lake	Duquesne Light Co	5487.0
Baldwin	Illinois Power Co	9208.0

PNAME	OLDNAME	OLDID
Plant name	Old name	Old ID
Baldwin	Illinois Power Co	9208.0
Baldwinsville	Niagara Mohawk Power Corp	13573.0
Baldwinsville	Niagara Mohawk Power Corp	13573.0
Bantam	Connecticut Light & Power Co	4176.0
Bantam	Connecticut Light & Power Co	4176.0
Bar Mills	Central Maine Power Co	3266.0
Bar Mills	Central Maine Power Co	3266.0
Barney M Davis	Central Power & Light Co	3278.0
Barney M Davis	Central Power & Light Co	3278.0
Bates Mill Lower	Central Maine Power Co	3266.0
Bates Mill Lower	Central Maine Power Co	3266.0
Bates Mill Upper	Central Maine Power Co	3266.0
Bates Mill Upper	Central Maine Power Co	3266.0
Bayonne	Public Service Electric&Gas Co	15477.0
Bayonne	Public Service Electric&Gas Co	15477.0
Bayview	Delmarva Power & Light Co	5027.0
Bayview	Delmarva Power & Light Co	5027.0
Bear Swamp	New England Power Co	13433.0
Bear Swamp	New England Power Co	13433.0
Beardslee	Niagara Mohawk Power Corp	13573.0
Beardslee	Niagara Mohawk Power Corp	13573.0
Beebee Island	Niagara Mohawk Power Corp	13573.0
Beebee Island	Niagara Mohawk Power Corp	13573.0
Belfort	Niagara Mohawk Power Corp	13573.0
Belfort	Niagara Mohawk Power Corp	13573.0
Bellows Falls	New England Power Co	13433.0
Bellows Falls	New England Power Co	13433.0
Bennetts Bridge	Niagara Mohawk Power Corp	13573.0
Bennetts Bridge	Niagara Mohawk Power Corp	13573.0
Benning	Pepco	15270.0
Benning	Pepco	15270.0

PNAME Plant name	NEWNAME New name	NEWID New ID	PRVOWNTY Previous owner type, if CHTYPE= OWN or OPR	OLDPERC Old percent, if CHTYPE= OWN	NEWPERC New percent, if CHTYPE= OWN
Abilene	AEP NUGs	-206.0	U	0.0000	0.0000
Abilene	AEP NUGs	-206.0	U	100.0000	100.0000
Alamitos	AES NUGs	-1001.0	U	0.0000	0.0000
Alamitos	AES NUGs	-1001.0	U	100.0000	100.0000
Albany	PSEG Fossil LLC	15147.0	U	0.0000	0.0000
Albany	PSEG Fossil LLC	15147.0	U	100.0000	100.0000
Allens Falls	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	0.0000	0.0000
Allens Falls	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	100.0000	100.0000
Allentown	PPL Generation LLC	-1227.0	U	0.0000	0.0000
Allentown	PPL Generation LLC	-1227.0	U	100.0000	100.0000
Androscog Mill Lower	FPL Energy	-1064.0	U	0.0000	0.0000
Androscog Mill Lower	FPL Energy	-1064.0	U	100.0000	100.0000
Androscoggin 3	FPL Energy	-1064.0	U	0.0000	0.0000
Androscoggin 3	FPL Energy	-1064.0	U	100.0000	100.0000
Armstrong	Allegheny Energy Supply Co	-1172.0	U	0.0000	0.0000
Armstrong	Allegheny Energy Supply Co	-1172.0	U	100.0000	100.0000
Aroostook Valley	FPL Energy	-1064.0	U	0.0000	0.0000
Aroostook Valley	FPL Energy	-1064.0	U	100.0000	100.0000
Arpin Dam	Flambeau Hydro LLC	6338.0	U	0.0000	0.0000
Arpin Dam	Flambeau Hydro LLC	6338.0	U	100.0000	100.0000
Arthur Kill	NRG Energy	-1105.0	U	0.0000	0.0000
Arthur Kill	NRG Energy	-1105.0	U	100.0000	100.0000
Astoria		0.0		0.0000	0.0000
Astoria (GT)	NRG Energy	-1105.0	U	0.0000	0.0000
Astoria (GT)	NRG Energy	-1105.0	U	100.0000	100.0000
Astoria (ST)	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	0.0000	0.0000
Astoria (ST)	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	100.0000	100.0000
Avon Lake	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	0.0000	0.0000
Avon Lake	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	100.0000	100.0000
Baldwin	Dynegy Marketing & Trade	-1054.0	U	0.0000	0.0000

PNAME Plant name	NEWNAME New name	NEWID New ID	PRVOWNTY Previous owner type, if CHTYPE= OWN or OPR	OLDPERC Old percent, if CHTYPE= OWN	NEWPERC New percent, if CHTYPE= OWN
Baldwin	Dynegy Marketing & Trade	-1054.0	U	100.0000	100.0000
Baldwinsville	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	0.0000	0.0000
Baldwinsville	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	100.0000	100.0000
Bantam	Northeast Generation Services	-180.0	U	0.0000	0.0000
Bantam	Northeast Generation Company	27972.0	U	100.0000	100.0000
Bar Mills	FPL Energy	-1064.0	U	0.0000	0.0000
Bar Mills	FPL Energy	-1064.0	U	100.0000	100.0000
Barney M Davis	AEP NUGs	-206.0	U	0.0000	0.0000
Barney M Davis	AEP NUGs	-206.0	U	100.0000	100.0000
Bates Mill Lower	FPL Energy	-1064.0	U	0.0000	0.0000
Bates Mill Lower	FPL Energy	-1064.0	U	100.0000	100.0000
Bates Mill Upper	FPL Energy	-1064.0	U	0.0000	0.0000
Bates Mill Upper	FPL Energy	-1064.0	U	100.0000	100.0000
Bayonne	PSEG Fossil LLC	15147.0	U	0.0000	0.0000
Bayonne	PSEG Fossil LLC	15147.0	U	100.0000	100.0000
Bayview	Conectiv Energy Supply Inc	-1188.0	U	0.0000	0.0000
Bayview	Conectiv Energy Supply Inc	-1188.0	U	100.0000	100.0000
Bear Swamp	PG&E National Energy Group	-1178.0	U	0.0000	0.0000
Bear Swamp	PG&E National Energy Group	-1178.0	U	100.0000	100.0000
Beardslee	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	0.0000	0.0000
Beardslee	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	100.0000	100.0000
Beebee Island	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	0.0000	0.0000
Beebee Island	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	100.0000	100.0000
Belfort	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	0.0000	0.0000
Belfort	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	100.0000	100.0000
Bellows Falls	PG&E National Energy Group	-1178.0	U	0.0000	0.0000
Bellows Falls	PG&E National Energy Group	-1178.0	U	100.0000	100.0000
Bennetts Bridge	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	0.0000	0.0000
Bennetts Bridge	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	100.0000	100.0000
Benning	Mirant Corp (formerly Southern Energy Inc)	-1138.0	U	0.0000	0.0000
Benning	Potomac Power Resources	15274.0	U	100.0000	100.0000

eGRID2002 Version 2.01 Electric Generating Company Note File

SEQEGCH eGRID2002 EGC change sequence number	SEQEGO00 eGRID2002 2000 file owner-based EGC sequence number	SEQEGP00 eGRID2002 2000 file location (operator)-based EGC sequence number	SEQEGO98 eGRID2002 1998 file owner-based EGC sequence number	SEQEGP98 eGRID2002 1998 file location (operator)-based EGC sequence number	EGCNAME EGC name	EGCID EGC ID	CHTYPE Type of note	CHDATE Change year
1	27	27	27	25	Albany City of	228.0	NN	1998
2	27	27	27	25	Albany City of	228.0	RC	2001
3	0	0	42	38	Alliant Energy/Interstate Power Co	9392.0	M	2002
4	0	0	42	38	Alliant Energy/Interstate Power Co	9392.0	NN	2000
5	0	0	42	38	Alliant Energy/Interstate Power Co	9392.0	NP	1998
6	0	0	42	38	Alliant Energy/Interstate Power Co	9392.0	R	2000
7	0	0	42	38	Alliant Energy/Interstate Power Co	9392.0	RC	1998
8	0	0	43	39	Alliant Energy/IES Utilities Inc	9162.0	M	2002
9	0	0	43	39	Alliant Energy/IES Utilities Inc	9162.0	NN	1998
10	0	0	43	39	Alliant Energy/IES Utilities Inc	9162.0	NP	1998
11	0	0	43	39	Alliant Energy/IES Utilities Inc	9162.0	R	2000
12	0	0	43	39	Alliant Energy/IES Utilities Inc	9162.0	RC	1998
13	38	38	44	40	Alliant Energy/Wisc Power & Light	20856.0	NP	1998
14	38	38	44	40	Alliant Energy/Wisc Power & Light	20856.0	R	2000
15	48	49	54	50	AmerenCIPS	3253.0	R	1997
16	48	49	54	50	AmerenCIPS	3253.0	RC	1998
17	49	50	55	51	AmerenUE	19436.0	R	1997
18	57	58	63	59	Ames City of	554.0	NC	1998
19	59	59	64	61	Anaheim City of	590.0	RC	1999
20	70	68	0	0	Aquila Networks-Colorado	-230.1	M	2002
21	71	69	0	0	Aquila Networks-Kansas	-230.2	M	2002
22	72	70	0	0	Aquila Networks-Missouri	-230.3	M	2002
23	78	77	80	75	Arkansas Electric Coop Corp	807.0	NN	1998
24	87	85	89	82	Associated Electric Coop Inc	924.0	NN	1998
25	92	89	93	85	Atlantic City Electric Co	963.0	NP	1998
26	92	89	93	85	Atlantic City Electric Co	963.0	NP	2002
27	103	99	103	94	Avista Utilities	20169.0	R	1999
28	107	0	106	0	Azusa City of	1050.0	RC	1999

SEQEGCH eGRID2002 EGC change sequence number	SEQEGO00 eGRID2002 2000 file owner-based EGC sequence number	SEQEGP00 eGRID2002 2000 file location (operator)-based EGC sequence number	SEQEGO98 eGRID2002 1998 file owner-based EGC sequence number	SEQEGP98 eGRID2002 1998 file location (operator)-based EGC sequence number	EGCNAME EGC name	EGCID EGC ID	CHTYPE Type of note	CHDATE Change year
29	112	0	32	0	AGC Division of APG Inc	261.0	R	2000
30	0	0	0	0	Baltimore Gas & Electric Co	1167.0	NP	1999
31	0	0	118	105	Bangor Hydro-Electric Co	1179.0	NP	2001
32	144	128	147	127	Bellevue City of	1515.0	NN	1998
33	144	128	147	127	Bellevue City of	1515.0	RC	1998
34	163	143	165	140	Black Hills Corp	19545.0	NP	0
35	0	0	0	0	Blackstone Valley Electric Co	1796.0	NP	2000
36	0	0	0	0	Blackstone Valley Electric Co	1796.0	NP	2002
37	169	147	172	144	Bloomfield City of	1869.0	NN	1998
38	0	0	0	0	Boston Edison Co	1998.0	NP	1999
39	203	175	205	173	Brooklyn City of	2287.0	NN	1998
40	203	175	205	173	Brooklyn City of	2287.0	RC	1998
41	211	182	212	178	Bryan City of	2439.0	RC	1998
42	225	192	226	188	Bushnell City of	2634.0	RC	1998
43	0	0	0	0	Cajun Electric Power Coop Inc	2777.0	NN	1998
44	240	203	240	202	California Dept-Wtr Resources	3255.0	RC	1999
45	247	209	247	207	Cambridge Electric Light Co	2886.0	NP	1999
46	0	0	250	0	Canal Electric Co	2951.0	NP	1999
47	256	215	258	216	Carmi City of	3040.0	RC	1998
48	257	216	259	217	Carolina Power & Light Co	3046.0	NP	2000
49	264	221	266	221	Cascade Municipal Utilities	3137.0	NN	1998
50	264	221	266	221	Cascade Municipal Utilities	3137.0	RC	1998
51	0	0	1446	1247	CenterPoint Energy	8901.0	NP	2002
52	0	0	1446	1247	CenterPoint Energy	8901.0	R	2002
53	276	231	277	232	Central Electric Power Coop	3242.0	NN	1998
54	278	232	279	233	Central Hudson Gas & Elec Corp	3249.0	NP	2000
55	279	233	280	234	Central Illinois Light Company	3252.0	NP	1999
56	279	233	280	234	Central Illinois Light Company	3252.0	P	0
57	280	234	281	235	Central Iowa Power Coop	3258.0	NN	1998

EGCNAME	CHDESC
EGC name	**Note text**
Albany City of	City of Albany moved from SPP to MAPP in 1998.
Albany City of	City of Albany's PCA reconfigured from St Joseph Light & Power Co/PCA to Missouri Public Service Co/PCA in 2001.
Alliant Energy/Interstate Power Co	Alliant Energy/IES Utilities Inc and Alliant Energy/Interstate Power Co merged to form Interstate Power and Light Company in 20
Alliant Energy/Interstate Power Co	Alliant Energy/Interstate Power Co moved from MAPP to MAIN in 1998.
Alliant Energy/Interstate Power Co	Alliant Energy/Interstate Power Co became a subsidiary of Alliant Energy Corp in 1998.
Alliant Energy/Interstate Power Co	Interstate Power Co was renamed Alliant Energy/Interstate Power Co in 2000.
Alliant Energy/Interstate Power Co	Alliant Energy/Interstate Power Co's PCA reconfigured from Interstate Power Co/PCA to Alliant West/PCA in 1998.
Alliant Energy/IES Utilities Inc	Alliant Energy/IES Utilities Inc and Alliant Energy/Interstate Power Co merged to form Interstate Power and Light Company in 20
Alliant Energy/IES Utilities Inc	Alliant Energy/IES Utilities Inc moved from MAPP to MAIN in 1998.
Alliant Energy/IES Utilities Inc	Alliant Energy/IES Utilities Inc became a subsidiary of Alliant Energy Corp in 1998.
Alliant Energy/IES Utilities Inc	IES Utilities Inc was renamed Alliant Energy/IES Utililties Inc in 2000.
Alliant Energy/IES Utilities Inc	Alliant Energy/IES Utilities Inc's PCA reconfigured from IES Utilities Inc/PCA to Alliant West/PCA in 1998.
Alliant Energy/Wisc Power & Light	Alliant Energy/Wisc Power & Light became a subsidiary of Alliant Energy Corp in 1998.
Alliant Energy/Wisc Power & Light	Wisconsin Power & Light Co was renamed Alliant Energy/Wisc Power & Light in 2000.
AmerenCIPS	Central Illinois Pub Serv Co was renamed AmerenCIPS in 1997.
AmerenCIPS	AmerenCIPS's PCA reconfigured from Central Illinois Pub Serv Co/PCA to Ameren Corp/PCA in 1998.
AmerenUE	Union Electric Co was renamed AmerenUE in 1997.
Ames City of	City of Ames moved from IES Utilities Inc/PCA to MidAmerican Energy Company/PCA in 1998.
Anaheim City of	City of Anaheim's PCA reconfigured from Southern California Edison Co/PCA to California ISO/PCA in 1999.
Aquila Networks-Colorado	West Plains Energy-CO, West Plains Energy-KS, and Missouri Public Service Co merged to form Aquila Networks in 2002; for E-
Aquila Networks-Kansas	West Plains Energy-CO, West Plains Energy-KS, and Missouri Public Service Co merged to form Aquila Networks in 2002; for E-
Aquila Networks-Missouri	West Plains Energy-CO, West Plains Energy-KS, and Missouri Public Service Co merged to form Aquila Networks in 2002; for E-
Arkansas Electric Coop Corp	Arkansas Electric Coop Corp moved from SPP to SERC in 1998.
Associated Electric Coop Inc	Associated Electric Coop Inc moved from SPP to SERC in 1998.
Atlantic City Electric Co	Atlantic City Electric Co became a subsidiary of Conectiv in 1998.
Atlantic City Electric Co	Atlantic City Electric Co became a subsidiary Pepco Holdings, Inc in 2002.
Avista Utilities	Washington Water Power Co was renamed Avista Utilities in 1999.
Azusa City of	City of Azusa's PCA reconfigured from Southern California Edison Co/PCA to California ISO/PCA in 1999.

EGCNAME	CHDESC
EGC name	**Note text**
AGC Division of APG Inc	Alcoa Generating Company was renamed AGC Division of APG Inc in 2000.
Baltimore Gas & Electric Co	Baltimore Gas & Electric Co became a subsidiary of Constellation Energy Group, Inc in 1999.
Bangor Hydro-Electric Co	Bangor Hydro-Electric Co became a subsidiary of Emera Inc in 2001.
Bellevue City of	City of Bellevue moved from MAPP to MAIN in 1998.
Bellevue City of	City of Bellevue's PCA reconfigured from Interstate Power Co/PCA to Alliant West/PCA in 1998.
Black Hills Corp	Black Hills Corp became a subsidiary of Black Hills Corp.
Blackstone Valley Electric Co	Blackstone Valley Electric Co became a subsidiary of National Grid Group PLC (UK) in 2000.
Blackstone Valley Electric Co	Blackstone Valley Electric Co became a subsidiary of National Grid Transco (UK) in 2002.
Bloomfield City of	City of Bloomfield moved from SPP to SERC in 1998.
Boston Edison Co	Boston Edison Co became a subsidiary of NSTAR in 1999.
Brooklyn City of	City of Brooklyn moved from MAPP to MAIN in 1998.
Brooklyn City of	City of Brooklyn's PCA reconfigured from IES Utilities Inc/PCA to Alliant West/PCA in 1998.
Bryan City of	City of Bryan's PCA reconfigured from Toledo Edison Co/PCA to FirstEnergy Corp/PCA in 1998.
Bushnell City of	City of Bushnell's PCA reconfigured from Central Illinois Pub Serv Co/PCA to Ameren Corp/PCA in 1998.
Cajun Electric Power Coop Inc	Cajun Electric Power Coop Inc moved from SPP to SERC in 1998.
California Dept-Wtr Resources	California Dept-Wtr Resources's PCA reconfigured from Pacific Gas & Electric Co/PCA to California ISO/PCA in 1999.
Cambridge Electric Light Co	Cambridge Electric Light Co became a subsidiary of NSTAR in 1999.
Canal Electric Co	Canal Electric Co became a subsidiary of NSTAR in 1999.
Carmi City of	City of Carmi's PCA reconfigured from Central Illinois Pub Serv Co/PCA to Ameren Corp/PCA in 1998.
Carolina Power & Light Co	Carolina Power & Light Co became a subsidiary of Progress Energy in 2000.
Cascade Municipal Utilities	Cascade Municipal Utilities moved from MAPP to MAIN in 1998.
Cascade Municipal Utilities	Cascade Municipal Utilities's PCA reconfigured from IES Utilities Inc/PCA to Alliant West/PCA in 1998.
CenterPoint Energy	CenterPoint Energy became a subsidiary of CenterPoint Energy in 2002.
CenterPoint Energy	Reliant Energy HL&P was renamed CenterPoint Energy in 2002.
Central Electric Power Coop	Central Electric Power Coop moved from SPP to SERC in 1998.
Central Hudson Gas & Elec Corp	Central Hudson Gas & Elec Corp became a subsidiary of CH Energy Group, Inc in 2000.
Central Illinois Light Company	Central Illinois Light Company became a subsidiary of AES Corp in 1999.
Central Illinois Light Company	Central Illinois Light Company's change to a subsidiary of Ameren Corp is pending
Central Iowa Power Coop	Central Iowa Power Coop moved from MAPP to MAIN in 1998.

e

EGCNAME	OLDNAME	OLDID	NEWNAME	NEWID
EGC name	**Old name**	**Old ID**	**New name**	**New ID**
Albany City of	SPP	8.0	MAPP	5.0
Albany City of	St Joseph Light & Power Co/PCA	17881.0	Missouri Public Service Co/PCA	12699.0
Alliant Energy/Interstate Power Co	Alliant Energy/Interstate Power Co	9392.0	Interstate Power and Light Company	-207.0
Alliant Energy/Interstate Power Co	MAPP	5.0	MAIN	4.0
Alliant Energy/Interstate Power Co		0.0	Alliant Energy Corp	-7004.0
Alliant Energy/Interstate Power Co	Interstate Power Co	9392.0	Alliant Energy/Interstate Power Co	9392.0
Alliant Energy/Interstate Power Co	Interstate Power Co/PCA	9392.0	Alliant West/PCA	193.0
Alliant Energy/IES Utilities Inc	Alliant Energy/IES Utilities Inc	9162.0	Interstate Power and Light Company	-207.0
Alliant Energy/IES Utilities Inc	MAPP	5.0	MAIN	4.0
Alliant Energy/IES Utilities Inc		0.0	Alliant Energy Corp	-7004.0
Alliant Energy/IES Utilities Inc	IES Utililties Inc	9162.0	Alliant Energy/IES Utilities Inc	9162.0
Alliant Energy/IES Utilities Inc	IES Utililties Inc/PCA	9162.0	Alliant West/PCA	193.0
Alliant Energy/Wisc Power & Light		0.0	Alliant Energy Corp	-7004.0
Alliant Energy/Wisc Power & Light	Wisconsin Power & Light Co	20856.0	Alliant Energy/Wisc Power & Light	20856.0
AmerenCIPS	Central Illinois Pub Serv Co	3253.0	AmerenCIPS	3253.0
AmerenCIPS	Central Illinois Pub Serv Co/PCA	3253.0	Ameren Corp/PCA	19436.0
AmerenUE	Union Electric Co	19436.0	AmerenUE	19436.0
Ames City of	IES Utililties Inc/PCA	9162.0	MidAmerican Energy Company/PCA	12341.0
Anaheim City of	Southern California Edison Co/PCA	17609.0	California ISO/PCA	-4.0
Aquila Networks-Colorado		0.0	Aquila Networks-Colorado	-230.1
Aquila Networks-Kansas		0.0	Aquila Networks-Kansas	-230.2
Aquila Networks-Missouri		0.0	Aquila Networks-Missouri	-230.3
Arkansas Electric Coop Corp	SPP	8.0	SERC	7.0
Associated Electric Coop Inc	SPP	8.0	SERC	7.0
Atlantic City Electric Co		0.0	Conectiv	-7013.0
Atlantic City Electric Co		0.0	Pepco Holdings, Inc	-7112.0
Avista Utilities	Washington Water Power Co	20169.0	Avista Utilities	20169.0
Azusa City of	Southern California Edison Co/PCA	17609.0	California ISO/PCA	-4.0

EGCNAME	OLDNAME	OLDID	NEWNAME	NEWID
EGC name	Old name	Old ID	New name	New ID
AGC Division of APG Inc	Alcoa Generating Company	261.0	AGC Division of APG Inc	261.0
Baltimore Gas & Electric Co		0.0	Constellation Energy Group, Inc	-7015.0
Bangor Hydro-Electric Co		0.0	Emera Inc	-7106.0
Bellevue City of	MAPP	5.0	MAIN	4.0
Bellevue City of	Interstate Power Co/PCA	9392.0	Alliant West/PCA	193.0
Black Hills Corp		0.0	Black Hills Corp	-7008.0
Blackstone Valley Electric Co		0.0	National Grid Group PLC (UK)	-7035.0
Blackstone Valley Electric Co		0.0	National Grid Transco (UK)	-7109.0
Bloomfield City of	SPP	8.0	SERC	7.0
Boston Edison Co		0.0	NSTAR	-7038.0
Brooklyn City of	MAPP	5.0	MAIN	4.0
Brooklyn City of	IES Utililties Inc/PCA	9162.0	Alliant West/PCA	193.0
Bryan City of	Toledo Edison Co/PCA	18997.0	FirstEnergy Corp/PCA	-5.0
Bushnell City of	Central Illinois Pub Serv Co/PCA	3253.0	Ameren Corp/PCA	19436.0
Cajun Electric Power Coop Inc	SPP	8.0	SERC	7.0
California Dept-Wtr Resources	Pacific Gas & Electric Co/PCA	14328.0	California ISO/PCA	-4.0
Cambridge Electric Light Co		0.0	NSTAR	-7038.0
Canal Electric Co		0.0	NSTAR	-7038.0
Carmi City of	Central Illinois Pub Serv Co/PCA	3253.0	Ameren Corp/PCA	19436.0
Carolina Power & Light Co		0.0	Progress Energy	-7069.0
Cascade Municipal Utilities	MAPP	5.0	MAIN	4.0
Cascade Municipal Utilities	IES Utililties Inc/PCA	9162.0	Alliant West/PCA	193.0
CenterPoint Energy		0.0	CenterPoint Energy	-7117.0
CenterPoint Energy	Reliant Energy HL&P	8901.0	CenterPoint Energy	8901.0
Central Electric Power Coop	SPP	8.0	SERC	7.0
Central Hudson Gas & Elec Corp		0.0	CH Energy Group, Inc	-7010.0
Central Illinois Light Company		0.0	AES Corp	-7001.0
Central Illinois Light Company	AES Corp	-7001.0	Ameren Corp	-7005.0
Central Iowa Power Coop	MAPP	5.0	MAIN	4.0

eGRID2002 Version 2.01 Parent Note File

SEQPRCH eGRID2002 parent company change sequence number	SEQPRO00 eGRID2002 2000 file owner-based parent company sequence number	SEQPRP00 eGRID2002 2000 file location (operator)-based parent company sequence number	SEQPRO98 eGRID2002 1998 file owner-based parent company sequence number	SEQPRP98 eGRID2002 1998 file location (operator)-based parent company sequence number	PRNAME Parent company name	PRNUM Parent company ID	CHTYPE Type of note	CHDATE Change year
1	3	3	2	2	Allegheny Energy Inc	550.0	R	1997
2	4	4	3	3	Alliant Energy Corp	-7004.0	M, NP	1998
3	5	5	4	4	Ameren Corp	-7005.0	P	2002
4	6	6	5	5	American Electric Power Co Inc	829.0	A	2000
5	6	6	5	5	American Electric Power Co Inc (east)	829.0	NP	2000
6	6	6	5	5	American Electric Power Co Inc (west	829.0	NP	2000
7	0	0	0	0	American States Water Company	-7006.0	NP	1999
8	9	9	68	64	Aquila Inc	-7062.0	R	2002
9	0	0	0	0	Atlantic City Energy Co	963.0	M	1998
10	11	11	8	8	AES Corp	-7001.0	A	1999
11	11	11	8	8	AES Corp	-7001.0	A	2001
12	11	11	8	8	AES Corp	-7001.0	AS	2001
13	12	12	9	9	ALLETE	-7003.0	NP	2000
14	0	0	11	0	BayCorp Holdings Ltd	-7007.0	NP	0
15	15	15	12	11	Black Hills Corp	-7008.0	NP	0
16	16	16	0	0	CenterPoint Energy	-7117.0	FP	2002
17	16	16	0	0	CenterPoint Energy	-7117.0	NP	2002
18	19	19	14	13	Citizens Communications	3611.0	R	2000
19	0	0	15	14	Conectiv	-7013.0	M	2002
20	0	0	15	14	Conectiv	-7013.0	M, NP	1998
21	20	20	16	15	Consolidated Edison Inc	-7014.0	NP	1999
22	21	21	17	16	Constellation Energy Group Inc	-7015.0	NP	1999
23	0	0	0	0	Cooperative Power Assoc.	4322.0	M	1999
24	22	22	18	17	CH Energy Group	-7010.0	NP	2000
25	23	23	19	18	CLECO Corporation	-7011.0	NP	1999
26	0	0	0	0	Delmarva Power & Lgt	5027.0	M	1998

PRNAME	CHDESC
Parent company name	**Note text**
Allegheny Energy Inc	Allegheny Power System Inc was renamed Allegheny Energy Inc in 1997.
Alliant Energy Corp	Alliant Energy Corp was formed by the merger of IES Utilities Inc, Interstate Power Co, and WPL Holdings Inc in 1998.
Ameren Corp	Ameren Corp's absorption of Central Illinois Light Company is pending.
American Electric Power Co Inc	Central & Southwest Corporation was absorbed by American Electric Power Inc in 2000.
American Electric Power Co Inc (east)	American Electric Power Co (east) is a "dummy" parent company consisting of the original AEP before its merger with Central &
American Electric Power Co Inc (west	American Electric Power Co (west) is a "dummy" parent company consisting of the original Central & Southwest Corp before its a
American States Water Company	American States Water Company became a parent company for Southern California Water Company in 1999.
Aquila Inc	Utilicorp United Inc was renamed Aquila Inc in 2002.
Atlantic City Energy Co	Conectiv was formed by the merger of Atlantic City Energy Co and Delmarva Power & Light Co in 1998.
AES Corp	CILCORP Inc was absorbed by AES Corp in 1999.
AES Corp	Ipalco Enterprises, Inc was absorbed by AES Corp in 2001.
AES Corp	Indianapolis Power & Light Co became a subsidiary of AES Corp in 2001.
ALLETE	ALLETE became a parent company for Minnesota Power and Superior Water Light&Power Co in 2000.
BayCorp Holdings Ltd	BayCorp Holdings Ltd became a parent company for Great Bay Power Corp and Little Bay Power Corp.
Black Hills Corp	Black Hills Corp became a parent company for Black Hills Power & Light, Black Hills Capital, and Adirondack Hydro Develop Cor
CenterPoint Energy	CenterPoint Energy was formerly the parent company of Reliant Resources until 2002.
CenterPoint Energy	CenterPoint Energy was formed from Reliant Energy Inc in 2002.
Citizens Communications	Citizens Utilities was renamed Citizens Communications in 2000.
Conectiv	Pepco Holdings, Inc was formed by the merger of Pepco and Conectiv in 2002.
Conectiv	Conectiv was formed by the merger of Atlantic City Energy Co and Delmarva Power & Light Co in 1998.
Consolidated Edison Inc	Consolidated Edison Inc became a parent company for Consolidated Edison of NY Inc in 1999.
Constellation Energy Group Inc	Constellation Energy Group Inc became a parent company for Baltimore Gas & Electric Co in 1999.
Cooperative Power Assoc.	Great River Energy was formed by the merger of Cooperative Power Association and United Power Association in 1999.
CH Energy Group	CH Energy Group became a parent company for Central Hudson Gas & Electric Co in 2000.
CLECO Corporation	CLECO Corporation became a parent company for CLECO Corporation and CLECO Utility Group, Inc in 1999.
Delmarva Power & Lgt	Conectiv was formed by the merger of Atlantic City Energy Co and Delmarva Power & Light Co in 1998.

PRNAME	OLDNAME	OLDID	NEWNAME	NEWID
Parent company name	**Old name**	**Old ID**	**New name**	**New ID**
Allegheny Energy Inc	Allegheny Power System Inc	12796.0	Allegheny Energy Inc	550.0
Alliant Energy Corp		0.0	Alliant Energy Corp	-7004.0
Ameren Corp	Central Illinois Light Company	3252.0	Ameren Corp	-7005.0
American Electric Power Co Inc	Central & Southwest Corporation	40023.0	American Electric Power Co Inc	829.0
American Electric Power Co Inc (east)	American Electric Power Co Inc	829.0	American Electric Power Co Inc (eas	829.0
American Electric Power Co Inc (west	Central & Southwest Corporation	40023.0	American Electric Power Co Inc (wes	829.0
American States Water Company		0.0	American States Water Company	-7006.0
Aquila Inc	Utilicorp United Inc	-7062.0	Aquila Inc	-7062.0
Atlantic City Energy Co	Atlantic City Energy Co	963.0	Conectiv	-7013.0
AES Corp	CILCORP Inc	-7078.0	AES Corp	-7001.0
AES Corp	Ipalco Enterprises, Inc	-7031.0	AES Corp	-7001.0
AES Corp		0.0	AES Corp	-7001.0
ALLETE		0.0	ALLETE	-7003.0
BayCorp Holdings Ltd		0.0	BayCorp Holdings Ltd	-7007.0
Black Hills Corp		0.0	Black Hills Corp	-7008.0
CenterPoint Energy	Reliant Resources	-1124.0		0.0
CenterPoint Energy		0.0	CenterPoint Energy	-7117.0
Citizens Communications	Citizens Utilities	3611.0	Citizens Communications	3611.0
Conectiv	Conectiv	-7013.0	Pepco Holdings, Inc	-7112.0
Conectiv		0.0	Conectiv	-7013.0
Consolidated Edison Inc		0.0	Consolidated Edison Inc	-7014.0
Constellation Energy Group Inc		0.0	Constellation Energy Group Inc	-7015.0
Cooperative Power Assoc.	Cooperative Power Assoc.	4322.0	Great River Energy	-7028.0
CH Energy Group		0.0	CH Energy Group	-7010.0
CLECO Corporation		0.0	CLECO Corporation	-7011.0
Delmarva Power & Lgt	Delmarva Power & Lgt	5027.0	Conectiv	-7013.0

eGRID2002 Version 2.01 Power Control Area Note File

SEQPCCH eGRID2002 PCA change sequence number	SEQPCO00 eGRID2002 2000 file owner-based PCA sequence number	SEQPCP00 eGRID2002 2000 file location (operator)-based PCA sequence number	SEQPCO98 eGRID2002 1998 file owner-based PCA sequence number	SEQPCP98 eGRID2002 1998 file location (operator)-based PCA sequence number	PCANAME PCA name	PCAID PCA ID	CHTYPE Type of note	CHDATE Change year
1	4	4	4	4	Alliant East/PCA	186.0	R	
2	5	5	5	5	Alliant West/PCA	193.0	M	1998
3	5	5	5	5	Alliant West/PCA	193.0	NN	2000
4	6	6	6	6	Ameren Corp/PCA	19436.0	M	1997
5	0	0	8	8	American Electric Power - West (ERC	3280.0	M	
6	0	0	8	8	American Electric Power - West (ERC	3280.0	M	2001
7	7	7	9	9	American Electric Power - West (SPP)	3283.0	M	
8	7	7	9	9	American Electric Power - West (SPP)	3283.0	NT	
9	11	11	125	126	Aquila Networks - Kansas/PCA	20391.0	R	
10	10	10	68	69	Aquila Networks - Missouri/PCA	12699.0	R	
11	13	13	12	12	Associated Electric Coop/PCA	924.0	NN	1998
12	0	0	13	13	Austin Energy/PCA	1015.0	M	2001
13	0	0	13	13	Austin Energy/PCA	1015.0	R	
14	14	14	14	14	Avista Corp/PCA	20169.0	R	
15	0	0	17	17	Brownsville Public Utils Board/PCA	2409.0	M	2001
16	17	17	18	18	California ISO/PCA	-4.0	M	2000
17	17	17	18	18	California ISO/PCA	-4.0	RC	2002
18	0	0	0	0	Central Illinois Public Service/PCA	3253.0	M	1997
19	0	0	0	0	Central Power & Light Co/PCA	3278.0	M	
20	0	0	0	0	Cincinnati Gas & Electric/PCA	3542.0	M	
21	21	21	22	22	Cinergy Corporation/PCA	3260.0	M	
22	0	0	0	0	City of Pasadena/PCA	14534.0	M	2000
23	0	0	0	0	Cleveland Electric Illuminating Co/PCA	3755.0	M	1997
24	24	24	25	25	CLECO Corporation/PCA	3265.0	R	
25	27	27	123	124	Dominion Virginia Power/PCA	19876.0	R	
26	28	28	28	28	Duke Power Co/PCA	5416.0	RC	
27	33	33	33	34	Entergy Electric System/PCA	12506.0	NN	1998
28	35	35	34	35	FirstEnergy/PCA	-5.0	M	1997

SEQPCCH eGRID2002 PCA change sequence number	SEQPCO00 eGRID2002 2000 file owner-based PCA sequence number	SEQPCP00 eGRID2002 2000 file location (operator)-based PCA sequence number	SEQPCO98 eGRID2002 1998 file owner-based PCA sequence number	SEQPCP98 eGRID2002 1998 file location (operator)-based PCA sequence number	PCANAME PCA name	PCAID PCA ID	CHTYPE Type of note	CHDATE Change year
29	36	36	35	36	Florida Municipal Power Pool/PCA	14610.0	A	2002
30	36	36	35	36	Florida Municipal Power Pool/PCA	14610.0	M	
31	0	0	0	0	Fort Pierce Utilities Auth/PCA	6616.0	M	
32	40	40	39	40	Golden Valley Electric Association/PC	7353.0	A	1999
33	42	42	41	42	Great River Energy/PCA	7570.0	R	
34	50	50	49	50	Independence City Of/PCA	9231.0	NT	
35	0	0	0	0	Interstate Power/PCA	9392.0	M	1998
36	0	0	0	0	IES Utilities Inc/PCA	9162.0	M	1998
37	52	52	51	52	JEA (City of Jacksonville)/PCA	9617.0	R	
38	0	0	0	0	Key West City of/PCA	10226.0	M	
39	0	0	0	0	Kissimmee Utility Authority/PCA	10376.0	M	
40	0	0	54	55	KGE, A Western Resources Co/PCA	10005.0	M	
41	113	113	55	56	KPL, a Western Resources Co/PCA	22500.0	A	
42	113	113	55	56	KPL, a Western Resources Co/PCA	22500.0	M	
43	55	55	56	57	Lafayette (LA) Utilities System/PCA	9096.0	R	
44	59	59	61	62	Louisiana Generating LLC/PCA	2777.0	NN	1998
45	59	59	61	62	Louisiana Generating LLC/PCA	2777.0	R	
46	0	0	62	63	Lower Colorado River Authority/PCA	11269.0	M	2001
47	60	60	63	64	LG&E Energy/PCA	11249.0	A	
48	62	62	65	66	Michigan Electric Power Coordination	12427.0	R	
49	10	10	68	69	Missouri Public Service Co/PCA	12699.0	A	2001
50	69	69	73	74	New England ISO/PCA	13434.0	R	
51	71	71	75	76	New York ISO/PCA	13501.0	R	
52	0	0	0	0	Ohio Edison Co/PCA	13998.0	M	1997
53	0	0	0	0	Pacific Gas & Electric/PCA	14328.0	M	2000
54	0	0	0	0	Public Service Co of Oklahoma/PCA	15474.0	M	
55	87	87	91	92	Puget Sound Energy Transmission/PC	15500.0	R	
56	0	0	0	0	PSI Energy Inc/PCA	15470.0	M	
57	0	0	94	95	Reliant Energy HL&P/PCA	8901.0	M	2001

SEQPCCH eGRID2002 PCA change sequence number	SEQPCO00 eGRID2002 2000 file owner-based PCA sequence number	SEQPCP00 eGRID2002 2000 file location (operator)-based PCA sequence number	SEQPCO98 eGRID2002 1998 file owner-based PCA sequence number	SEQPCP98 eGRID2002 1998 file location (operator)-based PCA sequence number	PCANAME PCA name	PCAID PCA ID	CHTYPE Type of note	CHDATE Change year
58	0	0	94	95	Reliant Energy HL&P/PCA	8901.0	R	
59	90	90	0	0	Sacramento Municipal Utility District/P	-7.0	NC	2002
60	0	0	96	97	San Antonio Public Service Bd/PCA	16604.0	M	2001
61	0	0	0	0	San Diego Gas & Electric/PCA	16609.0	M	2000
62	0	0	103	104	South Texas Electric Coop Inc/PCA	17583.0	M	2001
63	98	98	104	105	Southeastern Power Administration/P(	-6.0	M	2000
64	0	0	0	0	Southern California Edison/PCA	17609.0	M	2000
65	0	0	0	0	Southwestern Electric Power/PCA	17698.0	M	
66	105	105	111	112	Springfield (IL) Water Light & Power/P	17828.0	NT	
67	105	105	111	112	Springfield (IL) Water Light & Power/P	17828.0	R	
68	0	0	112	113	St Joseph Light & Power/PCA	17881.0	A	2001
69	0	0	112	113	St Joseph Light & Power/PCA	17881.0	NN	1998
70	0	0	0	0	Starke City of/PCA	18004.0	M	
71	107	107	114	115	Tacoma City Dept Of Public Utilities/P	18429.0	NT	
72	0	0	118	119	Texas Municipal Power Pool/PCA	18664.0	M	2001
73	0	0	119	120	Texas-New Mexico Power Co/PCA	40051.0	M	2001
74	0	0	0	0	Toledo Edison Co/PCA	18997.0	M	1997
75	0	0	121	122	TXU Electric/PCA	44372.0	M	2001
76	0	0	121	122	TXU Electric/PCA	44372.0	R	
77	6	6	6	6	Union Electric/PCA	19436.0	M	1997
78	0	0	0	0	Vero Beach City of/PCA	19804.0	M	
79	0	0	0	0	West Texas Utilities/PCA	20404.0	M	
80	113	113	55	56	Westar Energy/PCA	22500.0	NT	
81	113	113	55	56	Westar Energy/PCA	22500.0	R	
82	113	113	55	56	Western Resources Inc/PCA	22500.0	M	
83	115	115	126	127	Wisconsin Energy Corporation/PCA	20847.0	R	
84	117	117	128	129	WAPA - Phoenix (LC)/PCA	19610.0	NT	
85	117	117	128	129	WAPA - Phoenix (LC)/PCA	19610.0	R	
86	118	118	129	130	WAPA - Rocky Mountains/PCA	28503.0	NT	

PCANAME	CHDESC
PCA name	**Note text**
Alliant East/PCA	Wisconsin Power & Light/PCA was renamed Alliant East/PCA.
Alliant West/PCA	Alliant West/PCA was formed by the merger of IES Utilities Inc/PCA and Interstate Power/PCA in 1998.
Alliant West/PCA	Alliant West/PCA moved from MAPP to MAIN in 2000.
Ameren Corp/PCA	Ameren Corp/PCA was formed by the merger of Central Illinois Public Service/PCA and Union Electric/PCA in 1997.
American Electric Power - West (ERC	American Electric Power - West (ERCOT)/PCA was formed by the merger of Central Power & Light Co/PCA, West Texas Utilities
American Electric Power - West (ERC	ERCOT ISO/PCA was formed by the merger of 10 PCAs: Austin Energy,Brownsville Public Utils Bd,AEP West-ERCOT,Reliant E
American Electric Power - West (SPP)	American Electric Power - West (SPP)/PCA was formed by the merger of Public Service Co of Oklahoma/PCA and Southwestern
American Electric Power - West (SPP)	American Electric Power - West (SPP)/PCA is called Central and Southwest by NERC.
Aquila Networks - Kansas/PCA	Westplains Energy/PCA was renamed Aquila Networks - Kansas/PCA.
Aquila Networks - Missouri/PCA	Missouri Public Service Co/PCA was renamed Aquila Networks - Missouri/PCA.
Associated Electric Coop/PCA	Associated Electric Coop/PCA moved from SPP to SERC in 1998.
Austin Energy/PCA	ERCOT ISO/PCA was formed by the merger of 10 PCAs: Austin Energy,Brownsville Public Utils Bd,AEP West-ERCOT,Reliant E
Austin Energy/PCA	City of Austin/PCA was renamed Austin Energy/PCA.
Avista Corp/PCA	Washington Water Power Co/PCA was renamed Avista Corp/PCA.
Brownsville Public Utils Board/PCA	ERCOT ISO/PCA was formed by the merger of 10 PCAs: Austin Energy,Brownsville Public Utils Bd,AEP West-ERCOT,Reliant E
California ISO/PCA	California ISO/PCA was formed by the merger of Pacific Gas & Electric/PCA, San Diego Gas & Electric/PCA, and Southern Calif
California ISO/PCA	Sacramento Municipal Utility District/PCA was formerly part of California ISO/PCA.
Central Illinois Public Service/PCA	Ameren Corp/PCA was formed by the merger of Central Illinois Public Service/PCA and Union Electric/PCA in 1997.
Central Power & Light Co/PCA	American Electric Power - West (ERCOT)/PCA was formed by the merger of Central Power & Light Co/PCA, West Texas Utilities
Cincinnati Gas & Electric/PCA	Cinergy Corporation/PCA was formed by the merger of Cincinnati Gas & Electric/PCA and PSI Energy Inc/PCA.
Cinergy Corporation/PCA	Cinergy Corporation/PCA was formed by the merger of Cincinnati Gas & Electric/PCA and PSI Energy Inc/PCA.
City of Pasadena/PCA	California ISO/PCA was formed by the merger of Pacific Gas & Electric/PCA, San Diego Gas & Electric/PCA, and Southern Calif
Cleveland Electric Illuminating Co/PC/	FirstEnergy/PCA was formed by the merger of Cleveland Electric Illuminating Co/PCA, Ohio Edison Co/PCA and Toledo Edison
CLECO Corporation/PCA	Central Louisiana Electric Co/PCA was renamed CLECO Corporation/PCA.
Dominion Virginia Power/PCA	Virginia Electric & Power Co/PCA was renamed Dominion Virginia Power/PCA.
Duke Power Co/PCA	Yadkin Inc/PCA was formerly part of Duke Power Co/PCA.
Entergy Electric System/PCA	Entergy Electric System/PCA moved from SPP to SERC in 1998.
FirstEnergy/PCA	FirstEnergy/PCA was formed by the merger of Cleveland Electric Illuminating Co/PCA, Ohio Edison Co/PCA and Toledo Edison

PCANAME	CHDESC
PCA name	**Note text**
Florida Municipal Power Pool/PCA	Lake Worth Utilities/PCA was absorbed by Florida Municipal Power Pool/PCA in 2002.
Florida Municipal Power Pool/PCA	FL Mun Pwr Pool/PCA was formed by the merger of Ft Pierce Ut Ath,Key W City of,W Ut Bd,Kissimmee Ut Ath,Starke City of,&V
Fort Pierce Utilities Auth/PCA	FL Mun Pwr Pool/PCA was formed by the merger of Ft Pierce Ut Ath,Key W City of,W Ut Bd,Kissimmee Ut Ath,Starke City of,&V
Golden Valley Electric Association/PC	City of Fairbanks/PCA was absorbed by Golden Valley Electric Association/PCA in 1999.
Great River Energy/PCA	United Power Association/PCA was renamed Great River Energy/PCA.
Independence City Of/PCA	Independence City Of/PCA is called City of Independence P&L Dept. by NERC.
Interstate Power/PCA	Alliant West/PCA was formed by the merger of IES Utilities Inc/PCA and Interstate Power/PCA in 1998.
IES Utilities Inc/PCA	Alliant West/PCA was formed by the merger of IES Utilities Inc/PCA and Interstate Power/PCA in 1998.
JEA (City of Jacksonville)/PCA	Jacksonville Electric Authority/PCA was renamed JEA (City of Jacksonville)/PCA.
Key West City of/PCA	FL Mun Pwr Pool/PCA was formed by the merger of Ft Pierce Ut Ath,Key W City of,W Ut Bd,Kissimmee Ut Ath,Starke City of,&V
Kissimmee Utility Authority/PCA	FL Mun Pwr Pool/PCA was formed by the merger of Ft Pierce Ut Ath,Key W City of,W Ut Bd,Kissimmee Ut Ath,Starke City of,&V
KGE, A Western Resources Co/PCA	Western Resources Inc/PCA was formed by the merger of KPL, a Western Resources Co/PCA and KGE, A Western Resources
KPL, a Western Resources Co/PCA	Midwest Energy/PCA was absorbed by KPL, a Western Resources Co/PCA.
KPL, a Western Resources Co/PCA	Western Resources Inc/PCA was formed by the merger of KPL, a Western Resources Co/PCA and KGE, A Western Resources
Lafayette (LA) Utilities System/PCA	City of Lafayette/PCA was renamed Lafayette (LA) Utilities System/PCA.
Louisiana Generating LLC/PCA	Louisiana Generating LLC/PCA moved from SPP to SERC in 1998.
Louisiana Generating LLC/PCA	Cajun Electric Power Coop/PCA was renamed Louisiana Generating LLC/PCA.
Lower Colorado River Authority/PCA	ERCOT ISO/PCA was formed by the merger of 10 PCAs: Austin Energy,Brownsville Public Utils Bd,AEP West-ERCOT,Reliant E
LG&E Energy/PCA	Kentucky Utilities/PCA was absorbed by LG&E Energy/PCA.
Michigan Electric Power Coordination	Michigan Power Pool/PCA was renamed Michigan Electric Power Coordination Center/PCA.
Missouri Public Service Co/PCA	St Joseph Light & Power/PCA was absorbed by Missouri Public Service Co/PCA in 2001.
New England ISO/PCA	New England Power Exchange/PCA was renamed New England ISO/PCA.
New York ISO/PCA	New York Power Pool/PCA was renamed New York ISO/PCA.
Ohio Edison Co/PCA	FirstEnergy/PCA was formed by the merger of Cleveland Electric Illuminating Co/PCA, Ohio Edison Co/PCA and Toledo Edison C
Pacific Gas & Electric/PCA	California ISO/PCA was formed by the merger of Pacific Gas & Electric/PCA, San Diego Gas & Electric/PCA, and Southern Califo
Public Service Co of Oklahoma/PCA	American Electric Power - West (SPP)/PCA was formed by the merger of Public Service Co of Oklahoma/PCA and Southwestern
Puget Sound Energy Transmission/PC	Puget Sound Power & Light Co/PCA was renamed Puget Sound Energy Transmission/PCA.
PSI Energy Inc/PCA	Cinergy Corporation/PCA was formed by the merger of Cincinnati Gas & Electric/PCA and PSI Energy Inc/PCA.
Reliant Energy HL&P/PCA	ERCOT ISO/PCA was formed by the merger of 10 PCAs: Austin Energy,Brownsville Public Utils Bd,AEP West-ERCOT,Reliant E

PCANAME	CHDESC
PCA name	**Note text**
Reliant Energy HL&P/PCA	Houston Lighting & Power Co/PCA was renamed Reliant Energy HL&P/PCA.
Sacramento Municipal Utility District/P	Sacramento Municipal Utility Dist EGC, previously part of California ISO/PCA, formed a new PCA, Sacramento Municipal Utility D
San Antonio Public Service Bd/PCA	ERCOT ISO/PCA was formed by the merger of 10 PCAs: Austin Energy,Brownsville Public Utils Bd,AEP West-ERCOT,Reliant E
San Diego Gas & Electric/PCA	California ISO/PCA was formed by the merger of Pacific Gas & Electric/PCA, San Diego Gas & Electric/PCA, and Southern Calif
South Texas Electric Coop Inc/PCA	ERCOT ISO/PCA was formed by the merger of 10 PCAs: Austin Energy,Brownsville Public Utils Bd,AEP West-ERCOT,Reliant E
Southeastern Power Administration/P(	Southeastern Power Administration/PCA was formed by the merger of SEPA Hartwell/PCA, SEPA Thurmond/PCA, and SEPA R
Southern California Edison/PCA	California ISO/PCA was formed by the merger of Pacific Gas & Electric/PCA, San Diego Gas & Electric/PCA, and Southern Calif
Southwestern Electric Power/PCA	American Electric Power - West (SPP)/PCA was formed by the merger of Public Service Co of Oklahoma/PCA and Southwestern
Springfield (IL) Water Light & Power/P	Springfield (IL) Water Light & Power/PCA is called City Water Light & Power by NERC.
Springfield (IL) Water Light & Power/P	City of Springfield/PCA was renamed Springfield (IL) Water Light & Power/PCA.
St Joseph Light & Power/PCA	St Joseph Light & Power/PCA was absorbed by Missouri Public Service Co/PCA in 2001.
St Joseph Light & Power/PCA	St Joseph Light & Power/PCA moved from SPP to MAPP in 1998.
Starke City of/PCA	FL Mun Pwr Pool/PCA was formed by the merger of Ft Pierce Ut Ath,Key W City of,W Ut Bd,Kissimmee Ut Ath,Starke City of,&V
Tacoma City Dept Of Public Utilities/P	Tacoma City Dept Of Public Utilities/PCA is called Tacoma Power by NERC.
Texas Municipal Power Pool/PCA	ERCOT ISO/PCA was formed by the merger of 10 PCAs: Austin Energy,Brownsville Public Utils Bd,AEP West-ERCOT,Reliant E
Texas-New Mexico Power Co/PCA	ERCOT ISO/PCA was formed by the merger of 10 PCAs: Austin Energy,Brownsville Public Utils Bd,AEP West-ERCOT,Reliant E
Toledo Edison Co/PCA	FirstEnergy/PCA was formed by the merger of Cleveland Electric Illuminating Co/PCA, Ohio Edison Co/PCA and Toledo Edison (
TXU Electric/PCA	ERCOT ISO/PCA was formed by the merger of 10 PCAs: Austin Energy,Brownsville Public Utils Bd,AEP West-ERCOT,Reliant E
TXU Electric/PCA	Texas Utilities Electric Co/PCA was renamed TXU Electric/PCA.
Union Electric/PCA	Ameren Corp/PCA was formed by the merger of Central Illinois Public Service/PCA and Union Electric/PCA in 1997.
Vero Beach City of/PCA	FL Mun Pwr Pool/PCA was formed by the merger of Ft Pierce Ut Ath,Key W City of,W Ut Bd,Kissimmee Ut Ath,Starke City of,&V
West Texas Utilities/PCA	American Electric Power - West (ERCOT)/PCA was formed by the merger of Central Power & Light Co/PCA, West Texas Utilities
Westar Energy/PCA	Westar Energy/PCA is called Western Resources dba Western Energy by NERC.
Westar Energy/PCA	Western Resources Inc/PCA was renamed Westar Energy/PCA.
Western Resources Inc/PCA	Western Resources Inc/PCA was formed by the merger of KPL, a Western Resources Co/PCA and KGE, A Western Resources
Wisconsin Energy Corporation/PCA	Wisconsin Electric Power Co/PCA was renamed Wisconsin Energy Corporation/PCA.
WAPA - Phoenix (LC)/PCA	WAPA - Phoenix (LC)/PCA is called Western Area Power Administration - DSW by NERC.
WAPA - Phoenix (LC)/PCA	WAPA-Lower Colorado/PCA was renamed WAPA - Phoenix (LC)/PCA.
WAPA - Rocky Mountains/PCA	WAPA - Rocky Mountains/PCA is called Western Area Power Administration - CM by NERC.

PCANAME	OLDNAME	OLDID
PCA name	Old name	Old ID
Alliant East/PCA	Wisconsin Power & Light/PCA	20856.0
Alliant West/PCA		0.0
Alliant West/PCA	MAPP	5.0
Ameren Corp/PCA		0.0
American Electric Power - West (ERC		0.0
American Electric Power - West (ERC	American Electric Power - West (ERCOT)/PCA	3280.0
American Electric Power - West (SPP)		0.0
American Electric Power - West (SPP)		0.0
Aquila Networks - Kansas/PCA	Westplains Energy/PCA	20391.0
Aquila Networks - Missouri/PCA	Missouri Public Service Co/PCA	12699.0
Associated Electric Coop/PCA	SPP	8.0
Austin Energy/PCA	Austin Energy/PCA	1015.0
Austin Energy/PCA	Austin City of/PCA	1015.0
Avista Corp/PCA	Washington Water Power Co/PCA	20169.0
Brownsville Public Utils Board/PCA	Brownsville Public Utils Board/PCA	2409.0
California ISO/PCA		0.0
California ISO/PCA	California ISO/PCA	-4.0
Central Illinois Public Service/PCA	Central Illinois Public Service/PCA	3253.0
Central Power & Light Co/PCA	Central Power & Light CO/PCA	3278.0
Cincinnati Gas & Electric/PCA	Cincinnati Gas & Electric/PCA	3542.0
Cinergy Corporation/PCA		0.0
City of Pasadena/PCA	City of Pasadena/PCA	14534.0
Cleveland Electric Illuminating Co/PCA	Cleveland Electric Illuminating Co/PCA	3755.0
CLECO Corporation/PCA	Central Louisiana Electric Co/PCA	3265.0
Dominion Virginia Power/PCA	Virginia Electric & Power Co/PCA	19876.0
Duke Power Co/PCA	Duke Power Co/PCA	5416.0
Entergy Electric System/PCA	SPP	8.0
FirstEnergy/PCA		0.0

PCANAME	OLDNAME	OLDID
PCA name	Old name	Old ID
Florida Municipal Power Pool/PCA	Lake Worth Utilities/PCA	10620.0
Florida Municipal Power Pool/PCA		0.0
Fort Pierce Utilities Auth/PCA	Fort Pierce Utilities Auth/PCA	6616.0
Golden Valley Electric Association/PC	Fairbanks City of/PCA	6129.0
Great River Energy/PCA	United Power Association/PCA	19514.0
Independence City Of/PCA		0.0
Interstate Power/PCA	Interstate Power/PCA	9392.0
IES Utilities Inc/PCA	IES Utilities Inc/PCA	9162.0
JEA (City of Jacksonville)/PCA	Jacksonville Electric Authority/PCA	9617.0
Key West City of/PCA	Key West City of/PCA	10226.0
Kissimmee Utility Authority/PCA	Kissimmee Utility Authority/PCA	10376.0
KGE, A Western Resources Co/PCA	KGE, A Western Resources Co/PCA	10005.0
KPL, a Western Resources Co/PCA	Midwest Energy Inc/PCA	12524.0
KPL, a Western Resources Co/PCA	KPL, a Western Resources Co/PCA	22500.0
Lafayette (LA) Utilities System/PCA	Lafayette City of/PCA	9096.0
Louisiana Generating LLC/PCA	SPP	8.0
Louisiana Generating LLC/PCA	Cajun Electric Power Coop/PCA	2777.0
Lower Colorado River Authority/PCA	Lower Colorado River Authority/PCA	11269.0
LG&E Energy/PCA	Kentucky Utilities Co/PCA	10171.0
Michigan Electric Power Coordination	Michigan Power Pool/PCA	12427.0
Missouri Public Service Co/PCA	St Joseph Light & Power/PCA	17881.0
New England ISO/PCA	New England Power Exchange/PCA	13434.0
New York ISO/PCA	New York Power Pool/PCA	13501.0
Ohio Edison Co/PCA	Ohio Edison Co/PCA	13998.0
Pacific Gas & Electric/PCA	Pacific Gas & Electric/PCA	14328.0
Public Service Co of Oklahoma/PCA	Public Service Co of Oklahoma/PCA	15474.0
Puget Sound Energy Transmission/PC	Puget Sound Power & Light Co/PCA	15500.0
PSI Energy Inc/PCA	PSI Energy Inc/PCA	15470.0
Reliant Energy HL&P/PCA	Reliant Energy HL&P/PCA	8901.0

PCANAME	OLDNAME	OLDID
PCA name	Old name	Old ID
Reliant Energy HL&P/PCA	Houston Lighting & Power Co/PCA	8901.0
Sacramento Municipal Utility District/P		0.0
San Antonio Public Service Bd/PCA	San Antonio Public Service Bd/PCA	16604.0
San Diego Gas & Electric/PCA	San Diego Gas & Electric/PCA	16609.0
South Texas Electric Coop Inc/PCA	South Texas Electric Coop Inc/PCA	17583.0
Southeastern Power Administration/P(		0.0
Southern California Edison/PCA	Southern California Edison/PCA	17609.0
Southwestern Electric Power/PCA	Southwestern Electric Power/PCA	17698.0
Springfield (IL) Water Light & Power/P		0.0
Springfield (IL) Water Light & Power/P	Springfield City of/PCA	17828.0
St Joseph Light & Power/PCA	St Joseph Light & Power/PCA	17881.0
St Joseph Light & Power/PCA	SPP	8.0
Starke City of/PCA	Starke City of/PCA	18004.0
Tacoma City Dept Of Public Utilities/P		0.0
Texas Municipal Power Pool/PCA	Texas Municipal Power Pool/PCA	18664.0
Texas-New Mexico Power Co/PCA	Texas-New Mexico Power Co/PCA	40051.0
Toledo Edison Co/PCA	Toledo Edison Co/PCA	18997.0
TXU Electric/PCA	TXU Electric/PCA	44372.0
TXU Electric/PCA	Texas Utilities Electric Co/PCA	44372.0
Union Electric/PCA	Union Electric/PCA	19436.0
Vero Beach City of/PCA	Vero Beach City of/PCA	19804.0
West Texas Utilities/PCA	West Texas Utilities/PCA	20404.0
Westar Energy/PCA		0.0
Westar Energy/PCA	Western Resources Inc/PCA	22500.0
Western Resources Inc/PCA		0.0
Wisconsin Energy Corporation/PCA	Wisconsin Electric Power Co/PCA	20847.0
WAPA - Phoenix (LC)/PCA		0.0
WAPA - Phoenix (LC)/PCA	WAPA - Lower Colorado/PCA	19610.0
WAPA - Rocky Mountains/PCA		0.0

PCANAME	NEWNAME	NEWID
PCA name	**New name**	**New ID**
Alliant East/PCA	Alliant East/PCA	186.0
Alliant West/PCA	Alliant West/PCA	193.0
Alliant West/PCA	MAIN	4.0
Ameren Corp/PCA	Ameren Corp/PCA	19436.0
American Electric Power - West (ERC	American Electric Power - West (ERCOT)/PCA	3280.0
American Electric Power - West (ERC	ERCOT ISO/PCA	-8.0
American Electric Power - West (SPP)	American Electric Power - West (SPP)/PCA	3283.0
American Electric Power - West (SPP)		0.0
Aquila Networks - Kansas/PCA	Aquila Networks - Kansas/PCA	20391.0
Aquila Networks - Missouri/PCA	Aquila Networks - Missouri/PCA	12699.0
Associated Electric Coop/PCA	SERC	7.0
Austin Energy/PCA	ERCOT ISO/PCA	-8.0
Austin Energy/PCA	Austin Energy/PCA	1015.0
Avista Corp/PCA	Avista Corp/PCA	20169.0
Brownsville Public Utils Board/PCA	ERCOT ISO/PCA	-8.0
California ISO/PCA	California ISO/PCA	-4.0
California ISO/PCA	California ISO/PCA	-4.0
Central Illinois Public Service/PCA	Ameren Corp/PCA	19436.0
Central Power & Light Co/PCA	American Electric Power - West (ERCOT)/PCA	3280.0
Cincinnati Gas & Electric/PCA	Cinergy Corporation/PCA	3260.0
Cinergy Corporation/PCA	Cinergy Corporation/PCA	3260.0
City of Pasadena/PCA	California ISO/PCA	-4.0
Cleveland Electric Illuminating Co/PC/	FirstEnergy/PCA	-5.0
CLECO Corporation/PCA	CLECO Corporation/PCA	3265.0
Dominion Virginia Power/PCA	Dominion Virginia Power/PCA	19876.0
Duke Power Co/PCA	Duke Power Co/PCA	5416.0
Entergy Electric System/PCA	SERC	7.0
FirstEnergy/PCA	FirstEnergy/PCA	-5.0

PCANAME	NEWNAME	NEWID
PCA name	**New name**	**New ID**
Florida Municipal Power Pool/PCA	Florida Municipal Power Pool/PCA	14610.0
Florida Municipal Power Pool/PCA	Florida Municipal Power Pool/PCA	14610.0
Fort Pierce Utilities Auth/PCA	Florida Municipal Power Pool/PCA	14610.0
Golden Valley Electric Association/PC	Golden Valley Electric Association/PCA	7353.0
Great River Energy/PCA	Great River Energy/PCA	7570.0
Independence City Of/PCA		0.0
Interstate Power/PCA	Alliant West/PCA	193.0
IES Utilities Inc/PCA	Alliant West/PCA	193.0
JEA (City of Jacksonville)/PCA	JEA (City of Jacksonville)/PCA	9617.0
Key West City of/PCA	Florida Municipal Power Pool/PCA	14610.0
Kissimmee Utility Authority/PCA	Florida Municipal Power Pool/PCA	14610.0
KGE, A Western Resources Co/PCA	Western Resources Inc/PCA	22500.0
KPL, a Western Resources Co/PCA	KPL, a Western Resources Co/PCA	22500.0
KPL, a Western Resources Co/PCA	Western Resources Inc/PCA	22500.0
Lafayette (LA) Utilities System/PCA	Lafayette (LA) Utilities System/PCA	9096.0
Louisiana Generating LLC/PCA	SERC	7.0
Louisiana Generating LLC/PCA	Louisiana Generating LLC/PCA	2777.0
Lower Colorado River Authority/PCA	ERCOT ISO/PCA	-8.0
LG&E Energy/PCA	LG&E Energy/PCA	11249.0
Michigan Electric Power Coordination	Michigan Electric Power Coordination Center/PCA	12427.0
Missouri Public Service Co/PCA	Missouri Public Service Co/PCA	12699.0
New England ISO/PCA	New England ISO/PCA	13434.0
New York ISO/PCA	New York ISO/PCA	13501.0
Ohio Edison Co/PCA	FirstEnergy/PCA	-5.0
Pacific Gas & Electric/PCA	California ISO/PCA	-4.0
Public Service Co of Oklahoma/PCA	American Electric Power - West (SPP)/PCA	3283.0
Puget Sound Energy Transmission/PC	Puget Sound Energy Transmission/PCA	15500.0
PSI Energy Inc/PCA	Cinergy Corporation/PCA	3260.0
Reliant Energy HL&P/PCA	ERCOT ISO/PCA	-8.0

PCANAME	NEWNAME	NEWID
PCA name	New name	New ID
Reliant Energy HL&P/PCA	Reliant Energy HL&P/PCA	8901.0
Sacramento Municipal Utility District/P	Sacramento Municipal Utility District/PCA	-7.0
San Antonio Public Service Bd/PCA	ERCOT ISO/PCA	-8.0
San Diego Gas & Electric/PCA	California ISO/PCA	-4.0
South Texas Electric Coop Inc/PCA	ERCOT ISO/PCA	-8.0
Southeastern Power Administration/P(	Southeastern Power Administration/PCA	-6.0
Southern California Edison/PCA	California ISO/PCA	-4.0
Southwestern Electric Power/PCA	American Electric Power - West (SPP)/PCA	3283.0
Springfield (IL) Water Light & Power/P		0.0
Springfield (IL) Water Light & Power/P	Springfield (IL) Water Light & Power/PCA	17828.0
St Joseph Light & Power/PCA	Missouri Public Service Co/PCA	12699.0
St Joseph Light & Power/PCA	MAPP	5.0
Starke City of/PCA	Florida Municipal Power Pool/PCA	14610.0
Tacoma City Dept Of Public Utilities/P		0.0
Texas Municipal Power Pool/PCA	ERCOT ISO/PCA	-8.0
Texas-New Mexico Power Co/PCA	ERCOT ISO/PCA	-8.0
Toledo Edison Co/PCA	FirstEnergy/PCA	-5.0
TXU Electric/PCA	ERCOT ISO/PCA	-8.0
TXU Electric/PCA	TXU Electric/PCA	44372.0
Union Electric/PCA	Ameren Corp/PCA	19436.0
Vero Beach City of/PCA	Florida Municipal Power Pool/PCA	14610.0
West Texas Utilities/PCA	American Electric Power - West (ERCOT)/PCA	3280.0
Westar Energy/PCA		0.0
Westar Energy/PCA	Westar Energy/PCA	22500.0
Western Resources Inc/PCA	Western Resources Inc/PCA	22500.0
Wisconsin Energy Corporation/PCA	Wisconsin Energy Corporation/PCA	20847.0
WAPA - Phoenix (LC)/PCA		0.0
WAPA - Phoenix (LC)/PCA	WAPA - Phoenix (LC)/PCA	19610.0
WAPA - Rocky Mountains/PCA		0.0

U.S. FUEL ETHANOL PRODUCTION CAPACITY
million gallons per year (mmgy)

http://www.ethanolrfa.org/eth_prod_fac.html

COMPANY	LOCATION	STATE	FEEDSTOCK	Current Capacity (mmgy)	Under Construction/ Expansion (mmgy)
Golden Cheese Company of California*	Corona, CA	CA	Cheese whey	5	
Parallel Products	R. Cucamonga, CA	CA		4	
Merrick/Coors	Golden, CO	CO	Waste beer	1.5	
Amaizing Energy, LLC*^	Denison, IA	IA	Corn		40
Archer Daniels Midland	Cedar Rapids, IA	IA	Corn		
Archer Daniels Midland	Clinton, IA	IA	Corn		
Big River Resources, LLC*	West Burlington, IA	IA	Corn	40	
Cargill, Inc.	Eddyville, IA	IA	Corn	35	
Central Iowa Renewable Energy, LLC*^	Goldfield, IA	IA	Corn		50
Golden Grain Energy, LLC*^	Mason City, IA	IA	Corn		40
Grain Processing Corp.	Muscatine, IA	IA	Corn	10	
Iowa Ethanol, LLC*	Hanlontown, IA	IA	Corn	45	
Little Sioux Corn Processors, LP*	Marcus, IA	IA	Corn	46	
Midwest Grain Processors*	Lakota, IA	IA	Corn	45	
Midwest Renewables^	Iowa Falls, IA	IA	Corn		40
Otter Creek Ethanol, LLC*	Ashton, IA	IA	Corn	45	
Permeate Refining	Hopkinton, IA	IA	Sugars & starches	1.5	
Pine Lake Corn Processors, LLC*^	Steamboat Rock, IA	IA	Corn		20
Quad-County Corn Processors*	Galva, IA	IA	Corn	23	
Siouxland Energy & Livestock Coop*	Sioux Center, IA	IA	Corn	18	
Tall Corn Ethanol, LLC*	Coon Rapids, IA	IA	Corn	45	
VeraSun Fort Dodge, LLC^	Ft. Dodge, IA	IA	Corn		110
Voyager Ethanol, LLC*^	Emmetsburg, IA	IA	Corn		50
J.R. Simplot	Caldwell, ID	ID	Potato waste	4	
Adkins Energy, LLC*	Lena, IL	IL	Corn	40	
Archer Daniels Midland	Decatur, IL	IL	Corn	1070	
Archer Daniels Midland	Peoria, IL	IL	Corn		
Aventine Renewable Energy, Inc.	Pekin, IL	IL	Corn	100	
Lincolnland Agri-Energy, LLC*	Palestine, IL	IL	Corn	40	
MGP Ingredients, Inc.	Pekin, IL	IL	Corn/wheat starch	78	
New Energy Corp.	South Bend, IN	IN	Corn	95	
Abengoa Bioenergy Corp.	Colwich, KS	KS		20	
East Kansas Agri-Energy, LLC*^	Garnett, KS	KS	Corn		35
ESE Alcohol Inc.	Leoti, KS	KS	Seed corn	1.5	

COMPANY	LOCATION	STATE	FEEDSTOCK	Current Capacity (mmgy)	Under Construction/ Expansion (mmgy)
MGP Ingredients, Inc.	Atchison, KS	KS			
Reeve Agri-Energy	Garden City, KS	KS	Corn/milo	12	
U.S. Energy Partners, LLC	Russell, KS	KS	Milo/wheat starch	40	
Western Plains Energy, LLC*	Campus, KS	KS	Corn	30	
Commonwealth Agri-Energy, LLC*	Hopkinsville, KY	KY	Corn	20	
Parallel Products	Louisville, KY	KY	Beverage waste	4	
Michigan Ethanol, LLC	Caro, MI	MI	Corn	45	
Agra Resources Coop. d.b.a. EXOL*	Albert Lea, MN	MN	Corn	38	
Agri-Energy, LLC*	Luverne, MN	MN	Corn	21	
Al-Corn Clean Fuel*	Claremont, MN	MN	Corn	30	
Archer Daniels Midland	Marshall, MN	MN	Corn		
Central MN Ethanol Coop*	Little Falls, MN	MN	Corn	20	
Chippewa Valley Ethanol Co.*	Benson, MN	MN	Corn	42	
Corn Plus, LLP*	Winnebago, MN	MN	Corn	44	
DENCO, LLC*	Morris, MN	MN	Corn	21.5	
Ethanol2000, LLP*	Bingham Lake, MN	MN	Corn	30	
Gopher State Ethanol	St. Paul, MN	MN	Corn/Beverage Waste	15	
Granite Falls Energy, LLC^	Granite Falls, MN	MN	Corn		45
Heartland Corn Products*	Winthrop, MN	MN	Corn	36	
Land O' Lakes*	Melrose, MN	MN	Cheese whey	2.6	
Minnesota Energy*	Buffalo Lake, MN	MN	Corn	18	
Northstar Ethanol, LLC^	Lake Crystal, MN	MN	Corn		50
Pro-Corn, LLC*	Preston, MN	MN	Corn	40	
Golden Triangle Energy, LLC*	Craig, MO	MO	Corn	20	
Mid-Missouri Energy, Inc.*^	Malta Bend, MO	MO	Corn		40
Northeast Missouri Grain, LLC*	Macon, MO	MO	Corn	40	
Alchem Ltd. LLLP	Grafton, ND	ND	Corn	10.5	
Archer Daniels Midland	Wallhalla, ND	ND	Corn/barley		
Abengoa Bioenergy Corp.	York, NE	NE	Corn/milo	50	
AGP*	Hastings, NE	NE	Corn	52	
Archer Daniels Midland	Columbus, NE	NE	Corn		
Aventine Renewable Energy, Inc.	Aurora, NE	NE	Corn	40	
Cargill, Inc.	Blair, NE	NE	Corn	83	
Chief Ethanol	Hastings, NE	NE	Corn	62	
Husker Ag, LLC*	Plainview, NE	NE	Corn	23	
KAAPA Ethanol, LLC*	Minden, NE	NE	Corn	40	

COMPANY	LOCATION	STATE	FEEDSTOCK	Current Capacity (mmgy)	Under Construction/ Expansion (mmgy)
Platte Valley Fuel Ethanol, LLC	Central City, NE	NE	Corn	40	
Trenton Agri Products, LLC	Trenton, NE	NE	Corn	30	
Abengoa Bioenergy Corp.	Portales, NM	NM		15	
Liquid Resources of Ohio^	Medina, OH	OH	Waste Beverage		4
Broin Enterprises, Inc.	Scotland, SD	SD	Corn	9	
Dakota Ethanol, LLC*	Wentworth, SD	SD	Corn	48	
Glacial Lakes Energy, LLC*	Watertown, SD	SD	Corn	48	
Great Plains Ethanol, LLC*	Chancellor, SD	SD	Corn	42	
Heartland Grain Fuels, LP*	Aberdeen, SD	SD	Corn	8	
Heartland Grain Fuels, LP*	Huron, SD	SD	Corn	14	
James Valley Ethanol, LLC	Groton, SD	SD	Corn	45	
Northern Lights Ethanol, LLC*	Big Stone City, SD	SD	Corn	45	
Sioux River Ethanol, LLC*	Hudson, SD	SD	Corn	45	
Tri-State Ethanol Co., LLC*	Rosholt, SD	SD	Corn	18	
VeraSun Energy Corporation	Aurora, SD	SD	Corn	100	
Tate & Lyle	Loudon, TN	TN	Corn	65	
Miller Brewing Co.	Olympia, WA	WA	Brewery waste	0.7	
ACE Ethanol, LLC	Stanley, WI	WI	Corn	30	
Badger State Ethanol, LLC*	Monroe, WI	WI	Corn	48	
Central Wisconsin Alcohol	Plover, WI	WI	Seed corn	4	
United WI Grain Producers, LLC*^	Friesland, WI	WI	Corn		40
Utica Energy, LLC	Oshkosh, WI	WI	Corn	24	26
Western Wisconsin Renewable Energy, LLC*^	Boyceville, WI	WI	Corn		40
Wyoming Ethanol	Torrington, WY	WY	Corn	5	
Total Existing Capacity				**3425.8**	
Total Under Construction/Expansions					**630**
Total Capacity				**4055.8**	

* farmer-owned

^ under construction

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One Massachusetts Ave., Suite 820, Washington DC 20001
Phone (202)289-3835, Fax (202)289-7519
e-mail info@ethanolrfa.org

http://www.ethanol.org/productionlist.htm

Ethanol Plants Currently Operating	City	State	MGY
Golden Cheese Company	Corona	CA	4.5
U.S. Liquids	Rancho Cucamonga	CA	4
Merrick/Coors	Golden	CO	1.5
Archer Daniels Midland	Cedar Rapids	IA	1030
Archer Daniels Midland	Clinton	IA	
Big River Resources, LLC	West Burlington	IA	40
Cargill	Eddyville	IA	35
Grain Processing Corp.	Muscatine	IA	60
Iowa Ethanol, LLC	Hanlontown	IA	45
Little Sioux Corn Processors	Marcus	IA	40
Midwest Grain Processors	Lakota	IA	45
Otter Creek Ethanol, LLC	Ashton	IA	45
Permeate Refining	Hopkinton	IA	2
Quad County Corn Processors	Galva	IA	20
Siouxland Energy & Livestock	Sioux Center	IA	15
Tall Corn Ethanol	Coon Rapids	IA	40
J.R. Simplot	Caldwell	ID	4
Adkins Energy, LLC	Lena	IL	43
Archer Daniels Midland	Decatur	IL	
Archer Daniels Midland	Peoria	IL	
Aventine Renewable Energy, Inc.	Pekin	IL	100
LincolnLand Agri-Energy	Robinson	IL	40
MGP Ingredients, Inc.	Pekin	IL	65
New Energy Corp.	South Bend	IN	95
Abengoa Bioenergy Corp.	Colwich	KS	20
ESE Alcohol,Inc.	Leoti	KS	1.5
MGP Ingredients, Inc.	Atchison	KS	30
Reeve Agri-Energy	Garden City	KS	12
U.S. Energy Partners, LLC	Russell	KS	40
Western Plains Energy, LLC	Campus	KS	30
Commonwealth Agri-Energy, LLC	Hopkinsville	KY	20
U.S. Liquids	Louisville	KY	4
Michigan Ethanol, LLC	Caro	MI	40
Agra Resources d.b.a. EXOL	Albert Lea	MN	37

Ethanol Plants Currently Operating	City	State	MGY
Agri-Energy, LLC	Luverne	MN	21
Al-Corn Clean Fuels	Claremont	MN	30
Archer Daniels Midland	Marshall	MN	
Central Minnesota Ethanol	Little Falls	MN	21
Chippewa Valley Ethanol	Benson	MN	45
Corn Plus, LLP	Winnebago	MN	44
Diversified Energy Co. (DENCO)	Morris	MN	21.5
Ethanol2000, LLP	Bingham Lake	MN	27
Gopher State Ethanol	St. Paul	MN	20
Heartland Corn Products	Winthrop	MN	35
Land O'Lakes	Melrose	MN	3
Minnesota Energy	Buffalo Lake	MN	18
Pro-Corn, LLC	Preston	MN	40
Golden Triangle Energy	Craig	MO	20
Northeast Missouri Grain	Macon	MO	45
Alchem, Ltd.	Grafton	ND	10.5
Archer Daniels Midland	Walhalla	ND	
Abengoa Bioenergy Corp.	York	NE	50
Ag Processing, Inc.	Hastings	NE	52
Archer Daniels Midland	Columbus	NE	
Cargill	Blair	NE	83
Chief Ethanol, Inc.	Hastings	NE	62
Husker Ag Processing, LLC	Plainview	NE	20
KAAPA Ethanol, LLC	Minden	NE	40
Nebraska Energy	Aurora	NE	35
Platte Valley Fuel Ethanol, LLC	Central City	NE	40
Trenton Agri-Products	Trenton	NE	30
Abengoa Bioenergy Corp.	Portales	NM	15
Broin Enterprises, Inc.	Scotland	SD	8.5
Dakota Ethanol, LLC	Wentworth	SD	40
Glacial Lakes Energy	Watertown	SD	45
Great Plains Ethanol, LLC	Chancellor	SD	40
Heartland Grain Fuels	Aberdeen	SD	8.9
Heartland Grain Fuels	Huron	SD	12
James Valley Ethanol, LLC	Groton	SD	45
Northern Lights Ethanol, LLC	Big Stone City	SD	40

Ethanol Plants Currently Operating	City	State	MGY
Sioux River Ethanol, LLC	Hudson	SD	45
VeraSun Energy	Aurora	SD	100
A.E. Staley	Loudon	TN	60
Miller Brewing Co.	Tumwater	WA	0.7
ACE Ethanol, LLC	Stanley	WI	15
Badger State Ethanol, LLC	Monroe	WI	48
Central Wisconsin Alcohol	Plover	WI	4
Utica Energy, LLC	Oshkosh	WI	20
Wyoming Ethanol	Torrington	WY	5
	Total: (million gallons per year)		**3334**

Ethanol Plants Under Construction	City	State	MGY
Amaizing Energy	Denison	IA	40
Central Illinois Energy Cooperative	Canton	IL	33
Cornhusker Energy Lexington, LLC	Lexington	NE	42
East Kansas Agri-Energy	Garnett	KS	20
Ethyl Alternative Fuels	Baton Rouge	LA	50
Golden Grain Energy LLC	Mason City	IA	40
Mid-Missouri Energy	Malta Bend	MO	40
Midwest Renewables	Alden	IA	40
Northstar Ethanol LLC	Lake Crystal	MN	49.5
Pine Lake Corn Processors, LLC	Steamboat Rock	IA	20
Tri-State Ethanol Company	Rosholt	SD	20
United Wisconsin Grain Producers	Friesland	WI	40
VeraSun Ft. Dodge	Ft. Dodge	IA	110
Voyager Ethanol, LLC	Emmetsburg	IA	50
	Total: (million gallons per year)		**594.5**

U.S. FUEL ETHANOL PRODUCTION CAPACITY
million gallons per year (mmgy)

COMPANY	LOCATION	STATE	FEEDSTOCK	Current Capacity (mmgy)	Under Construction/ Expansions (mmgy)	Address	City/State/Zip
Merrick/Coors	Golden, CO	CO	Waste beer	1.5		13th and Ford St	Golden, CO 80401
Abengoa Bioenergy Corp.	Colwich, KS	KS		20		523 East Union A	Colwich, KS 67030 USA
East Kansas Agri-Energy, LLC*^	Garnett, KS	KS	Corn		35		
ESE Alcohol Inc.	Leoti, KS	KS	Seed corn	1.5		PO Box 813	Leoti, KS 67861
MGP Ingredients, Inc.	Atchison, KS	KS				1300 Main Stree	Atchison, KS 66002
Reeve Agri-Energy	Garden City, KS	KS	Corn/milo	12		PO Box 1036	Garden City, KS 67849
U.S. Energy Partners, LLC	Russell, KS	KS	Milo/wheat starch	40		1224 E. 15th	Russell, Kansas 67665
Western Plains Energy, LLC*	Campus, KS	KS	Corn	30		3022 County Ro	Oakley, Kansas 67748
Abengoa Bioenergy Corp.	Portales, NM	NM		15		1827 Industrial D	Portales, NM 88130 USA
Wyoming Ethanol	Torrington, WY	WY	Corn	5		307.532.2449	
Total Existing Capacity				**125**			
Total Under Construction/Expansions					**35**		
Total Capacity				**160**			

* farmer-owned
^ under construction
Last Updated: October 2004

One Massachusetts Ave., Suite 820, Washington DC 20001
Phone (202)289-3835, Fax (202)289-7519
e-mail info@ethanolrfa.org

Appendix H: Risk Factors - Assessment and Evaluation

A critical aspect of the SWP Phase 1 program was to gather information necessary to evaluate under what conditions will sequestration technologies be safe and have minimal and controllable impact on the environment. We concluded that specific validation and/or deployment sites will require a systematic evaluation of uncertainty and risks associated with CO2 storage to develop a quantitative assessment of potential impacts from any unintended CO2 release. Furthermore, analysis by the SWP during its Phase I program suggests that for any and all validation and deployment phases of sequestration, risk potential may best be approached with a combined program of risk assessment and risk mitigation; we view assessment and mitigation as different components that must be employed in tandem.

Risk assessment and risk management methods developed by the nuclear power industry and other industries are an extremely valuable resource. Specifically, the SWP drew on industry resources to develop a screening methodology for evaluating potential environmental and safety risks of geologic CO_2 storage projects. The methodology is based on the "FEPs" approach developed previously by others, including Quintessa (2004; see http://www.quintessa.org/about/news04.html). FEPs are the features, events, and processes that make up the physical and chemical behavior of CO2 in the system being assessed – physical and chemical Features of the system, relevant Processes that may influence the evolution of the system, and specific Events that may impact sequestration and take place over timescales coincident with sequestration.

For any specific validation (e.g., Phase 2) or deployment programs, risk factors in the form of FEPs specific to the site(s) must be quantitatively described and catalogued in a database, including and especially uncertainties. We recommend that pre-pilot geologic characterization and associated modeling results be used to establish this basic database. During the course of each pilot test, the databases will continue to be populated and expanded with additional data, observations, model results, and specialized analysis. This approach is designed to integrate fundamental observations with results of detailed analysis and interpretation, and will facilitate an objective and quantitative assessment of potential risks for each site and provide outreach to stakeholders.

For future geologic sequestration validation (e.g., Phase 2) and deployment programs, we recommend that fundamental risk assessment should continue throughout injection operations. Reservoir and seal performance, using all MMV data and quantitative description of specific FEPs, will be analyzed continuously, and reservoir simulation models and their forecasts should be updated periodically (~ monthly). Additionally, uncertainty and risk assessment data will also be updated continuously. This evolving risk assessment framework could in turn be used to guide subsequent MMV and data collection activities, as well as pilot test engineering design (injection, etc.). In sum, combined MMV and risk assessment data could be used in tandem to guide engineering operations and vice-versa, in the form of a continuous, iterative feedback loop.

The most general risk criteria associated with geologic sequestration include

- Leakage through poor quality or aging injection well completions
- Leakage up abandoned wells
- Leakage due to inadequate caprock characterization
- Inconsistent or inadequate monitoring

Even a basic FEPs database for a given site will provide a mechanism for communicating risk potential, which affects regulatory permitting, identification of regulatory gaps, MMV design, and outreach and education of stakeholders.

We suggest that the most basic, but also most important, FEPs – risk factors are those that address CO2 trapping mechanisms. Perhaps future geologic sequestration validation (e.g. Phase 2) and deployment operations could begin with FEPs (risk factors) associated with trapping mechanisms and their failure modes, and then proceed with other FEPs of the system under consideration. For sake of example, and for the purpose of outlining what we suggest as the most essential FEPs to consider, the next section describes fundamental CO2 trapping mechanisms, basic failure modes of each, and an approach we recommend for quantifying uncertainty of these FEPs through development of appropriate probability distribution functions.

CO_2 Trapping Mechanisms and Associated Failure Modes

In this report we consider four primary trapping mechanisms, including hydrostratigraphic, residual gas, solubility, and mineral trapping. Failure modes of each trapping mechanism are outlined, including discussion of how to define uncertainty of these failure modes.

Hydrostratigraphic trapping: hydrostratigraphic trapping refers to trapping of CO_2 by low permeability sealing layers. This type of trapping is often distinguished by whether the CO_2 is contained by stratigraphic and structural traps, e.g., similar to oil and gas reservoirs, called <u>static accumulations</u>, or whether it is trapped as a migrating plume in large-scale flow systems, called <u>hydrodynamic trapping</u>. Major failure modes for hydrostratigraphic trapping include:

(1) unintended migration by pre-existing but unidentified faults, fractures, or other fast-flow paths,
(2) unintended migration by stress-induced or reactivated fractures or faults,
(3) unintended migration by reaction-induced breaching of a seal layer
(4) unintended lateral flow to unintended areas,
(5) catastrophic events (e.g., unexpected earthquakes, etc.),
(6) wellbore failure events.

One approach to mitigating several of these failure modes is to select a storage site with multiple alternating seals and reservoirs above the primary (intended) reservoir, sometimes described as stacked reservoirs. However, even when stacked reservoirs are present, other measures must be taken to minimize risk of failure.

Residual gas trapping: At the interface between two different liquid phases (such as CO_2 and water), the cohesive forces acting on the molecules in either phase are unbalanced. This imbalance exerts tension on the interface, causing the interface to contract to as small an area as possible. The importance of this interfacial tension in multiphase flow is paramount; the multiphase CO_2-brine-oil-gas flow equations are more sensitive to interfacial tension than many other fluid properties. Interfacial tension may trap CO_2 in pores, if fluid saturations are low. The threshold at which this occurs is called the “irreducible saturation” of CO_2, and is a key concept for defining “residual gas trapping.” The magnitude of residual CO_2 saturation within rock, and thus the amount of CO_2 that can be trapped by this mechanism, is a function of the rock's pore network geometry as well as fluid properties. Geologic conditions that impact the amount of CO_2 trapped as a residual phase include petrophysics, burial effects, temperature and pressure gradients, CO_2 properties (density) under different P-T conditions, and on engineering parameters such as injection pressure, induced flow rates, and/or well orientation.

The primary failure mode for residual gas trapping is loss of capillary forces (surface tension) of the pore matrix. Such loss would be due to any process that changes the pore geometry or size or changes the interfacial tension, including compaction, dissolution or precipitation of cements in or around pores, or changing fluid composition.

Solubility trapping: Perhaps the most fundamental type of trapping is dissolution, or "solubility trapping." First, CO_2 dissolves to an aqueous species followed by rapid dissociation of carbonic acid producing bicarbonate and carbonate ions while lowering pH. The primary failure mode for solubility trapping is exsolution, which would only occur under significant (large) changes in pressure or temperature.

Mineral trapping: "Mineral trapping" refers to the process of CO_2 reacting with divalent cations to form mineral precipitates in the subsurface. The reactions, especially reaction rates and associated processes that affect rates (e.g., complexation, pH buffering, etc.) are complicated and make estimates of CO_2 storage capacity difficult. The primary failure mode for mineral trapping is dissolution of the carbonate minerals that trapped CO_2.

An Approach for Quantifying Uncertainty of Trapping Mechanisms and Failure Modes

Quantitative assessment of geologic uncertainty has been of great interest in the last few years (Caumon, et al., 2004), and that interest is growing with the advent of new carbon sequestration testing programs. In the oil industry, several different approaches have been used to obtain probability distribution functions (PDFs) of desired parameters, such as hydrocarbons in place, recovery factors, etc. In CO_2 sequestration one might want to determine critical fault properties that could lead to hydrostratigraphic trapping failure or to thickness variations of the seal that could lead to seal breach. The two most prominent methods for developing effective PDFs are:

- Experimental design based methods
- Bayesian probabilistic formalism

We suggest employing both methods for defining PDFs of critical parameters for each trapping mechanism failure mode.

In general, experimental design methods are based on generating simpler response surfaces using selected rigorous simulations (for example, reservoir models with appropriate fully coupled thermal-hydrologic-chemical-mechanical processes) followed by Monte Carlo simulations to identify the parameters that are most critical in affecting the targeted outcome. Initial rigorous models should be simulated to honor observed data. Such history matching is critical to the success of this method.

Sufficient data to validate models of trapping mechanisms and associated failure modes FEPs may not be available from previous field tests. For example, very few new wells that could provide calibration data, including log and seismic data, will be drilled in most ongoing or planned field demonstrations. It is possible that data available from these wells may be limited to logs and seismic data. In these situations where information is sparse, the Bayesian framework suggested by Caumon et al. (2004) will be used to obtain probability distributions of critical parameters. In this approach several conceptual geologic models are constructed based on all available data. Each scenario is then depicted using a spatial variability model. At that stage, several choices of spatial variability models (variograms, for example) are available. The global estimate of a given target variable is constructed using the interpretation of the quantitative data under a given geologic scenario. Once the uncertainty in a given parameter is quantified, specific experimental design tools can be identified and used to collect additional data (such as well-bore seismic, logs etc.) to reduce uncertainty.

In summary, we recommend identifying FEPs for a given system, followed by a quantitative evaluation of relevant FEPs, e.g. for trapping mechanism failure modes, in the form of developing appropriate PDFs for each critical parameter employing either experimental design-based methods or Bayesian probabilistic formalisms. As injection proceeds and MMV data are collected, these PDFs describing the FEPs and associated risk can be updated and refined. This framework can be used to identify and catalog potential longer-term impacts to the system. Figure 1 summarizes the general approach in schematic fashion.

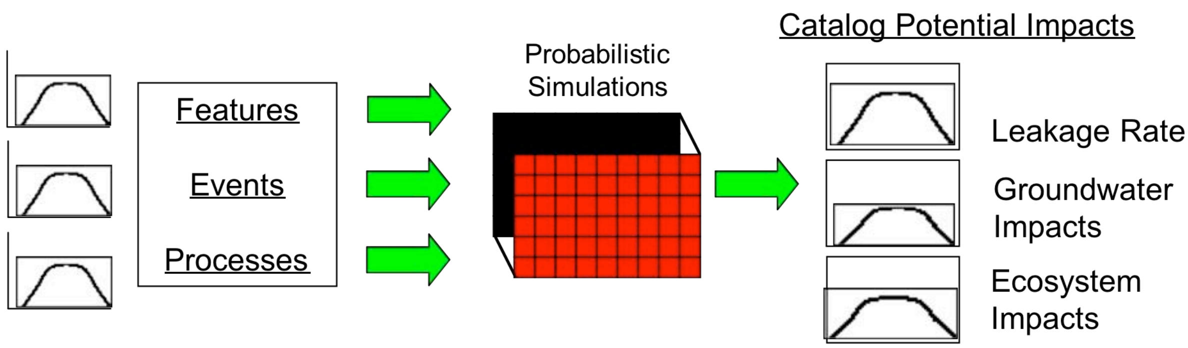

Figure 1. Schematic of general risk and uncertainty analysis, left-to-right: FEPs identified, then PDFs evaluated through probabilistic simulations, leading to a cataloging of potential longer-term impacts on the system. Adapted from Benson, S.M., 2004, written communication.

Reference

Caumon, et al., 2004, Assessment of Global Uncertainty in the early Assessment of Hydrocarbon Fields, SPE 89943, Society of Petroleum Engineers, Dallas, Texas.

Appendix I: Monitoring Protocols and Gaps in Coverage

MMV is at the heart of all SWP activities. MMV deployment and associated modeling will be the primary vehicles for determining how well the southwest region may meet or exceed performance targets of the Carbon Sequestration Roadmap, including prediction of storage capacity to +/- 30% accuracy, verification of indirect sequestration and associated costs, and verification of MMV technology efficacy. MMV is also central to our risk assessment and risk mitigation approaches. It is possible that MMV deployment of the Southwest and other partnerships' pilot tests will influence how regulation and permitting evolves and how regulatory gaps are filled. All MMV protocols are designed to meet the performance goals of the DOE Roadmap and the DOE EIA 1605B "Voluntary Guidelines for Greenhouse Gas Reporting," where possible, to meet the needs of evolving voluntary carbon markets in the U.S.

Results of the SWP Phase I program suggests recommendation of extensive MMV protocols, including direct and indirect approaches. MMV plans for the region should be designed to track the movement and fate of CO_2 injected into deep saline aquifers and coal beds, and oil and gas reservoirs. Additional MMV goals are to monitor CO_2 well injectivity, verify abandoned well veracity, and to assist with risk assessment and mitigation. Baseline MMV activities will elucidate geologic, hydrogeochemical, isotopic and other physical conditions prior to injection. During pilot tests and possible long-term sequestration operations, baseline data will be compared to results of repeat and continuous MMV surveys conducted after injection to forecast ultimate fate of CO_2 in the subsurface for different conditions.

The SWP conducted extensive analysis of sequestration options in the region, and ranked the top 5 sites/options in the region for comprehensive pilot-testing. Our MMV programs proposed for each of the ranked sites are tailored for the unique setting of each site and for maximizing comparisons to approaches deployed at the other sites.

In the following sections we summarize recommended MMV technologies.

Direct MMV Technologies Recommended for the Southwest Region

INJECTION WELL MONITORING: At the injection well, continuous measurements of injection rate, pressure and temperature will be monitored. Periodic shut-in tests will provide permeability changes in near- and far-well regions. Pressure transient tests prior to injection are proposed for all sites.

IN SITU FIBER OPTIC P/T SENSORS: In-situ borehole monitoring faces two major technical challenges: 1) the high-temperature and high-pressure, harsh environment of boreholes has excluded many conventional chemical sensors (e.g. electronic sensors), and 2) the long-distance from depth to the surface presents a challenge for high fidelity data transmission. Recently, optical fiber based in-situ physical sensors have been demonstrated successfully in field trials for downhole oil recovery and geothermal applications (Xiao et al., 2005a; Wang et al., 2001; May et al., 1999). Zeolite-coated optical fiber chemical sensors have also shown great potential for applications under hostile conditions found in typical borehole environment (Xiao et al., 2005b). For MMV at all sites, optical fiber based pressure and temperature sensors will be deployed in the injection wells for in-situ monitoring of CO_2 injectivity. These sensors, less than 1 mm in size, operate on the remote interrogation using Faby-Perot interferometer (EFPI). Test data show that the sensor is capable of measuring temperature up to 600°C and hydraulic pressure up to 8000 psi at temperatures up to 220°C.

SPINNER FLOWMETER SURVEYS: At an injection well, spinner surveys will be performed to determine vertical injection conformance.

PRODUCTION WELL IN-SITU LI-COR©: In addition to continuous monitoring of gas and water production rates and pressures, continuous monitoring of produced gas CO_2 content will be made using LI-COR© IRGA devices at selected production wells.

ABANDONED WELL LI-COR©: At selected abandoned wells nearby, LI-COR© IRGA devices will also be installed in situ, to monitor potential flow of CO_2 from units below (e.g., degraded well-casings).

GAS PIEZOMETERS USING LI-COR©: We propose drilling five shallow wells of less than 800 ft depth for the purposes of cross-well seismic, ASTLI, and/or VSP, described below. These wells will be outfitted with in situ LI-COR© IRGA devices with dataloggers and wireless data transmission, for constant monitoring. In concept, these are like water-well piezometers, but instead of measuring hydraulic head, they will record CO_2 flux from depth.

ISOTOPIC AND COMPOSITION MEASUREMENTS: Periodic gas sampling and measurements of produced CO_2 isotopic signatures will also be made to distinguish between naturally produced CO_2 (CO_2 content of the produced gas is currently –25 ‰ to –27 ‰ range for $\delta^{13}C$) and the $\delta^{13}C$ of the injected CO_2 (either –1 ‰ to –2 ‰ from magmatic sources of CO_2 or –38 ‰ to –43 ‰ from industrial sources of CO_2) (~monthly). Periodic gas and water samples will also be collected for compositional analysis (~monthly), and pressure transient tests performed to monitor any changes in coal permeability (~every six months). Baseline measurements of gas CO_2 content and isotopic signature, as well as gas/water compositional analyses, and water chemistry will be obtained prior to injection of CO_2.

TILTMETERS [For the SJB ECBM pilot only] Potential coal swelling will likely cause a significant geodetic response. Specifically, actual laboratory strain measurements on San Juan basin coal, when methane is replaced with CO_2 at pressures of around 100 psi, show a volumetric strain on the order of 0.5–1.0% occurs due to coal swelling. Furthermore, computations of potential larger-scale response were made by Sandia National Lab (Warpinski, written communication, 2005), showing that such coal-swelling by injection at the depths and conditions at the San Juan basin ECBM site may result in a l° tilt at the surface. Thus, this is a promising method for tracking CO_2 movement in coal seams.

Indirect MMV Technologies Recommended for the Southwest Region

2-D and 3-D SEISMIC SURVEYS: 2-D or 3-D seismic surveys, coupled with borehole seismic data, will be used to monitor the injection process at the pilot sites. At Aneth and SJB ECBM, repeated 2-D seismic surveys will be conducted. At SACROC-Claytonville, 3-D seismic surveys will be conducted. For both 2-D and 3-D surveys, surface seismic data will be collected before, during, and after injection to allow us to assess changes in seismic response of the reservoir caused by the CO_2 injection.

VERTICAL SEISMIC PROFILES (VSP) AND CROSSWELL SEISMIC: Boreholes will be used to collect VSP data, which will have significantly higher frequencies than surface data and hence be more sensitive to small-scale changes in reservoir properties. By drilling multiple boreholes at each site, we will be able to collect data in both surface-downhole geometry and downhole-downhole (crosswell) geometry to allow interrogation of the reservoir on different scales and over different region sizes. VSP and crosswell data will be interpreted to infer changes in reflection character due to the presence of CO_2. We will also employ Active-Source Time-Lapse Intercomparison, or ASTLI: small changes in the phases of the individual wave packets measured before, during, and after the injection can be measured using an interferometric approach to determine very small changes in seismic velocity within the reservoir. Borehole sensors will record seismic data when the 2D surface seismic surveys are being conducted, allowing us to compare surface and downhole data in addition to giving us more source location coverage than would be available if a conventional VSP survey alone was conducted. For analysis of crosswell data, we will use a combination of crosswell tomography and seismic migration, which is a fairly new application to crosswell data been shown to yield high-resolution information about the interwell region.

PASSIVE SEISMIC**:** Passive seismic monitoring using instruments placed in boreholes will be used to detect induced seismicity caused by the CO_2 injection. It has been shown that there is considerable information in the pattern of locations of induced seismic events about the interaction of the injected fluid with the fracture system and regional stress field (see Fehler et al., 2001).

SEISMIC MODELING: Appropriate modeling will determine the optimum data acquisition geometry for both surface and borehole, and active/passive seismic data.

HIGH RESOLUTION RESISTIVITY METHOD FOR BOREHOLE INTEGRITY: We are pleased to add an international partner, the National Institute for Advanced Industrial Science and Technology (AIST) of Japan, who will deploy and field test an advanced electrical method at two field sites (see attached support letter). The proposed technology is based on electro-kinetic changes and will be deployed to perform continuous monitoring. At Aneth, the method will be used to monitor for possible CO_2 leakage near the surface in the vicinities of well bores. At Claytonville, the method will be used to monitor CO_2 plume migration. AIST will conduct all fieldwork and facilitate interpretation.

DATA TRANSMISSION: IRGA devices and dataloggers will be connected to each operator's wireless data transmission system such that pattern performance can be monitored continuously and remotely.

MMV Options for the Top-Ranked Sequestration Sites/Options: Aneth Field, Utah – Deep Saline Sequestration and EOR with Sequestration

For future testing at Aneth, the primary contrast with other recommended pilot sites is the application and testing of 2-D seismic lines. Additionally, passive seismic monitoring promises to be particularly effective at the Aneth site, because a brine injection facility (Allis, Utah GS, personal communication) near the Colorado–Utah border provides an abundance of passive seismic energy.

MMV Options for the Top-Ranked Sequestration Sites/Options: San Juan Basin, New Mexico – ECBM with Sequestration and Riparian Restoration for Terrestrial Sequestration

For future San Juan basin pilot-tests, the primary contrast with other potential test sites concerns coal and CH_4. Specifically, we recommend testing techniques to help track the movement of CO_2 within the coalbeds, a potentially difficult task given that the coals are already saturated with CH_4. Thus, we recommend several special MMV applications. As CO_2 is injected, swelling of the coals will occur, permeability will reduce, and fluid pressures will increase dramatically. Swelling may be significant and detectable by tiltmeters. For example, a patternedgrid array of 30 or more surface tiltmeters could be deployed throughout an area, calibrated by fixed GPS stations, and could serve as one of the primary monitoring methods of CO_2 movement in coals. In any interwell areas, continuous monitoring of tiltmeter arrays may effectively monitor surface deformation related to coal swelling with CO_2 injection. In the event the CO_2 plume extends beyond the pattern, interferometric synthetic aperture radar (In SAR) data may be obtained periodically (~monthly) to monitor surface deformation over a larger area. Additionally, spinner surveys near injection wells may be used to determine vertical injection conformance among the individual coal seams that exist at specific sites.

Finally, we recommend focusing on both 2-D and 1-D seismic methods, to evaluate CO_2 movement out of the top and bottom of the coal beds. If coals are already saturated with CH4, MMV plans must account for seismic properties of CH4 and CO_2 being nearly identical, and thus resolving the CO_2 front (laterally) will likely be impossible, and 3-D surveys may be excessive (e.g., “overkill”). Thus, the SWP recommends focusing on evaluating the vertical change in seismic reflectors as a means of tracking the CO_2 front; 1-D and 2-D seismic methods (single source reflection; borehole methods such as VSP, etc.) will likely be effective for resolving changes in vertical reflectors at the coal boundaries. Combining and co-interpreting seismic and borehole geophysical methods with tiltmeters is a promising “coupled” approach for monitoring CO_2 and its effects on injectivity, methane production, and efficacy of CO_2 storage in the coals.

MMV Options for the Top-Ranked Sequestration Sites/Options: Permian Basin, Texas EOR with Sequestration

The SWP recommends EOR-related sequestration pilot tests for the Permian basin, site of decades of CO2 injection for EOR purposes. For future Texas pilot tests, we recommend application and testing of 3-D seismic lines. We will also recommend comparison of efficacy and approaches for these 4-D surveys to planned repeat 2-D surveys in other potential pilot test sites in the region.

Establishing and communicating the consequences and tradeoffs between alternate sequestration sites and strategies to store GHG is the necessary first step in formulating an effective and publicly acceptable sequestration program, and in addressing the 2007 and 2012 metrics for success of the DOE Carbon Sequestration Technology Roadmap. In the field pilot operations, MMV protocols and associated modeling are the primary vehicles for determining how well the SWP meets or exceeds performance targets of the CST Roadmap, including prediction of storage capacity to +/- 30% accuracy, verification of indirect sequestration and associated costs, and verification of MMV technology efficacy.

Monitoring Methods Coverage and General Gap Analysis

We evaluated the spatial (areal) and depth coverage of MMV (monitoring) technologies appropriate for the region, and from this analysis interpreted potential gaps in coverage that should receive extra attention as validation (e.g., Phase 2) and deployment programs are undertaken. Figure I-1 is a crude schematic diagram that depicts which types of monitoring technologies apply at the range of spatial (areal) scales to consider for geologic sequestration. Point measurements of surface or subsurface gas fluxes (“gas piezometer” via wells) and groundwater chemistry apply at small spatial scales, although if the point measurements are distributed over larger areas and tracked over time, larger areas may be monitored effectively for movement of CO2 at the surface, within the target reservoir, and within any geologic units that well-screens penetrate. Unfortunately, wells typically only penetrate oil or freshwater reservoirs, because of the high cost of drilling and completion.

Figure I-2 is a schematic diagram that depicts the depth-scales covered by the range of monitoring technologies appropriate for the region. Geophysical methods such as seismic technologies, electrical resistivity, microgravity, etc., offer the broadest spatial (areal) coverage (Figure I-1) and the best depth coverage (Figure I-2) independent of available wells. The method with the highest resolution for imaging CO2 migration over large areas (Figure I-1) and depth (Figure I-2) is seismic-reflection surveying, but this is also the most expensive method. Results of the Weyburn project suggest that even the most sophisticated 4-D seismic approaches have limited efficacy for CO_2 sequestration monitoring; seismic methods are very effective for detecting the "front" of a CO_2 plume, but are not very effective for determining volumes or amounts of CO_2 behind the plume front. Thus, we recommend investigation of how to optimize 2-D seismic lines for detection and monitoring purposes, because 2-D lines are two to four times less expensive than 3-D. We recommend optimization of 2-D seismic efficacy by combining surveys with crosswell, VSP, and ASTLI. We also recommend comparison of the efficacy and approaches for 2-D surveys to planned 3-D surveys at other sites in the region.

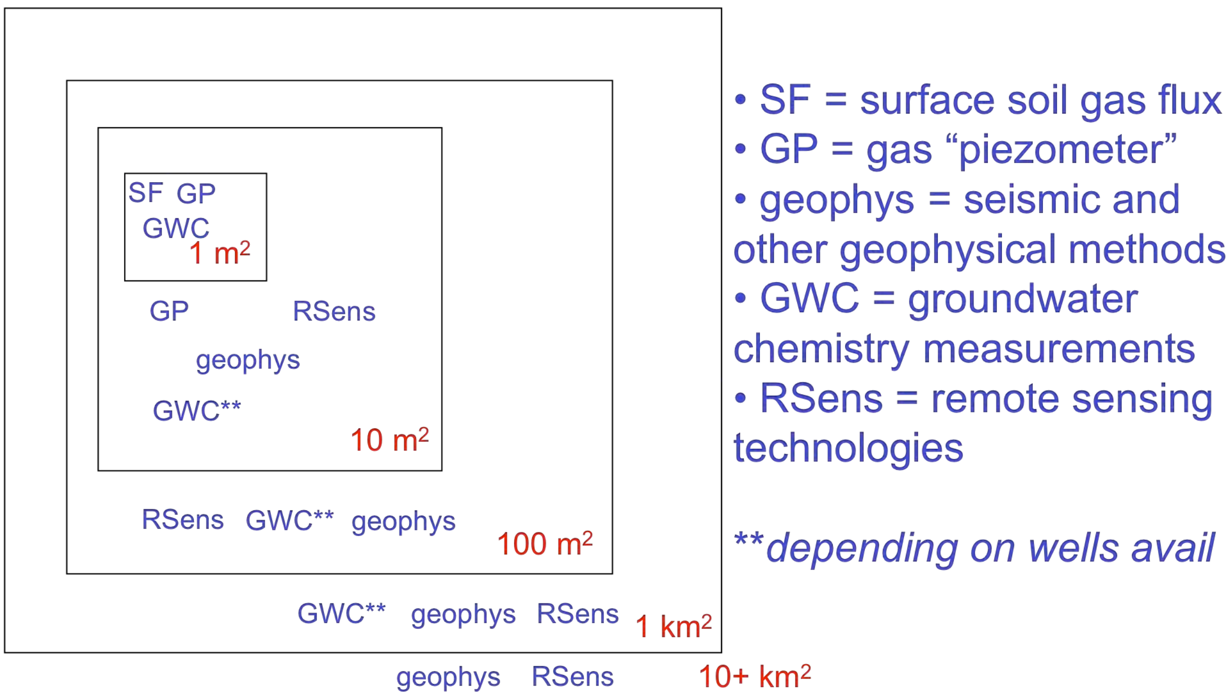

Figure I-1. Applicable spatial scales of different monitoring types/categories.

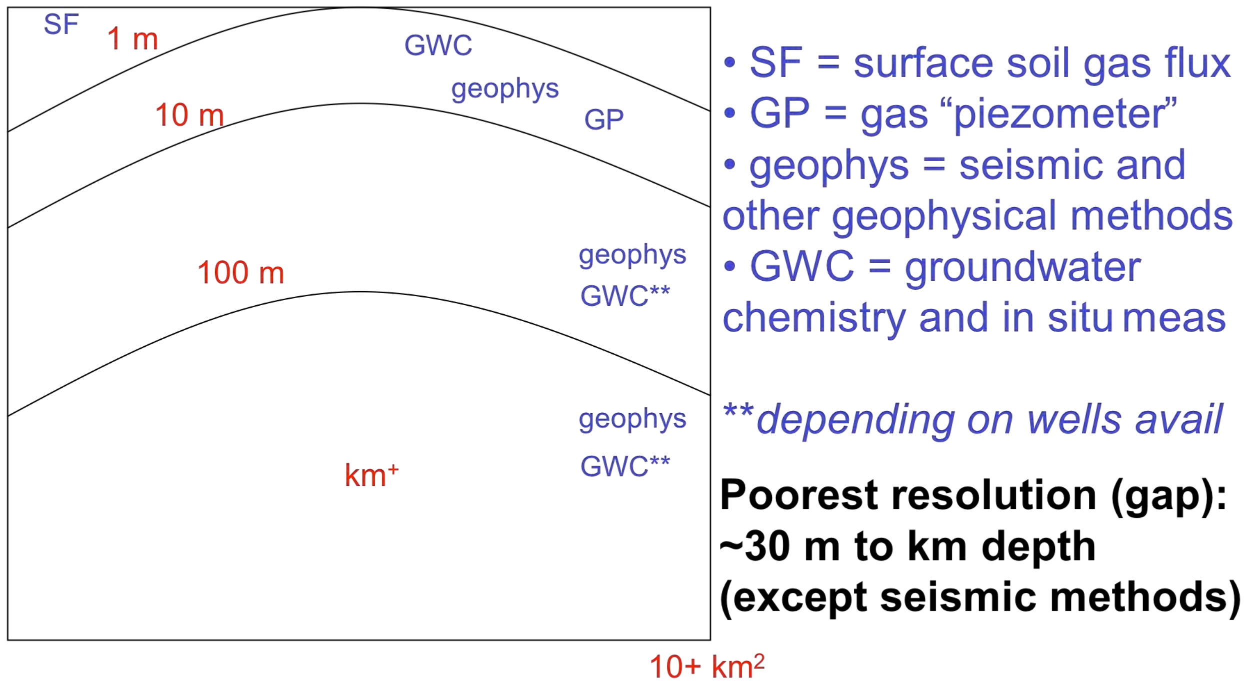

Figure I-2. Applicable depth scales of different monitoring types.

Figure I-2 illustrates that, in general, the most significant gap in monitoring coverage is what we call the "Intermediate Zone" (IZ), which is the depth interval between approximately 30 m depth to the geologic unit just above the target reservoir's seal/caprock formation. The extent of the IZ can be minimized and resolution maximized with more wells that penetrate units within the IZ or with high resolution geophysical methods (e.g., seismic imaging). However, both of these monitoring options are extremely expensive. For future validation (e.g., Phase 2) and deployment operations, we recommend extreme attention be paid to development of monitoring technologies that will increase resolution of CO2 detection in the IZ.

Regarding temporal coverage of monitoring technologies, cost is the only limiting factor; larger budgets translate to smaller temporal gaps in coverage. Remote sensing (for example, direct observations of surface vegetation albedo from satellite measurements) is probably the least expensive monitoring method, but necessarily only a surface monitor. Point measurements of gas fluxes and water chemistry are labor-intensive but perhaps the next least expensive among monitoring methods, and thus offer the most frequent observations. However, such point measurements are limited to available well coverage (Figure I-2). Seismic imaging methods offer the highest resolution over depth and area, including the IZ, but the high expense prohibits frequent surveys.

In sum, at this time, spatial and temporal gaps in monitoring are significant, and our ability to minimize these gaps are a direct function of available budget. We recommend focus on improving ability to monitor the IZ; optimization of 2-D seismic imaging methods (rather than more expensive 3-D methods) offers a great deal of promise for improving IZ-monitoring. Efficacy of microgravity and other novel geophysical methods also need to be evaluated in greater detail.

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Appendix J: Western Governors' Association Activities for the SWP

A. Objectives

Provided support to the U.S. Department of Energy, Office of Fossil Energy, to advance the concepts and promote the infrastructure for carbon sequestration in the Western United States. Working in collaboration with the Western Interstate Energy Board, an affiliate organization, WGA provided services and completed tasks as described below to meet that objective.

B. Scope of Work

(1)Provide information and promote technology transfer for carbon sequestration concepts in the Western United States; and (2) promote infrastructure development for possible wide-scale deployment of Greenhouse Gas Mitigation strategies in the Western United States.

C. Tasks to be Performed and Accomplishments

Task 1: Provide Information and Promote Technology Transfer for Carbon Sequestration Concepts in the Western United States

Accomplishments:

a) Established a Web site page on the four Western Carbon Sequestration Partnerships. The Western Interstate Energy Board was tasked with keeping the site up to date and maintaining links to each of the four partnerships' Web pages.

b) Organized efforts of the four Western partnerships to participate in a poster session during the Western Governors' Association's North American Energy Summit, held April 14 – 16, 2004 in Albuquerque. The summit attracted nearly 700 participants as well as members of the general public and the media. Participants included the private sector; non-profit groups; and state, provincial, tribal and federal officials from the U.S., Canada and Mexico.

c) During November and December of 2005, a representative of WIEB attended the meetings of three of the Western carbon sequestration partnerships, during which they wrapped-up Phase 1 and kicked-off Phase II. Reports on each of these meetings was prepared and sent to the appropriate staff for WGA's lead Governors for Carbon Sequestration, Govs. Mike Rounds (S.D.) and Bill Richardson (N.M.).

d) Participated in the 2004 and 2005 National Conference on Carbon Capture and Sequestration. Representatives from WGA and WIEB participated in breakout sessions and discussions on outreach activities

e) Representatives from WGA and WIEB participated on monthly calls of the Outreach and Education Working Group to stay informed of education and outreach developments and to share information with governors' offices as needed.

f) Governors and WGA's Staff Council were kept informed of the work of the partnerships through a quarterly management status report and Annual Report in both 2004 and 2005.
g) In late fall of 2003, a representative of WGA/WIEB attended the Phase I kick-off meetings of the Plains CO2 Reduction Partnership, the Southwest Regional Partnership on Carbon Sequestration, and the West Coast Regional Carbon Sequestration Partnership. In addition, a representative attended: one of the SW partnership's public outreach meetings; the Plains Second Advisory Board meeting in October 2004; and the West Coast advisory committee meeting in May 2005. WGA/WIEB also helped the West Coast partnership identify state employees and others who could be helpful when holding its October 27, 2004 forum in Portland, Oregon.
h) The Western Interstate Energy Board (WIEB) invited the partnerships to its April 13, 2004 meeting to explain the work of the partnerships to the energy advisors for Western Governors and Premiers.

Task 2: Promote Infrastructure Development for Possible Wide Scale Deployment of Greenhouse Gas Mitigation Strategies in the Western United States

Accomplishments:

a) As part of this task, WGA held a stakeholder meeting. During WGA's Annual Meeting on June 20, 2004 in Santa Fe, N.M., Gov. Mike Rounds of South Dakota moderated a Q & A session on the work of the four western partnerships. The partnerships' representatives briefly described the technologies and infrastructures they are evaluating to determine which ones have the best potential to sequester or reuse CO2, thereby reducing greenhouse gas emissions. Materials on the partnerships were available to all the 300-plus participants at the Annual Meeting, including representatives from government, the private sector, non-profit groups and the media.
b) The potential role of carbon sequestration in increasing clean and diversified energy throughout the West was discussed extensively at meetings of WGA's Clean and Diversified Energy Advisory Committee and its Advanced Coal Task Force. The report was open to public comment and was made available on WGA's Web site. It includes several recommendations states can take to encourage the development of four to five 500 MW advanced coal plants with at least 60 percent carbon sequestration. Western Governors will consider the recommendations at their Annual Meeting in June 2006.
c) Communications materials were prepared and distributed on the work for the four Western Partnerships at the North American Energy Summit in April 2004 in Albuquerque.

d) Designed a standardized web-based GIS database for the Western carbon sequestration partnerships. With input from partnerships, created GIS dataset. Data was added to the central database as received from the western partnerships and normalized as needed to allow for query and display. After the database was designed and the dataset created, we developed and hosted the necessary Web-based interactive maps that utilize GIS datasets for map display, query, and organization/integration of partnership carbon sequestration data.

D. Deliverables

As noted in Task 1 and 2 above, the WGA and WIEB completed the following deliverables:

- Internet site and other appropriate communication media
- Regional GIS map server of partnership carbon sequestration data
- Formation of WGA oversight subcommittee (Lead Govs. Rounds and Richardson)
- At least two meetings engaging stakeholders
- Final report summarizing the activities undertaken throughout the budget period.

Appendix K: Proposed SWP Phase 2 Action Plan

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1. TECHNOLOGY MERIT AND IMPLEMENTATION PLAN

Overview of Most Promising Sequestration Technologies: First Options for Sequestration

The Southwest Regional Partnership on Carbon Sequestration (SWP) proposes to conduct a series of validation tests of the most promising sequestration technologies for the region, including three major geologic pilot tests and two terrestrial pilot test programs. A possible theme of the SWP is “First Options for Carbon Sequestration.” The Regional Partnerships are collectively evaluating sequestration options and will begin testing options soon. If carbon sequestration becomes a practical carbon management approach, the “first options” of sequestration will likely be those that fall along existing CO_2 transportation infrastructure. The Southwest region possesses an extensive CO_2 pipeline network that transports over 30 Mt of naturally-sourced CO_2 per year from the central Rockies to the Permian basin (Figure 1). In our Phase I project, we concluded that the “lowest-hanging fruit” for sequestration would be to supplant the natural CO_2 in those pipelines with anthropogenic CO_2 (e.g., power-plant sourced). With such an approach the region would meet, at the least, minimum GHG intensity reduction targets for the region. We maintain this idea and suggest that “first options” for the nation will lie along existing pipelines. If deliberate CO_2 sequestration becomes necessary, pipeline infrastructure may expand and increase the number of practical and cost-effective sequestration opportunities. Our Phase I ranking of sequestration opportunities factored proximity to sources and/or pipeline infrastructure in addition to economic, safety, risk mitigation potential, and other factors. The result of the Phase I ranking process resulted in this proposal of three geologic pilot tests that are located on the CO_2 pipeline infrastructure, illustrated in Figure 1.

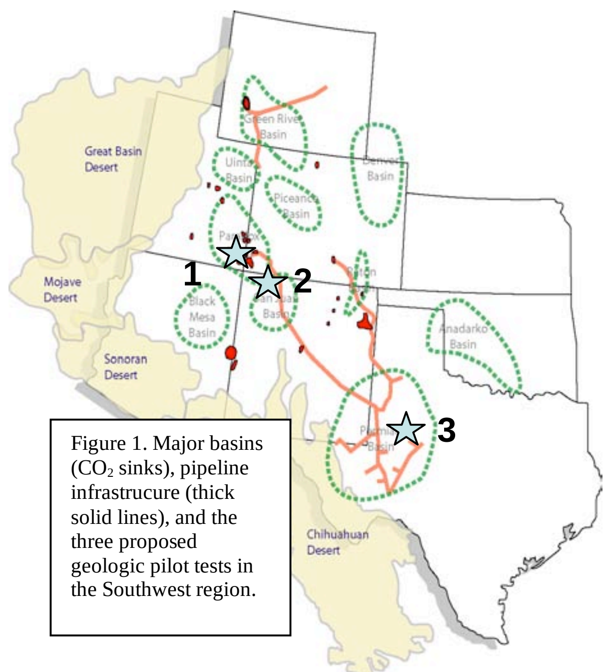


Figure 1. Major basins (CO_2 sinks), pipeline infrastrucure (thick solid lines), and the three proposed geologic pilot tests in the Southwest region.

The SWP proposes a truly regional approach for its technology validation program, including geologic pilot tests located in Utah, New Mexico, Texas, and a region-wide terrestrial analysis. Each geologic sequestration test will include injection of a minimum of ~75,000 tons/year to ~150,000 tons/year, with a minimum injection duration of one year. Our SWP proposed pilots are summarized in Table 1.

Table 1: Pilot Test Portfolio

Pilot Test Location	**Type of Pilot(s)**	**Amount/Duration of CO_2 Injection**	**Key Industry / Govt. Partner(s)**
Aneth Field, Paradox basin, near Bluff, UT	Deep Saline Aquifer and EOR with Sequestration	Up to 150,000 tons per year for 3.5 years	Navajo Nation Oil and Gas Co. Resolute Natural Resources Co.
San Juan basin Coal Fairway, near Navajo City, NM	ECBM and Sequestration, with Produced Water Desalination, and Terrestrial Riparian Restoration Sequestration	Est. 75,000 tons per year for 1 year	Burlington Resources, BLM, USDA
SACROC-Claytonville Fields, Permian basin, near Snyder, TX	EOR with Sequestration	Over 150,000 tons per year for 2 years	Kinder Morgan CO_2 Company, L.P. (KinderMorgan)
Entire Southwest Region	Regional Terrestrial Analysis	N/A	USDA

Aneth Background: The Aneth oil field, discovered in 1956, is one of the largest in the nation. Because the field is Navajo Nation land, mineral royalties go to the Navajo Nation and are utilized in many ways, including a scholarship fund. Aneth is located on the CO_2 pipeline system, and the sheer size of the field makes it a possible target for larger-scale sequestration operations. Petroleum production interests were recently purchased from ChevronTexaco, and now these interests are jointly owned by Resolute Natural Resources Company (Resolute) and the Navajo Nation Oil and Gas Company. Both companies operate the field together, and the SWP is pleased to partner with Resolute and the Navajo Nation OGC in a combined deep saline aquifer – EOR – sequestration pilot test.

San Juan Enhanced Coalbed Methane (ECBM) Background: The San Juan basin (SJB) is one of the top ranked basins in the world for CO_2 coalbed sequestration because it has: 1) advantageous geology and high methane content; 2) abundant anthropogenic CO_2 from nearby power plants, 3) low capital and operating costs; 4) well developed natural gas and CO_2 pipeline systems; and 4) local companies, e.g., Burlington Resources, with CBM and ECBM expertise. Burlington has agreed to operate a project in collaboration with the SWP, specifically to examine ECBM efficacy with CO_2 sequestration. Because of its enormous coal resource, the SJB offers a tremendous sequestration opportunity with value-added natural gas production. An extensive CO_2 infrastructure is already in place, making the area ready for future operations. In addition to the ECBM pilot test, a terrestrial pilot test will be conducted. ECBM operations are notorious for producing huge volumes of water. We propose to desalinate produced water from our ECBM pilot and use this water for irrigating a riparian restoration project, forming a combined ECBM – terrestrial sequestration project. The BLM and Burlington are both interested in making beneficial and environmentally-friendly use of the produced water.

SACROC-Claytonville Background*:* The SACROC Unit in the Permian Basin of Texas is the oldest CO_2-EOR operation in the United States, with CO_2 injection dating from 1972—only one CO_2-EOR project in Hungary is older, dating from ~1969. SACROC continues to be flooded by the current owner/operator, Kinder Morgan CO_2 Company, L.P. (KinderMorgan). Current operations inject ~13.5 $MtCO_2$/yr and withdraw/recycle ~7 $MtCO_2$/yr, for a net storage of ~6.5 $MtCO_2$/yr. In total, the site has accumulated more than 55 $MtCO_2$.

Our first effort at the SACROC unit will be an intensive post-audit modeling analysis to understand the fate of the CO_2 injected over 30 years time. KinderMorgan maintains a vast database of CO_2 injection/production data to facilitate an effective analysis. We will also conduct extensive MMV studies at SACROC during its ongoing injection operations. Results of these analyses will then be used to define a better working model of the Claytonville field, a nearby field with similar geology recently acquired by KinderMorgan that has never been subjected to CO_2 injection. The combined SACROC-Claytonville pilot represents an unprecedented opportunity for CO_2 storage history-matching in tandem with large-scale MMV operations. Finally and most importantly, the SACROC-Claytonville pilot will be an initial high resolution analysis of the potential for CO_2 storage in the broader carbonate “Horseshoe Atoll” system, a huge (area and volume) system with potentially enormous CO_2 capacity (Figure 2). Given that most of the western side of the atoll is below the oil-water contact, it is particularly appealing for large-scale sequestration, as suggested by our Phase 1 analysis of the region.

In sum, the SWP proposes a regional portfolio of sequestration technology validation tests in a broad variety of carbon sink targets, with demonstration of multiple value-added benefits, including testing of deep saline sequestration, enhanced oil recovery and sequestration, enhanced coalbed methane production and sequestration combined with a local terrestrial (riparian restoration) sequestration pilot, and a regional terrestrial sequestration pilot program focusing on improved terrestrial MMV methods and reporting approaches specific for the Southwest region. All of our proposed pilots represent “first opportunities” because of their proximity to CO_2 pipeline infrastructure. And, all proposed pilots represent medium-scale tests of possible larger-scale sequestration operations in the future. The SWP’s portfolio of proposed pilots seek to maximize specific performance, economic, and environmental goals of the DOE Carbon Sequestration Roadmap.

<u>Overview of Proposed Geologic Pilot Tests</u>

Regulatory, Permitting, and NEPA Approach for all Geologic Pilots

Regulatory efforts for Phase 2 activities have two complementary objectives: (1) to ascertain and monitor the permitting requirements for each State in the SWP as a resource for future carbon sequestration projects, and (2) to outline a specific action plan to secure permits for proposed test projects.

Manual of Best Practices: The SWP began developing regulatory and permitting action plans during Phase I, and will continue that effort in Phase 2. Action plans will be produced in the form of a “Manual of Best Practices,” and will outline and satisfy project permitting requirements to conduct sequestration projects (including but not limited to capture, transportation, storage, monitoring, and risk assessment and mitigation). The permitting guidelines will specify steps for satisfying the federal National Environmental Policy Act (NEPA) requirements for Environmental Assessments (EA) and developing required Environmental Impact Statements (EIS) for each of the Southwest pilot tests.

The Regulatory and Permitting Manual of Best Practices will be useful both to SWP members and

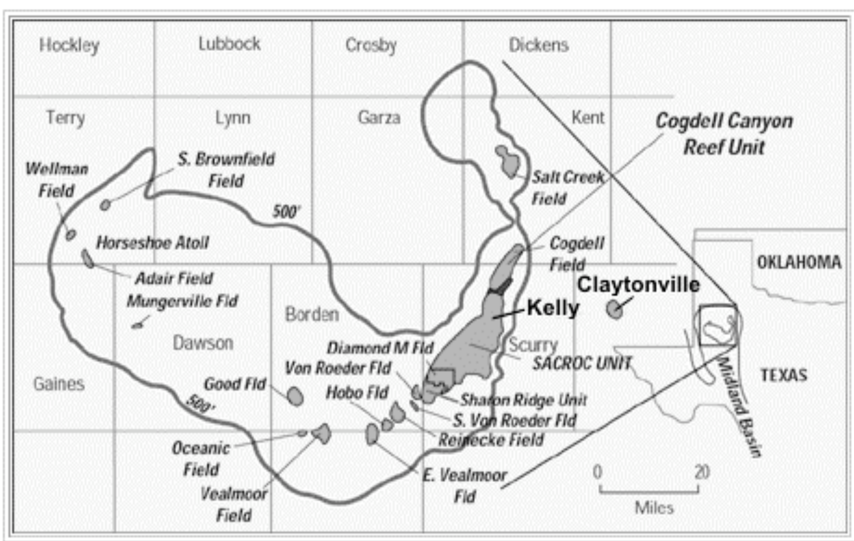


Figure 2. Schematic of the “Horseshoe Atoll” that represents an extremely large CO_2 sink and sequestration opportunity (dark line). Also indicated are the locations of Kelly (SACROC) and Claytonville Pilot tests. Figure adapted from WorldOil.com.

to others considering future carbon sequestration projects. It will provide a "roadmap" for permitting sequestration projects anywhere in the region, and will detail existing regulatory gaps, uncertainties and an explanation of potential barriers for technology deployment. A significant start has been made by the Interstate Oil and Gas Compact Commission (IOGCC) Geological Sequestration Task Force, who already assembled a regulatory framework for carbon capture and geological storage at the request of the Department of Energy (IOGCC, written communication, 2005). Its report summarizes the current regulatory regime for CO_2 on a state-by-state basis. It is possible that current regulations may change in response to the test phase projects or other external factors during Phase 2. The manual will capture these changes at the federal and state levels. The manual of best practices will be designed as a permitting roadmap for the partnership and others engaging in carbon sequestration activities.

Permitting Test Case Projects: The geologic pilots will require the strictest permitting requirements, and fortunately, Utah, Texas, and New Mexico already have some existing regulatory regimes for CO_2 injection in EOR projects, as a start. The development of MMV protocols for carbon sequestration projects is an evolutionary process, and therefore the designs implemented for the test cases could become permitting requirements. Our intention is to work closely with the appropriate regulators to identify and implement appropriate MMV procedures. In addition to state-specific permitting, any permitting required from the Bureau of Land Management (BLM), inclusive of environmental assessments or environmental impact statements, will be conducted in a manner that satisfies requirements of the NEPA.

Risk Assessment and Evaluation

The SWP will address risk potential with a combined program of risk assessment and risk mitigation; we view assessment and mitigation as different components that must be employed in tandem. Regarding risk assessment and evaluation, during Phase I, the SWP developed a screening methodology for evaluating potential environmental and safety risks of geologic CO_2 storage projects. Similar to our Phase I approach, pre-pilot geologic characterization and associated modeling results will be used to establish a basic database of risk factors or criteria for each pilot site. During the course of each pilot test, the databases will continue to be populated and expanded with additional data, observations, model results, and specialized analysis. This approach is designed to integrate fundamental observations with results of detailed analysis and interpretation, and will facilitate an objective and quantitative assessment of potential risks for each site and provide outreach to stakeholders. General risk criteria associated with geologic sequestration include (1) integrity of immediate seals and therefore CO_2 containment potential of the primary sequestration target unit; (2) secondary and tertiary CO_2 containment potential if immediate seals or borehole casings fail; (3) potential to mitigate effects of CO_2 migration to surface and associated time constants, in the unlikely event that CO_2 is not contained. This database and risk analysis framework is basic, but it provides a mechanism for communicating risk potential, which affects regulatory permitting, identification of regulatory gaps, MMV design, and outreach and education of stakeholders. A new partner, the Det Norske Veritas (DNV) research organization of Norway, offers expertise in both risk assessment and mitigation. DNV will use its own funding for the project (see attached letter).

Risk Mitigation Approach: Continuous Iterative Risk Assessment and Adaptive Pilot Design

Risk assessment will continue throughout the duration of each SWP pilot. As described in subsequent sections of this proposal, our MMV activities will produce large amounts of time series data. These data will provide the basis of an adaptive risk mitigation approach. Specifically, pilot test performance, using all MMV data, will be analyzed continuously, and reservoir simulation models and their forecasts will be updated periodically (~ monthly). The risk assessment frameworks will also be updated continuously throughout the duration of the pilots. This adaptive risk assessment framework will then in turn be used to guide subsequent MMV and data collection activities, as well as pilot test engineering design (injection, etc.). In sum, combined MMV and risk assessment data will be used in tandem to guide engineering operations and vice-versa, in the form of a continuous feedback loop. For example, methane recovery and concomitant CO_2 migration and storage efficacy will be monitored in the SJB ECBM pilot, and appropriate engineering responses will be made by the operator, Burlington, and in turn the risk assessment framework and MMV design updated, etc. This approach will be taken with all pilots.

Injection/production performance, abandoned wells, and all other MMV data will be continuously evaluated, and these data along with associated reservoir simulations will be used to update risk criteria, including any new, unanticipated impacts and processes. In addition, models will be used to evaluate how the system may evolve after the pilot concludes. Following the example of previous risk assessment studies (e.g. Wilson and Monea, 2005), we will evaluate an extensive range of model scenarios to assess future possible risks such as those associated with specific geologic features – faults, fracture zones, seal degradability, etc. In addition to deterministic models, we will also carry out probabilistic analyses; the DNV brings state-of-the-art probabilistic modeling and analysis approaches to the SWP projects.

Summary and Overview of MMV Protocols Planned for the Southwest Geologic Pilots

MMV is at the heart of all SWP activities. MMV deployment and associated modeling are the primary vehicles for determining how well the SWP meets or exceeds performance targets of the Carbon Sequestration Roadmap, including prediction of storage capacity to +/- 30% accuracy, verification of indirect sequestration and associated costs, and verification of MMV technology efficacy. MMV is also central to our risk assessment and risk mitigation approaches. It is possible that MMV deployment of the Southwest and other partnerships' pilot tests will influence how regulation and permitting evolves and how regulatory gaps are filled. All MMV protocols are designed to meet the performance goals of the DOE Roadmap and the DOE EIA 1605B "Voluntary Guidelines for Greenhouse Gas Reporting," where possible, to meet the needs of evolving voluntary carbon markets in the U.S.

We propose extensive MMV protocols, including direct and indirect approaches. Our MMV plans for each field pilot are designed to track the movement and fate of CO_2 injected into deep saline aquifers and coal beds, and oil and gas reservoirs. Additional MMV goals are to monitor CO_2 well injectivity, verify abandoned well veracity, and to assist with risk assessment and mitigation. Baseline MMV activities will elucidate the geologic, hydrogeochemical, isotopic and other physical conditions prior to injection. These baseline data will be compared to results of repeat and continuous MMV surveys conducted after injection to forecast ultimate fate of CO_2 in the subsurface for different conditions.

In the following sections we will first summarize all components of our MMV program. Subsequent site-specific pilot-test descriptions will tabulate the specific MMV approaches to be deployed at each site.

The specific MMV technologies proposed for each pilot-test site were selected based on the unique geologic setting of the site and to maximize our ability to test MMV technology efficacy.

Direct MMV Technologies Proposed

INJECTION WELL MONITORING: At the injection well, continuous measurements of injection rate, pressure and temperature will be monitored. Periodic shut-in tests will provide permeability changes in near- and far-well regions. Pressure transient tests prior to injection are proposed for all sites.

IN SITU FIBER OPTIC P/T SENSORS: In-situ borehole monitoring faces two major technical challenges: 1) the high-temperature and high-pressure, harsh environment of boreholes has excluded many conventional chemical sensors (e.g. electronic sensors), and 2) the long-distance from depth to the surface presents a challenge for high fidelity data transmission. Recently, optical fiber based in-situ physical sensors have been demonstrated successfully in field trials for downhole oil recovery and geothermal applications (Xiao et al., 2005a; Wang et al., 2001; May et al., 1999). Zeolite-coated optical fiber chemical sensors have also shown great potential for applications under hostile conditions found in typical borehole environment (Xiao et al., 2005b). For MMV at all sites, optical fiber based pressure and temperature sensors will be deployed in the injection wells for in-situ monitoring of CO_2 injectivity. These sensors, less than 1 mm in size, operate on the remote interrogation using Faby-Perot interferometer (EFPI). Test data show that the sensor is capable of measuring temperature up to 600°C and hydraulic pressure up to 8000 psi at temperatures up to 220°C.

SPINNER FLOWMETER SURVEYS: At an injection well, spinner surveys will be performed to determine vertical injection conformance.

PRODUCTION WELL IN-SITU LI-COR©: In addition to continuous monitoring of gas and water production rates and pressures, continuous monitoring of produced gas CO_2 content will be made using LI-COR© IRGA devices at selected production wells.

ABANDONED WELL LI-COR©: At selected abandoned wells nearby, LI-COR© IRGA devices will also be installed in situ, to monitor potential flow of CO_2 from units below (e.g., degraded well-casings).

GAS PIEZOMETERS USING LI-COR©: We propose drilling five shallow wells of less than 800 ft depth for the purposes of cross-well seismic, ASTLI, and/or VSP, described below. These wells will be outfitted with in situ LI-COR© IRGA devices with dataloggers and wireless data transmission, for constant monitoring. In concept, these are like water-well piezometers, but instead of measuring hydraulic head, they will record CO_2 flux from depth.

ISOTOPIC AND COMPOSITION MEASUREMENTS: Periodic gas sampling and measurements of produced CO_2 isotopic signatures will also be made to distinguish between naturally produced CO_2 (CO_2 content of the produced gas is currently –25 ‰ to –27 ‰ range for $\delta^{13}C$) and the $\delta^{13}C$ of the injected CO_2 (either –1 ‰ to –2 ‰ from magmatic sources of CO_2 or –38 ‰ to –43 ‰ from industrial sources of CO_2) (~monthly). Periodic gas and water samples will also be collected for compositional analysis (~monthly), and pressure transient tests performed to monitor any changes in coal permeability (~every six months). Baseline measurements of gas CO_2 content and isotopic signature, as well as gas/water compositional analyses, and water chemistry will be obtained prior to injection of CO_2.

TILTMETERS [For the SJB ECBM pilot only] Potential coal swelling will likely cause a significant geodetic response. Specifically, actual laboratory strain measurements on San Juan basin coal, when methane is replaced with CO_2 at pressures of around 100 psi, show a volumetric strain on the order of 0.5–1.0% occurs due to coal swelling. Furthermore, computations of potential larger-scale response were made by Sandia National Lab (Warpinski, written communication, 2005), showing that such coal-swelling by injection at the depths and conditions at the San Juan basin ECBM site may result in a l° tilt at the surface. Thus, this is a promising method for tracking CO_2 movement in coal seams.

Indirect MMV Technologies Proposed (Seismic)

2-D and 3-D SEISMIC SURVEYS: 2-D or 3-D seismic surveys, coupled with borehole seismic data, will be used to monitor the injection process at the pilot sites. At Aneth and SJB ECBM, repeated 2-D seismic surveys will be conducted. At SACROC-Claytonville, 3-D seismic surveys will be conducted. For both 2-D and 3-D surveys, surface seismic data will be collected before, during, and after injection to allow us to assess changes in seismic response of the reservoir caused by the CO_2 injection.

VERTICAL SEISMIC PROFILES (VSP) AND CROSSWELL SEISMIC: Boreholes will be used to collect VSP data, which will have significantly higher frequencies than surface data and hence be more sensitive to small-scale changes in reservoir properties. By drilling multiple boreholes at each site, we will be able to collect data in both surface-downhole geometry and downhole-downhole (crosswell) geometry to allow interrogation of the reservoir on different scales and over different region sizes. VSP and crosswell data will be interpreted to infer changes in reflection character due to the presence of CO_2. We will also employ Active-Source Time-Lapse Intercomparison, or ASTLI: small changes in the phases of the individual wave packets measured before, during, and after the injection can be measured using an interferometric approach to determine very small changes in seismic velocity within the reservoir. Borehole sensors will record seismic data when the 2D surface seismic surveys are being conducted, allowing us to compare surface and downhole data in addition to giving us more source location coverage than would be available if a conventional VSP survey alone was conducted. For analysis of crosswell data, we will use a combination of crosswell tomography and seismic migration, which is a fairly new application to crosswell data been shown to yield high-resolution information about the interwell region.

PASSIVE SEISMIC**:** Passive seismic monitoring using instruments placed in boreholes will be used to detect induced seismicity caused by the CO_2 injection. It has been shown that there is considerable information in the pattern of locations of induced seismic events about the interaction of the injected fluid with the fracture system and regional stress field (see Fehler et al., 2001).

SEISMIC MODELING: Appropriate modeling will determine the optimum data acquisition geometry for both surface and borehole, and active/passive seismic data.

HIGH RESOLUTION RESISTIVITY METHOD FOR BOREHOLE INTEGRITY: We are pleased to add an international partner, the National Institute for Advanced Industrial Science and Technology (AIST) of Japan, who will deploy and field test an advanced electrical method at two field sites (see attached support letter). The proposed technology is based on electro-kinetic changes and will be deployed to perform continuous monitoring. At Aneth, the method will be used to monitor for possible

CO_2 leakage near the surface in the vicinities of well bores. At Claytonville, the method will be used to monitor CO_2 plume migration. AIST will conduct all fieldwork and facilitate interpretation.

DATA TRANSMISSION: IRGA devices and dataloggers will be connected to each operator's wireless data transmission system such that pattern performance can be monitored continuously and remotely.

CO_2 Sources and Transportation for All Geologic Pilot Tests

CO_2 for Aneth and the SJB ECBM test will be sourced from McElmo dome, and is ~98% pure CO_2, with < 2% nitrogen and methane. At SACROC-Claytonville, CO_2 (~98% purity) will come from natural sources (McElmo, Sheep Mountain, and Bravo Dome), with ~10–15% derived from Val Verde's gas purification facility. All pilots are located on the KinderMorgan pipeline infrastructure in the region (Figure 1), and thus transportation is provided. CO_2 cost details are provided in the budget volume; the SWP is paying ~$8/ton for CO_2 at Aneth, ~$5/ton for CO_2 at SJB ECBM, and CO_2 is provided free of charge by KinderMorgan for SACROC-Claytonville. Amounts to be injected are summarized in Table 1.

Pilot Deployment Plan: Aneth Deep Saline and EOR Pilot Test, Bluff, UT

Suitability, Availability, and Characterization

The Greater Aneth Field is the largest oil field in the Paradox Basin, covering approximately 48,000 acres in San Juan County, extreme southeastern Utah. This field is typical of many petroleum reservoirs in the Rocky Mountains and intermountain west. The petroleum accumulation is a stratigraphic trap formed by the localized deposition of a large carbonate mound, and possesses a great potential for CO_2 storage subsequent to EOR operations. The Texas Company (Texaco) drilled the discovery well (23-T40S-R24E) in 1956 on Navajo Indian Tribal lands, which had an initial production of 568 BOPD and no water from perforations at ~5,800 feet depth. The Aneth Unit is currently producing about 3,100 BOPD from 133 producing wells with a 94% water cut. It has produced 147 MMBO since discovery.

Resolute purchased the Aneth Field from ChevronTexaco in December 2004. Resolute is making its upcoming CO_2 injection for EOR operation available for extensive MMV studies of associated sequestration in this large oil reservoir. Additionally and more importantly, Resolute has agreed to work with the SWP to field-test CO_2 injection in the deep Mississippian Leadville Limestone, a saline aquifer (no oil in place) below the oilfield. Thus, the Aneth pilot offers both deep saline sequestration testing and EOR sequestration testing.

Pilot Site Location and Description

The pilot test site is located within the Aneth mound complex (Figure 3), which formed on a weak structural nose. The present-day structural relief of about 150 feet is largely the result of differential compaction. The primary CO_2 sequestration target is the Pennsylvanian Desert Creek and overlying Ismay members of the Paradox formation, the primary producers in the Greater Aneth Field. These carbonate strata were deposited on the southwestern flank of the Paradox evaporite basin, and are laterally equivalent to the more basinward anhydrites and salts. The “seal” unit above the sequestration target is the low-permeability Gothic Shale, and the underlying seal is an organic-rich mud deposit, the Chimney Rock Shale. Both shales are seals as well as original oil source rocks. Oil generation began during the Cretaceous as these strata were buried to depths greater than 10,000 feet. Later tectonic uplift and gentle structural development had only minor effects on redistribution of the accumulation.

The Aneth Unit was originally developed with vertical wells drilled on 80-acre spacing. The field was

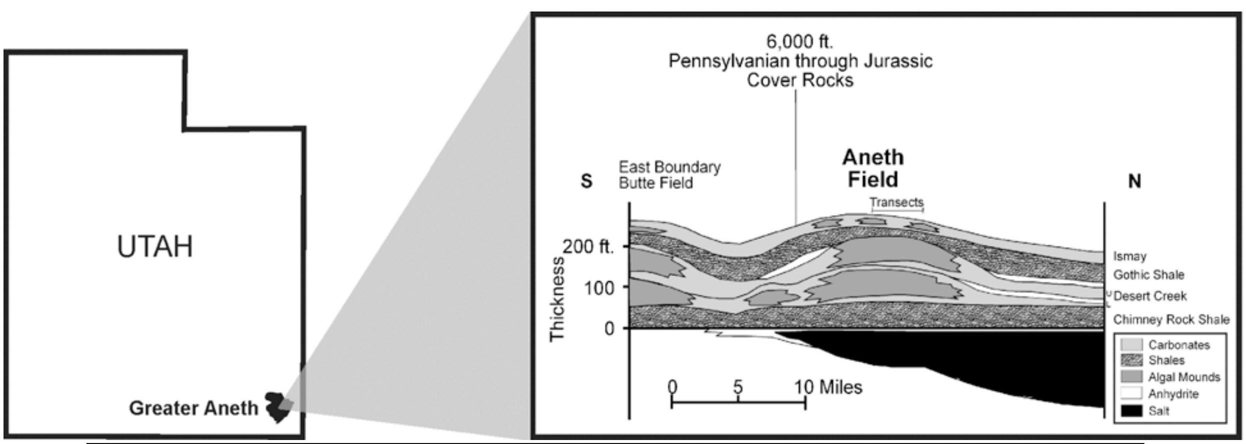


Figure 3. Location map of Aneth field and pilot site (left) and representative cross-section (right). The area indicated by “transects” is the location of a profile of CO_2 flux measurements the Partnership conducted in January 2005.

infill drilled in the 1970s to 40 acre spacing. The field has been managed with water injection that began with unitization in the early 1960s. In 1996 Texaco drilled 43 multi-lateral horizontal wells (23 producers and 20 injectors). In 1998, the injectors in section 14 were converted to a CO_2 WAG project to pilot the possibility of a field wide CO_2 injection program. Thus, monitoring of horizontal CO_2 injection is an added attraction offered by this pilot test site.

Task 1: Site/Reservoir Characterization and Model Development

All information for the site will be collected from Resolute, and a thorough site and reservoir characterization developed. The information collected will include precise well locations, completion and stimulation information, and production and operating histories for each. Historical gas and water production data will also be obtained. From a reservoir characterization perspective, well logs, core data, pressure-transient data, and any other relevant information for the area will be obtained from Resolute. Resolute currently possesses core and pressure transient data for over 80 wells within 10 miles of the demonstration site. Using this information, a detailed numerical reservoir model and operating/production history will be constructed for the demonstration site. In this task, we will also continue working on the initial risk assessment that was begun in Phase 1.

Task 2: Implement Regulatory Permitting Requirements and Risk Mitigation

For the Aneth pilot, we will follow the overall proposed regulatory and permitting plan, including development of a best practices manual, described in a previous section of this proposal. An important regulatory aspect specific to the Aneth pilot is that, in Utah, wells that are used for the enhanced recovery of oil and gas are considered Class II wells under the Underground Injection Control (UIC) program, and normally regulated by the Utah Division of Oil, Gas, and Mining of the State's Department of Natural Resources. However, the regulation of Class II injection on Native American tribal lands is retained by the federal government through the U.S. Environmental Protection Agency, specifically the Region 8 office in Denver, Colorado. The proposed Aneth pilot project is on Navajo Nation land, and therefore falls under EPA jurisdiction. In this second task, we will also begin integration of our reservoir models, risk assessment criteria, regulatory constructs, and the MMV protocols for the systematic risk mitigation approach (described earlier in this proposal). Please refer to Gantt charts (Section 3) for schedules.

Task 3: Construction, Safety and Site Preparation, Baseline MMV

The Aneth Unit has an 800 acre CO_2 pilot program in the eastern side of the field and it has been running since 1998. Resolute intends to expand the program to cover much of the remainder of the field, probably avoiding the portion (eastern side) of the field that has already been drilled up with horizontal wells. As an initial “reconnaissance” of CO_2 flux for baseline MMV information, the SWP sampled a representative transect of 35 flux measurements (location indicated on Figure 3); all measurements suggest ambient fluxes are completely soil/ biogenic.

The extension of the CO_2 area to the west will entail at least three phases of development with each phase accessing approximately 1600 acres of new CO_2 flood area. In each development Resolute will be constructing approximately 50 miles of new flow lines, two new injection well headers, new production well headers at each separating facility and a new parallel production facility at each current production facility location. The new lines will be required to distribute the CO_2 to the western side of the field, replace the existing flow lines from the wells to the tank batteries (to enable CO_2 service) and provide for parallel new produced gas return lines so that produced gas high in CO_2 can be returned for reinjection while the still-uncontaminated gas can be directed to sales. The new injection headers will allow the CO_2 and injected water in the water-alternating-gas system to be diverted to the appropriate injection wells at the appropriate time. New production headers will be necessary so that the wells producing high CO_2 concentrations can be diverted to one production separation facility where the gas will be diverted to re-injection. The new production headers will allow wells still low in CO_2 to be directed to the current facility where these will have their gas diverted to sales.

The first phase of the CO_2 expansion will be up to the western edge of the Navajo Nation land within the unit. The second and third phases will be for 2) BLM land to the west of the Navajo Nation lands (the farthest west portion of the field) and 3) the remainder of the field between the first phase discussed above and the existing pilot and horizontal wells. Each phase will probably have 10 wells dedicated to each injection header and 20 or more producing wells in each production facility.

In this third task, we will conduct baseline measurements of our MMV program; MMV protocols for the Aneth pilot are described under Task 5, below. Gantt chart schedules are provided in Section 3.

Task 4: Injection Operations, MMV and Capacity Analysis

<u>*EOR Testing*</u>: The field has the capacity to take delivery of up to 20 MMCF per day of CO_2 and re-

injection capacity of a similar amount. The CO_2 comes from the McElmo Dome CO_2 source and arrives at a pressure of about 2750 psi, which is sufficient to inject it into the wells without compression.

For our proposed combined EOR/sequestration program, individual well CO_2 injection rates are planned and expected to be about 300 MCF per day per well. The process of displacing approximately 20% of the reservoir pore volume will take about five to eight years. It is proposed to inject CO_2 at the site for a period of several years and to intensely monitor CO_2 movement for 18 to 24 months. Lower-intensity monitoring will be performed for the remaining period of the four-year SWP Phase 2 program. It is assumed CO_2 injection will commence in early 2006. State-of-the-art reservoir modeling will be used to simulate flow and chemical processes and forecast ultimate CO2 storage capacities.

Deep Saline Sequestration Testing: A deeper non-hydrocarbon bearing zone would make a better longer-term carbon dioxide sequestering interval, due to its larger areal extent and volume, and the fact that injection into this type of interval would not be subject to limitations in rate and volume related to using CO_2 for an oil recovery process. Explicitly for this Phase 2 project (i.e., Resolute NRC would not do this if the SWP was not proposing the pilot), Resolute will complete an available well in a deeper porous formation and test the reservoir's permeability and injective capacity by first injecting water into the interval. This testing would consist of a pressure transient test conducted after some period of water injection. Resolute will then connect the well to the CO_2 supply being used for the oil recovery process by installing a temporary surface flow line and inject CO_2 for a brief period (e.g., 1500 to 2000 tons of CO_2 over a period of ~1 week). During the injection of CO_2, Resolute will measure injection pressure and conduct a subsequent pressure transient fall-off test. This information will allow us to determine the relationship between the capacity for the injection of water (single phase – natural occurring conditions) and CO_2 into the same potential carbon dioxide sequestering formation. This information would allow the same formation in other areas to be tested with water injection alone (where CO_2 is not readily available for injection) and to use those results to better predict the capacity of the formation to handle CO_2 injection and sequestration. MMV protocols would be implemented for the deep saline test and continue for the duration of the SWP program.

MMV Operations: All MMV protocols to be deployed by the SWP are summarized earlier in this proposal. The specific MMV methods for the Aneth pilot are tabulated below.

Direct MMV Methods at Aneth		**Indirect MMV Methods at Aneth**	
Injection rate monitoring	Prod. well LI-COR©	2-D seismic surveys	VSP
Abandoned well LI-COR©	H_2O chem. & isotopes	crosswell seismic	ASTLI
Gas piezometers (LI-COR©)	Fluid/gas chemistry and isotope analysis	passive seismic	Integrated seismic model
In situ P/T well monitoring (fiber optic sensors)		Borehole integrity by resistivity monitoring	State-of-the-art reservoir modeling

Our MMV programs proposed for each site are tailored for the unique setting of each site and for maximizing comparisons to approaches deployed at the other two geologic pilots (SJB ECBM and SACROC-Claytonville). For Aneth, the primary contrast with other field project sites is the application and testing of 2-D seismic lines. Results of the Weyburn project suggest that even the most sophisticated 4-D seismic approaches have limited efficacy for CO_2 sequestration monitoring; seismic methods are very effective for detecting the “front” of a CO_2 plume, but are not very effective for determining volumes or amounts of CO_2 behind the plume front. Thus, we plan to investigate how to optimize 2-D seismic lines for detection and monitoring purposes, because 2-D lines are two to four times less expensive than 3-D. We will attempt to maximize 2-D seismic efficacy by combining surveys with crosswell, VSP, and ASTLI. We will also compare efficacy and approaches for 2-D surveys to planned 3-D surveys in our proposed SACROC-Claytonville pilot. Additionally, passive seismic monitoring promises to be particularly effective at the Aneth site, because a brine injection facility (Allis, Utah GS, personal communication) near the Colorado–Utah border provides an abundance of passive seismic energy.

<u>Pilot Plan: San Juan Basin Enhanced Coalbed Methane (ECBM) Pilot Test, Navajo City, NM</u>

Suitability, Availability, and Characterization

The SJB ECBM/CO_2 sequestration field test site is located in San Juan County, New Mexico, in the heart of the San Juan Basin (SJB) coalbed methane (CBM) fairway (Figure 4). This location is uniquely favorable for an ECBM/sequestration demonstration for several reasons. For instance, the SJB has been previously assessed by Advanced Resources International (ARI) under the DOE-sponsored Coal-Seq project as one of the nation's top coal basins for sequestration in terms of potential storage capacity (12 Gt of CO_2, 12% of U.S. total), ECBM potential (16 TCF, 10% of U.S. total), and potential cost of storage (at a predicted net profit of $4-8/ton of CO_2). The results of the demonstration would be directly scalable to a large portion of the SJB for significant, low-cost sequestration.

The SJB is a mature CBM play, and thus much of the infrastructure and services required to implement large-scale sequestration are already in place (e.g., wellbores, gathering and distribution systems, processing facilities, etc.). In addition, a well-established, reasonably-priced service capability to maintain and expand that infrastructure exists. Finally, and perhaps most importantly, the infrastructure to deliver CO_2 to the region exists – the Cortez pipeline that delivers (natural) CO_2 from McElmo Dome to West Texas passes directly through the SJB (Figure 4). If/when that pipeline begins transporting anthropogenic CO_2, the SJB will become a premier national sequestration site. Thus, the SJB represents an important near-term option for CO_2 sequestration.

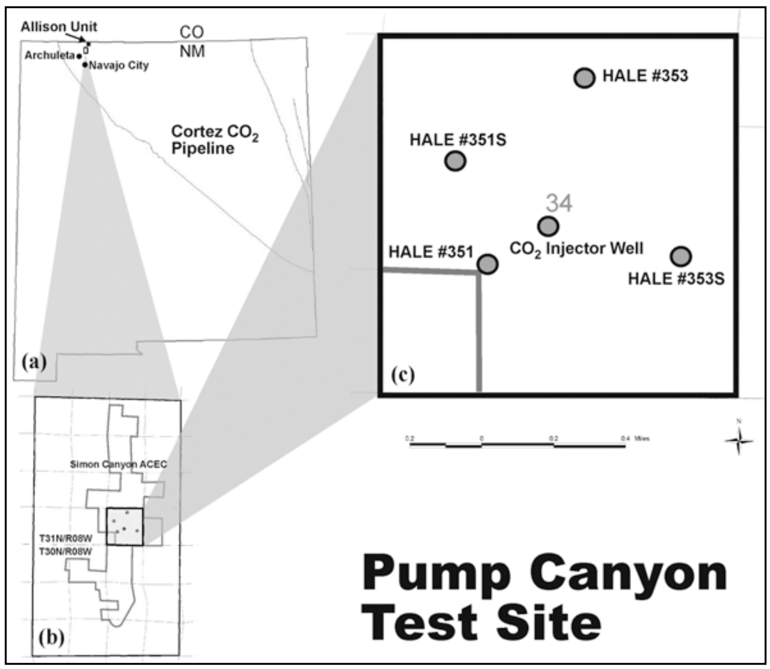


Figure 4: Location of SJB ECBM (Pump Canyon) Demonstration Site in San Juan Basin, NM.

The coals in the SJB fairway area are of exceptionally high permeability—100s of millidarcies. Due to the tendency of coal to swell when in contact with CO_2, high initial coal permeability is required to maintain high CO_2 injection rates over time. Maintaining high injectivity is an important requirement for large-scale, low-cost CO_2 sequestration in coal, and demonstrating this is an important DOE carbon sequestration program goal (as stated in DOE's 2004 Technology Roadmap and Program Plan). This demonstration represents an ideal opportunity to achieve that goal. The SJB ECBM pilot site lies entirely within the BLM's Simon Canyon Area of Critical

Environmental Concern (ACEC) (Figure 4). This 4,000 acre ACEC, which is managed for semi-primitive forms of recreation including fishing, hiking, and backpacking, was established in 1950 and is the oldest ACEC in New Mexico. We will be working closely with the BLM's Farmington Office to ensure that the entire project is done in an environmentally friendly manner and that all federal regulations concerning safety and environment are strictly followed. As part of this local terrestrial sequestration pilot, we are proposing to desalinate produced water so that it can be used in nearby riparian areas within the ACEC.

Site Location and Description

The exact pilot site location is Section 34, T31N, R8W in northeastern San Juan County, New Mexico (Figure 4). The site will consist of four CBM producing wells drilled on 80-acre spacing. The primary gas-producing horizons in this area are coal beds in the Upper Cretaceous Fruitland Formation. The coals, which occur at depths of approximately 3,000 feet, are about 75 feet thick split among three seams over a 175-foot gross interval. This area of the fairway has undergone significant CBM production, and reservoir pressures at the test site are less than100 psi. Coal matrix shrinkage is significant at these low pressures, contributing to the high coal permeabilities that exist there. In addition, CO_2 injection pressures will be low, eliminating any potential CO_2 compression needs for the pilot project. The site is operated by Burlington, San Juan Division, operator of more than 1,200 CBM wells in the SJB (more than any other company), and a pioneer in CO_2-ECBM technology. Burlington was the operator of the Allison Unit CO_2-ECBM pilot located in San Juan County, NM, just north of the proposed test site (Figure 4). To date, the Allison Pilot is the largest and longest-running CO_2 injection project in coal for the purposes of ECBM. That project, analyzed by ARI as part of the DOE's Coal-Seq project, has provided most of industry's experience and technical foundation regarding CO_2-ECBM. Burlington remains the single most experienced and knowledgeable operator in the world regarding CO_2 injection in coal.

Task 1: Site/Reservoir Characterization and Model Development

In this task all of the information for the site will be collected from Burlington, and a thorough site and reservoir characterization and numerical model will be developed. The information collected will include precise well locations, completion and stimulation information, and production and operating histories for each well. Historical gas and water compositional data will also be obtained. From a reservoir characterization perspective, well logs, core data, pressure-transient data, and any other relevant information for the area will be obtained. Burlington currently possesses core and pressure transient data for several wells within 10 miles of the demonstration site. Using this information, a detailed geologic model and operating/production history will be constructed for the demonstration (Figure 4). The area's CBM performance history will then be matched via reservoir simulation to calibrate unknown reservoir properties (e.g., relative permeability), which will be the primary basis for understanding subsequent pattern performance under CO_2 injection. Initial forecasting of pattern performance under CO_2 injection will be performed to aid in operational planning for the demonstration (i.e., fine-tune injection rates, estimate injection pressures, etc.). In this first task, we will also continue working on the initial risk assessment that was begun in Phase 1.

Task 2: Implement Regulatory Permitting Requirements and Risk Mitigation

For the San Juan ECBM pilot, we will follow the overall proposed regulatory and permitting plan, including development of a best practices manual, described in a previous section of this proposal. An important regulatory aspect specific to the ECBM pilot is that New Mexico already has an existing regulatory construct for CO_2 injection—New Mexico classifies EOR and EGR injection activity as Class II under UIC. The State has also adopted specific rules and regulations governing long-term CO_2 storage through the Oil Conservation Division. Thus, the enhanced coalbed methane project in the San Juan Basin will be permitted under rules and regulations developed and administered by the New Mexico Oil Conservation Division (IOGCC, 2005), and the San Juan basin terrestrial project (riparian restoration, described below) will be conducted by the U.S. Forest Service and permitted in accordance with USDA regulations. In this second task, we will also begin integration of our reservoir models, risk assessment criteria, regulatory constructs, and the MMV protocols for the systematic risk mitigation approach (described earlier in this proposal). Please refer to Gantt charts (Section 3) for schedules.

Task 3: Construction, Safety and Site Preparation, Baseline MMV

The next task will be to prepare the site for the demonstration. This will firstly involve the drilling of the CO_2 injection well. The proposed well location is in the center of four CBM production wells (Figure 4). The well will be drilled vertically to a depth of ~ 3200 ft, completed open-hole to minimize formation damage, and stimulated using hydra-jetting or a similar method. (Burlington's experience with the open-hole, cavitation technique in low reservoir pressure environments has been mixed at best, and thus an alternative stimulation approach is proposed). Stimulation will provide the greatest opportunity for sustaining high CO_2 injection rates throughout the demonstration. One of the key findings from the Allison Pilot, where the injection wells were not stimulated, was that well stimulation (in addition to high coal permeability) will probably be necessary for successful CO_2-ECBM sequestration.

Coal cuttings will be collected when drilling though each of the three main coal seams, and methane and CO_2 isotherms measured at in-situ reservoir temperature. Other coal characterization tests will also be performed, such as vitrinite reflectance, maceral composition, and proximate analysis.

The well will be equipped with carbon-steel casing, fiberglass-coated tubing, and a stainless-steel injection packer. A permanent, surface-readout, downhole pressure gauge will also be installed to monitor injection pressures continuously throughout the demonstration. The surface equipment will consist of a heater to heat the CO_2 to reservoir temperature prior to injection, and flow rate and pressure monitoring devices. Appropriate safety and emergency shut-off devices will also be installed.

To transport the CO_2 approximately two miles from the existing pipeline to the well, a 2-in. pipeline along the access road right-of-way will be installed. Burlington's 4-in. pipeline off Kinder-Morgan's Cortez pipeline (which operates at approximately 2,000 psi in this area), is currently unused and filled with nitrogen for corrosion prevention. It will be returned to CO_2 service (Figure 4). A pressure reduction manifold will be installed at the tap between the 4-in. and 2-in. lines. In this third task, we will conduct baseline measurements of our MMV program – MMV protocols for the SJB ECBM pilot are described under Task 5, below. Gantt chart schedules are provided in Section 3.

Task 4: Injection Operations, MMV and Capacity Analysis

We propose injecting CO_2 at the site for a period of 12 months and monitoring CO_2 movement intensely over a period of 24 months, which includes an additional 12 months after injection (assuming

CO_2 injection will commence around January, 2008). The volume of CO_2 to be injected was computed by first estimating the methane storage capacity of the coal in the pattern area (160 acres) at 35 psi (Burlington's expected abandonment pressure). Assuming a CO_2:CH4 replacement ratio of 2:1 (based on isotherm measurements from the Allison Unit), and a volumetric sweep efficiency of 75%, the CO_2 volume required to sweep the inter-well area of methane is approximately 1.2 BCF. Over 12 months, this translates to an average CO_2 injection rate of about 3.5 MMCFD. This approach to volume estimation minimizes the potential for injected CO_2 to breakthrough prematurely to producing wells and contaminate the gas production in the pattern. Volumes will be estimated by coal/reservoir modeling, also.

Injection will be controlled using a constant surface injection pressure, and the injection rate will be allowed to vary as downhole conditions change, similar to successful operations at Allison. The actual injection pressures will be estimated based upon initial reservoir modeling, and thereafter supplemented with field experience and continued modeling. It is anticipated that the CO_2 will be heated to reservoir temperature prior to injection to minimize tubing expansion/contraction during shut-down periods, and also to reduce CO_2 adsorptive capacity in the near-well region (to reduce coal swelling). However, some experimentation with unheated CO_2 injection will be performed to investigate whether thermal contraction of the coal at lower temperatures improves or worsens CO_2 injectivity.

MMV Operations: All MMV protocols to be deployed by the SWP are summarized earlier in this proposal. The specific MMV methods for the San Juan ECBM pilot are tabulated below.

Direct MMV Methods at San Juan ECBM		**Indirect MMV Methods at San Juan**	
Injection Rate Monitoring	Prod. Well LI-COR©	2-D Seismic Surveys	VSP
Abandoned Well LI-COR©	H_2O Chem & Isotopes.	Crosswell Seismic	ASTLI
Gas Piezometers (LI-COR©)	Fluid/gas Chemistry and Isotope Analysis	Passive Seismic	Integrated seismic model
In situ P/T well monitoring (fiber optic sensors)		Borehole integrity by resistivity monitoring	State-of-the-art reservoir models
Tiltmeter Arrays	Spinner Surveys		

Our MMV programs proposed for each site are tailored for the unique setting of each site and for maximizing comparisons to approaches deployed at the other two geologic pilots (Aneth and SACROC-Claytonville). For the SJB ECBM pilot, the primary contrast with other field project sites concerns coal and CH_4. Specifically, we must apply techniques to help track the movement of CO_2 within the coalbeds, a potentially difficult task given that the coals are already saturated with CH_4. Thus, we plan for several special MMV applications. As CO_2 is injected, swelling of the coals will occur, permeability will reduce, and fluid pressures will increase dramatically. Swelling will be significant and detectable by tiltmeters, as discussed in the MMV section of the proposal. An array of 30 surface tiltmeters will be deployed throughout the pattern area, calibrated by three fixed GPS stations, as one of the primary monitoring methods of CO_2 movement in the coal. In the interwell area, continuous monitoring of the tiltmeter array will be performed to monitor surface deformation related to coal swelling with CO_2 injection. In the event the CO_2 plume extends beyond the pattern, interferometric synthetic aperture radar (In SAR) data will be obtained periodically (~monthly) to monitor surface deformation over a larger area. Additionally, spinner surveys will be performed in the injection well to determine vertical injection conformance among the individual coal seams that exist at the site (~every six months).

Finally, we will employ and focus on both 2-D and 1-D seismic methods, to evaluate CO_2 movement out of the top and bottom of the coal beds. Because the coals are already saturated with CH4 and the seismic properties of CH4 and CO_2 are nearly identical, resolving the CO_2 front (laterally) will likely be impossible, and 3-D surveys may be excessive (e.g., “overkill”). Thus, we will focus on evaluating the vertical change in seismic reflectors as a means of tracking the CO_2 front; 1-D and 2-D seismic methods (single source reflection; borehole methods such as VSP, etc.) will likely be effective for resolving changes in vertical reflectors at the coal boundaries. Combining and co-interpreting seismic and borehole geophysical methods with tiltmeters is a promising “coupled” approach for monitoring CO_2 and its effects on injectivity, methane production, and efficacy of CO_2 storage in the coals.

Task 5: Post-Injection Monitoring and Analysis

Following the injection period, the monitoring program described for previous tasks will continue for an additional period of approximately 12 months. Following that initial 12-month post-injection period, the site will be monitored on a less-frequent and lower intensity basis for the balance of the project (approximately 18 mos). While the specifics of the scale-down will be decided at the time, when a better understanding of what data are providing the most useful information, and how frequently it should be collected, it is envisioned at this point that the tiltmeter array will be demobilized, and continuation and/or frequency of other periodic measurements evaluated. As with during injection, post-injection reservoir simulation models will be periodically updated (approximately three months). Long-term predictions of CO_2 movement/storage will be made by interpretation and modeling, as well as ECBM performance.

San Juan Basin Terrestrial Sequestration Pilot

Rangelands in the San Juan Basin of New Mexico are a potentially large reservoir for carbon, in addition to their value as recreational lands. The challenges to achieving their potential lie primarily in the limited growing conditions (erratic precipitation) and reduced capacity for recovery (ongoing disturbance and poorly developed soils). Optimizing carbon storage in soils and vegetation while increasing the value of other ecosystem services requires a two-pronged strategy: enhancing existing and reintroducing woody plant species along riparian areas and reestablishing native grasses and shrubs in upland areas. The limiting factor in both cases is water, both quality and quantity. A reliable source of water of sufficient quality for agricultural irrigation could provide the necessary base for the reestablishment of native vegetation with a host of environmental benefits in addition to carbon sequestration. The water produced during ECBM production should provide that source.

Work Plan: Regulatory and permitting requirements will be addressed first. The terrestrial sequestration activities in this project will all take place on land administered by the BLM, who has an established permitting process for such activities. As a strategy of retrieving maximized CBM clean water for beneficial use and minimized wastewater for disposal, we developed and demonstrated a new method using zeolite RO membrane for produced water purification. The zeolite RO has advantages of organic solvent resistance and can separate salt and organics from produced water simultaneously (Li et al., 2004a). The molecular sieve MFI-type zeolite membrane can separate ion and organics from water with a high separation efficiency based on size exclusion mechanism because the hydrated ions and organics have effective sizes (0.8~1.0 nm) much larger than the uniform zeolite pore size (0.56 nm) while the dynamic size of water molecules (~0.29 nm) is much smaller than the zeolite pore size and therefore can transport freely (Lin et al., 2001; Li et al., 2004b, 2004c). Recently, an overall 83.5% ion rejection was achieved for a real CBM produced water containing TDS of ~1.86×10^4 mg/l on a MFI zeolite membrane.

Desalinated produced water will be applied to 5 linear km of second order or higher stream where riparian vegetation is currently degraded. Frequency of applications of water will be determined by the amount of water available, but will not be less than bank-full, for one week, monthly, April-November; and bank-full for one week every other month December through March. To assess the impact on vegetation, standard indicators of rangeland riparian ecosystems will be measured at the beginning of the project and seasonally thereafter (Winward, 2000). Water will be applied to at least 100 ha of upland soils, reseeded with drought tolerant native grasses at least three times per year to simulate 2.5 cm of natural precipitation. Impacts of the upland reseeding and irrigation will be determined by application of rangeland health monitoring standards (Herrick et al., 2005). *The Big Sky Partnership will collaborate with the Southwest Partnership on this project, specifically on economic modeling and analysis.*

Pilot Deployment Plan: SACROC-Claytonville EOR Pilot Test, Snyder, Texas

Suitability, Availability, and Characterization

The SACROC unit and Claytonville (Canyon lime) reservoir are part of the Horseshoe Atoll and Pennsylvanian Reef/Bank plays (Figure 2). The two plays have produced more than 3.2 billion barrels of oil, a very large pore volume for potential CO_2 sequestration. The pilot sites are in a very sparsely populated portion of Texas. There are no metropolitan areas in the counties that the pilot areas cover; residents are involved in either the oil industry or agriculture. A large oil industry infrastructure exists, including pipelines, supply stores, and oil processing facilities. The infrastructure to deliver CO_2 is part of the largest CO_2 pipeline infrastructure in the world. Land use over the pilot areas consists of tilled farming and animal grazing. Information about the two fields is summarized in Table 2.

Both reservoirs are highly suitable for a CO_2 pilot demonstration project. The reef depositional setting is representative of the larger Permian Basin Pennsylvanian oil plays. The minimum miscibility pressure of CO_2 in oil for both reservoirs is estimated to be 1,500 psi, well below the initial reservoir pressures. Both fields contain low production-rate oil wells, shut-in wells, and plugged and abandoned wells. The high gravity oil in each field also makes them good candidates for CO_2 enhanced oil recovery.

Pilot Site Location and Description

The exact pilot site locations include the center of the SACROC Kelly oilfield (Figure 2), where CO_2 injection is ongoing, and the northeastern portion of the Claytonville field (Figure 2). At both Claytonville and SACROC, the geology of the injection zone is comparable to a large class of potential brine storage reservoirs. Depth of the flooded zones range from ~6300–7100 ft (1900–2200 m) with average reservoir pressures of ~2600 psig. The reservoir fluids in the flooded zones are typical brines. Impermeable shale caps the limestone reservoir, which itself has permeabilities generally <~50 md and porosities in the range of 2–15%. KinderMorgan has a well-developed CO_2 handling infrastructure, with ~1850 wells within the ~50,000 acre site. Roughly 175 of these wells are CO_2 injection wells. The area currently has a gas separation facility capable of handling 635 MMscf/d (~13 MtCO_2/yr). An amine-based process is used for

Table 2.	**SACROC**	**Claytonville**
County	Scurry	Fischer
Discovery year	1948	1952
Play	Horseshoe Atoll	Pennsylvanian Reef/Bank
Trend	NE-SW	N-S
Porosity	8%	5%
Permeability	19 md	10 md
Initial BH Pressure	3122 psi	2335 psi
API Gravity	42	42
Pore Types	Vugs, interparticle, fractures	Vugs, interparticle, fractures
Depositional Setting	Reef	Reef
CO_2 Flooding	1973	1975
Size	170 mi long	3360 acres (5 x 0.75 mi)
Production	1227 mmbo	66 mmbo

scrubbing/polishing the last 10% of CO_2 from final gas mixtures. Compression facilities are capable of pressurizing comparable volumes of CO_2 to reservoir injection conditions. KinderMorgan has generously agreed to provide all CO_2 for the proposed EOR/sequestration analysis at SACROC and Claytonville. SACROC injection is ongoing, and MMV operations can begin right away. Redevelopment of the Claytonville Canyon Lime reservoir with a CO_2 enhanced oil recovery project will be rapid. A branch pipeline will be laid from SACROC to the Claytonville reservoir in 2006. During this time workovers and new wells will be drilled to obtain the necessary perforated well coverage. Additionally, surface facilities and high pressure CO_2 lines will be constructed. The target date for injection to begin will be January 2007; see Gantt charts in section 3 for all schedules.

Research work will aid in the determination of the approach that will be taken for the CO_2 EOR flood. A gravity stable flood is likely because of the steeply dipping reservoir with good vertical communication. This type of flood injects CO_2 at the top of the structure and causes oil to be produced at lower structural positions. This effectively “fills” the structure with CO_2 and could represent an optimal approach to both enhancing oil recovery and increasing the amount of CO_2 sequestered. Initial CO_2 injection is planned to begin in the north-east structural high. Injection quantities and rates are yet to be determined. Any produced CO_2 will likely be reinjected with minimal methane removal. This location will thus focus the MMV work within the project.

Task 1: Site/Reservoir Characterization and Model Development

In this task all of the information for the site will be collected from KinderMorgan, and a thorough site and reservoir characterization developed. The information collected will include, for example, precise well locations, completion and stimulation information, and production and operating histories for each. Historical oil, gas and water compositional data will also be obtained. From a reservoir characterization perspective, well logs, core data, pressure-transient data, and any other relevant information for the area will be obtained from KinderMorgan. KinderMorgan currently possesses, or will acquire in 2005, core and pressure transient data for several wells within or near to the demonstration site.

One of the project collaborators, ARI, is also working on a separate DOE-sponsored project at the SACROC Unit. The primary objective of that effort is to develop a reservoir characterization of the northern platform area, which contains the bulk of the oil for the field, to evaluate the feasibility of gravity-stable CO_2-EOR there. Gravity-stable CO_2-EOR is not only more efficient than pattern flooding, but it has the potential to sequester more CO_2, creating a win-win situation. However, this technique requires specific geologic conditions to be effective, conditions that are believed to exist in the northern platform area. To assess geologic and reservoir conditions, core and cross-well seismic data are being acquired in four wells in the area. A 3-D surface seismic survey already exists over the area.

Through the ARI project, these data will also benefit the SWP's efforts to understand CO_2 movement at SACROC. Another project collaborator, the Texas BEG, also has a detailed characterization implemented in an existing numerical model of the SACROC area, based on seismic stratigraphy and other data. These combined a priori characterizations of SACROC will be leveraged to develop a better model of the SACROC field and also to develop the basis for a sound characterization of Claytonville. Detailed geologic models and operating/production histories will be constructed for both demonstration sites. Production histories will then be matched via reservoir simulation to calibrate unknown reservoir properties (e.g., relative permeability), which will be the primary basis for understanding subsequent performance under CO_2 injection. Initial forecasting of performance under CO_2 injection will be performed to aid in operational planning for the demonstration (i.e., fine-tune injection rates, estimate injection pressures, etc.). As described in the introduction, SACROC provides an unparalleled opportunity for "back-forecasting" or history-matching: over 30 years of CO_2 injection and EOR operations provides a sound database and basis for understanding new operations at Claytonville. In this first task, we will also continue working on the initial risk assessment that was begun in Phase 1.

Task 2: Implement Regulatory Permitting Requirements and Risk Mitigation

For the SACROC-Claytonville pilots, we will follow the overall proposed regulatory and permitting plan, including development of a best practices manual, described in a previous section of this proposal. In Texas, such activity is classified as Class II injection under UIC. Furthermore, the industry partner for this project, KinderMorgan, has extensive experience transporting and injecting CO_2, and is familiar with the permitting requirements. In this second task, we will also begin integration of our reservoir models, risk assessment criteria, regulatory constructs, and the MMV protocols for the systematic risk mitigation approach (described earlier in this proposal). Please refer to Gantt charts (Section 3) for schedules.

Task 3: Construction, Safety and Site Preparation, Baseline MMV

The next task will be to prepare the site for the demonstration, including construction. This includes transportation of CO_2 to the Claytonville field from KinderMorgan's Cortez and Centerline pipelines (which operate at approximately 2,000 psi in this area) and a new 30-mile pipeline to be built from the terminus of the Centerline Pipeline at Snyder, Texas, to the Claytonville field. Other activities will include construction of a CO_2 injection distribution system within the field, a new gathering system to collect all produced CO_2 and hydrocarbon gases, and a gas plant to recover at least some of the hydrocarbons in the produced stream. State-of-the-art reservoir modeling will be used to simulate flow and chemical processes and forecast ultimate CO2 storage capacities. In this third task, we will conduct baseline measurements of our MMV program; MMV protocols for the Texas pilot are described under Task 5, below. As an initial "reconnaissance" of CO_2 flux for baseline MMV information, the SWP sampled a representative transect of 25 flux measurements; all measurements suggest ambient fluxes are completely soil/ biogenic. Gantt chart schedules are provided in Section 3

Task 4: Injection Operations, MMV and Capacity Analysis

Injection at SACROC is ongoing, as it has been for over 30 years. KinderMorgan plans to inject CO_2 at Claytonville for several years, and the SWP proposes to intensely monitor CO_2 movement for the entire period (see Gantt charts in Section 3). Enhanced oil recovery will require injection of CO_2 for several years, possibly using a water-alternating-gas scheme. Lower-intensity monitoring will be performed for the final ~18-months of the project (it is assumed CO_2 injection will commence around January 1, 2007). The daily rate of CO_2 to be injected will be between 5 and 15 MMcf / day. An average well will inject 5 BCF of CO_2 over its life. Injection will be controlled using a constant injection pressure, and the injection rate will be allowed to vary as downhole conditions change. At a later time when CO_2 is produced with hydrocarbon gases, some gas may remain in the recycled CO_2 stream and will be reinjected. It is not anticipated that the hydrocarbon fraction in the reinjected stream will ever exceed 15% by volume.

MMV Operations: All MMV protocols to be deployed by the SWP are summarized earlier in this proposal. The specific MMV methods for the SACROC-Claytonville pilot are tabulated below.

Direct MMV Methods at SACROC-Claytonville		**Indirect MMV Methods at SACROC-Claytonville**	
Injection Rate Monitoring	Prod. Well LI-COR©	4-D Seismic Surveys	VSP
Abandoned Well LI-COR©	H_2O Chem & Isotopes.	Crosswell Seismic	ASTLI
Gas Piezometers (LI-COR©)	Gas Chem & Isotopes.	Passive Seismic	Integrated seismic model
In situ P/T well monitoring (fiber optic sensors)		Borehole integrity by resistivity monitoring	State-of-the-art reservoir models

Our MMV programs for each site are tailored for the unique setting of each site and for maximizing comparisons to approaches deployed at the other two geologic pilots (SJB ECBM and Aneth). For the Texas pilots, the primary contrast with other sites is the application and testing of 3-D seismic lines. We will be testing 2-D seismic comprehensively at Aneth; we propose to use repeat 3-D (i.e., 4-D) surveys at SACROC-Claytonville, and leverage or couple interpretation and modeling of 4-D results with borehole geophysical results (VSP, ASTLI, crosswell) – i.e., we will attempt to maximize 4-D seismic efficacy by combining surveys with crosswell, VSP, and ASTLI results. We will also compare efficacy and approaches for these 4-D surveys to planned repeat 2-D surveys in our proposed Aneth pilot.

Southwest Regional Terrestrial Pilot Test

The analyses conducted in Phase I on carbon sequestration potential for the region clearly showed that there is tremendous potential to increase carbon storage in soils and vegetation through changes in land use and management. Achieving that potential, however, is constrained by three factors: (1) low per ha rates of accumulation due to low rainfall and soil fertility (2) year to year climatic variability that makes local prediction of sequestration difficult (3) lack of cost effective carbon measurement systems.

The greatest influence on carbon stocks in the area, without doubt, is yearly variation in precipitation. However, changes in land use and management also greatly influence soil and vegetation carbon fluxes. Broad, landscape scale analysis showed that much of the region would be predicted to accumulate soil carbon at less than 0.1 t/ha/y unless changes in land use occurred, primarily converting cropland to perennial grasses or trees. Land use conversion can result in accumulation rates of up to 1.0 t/ha/y in a limited portion of the region. Given current economic constraints on the ability of land managers to change land use, the potential for conversion is limited.

The dominant influence on land use and management in the region is government policy. The impact of federal conservation programs on private land management is prevalent throughout the region. Government programs such as the Conservation Reserve Program (CRP) encourage land conversion from cropland to perennial plant cover and other programs such as the Conservation Security Program (CSP), Environmental Quality Incentives Program (EQIP), Wildlife Habitat Incentives Program (WHIP), etc., provide incentives for land managers to adopt conservation practices on cropland, rangeland and forestland. It is through these land use changes and adoption of management practices that the greatest increases in terrestrial carbon storage will occur.

Crediting changes in terrestrial carbon and assigning them to specific management requires a system of monitoring, measurement and verification that can reliably separate changes in climatically driven fluxes from those due to actions taken by land managers. The ability to partition changes in carbon stocks is greatly limited by the climatic and edaphic constraints described above.

To overcome these constraints, we will develop a carbon reporting and monitoring system that functions consistently across hierarchical scales and is compatible with the existing technology underlying the 1605b reporting system. Our major objectives in developing and implementing this system are :(1) Develop improved technologies and systems for direct measurements of soil and vegetation carbon at reference sites selected within SWP region. (2) Develop remote sensing and classification protocols to improve mesocsale (km^2) soil and vegetation carbon estimates. (3) Construct ecological process (State and Transition) models that reflect soil/vegetation changes resulting from current land use and land use associated with implementation of programs to sequester carbon or reduce carbon losses. (4) Develop a regional inventory and decision support tool that integrates information gathered during the course of the Phase I investigation and from Objective 1-3 above.

Task 1: *Develop improved technologies and systems for direct measurements of soil and vegetation carbon at reference sites selected within Southwest Carbon Partnership region:* The purpose of Task 1 is to use advanced instrumentation on the ground to identify and characterize the distribution of, then to relate these distributions to the land use practices implemented at the site. Advanced techniques for measuring soil carbon and other nutrients are needed. We will address three subtasks for Objective 1: (1) Calibrate and test the newly developed Laser-Induced Breakdown Spectroscopy (LIBS) instrument along with portable Near Infrared Spectroscopy (NIRS) for soil carbon measurements. (2) Determine near land surface patterns of soil carbon in a spatially extensive manner. (3) Relate near land surface patterns of soil carbon to associated soil profiles, site inventories, and management practices. (4) Improving estimates of carbon inventories in soils is currently hindered by lack of a rapid analysis method for total soil carbon.

A rapid, accurate, and precise method that could be used in the field would be a significant benefit to researchers investigating carbon sequestration. Recent tests suggest that the LIBS method (Cremers et al., 2001) rapidly and efficiently measures soil carbon with excellent detection limits (~300 mg / kg), precision (4-5%), and accuracy (3-14%). Initial testing shows that LIBS measurements and dry combustion analyses are highly correlated (adjusted $r^2 = 0.96$) for soils of distinct morphology, and that a sample can be analyzed by LIBS in less than one minute. The LIBS method has been adapted to a field-portable instrument, and this attribute—in combination with rapid and accurate sample analysis— suggest that this new method offers promise for improving measurement of total soil carbon.

NIRS technology has recently been used for assessing soil carbon in both crop and rangeland conditions. As part of work conducted under the Consortium for Agricultural Soil Mitigation of Greenhouse Gases (CASMGS) project, we found that NIRS had the potential to be a useful method for rapidly assessing carbon in the field (CASMGS 2003). Although predictions of carbon were not consistently as accurate as conventional laboratory methods, the ability to collect many samples and the reduced cost of sampling make this an attractive method. In conjunction with the calibration of the LIBS instrument, we will work to improve calibration of the field instrument and examine its potential as methodology complimentary to the LIBS system.

Key data need to be collected to link changes in soil carbon to vegetation change related to management practices to sequester soil carbon. To accomplish this, a series of shallow and spatially extensive measurements of soil carbon will be collected to characterize distributions of soil carbon and nutrients at selected sites across the SWP region that were identified during the Phase I analysis. This information will be used for assessing correspondence to remote sensing data (Objective 2) and for development of state and transition models (Objective 3). This data will also be used as part of the regional inventory and decision support system (Objective 4).

Task 2: *Develop remote sensing and classification protocols to improve mesocsale (km^2) soil and vegetation carbon estimates:* The purpose of this objective is to identify and refine existing techniques in remote sensing that can detect and link changes in vegetation and soil properties that reflect soil C at a scale consistent with the output from Objective 1. While remotely sensed imagery has been valuable in natural resource management as a tool for inventory and large-scale production estimation, there has been little, if any, application to site-specific management such as land use and management change related to carbon sequestration. Two subtasks include: (1) Using results of the spatial characterization of carbon at the selected study sites in Objective 1, determine remote sensing technology(ies) capable of providing appropriate scale and frequency of imagery that could be useful in assessing changes in carbon stocks; (2) Integration of remote sensing data identified in Task 1, above, into the state and transition models and a regional inventory and decision support tool (Objective 4).

While the use of LANDSAT imagery is fairly common in agricultural and forestland resource inventories and assessments, the scale associated with this technology is likely to be inappropriate for detecting patterns at <$10m^2$ scale. However, new satellites and aircraft borne instruments, such as multispectral videography, which can generate information down to cell sizes of ~$1m^2$ and can be gathered frequently, offer the most promise in this area (Havstad et al., 2000).

Task 3: *Construct ecological process (State and Transition) models that reflect soil/vegetation changes resulting from current land use and land use associated with implementation of programs to sequester carbon or reduce carbon losses:* The purpose of this objective is to integrate existing qualitative knowledge about soil/vegetation change in response to management and climate variability and quantitative information gained as a result of Objective 1 into State and Transition Models (STMs) appropriate for the regions represented by our study sites, link to objective remotely sensed land attributes (Objective 2) and provide inputs to improve model estimates (Objective 4). Estimates are that approximately 50% of changes in carbon stocks on rangelands are attributable to changes in management practices (Follett et al., 2001). Unfortunately, the application of these types of practices (i.e. changes in grazing intensity) is difficult to detect and highly variable in their effect on soil C. However, vegetation structure has been shown to reflect soil C more accurately when the complex spatial relationships are accounted for and vegetation structure is much easier to detect objectively via remote sensing (Objective

2). STMs can be used to guide land managers and policy makers in selecting which practices can result in changes in soil C. Once the STMs are developed for specific management practices/land uses, they can be distributed to soil mapping units within the region and thereby expand the influence of the study. Currently, the only available model for estimating soil C changes on rangelands (COMET VR; see Objective 4) requires management inputs in terms of practices applied and the uncertainty associated with this approach is unacceptably high (>50%). Thus, associating soil C changes with vegetation state will both improve support of decision making and increase estimation accuracy. Finally, we will alter COMET VR to allow for inputs in terms of ecological state rather than practices, which more accurately reflect soil and vegetation C levels. Subtasks include: (1) Develop State and Transition Models (STMs) for the range of soil/vegetation combinations represented by the carbon management practices and land uses in the selected study areas. (2) Distribute STMs across appropriate soil units within the region. (3) Integrate the STMs into the regional inventory and decision support system.

The development of STMs requires a combination of field inventory and literature review. Although STMs have been proposed for over a decade, their field use is limited as a basis for management, especially in areas where vegetation structure is complex. We will use existing information from long-term studies at the selected study sites to assemble a catalog of vegetation states and transitions associated with past and current land use and with implementation of programs to sequester carbon.

Task 4. *Develop a regional inventory and decision support tool that integrates information gathered during the course of the Phase I investigation and from Objective 1-3 above*: The purpose of this objective is the development of a tool that will allow the integration of the spatial and carbon sequestration potential data developed under Phase I along with the information and data gathered as part of Objectives 1,2, and 3 of this effort into a decision support framework that can be used by landholders, service agencies (NRCS), and policy makers. This tool would allow a spatially explicit analysis of carbon sequestration at local scales and allow aggregation of sequestration response under various conditions to regional scales. Subtasks include: (1) Build a web-based tool, with a GIS framework, that incorporates the soil, climate, and land use data gathered and processed in Phase I along with the soil carbon, state and transition, and remote sensing data gathered in the Phase II efforts. (2) Establish a linkage to the COMET VR tool that will allow the data fields required by COMET VR to be automatically filled based on the latitude/longitude, premise boundary, or region input or selected by the user. (3) Build a state and transition interface that will allow users to examine carbon sequestration under various management practices, government programs, or land uses. (4) Design display tools for mapping, data visualization, and reporting in a spatially coherent manner. (5) Improve the COMET VR tool for assessing carbon sequestration at the individual field and farm scale for arid and semi-arid rangelands and croplands. (6) Develop protocols for updating the system with new data (NASS, NRI) and options for carbon sequestration so that the system will stay current with relevant government programs and incentives. This regional inventory system and decision support tool will be designed for use in estimating carbon change at varying levels of scale using existing models. This system will allow users to examine carbon sequestration alternatives and to track progress of an implemented program. The system will also give policy makers the ability to examine impacts of implementing carbon sequestration programs at local and regional scales, thus improving program and policy decision making.

Collaboration: To improve technology transfer and enhance quality of the science in the project, we will meet annually with scientists of the Big Sky and WESTCARB projects for a one-week workshop. Additionally, Big Sky will collaborate directly with us on the project, on economic modeling and analysis.

Merit of Proposed Projects In Context of GHG Reduction Goals and Economics

In our Phase I proposal, we suggested that a possible first approach to CO_2 sequestration in the Southwest would be to supplant natural CO_2 supplies used for EOR with anthropogenic CO_2 (e.g., power-plant sourced). Our Phase 1 analysis showed that such an approach the region would meet, at the least, minimum GHG intensity reduction targets for the region, and our Phase 2 portfolio of pilot tests are based on this theme. Furthermore, as part of the SWP Phase 1, an integrated economic/GHG model was developed, based on an initial SWP regional “test case” analysis. The economic/GHG model analysis has been used to evaluate all potential Phase 2 pilot tests, and is now being applied to the Southwest region overall. The integrated economic/GHG model analysis, developed in tandem by economists, engineers and scientists in the SWP and lead by Sandia National Lab, is being used to project to 2025 the region's total greenhouse gas (GHG) emissions based on total energy use, by fuel type, and to assess the potential to reduce GHG intensity in the region. Regional economic, energy and GHG data are based on projections developed by the Energy Information Administration. In addition, capacities and costs of capture and sequestration technologies for the region, including the proposed pilot tests (Aneth, SJB ECBM, and SACROC-Claytonville) are factored in the economic/GHG analysis, including delays and costs associated with project permitting and MMV requirements. Establishing and communicating the consequences and tradeoffs between alternate sequestration sites and strategies to store GHG is the necessary first step in formulating an effective and publicly acceptable sequestration program, and in addressing the 2007 and 2012 metrics for success of the DOE Carbon Sequestration Technology Roadmap. In the field pilot operations, MMV protocols and associated modeling are the primary vehicles for determining how well the SWP meets or exceeds performance targets of the CST Roadmap, including prediction of storage capacity to +/- 30% accuracy, verification of indirect sequestration and associated costs, and verification of MMV technology efficacy. Public perceptions and acceptance will be in part addressed by giving interested parties access to the integrated assessment model (see Outreach plans in the next section) to determine if the analysis approach reflects the important sequestration and GHG issues, and to increase understanding of the tradeoffs between different sequestration approaches.

Outreach and Education Plans

We have designed a regional outreach initiative to initiate and then facilitate a public dialogue regarding CO_2 sequestration. Our approach begins with an assessment of public knowledge bases, and then delivers outreach and public education in appropriate formats. Our programs builds on the NIST's (2002) recommendations that effective science communication programs should (a) illustrate both the process and product of science, (b) involve scientists, (c) involve decision makers, (d) use multimedia and interactivity, (e) relate science to everyday life, (f) avoid parochialism, (g) view the topic from the audience's perspective, (h) use face-to-face methods, and (i) provide readily usable information to media.

Dissemination methods, activities, and media are guided by learning theory and basic research on public awareness of science and technology. The concept of Collaborative Learning (Daniels and Walker, 2001) guides our outreach program, allowing for variations according to the socio-political dimensions and demographics of each locale. This approach provides a non-threatening format within which constituent groups with varied values and goals can establish a common understanding. The process encourages integration of individual interests within a broad, systemic view to achieve mutual benefit.

For decision makers, policy leaders, and the “attentive public” (Miller and Pardo, 1999), Mediated Modeling facilitates learning among constituents (van den Belt, 2004). It features a streamlined user interface that representatives can use with various groups to choose between a set of alternatives and build quantitative models of carbon sequestration strategies. The models are intended as educational tools, and results are intended for comparison of the impacts of various sequestration strategies.

We will begin with concentrated information gathering in communities near pilot projects. We will conduct focus groups with opinion leaders and decision-makers in the communities to identify relevant (1) local knowledge and (2) local opinion. We will use transcripts from those focus groups, along with existing NETL materials, to construct a questionnaire for distribution to a random sample of the population in relevant communities. Questionnaires will be administered by telephone. We will use the results of this information gathering to guide information dissemination and community-based activities.

In cooperation with NETL’s national efforts, we will work with local media outlets to develop quarterly press releases, potential radio/television segments. We also will invite local media to attend workshops & community events. We will expand and revise the SWP web site to include interactive capabilities. We will encourage science teachers to use the web site as appropriate to their curriculum. The website will include an education section with supplementary curriculum materials and guides for science teachers. The website also will provide public access to the system model (see below). We will develop and disseminate a library of interactive CO_2 sequestration tutorials on CD. These tutorials include digital field trips, demonstrations of best practices, and self-teaching modules. Field trips allow users to interact with the site; best practice modules are broken down into small tasks with recognized experts demonstrating proper procedure; and self-teaching modules include interactive opportunities for self-evaluation. We will encourage teachers, industry partners, and local community leaders to use this library. We also will make it available to local commercial media.

We will develop print materials for distribution at community events. Both to enhance credibility and to maximize convenience for community members, we will use existing venues, rather than scheduling additional meetings. Distribution methods can range from providing a guest speaker to providing written materials to hand out. Organizations to target include school districts, chambers of commerce, environmental groups, parent-teacher organizations, and county/city governments. We will recruit decision makers, policy leaders, and members of the attentive public for expanded participation in mediated modeling activities. During Phase I we worked with industry to develop and test a preliminary system model. We will continue model development with an expanded group of stakeholders.

Broad inclusion in mediated modeling alternatives will enable us to directly involve interested community residents in determining what factors should be considered, and how those factors relate to each other. It provides opportunities for participants to discover common ground and negotiate mutual benefits. By working within a learning format, participants with varied values, interests, and insights can establish commonalities with diminished fear of practical, political impacts. The workshops deepen participants' understanding of the potential impacts CO_2 sequestration projects may have on the quality of life experienced by residents. The experience has immediate benefits, as community members gain a sense of ownership over the process and resulting decisions. At the conclusion of the project, we will engage in a mirrored set of concentrated information gathering activities. We will again conduct focus groups with opinion leaders and decision-makers, and we will administer questionnaires to the broader public. Analysis of the resulting data will be used to determine

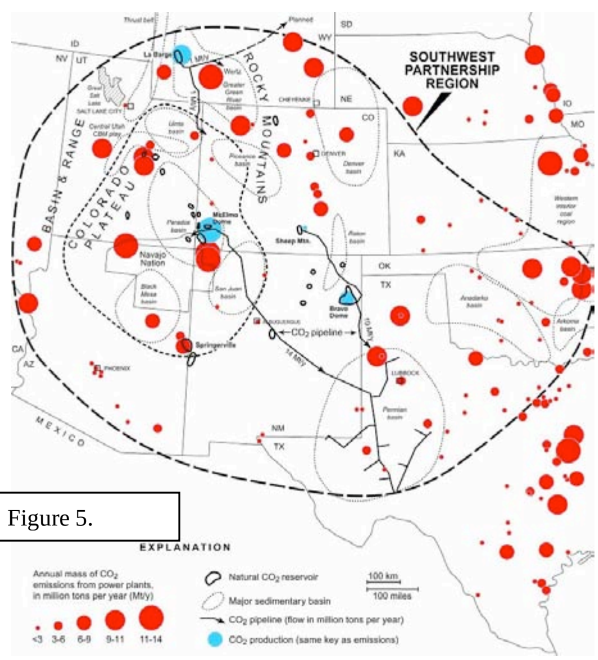


Figure 5.

how public perceptions of CO_2 sequestration (in communities near pilot projects) have changed during the pilot project.

2. CHARACTERIZATION OF REGION AND EVALUATION OF OPPORTUNITIES

The SWP region includes all of Arizona, Colorado, Kansas, New Mexico, Oklahoma, and Utah, roughly one-third of Texas, and significant portions of southern Wyoming and eastern Nevada (Figure 5). The SWP comprises a large, diverse group of expert organizations and individuals specializing in carbon sequestration science and engineering, and public policy and outreach.

Southwest CO_2 Sources: The region is energy-rich and possesses one of the largest population and energy-production growth rates in the nation. Two major CO_2 pipeline networks transport more than 30 million tons/year of natural, subsurface CO_2 from southern Colorado and northern New Mexico to petroleum fields in the Permian Basin, where it is used for enhanced oil recovery. The 10 largest coal-fired power plants in the region produce about 140 million tons of CO_2/year, with roughly 50% of that coming from fossil fuel combustion. Other point sources include natural gas processing plants, refineries, and ammonia/fertilizer, ethylene and ethanol, and cement plants. More than 40 databases were integrated into the main SWP database.

Sequestration Sinks and Aggregate GHG Storage Potential: The *geologic sinks* data were collected in modified GASIS databases, one for each state. Only hydrocarbon fields with 2003 cumulative productions that exceeded 1 million barrels of oil or 10 billion cubic feet of gas were considered large enough for further analyses. Colorado's data are typical of the detail available for each state, and thus we summarize Colorado's GHG sink potential, for sake of example of our Phase I regional characterization and the basis for continued Phase 2 characterization activities.

Although CO_2 sink potential is widely distributed across Colorado, data collection focused on seven primary study areas. These areas were chosen on the basis of maximum diversity in potential sequestration options that were within 50 miles of a power plant. The estimated CO_2 sequestration capacity of the seven study areas exceeds 150 billion tons, providing the potential for several hundred years of carbon storage based on 1999 emission levels (Table 3).

Of the 223 oil and gas fields in the Colorado database, 122 are located within 30 miles of a large, coal-burning power plant and are deep enough to maintain CO_2 at supercritical conditions. The preliminary forecast of CO_2 capacity for oil and gas reservoirs in the seven study areas is 443 million tons with more than 80% of that capacity contained in the Denver, Ignacio, and Rangely study areas. This was determined by converting all liquid production to thousand cubic feet gas equivalent at surface conditions (Mscf), combining this volume with gas production, and applying a conversion factor of 17.15 Mscf per ton CO_2. These CO_2 capacity calculations are conservative due to underestimation of water production.

Table 3. Estimated Carbon Sequestration Capacity for Colorado
(in Million Short Tons)

1999 Emissions		**Geologic**			**Mineralization**		**Total Capacity**
		Oil & Gas	**CBM**	**Saline Aquifers**	**Silicates**	**Produced Waters**	
Canon City	12	0	0	22,300	2,200		24,500
Craig	10	9	0	9,300	30,000	0.001	39,309
Denver	7	183	0	22,600		<0.001	22,783
Fort Morgan	5	16	0	8,700		<0.001	8,716
Ignacio	29	93	838	15,800		0.009	16,731
Palisade	1	56	8	22,800	200	<0.001	23,064
Rangely	4	86	1	19,300		0.015	19,387
Total	***68***	***443***	***847***	***120,800***	***32,400***	***0.026***	***154,490***

One of the most promising sequestration options is in coal beds at depths greater than 2,000 ft. The preliminary forecast of CO_2 sequestration capacity for coalbed methane reservoirs in Colorado is 847 million tons with nearly all of that capacity associated with the Fruitland coal play in the Ignacio study area. This estimate of capacity was made by assuming that four CO_2 molecules would replace one methane molecule in the coal matrix. The process is far more complicated and requires a reservoir simulator to be calculated accurately. This CO_2 capacity calculation is conservatively low due to the absence of significant coalbed methane production in emerging basins in the state.

ECBM: The first CO_2-enhanced coal bed methane (ECBM) production occurred in the New Mexico portion of the San Juan Basin (SJB) in 1995. At Burlington's Allison Unit more than 100,000 tons of CO_2 were injected over a three-year period to enhance production of coalbed methane. The CO_2 is now sequestered in the coal at depths in excess of 3,000 ft. Critical factors for sequestration include coal seam continuity, cleat permeability, coal shrinkage/swelling, gas adsorption/desorption, and seal integrity. The SJB is one of the top ranked basins in the world for CO_2 coalbed sequestration because it has: 1) advantageous geology and high methane content; 2) abundant anthropogenic CO_2 from nearby power plants, 3) low capital and operating costs; 4) well developed natural gas and CO_2 pipeline systems; and 4) local companies, e.g., Burlington, with CBM and ECBM expertise. Selection of potential coal bed methane CO_2 sequestration sites in the SJB is difficult without the detailed CBM knowledge and reservoir studies because: 1) the coal seams are discontinuous; 2) all coalbed methane production from the Fruitland Formation in the SJB is now reported as coming from a single pool (= gas field) by the New Mexico Oil and Gas Commission, making it difficult to know how much methane has been produced from a single reservoir. We thus propose a SJB ECBM pilot test for Phase 2 validation testing.

Terrestrial sequestration: Terrestrial carbon capacity in the region is limited by low average annual precipitation and yearly variability in precipitation. Even in systems managed for carbon storage, wet years followed by a series of dry years may result in a net carbon flux from the system. There is limited opportunity to increase carbon storage on rangelands because most areas are at a relatively stable equilibrium given land use history and management. Much of the desert grassland and shrubland areas with less than 12 inches of annual precipitation is subject to loss of cover and exposure to wind and water erosion. Retaining soil carbon levels in these ecosystems will require active restoration practices that are risky and unreliable given the current technologies.

CO_2 mineralization engineering: mineralization, the process by which CO_2 is bound in a solid, is an integral component of regional CO_2 storage options. Above-ground mineralization using cations extracted from either produced waters (e.g., brines) or mined ores (e.g., silicates) offers two potential roles for engineered long-term storage. Although no workable process currently exists for these options, ongoing research in both areas is encouraging. Phase I regional analyses of mineralization opportunities suggest these approaches are not economic at this time.

Plans for Continued Characterization of Region: The SWP continues to refine GHG *sequestration capacity data* on a state-by-state basis. Our approach accounts for both economic tradeoffs and value-added benefits. We have developed a regional model that characterizes CO_2 sources, the geologic sinks, and the costs associated with sequestration options. Sources are characterized by annual CO_2 emissions, power plant efficiency, age of plant, and location. Sink characterization includes location, depth, volume, injectivity, sequestration capacities, and risk of leaks (based on geologic parameters). Cost equations for CO_2 separation, collection, transport, and injection based on emissions volumes have been developed based on information collected from relevant literature, and verified by members of the Physical Infrastructure and Sources Committee. These equations have been used to develop prototype cost algorithms for the regional integrated assessment model, and will be evaluated for the test area. These models have been vetted in workshops and web conferences to increase understanding by external parties, and to get input on desired interfaces – what elements of the model are accessible by users to explore different "what if" questions about sequestration alternatives.

The SWP proposes for Phase 2 to continue its *regional characterization* and *data collection* efforts on a state-by-state basis. These data are added to our GIS database by the Utah Automated Geographical Reference Center. These, in turn, are fed into the NATCARB database. For example, during Phase 1, Colorado focused on the seven key areas. During Phase 2, Colorado will add more detail to sinks throughout the entire state. New Mexico has refined the search engine in the GASIS Database to find fields that meet or exceed ten key criteria for CO_2 sequestration. They have also refined a procedure for estimating CO_2 sequestration capacity based on produced fluids. Those capacity numbers are now part of its database and can be searched by the new search engine. A procedure manual and spreadsheet for calculating these capacities is in draft form and will be circulated throughout the SWP shortly.

Value-Added Benefits and How Phase 1 Led to Phase 2 Field Pilot Options: Based on Phase 1 activities, the SWP is proposing three geologic pilot tests and two terrestrial pilots from an original regional list of 12, which included high potential projects in Wyoming, Arizona, Utah, New Mexico, Oklahoma, Texas, and Kansas. The SWP used an integrated assessment approach for ranking potential pilot tests, factoring in storage capacity, risk assessment and mitigation potential, costs and economic tradeoffs, proximity to sources, and other factors. The chosen pilots described in the previous section of the proposal provide distinct *value-added benefits*, including of enhanced methane production and enhanced oil production. An environmental value-added benefit is associated with cleanup of ECBM-produced brines and application of the desalinated water for a terrestrial pilot test consisting of re-vegetation of nearby riparian areas. A less obvious value-added benefit of the ECBM pilot is that the pilot test site is located wholly within a BLM Area of Critical Environmental Concern (ACEC), meaning that we will have to satisfy stringent environmental regulations in order to sequester CO_2. The best practices that are learned at the San Juan ECBM pilot could become the model for environmentally-friendly sequestration guidelines in future projects.

3. PROJECT PLAN AND APPROACH

A. OBJECTIVES

The Southwest Regional Partnership on Carbon Sequestration proposes to carry out five field pilot tests to validate the most promising sequestration technologies and infrastructure concepts, including three geologic pilot tests and two terrestrial pilot programs. This field-testing will demonstrate efficacy of proposed sequestration technologies to reduce or offset greenhouse gas emissions in the region. Risk mitigation, optimization of MMV protocols, and effective outreach and communication are additional critical goals of these field validation tests.

B. SCOPE OF WORK

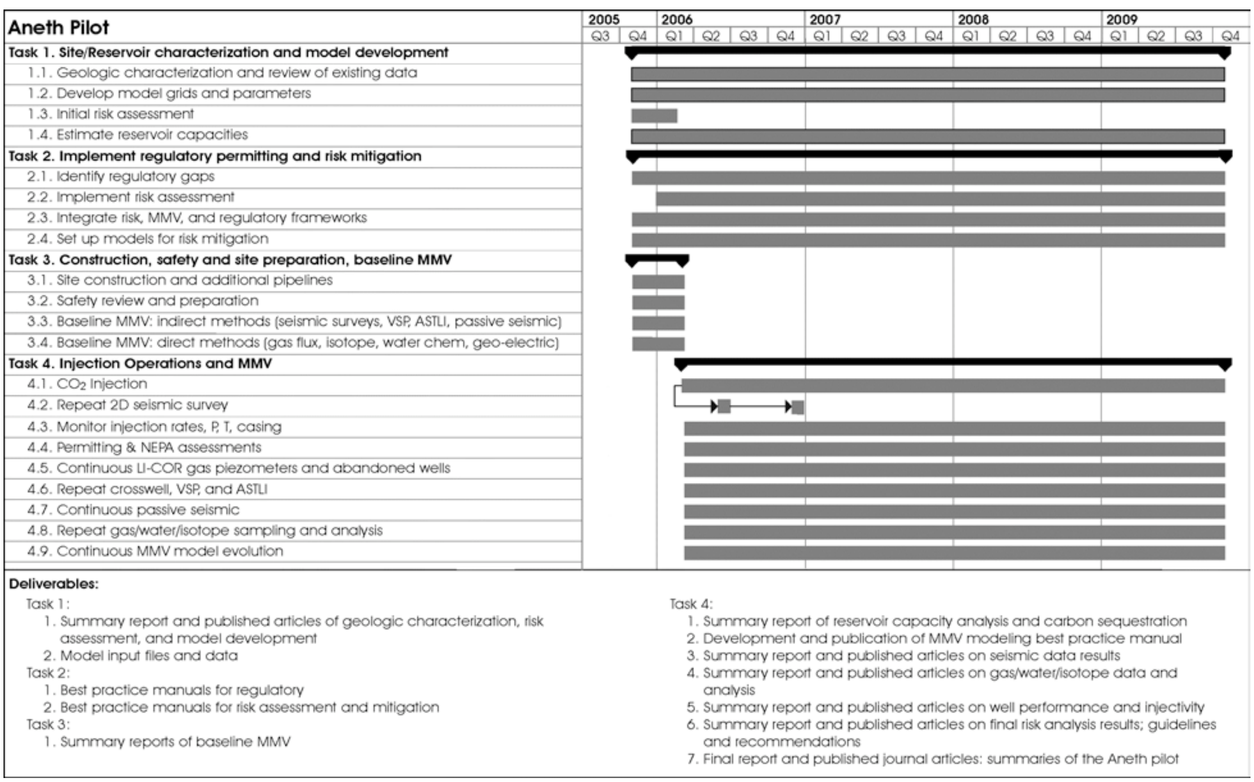
The Southwest Partnership proposes a truly regional approach for its technology validation program, including geologic pilot tests located in Utah, New Mexico, Texas, and a region-wide terrestrial analysis. Each geologic sequestration test will include injection of a minimum of ~75,000 tons/year to ~150,000 tons/year CO_2, with a minimum injection duration of one year.

C. TASKS TO BE PERFORMED AND DELIVERABLES

The SWP will carry out six major tasks, including five proposed carbon sequestration field validation pilot tests. A sixth major task is the extensive Outreach and Education program necessary for effective communication with the public, regulators, and other stakeholders. The suite of pilot tests will be conducted over four years' time, and the individual tasks and subtasks associated with each pilot will overlap to some degree. Additionally, scheduling of pilots was made to meet the business plans or needs of field operators. Thus, while the proposed SWP program will have two distinct budget phases, its technical phases will be relatively continuous. The SWP program is extremely large with dozens of tasks and deliverables, because of the number and breadth of the six major projects. Thus, for brevity we will use Gantt charts to summarize each of these major projects.

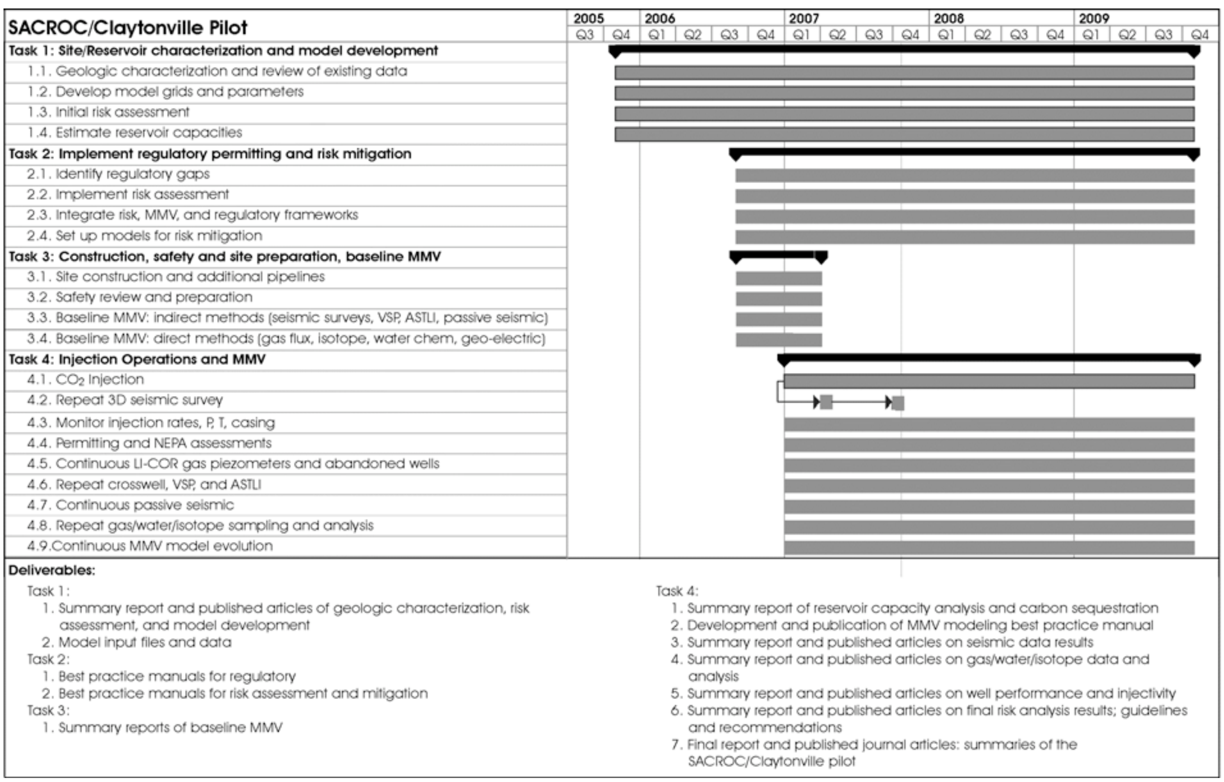
Major Task 1: Aneth EOR / Deep Saline Pilot Test

Our first pilot test will be a combined EOR – Deep Saline sequestration pilot injection test, to be conducted in the Aneth Field near Bluff, Utah. The operators of the field, Resolute Natural Resources Company and the Navajo Nation Oil and Gas Company, will work with the SWP and inject up to 150,000 tons per year for 3.5 years. The SWP will conduct extensive MMV studies, including a suite of direct techniques (direct CO_2 flux measurements) and indirect techniques (e.g., seismic methods). MMV design will depend on baseline MMV measurements and detailed reservoir models based on extensive geological characterization. Tasks, subtasks, and associated deliverables are detailed in the Gantt chart below. The pilot will begin in November, 2005, and conclude in November, 2009. The overall project goals are to validate sequestration technologies, including MMV and risk mitigation approaches, and to identify regulatory gaps. The tasks listed below tackle these objectives explicitly.



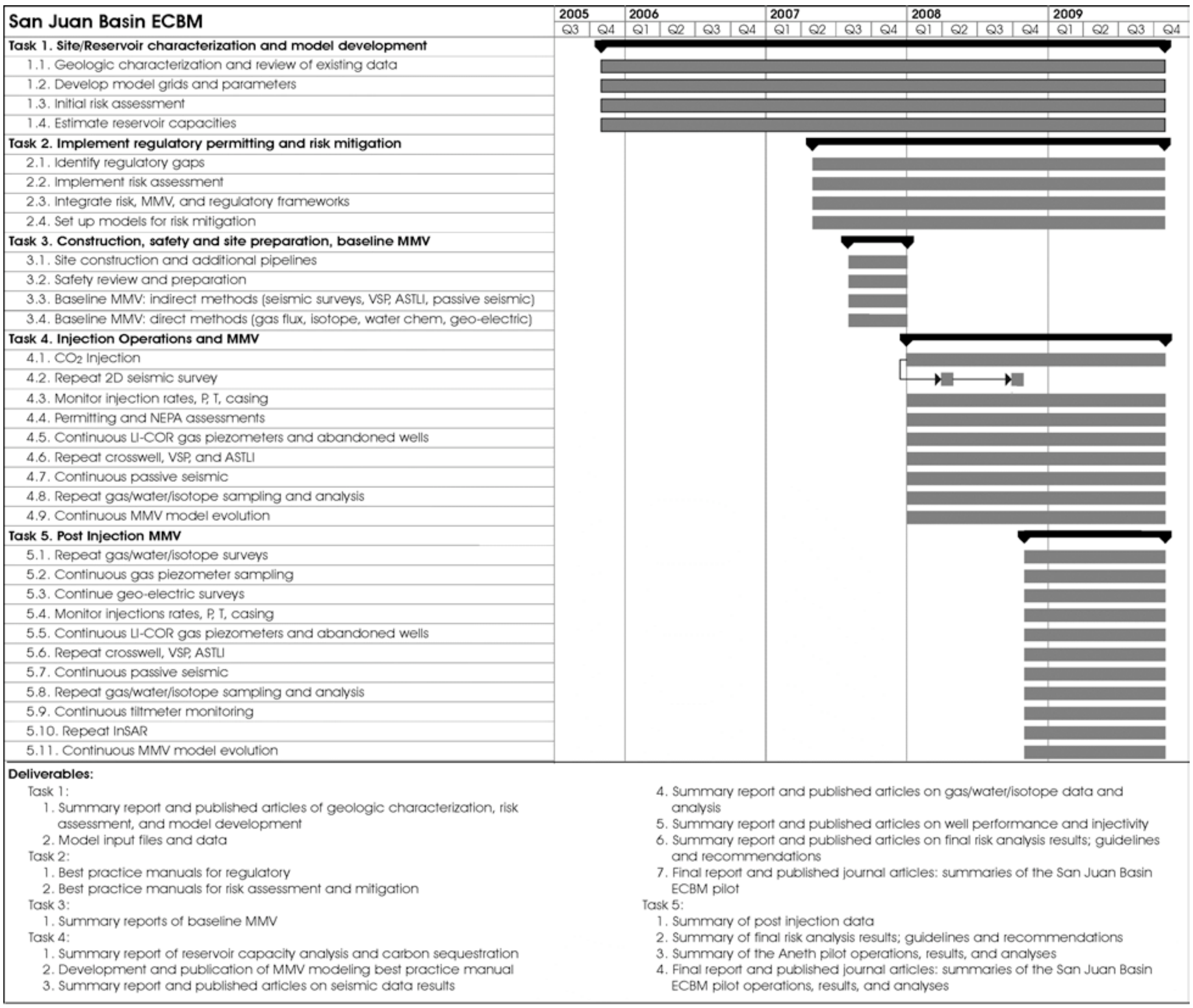
Major Task 2: SACROC - Claytonville EOR - CO_2 Sequestration Pilot Test

The second SWP geologic field pilot is the SACROC-Claytonville pilot test, in which we will evaluate enhanced oil recovery efficiency with concomitant CO_2 storage efficacy. The pilot is scheduled to begin in January, 2007 and will continue until project end, November of 2009. The details of tasks and deliverables for these projects are listed in the following Gantt chart. MMV design will depend on baseline MMV measurements and detailed reservoir models already begun by SWP partners Texas BEG and ARI. The geology of Aneth and the SACROC-Claytonville fields are slightly similar (carbonate reservoirs), but their depth ranges are different and offer very different hydrodynamic settings. A particular goal of MMV for the SACROC-Claytonville pilots, similarly, is to examine 3-D seismic efficacy and compare these seismic results to 2-D seismic efficacy at the other two geologic pilot sites. Among the project's goals is to compare MMV approaches and efficacy for a diversity of settings. General project goals are to validate sequestration technologies and employ risk mitigation approaches.



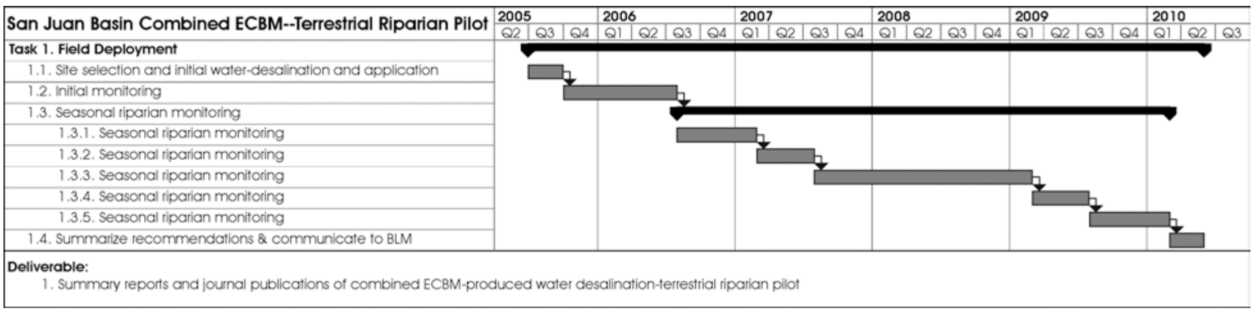
Major Task 3: San Juan Basin Enhanced Coalbed Methane – CO_2 Sequestration Pilot Test

The third SWP geologic field pilot is the San Juan ECBM pilot test, in which we will evaluate coalbed methane production efficiency with concomitant CO_2 storage efficacy. Pilot CO_2 injection is scheduled to begin around January, 2008, and continue for one year. Plans include injection of ~75,000 tons CO_2 during that year. Burlington will carry out this project exclusively for the SWP, including drilling an injection well for the pilot. This pilot, like the others planned, is intended to test a suite of MMV approaches tailored for its unique geology (coalbeds) and value-added benefit (methane production). Additional objectives include detailed risk assessment and mitigation plans, and to identify regulatory gaps for ECBM and CO_2 sequestration. Tasks and deliverables address these objectives explicitly:



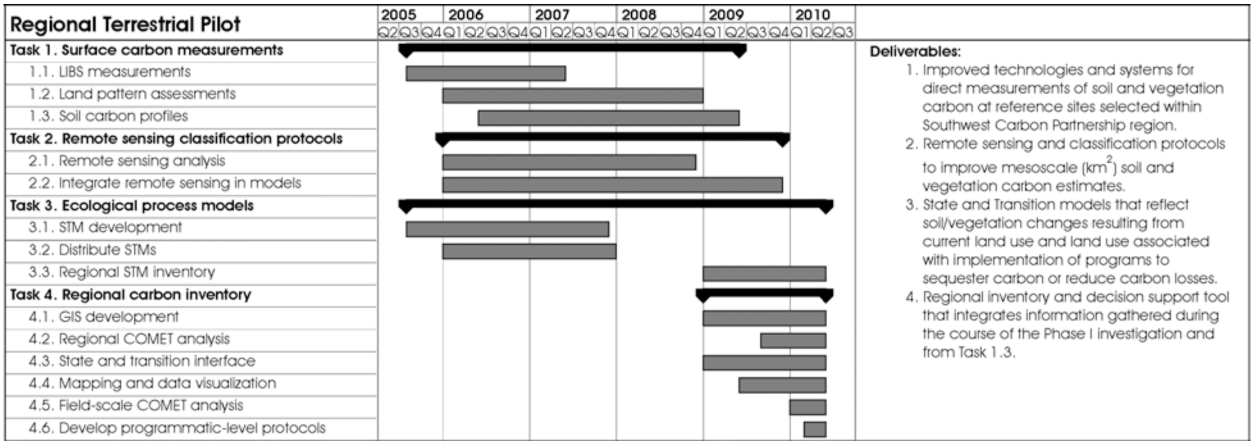
Major Task 4: San Juan Basin Terrestrial Sequestration Pilot

An additional pilot test planned for the San Juan basin is a local terrestrial sequestration pilot test. We propose a riparian area restoration project tied to the ECBM pilot test. Specifically, produced water from the San Juan basin will be desalinated and applied to a riparian area and CO_2 sequestration monitored and evaluated. While the ECBM pilot injection will begin in January, 2008, the terrestrial pilot will begin at the start of the Phase 2 program. Initial testing will involve produced water from other SJB wells, but will ultimately involve the production wells of the ECBM pilot. The overall project goals are to validate sequestration technologies, including MMV and risk mitigation approaches, and to identify regulatory gaps. The tasks listed below tackle these objectives explicitly.



Major Task 5: Regional Terrestrial Pilot

The SWP will continue its terrestrial analyses from the Phase 1 project, and will leverage results of that initial analysis for a comprehensive regional pilot. Goals for this pilot include improved technologies and systems for direct measurements of soil and vegetation carbon, remote sensing and classification protocols to improve mesoscale (km^2) soil and vegetation carbon estimates, state and transition models that reflect soil/vegetation changes resulting from current land use and land use associated with implementation of programs to sequester carbon or reduce carbon losses, and finally a regional inventory and decision support tool that integrates information gathered during the course of the Phase I project. The tasks and deliverables summarized below address these goals.



Major Task 6: Outreach and Education Plans

The SWP plans to implement a comprehensive outreach and education plan, designed to maximize awareness of sequestration opportunities in the southwest and provide stakeholders information about proposed deployment efforts and possible future efforts. All outreach tasks will begin at the start of the Phase 2 project and run continuously till the end of Phase 2, as depicted in the Gantt chart. The SWP will comply with NEPA and regulatory permitting public involvement requirements as appropriate. The SWP has developed an action plan for all pilots describing the effort required to inform and educate the public.

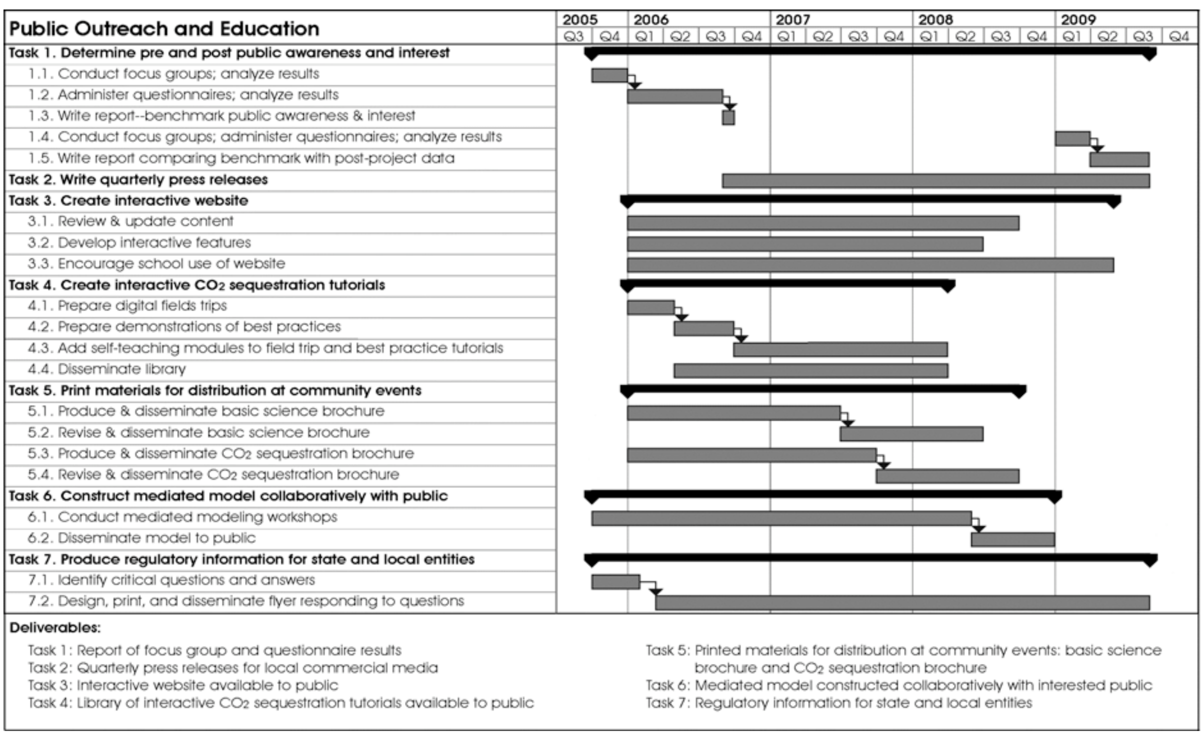


Table 1. Estimated labor hours and categories for each pilot project task.

Pilot	*Aneth*				*SJB-ECBM*				*SJB-Terrestrial*				*SACROC/Claytonville*			
Task	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4
PI/Project Manager	231	231	231	231	231	231	231	231	231	231	231	231	231	231	231	231
Eng. & Eco.*	622	622	622	622	1448	1448	1448	1448	589	589	589	589	1497	1497	1497	1497
Technician	179	179	179	179	335	335	335	335	179	179	179	179	833	833	833	833
Scientific	3913	3913	3913	3913	4500	4500	4500	4500	2780	2780	2780	2780	3972	3972	3972	3972
Clerical	0	0	0	0	83	83	83	83	0	0	0	0	87	87	87	87

Pilot	*Regional Terrestrial*				*Outreach & Education*					
Task	1	2	3	4	1	2	3	4	5	6
PI/Project Manager	231	231	231	231	154	154	154	154	154	154
Eng. & Eco.*	662	662	662	662	0	0	0	0	0	0
Technician	1539	1539	1539	1539	0	0	0	0	0	0
Scientific	4690	4690	4690	4690	0	0	0	0	0	0
Clerical	0	0	0	0	0	0	0	0	0	0
Outreach specialist	0	0	0	0	587	587	587	587	587	587

*Economists and some engineers are working on economic aspects.

Cost-share Contributions to Phase 2

Colorado Geol. Survey	$35,046	In Kind
ARI	$144,300	Software
Utah Geol. Survey	$107,500	In Kind
Gas Technology Institute	$111,449	In Kind
Resolute Natural Resources	$289,030	In Kind
Texas A&M University	$264,461	In Kind
University of Utah	$100,769	In Kind
The CRUX	$43,072	In Kind
Texas BEG	$250,000	In Kind
Steve Hook	$45,000	In Kind
Western Governors Association	$30,000	In Kind
Burlington Resources	$447,500	In Kind
Kinder Morgan CO2	$889,240	In Kind
Pinnacle	$84,000	In Kind
Los Alamos National Lab	$0	NONE
Sandia National Lab	$305,000	In Kind
NMIMT	$448,658	Cash

Table 2. Cumulative proposed travel for the entire duration of the Phase 2 Project.

Organization	*NMIMT*	*Sandia*	*LANL*	*ARI*	*AZU*	*BREDEHOEFT*	*CRUX*
Purpose	DC/ RM/PM	DC/ RM/PM	DC/ RM/PM	DC/ RM/PM	DC/ RM/PM	DC/ RM/PM	RM/PM
No. trips	137	35	60	15	2	12	37
Origin	Socorro, NM	ABQ	Los Alamos, NM	HOU	Tempe, AZ	Sausalito, CA	College Station, TX
Destination	FIELD/ABQ, WDC, HOU, WVA ,SLC, OK	FIELD/ABQ/WDC, HOU, WVA	FIELD/ABQ/WDC, HOU, WVA	FIELD/ABQ/WDC, WVA	FIELD/ABQ/WDC, HOU, WVA	FIELD/ABQ/WDC, HOU, WVA	ABQ/WDC, HOU, WVA
Duration	2-3 days	2 days	2 days	2 days	2 days	2 days	2 days
Personnel	2	2	1	1	1	1	1
Organization	*CGS*	*UGS*	*GTI*	*TAMU*	*BEG*	*WGA*	
Purpose	DC/ RM/PM	DC/ RM/PM	RM/PM	DC/ RM/PM	DC/ RM/PM	RM/PM	
No. trips	19	40	13	12	54	26	
Origin	Denver CO	SLC	Des Plaines, IL	College Station, TX	Austin TX	Denver, CO	
Destination	FIELD/ABQ/WDC, HOU, WVA	FIELD/ABQ/WDC, HOU, WVA	ABQ/WDC, HOU, WVA	FIELD/ABQ/WDC, HOU, WVA	FIELD/ABQ/WDC, HOU, WVA	ABQ/WDC, HOU, WVA	
Duration	2 days	2 days	2 days	2 days	2 days	2 days	
Personnel	1	1	1	1	1	1	

Key: DC = collection; RM = review meetings; PM = professional meetings; FIELD = field locations for pilot sites; ABQ = Albuquerque, NM; HOU = Houston, TX;
MWV = Morgantown, WV; WDC = Washington, DC; SLC = Salt Lake City, UT; OK = Oklahoma City, OK

Management Tools and Inter-Partnership Technical Working Group Participation

Standard management tools will be used to coordinate and manage the project, by key personnel described in the following section. Technical communication and inter-partnership communication will continue with Partnership technical working groups organized in Phase 1.

4. REGIONAL PARTNERSHIP COMPOSITION, TECHNICAL, AND MANAGEMENT

Credentials, Capabilities, and Experience of the Organizations Involved

The Southwest Regional Partnership on Carbon Sequestration (SWP) comprises a diverse group of expert organizations specializing in carbon sequestration science and engineering, as well as economics, public policy and outreach. These partner organizations are drawn from: 1) industry, 2) State governmental agencies and universities, 3) U.S. Federal government entities, and 4) other specialized partners like the Western Governors Association. All Partner organizations in the SWP played key roles in the Phase I program, and thus a wealth of experience is ready for the Phase 2 field validation testing program. A new priority for Partnership success in Phase 2 is strong participation by industry partners. Industry assistance and collaboration is critical for the proposed field validation and verification testing of sequestration technologies. Key industry partners in the proposed Phase 2 validation testing include Kinder Morgan CO_2 L.P. (KinderMorgan), Burlington Resources, Inc., Resolute Natural Resources Company, and the Navajo Oil and Gas Company, all of whom are operators of proposed field pilot test sites. Also paramount to Phase 2 success is continued collaboration on the part of power companies such as Public Service Co. of New Mexico (PNM), Pacificorp, Intermountain Power Agency, Tucson Electric Power, and Oklahoma Gas & Electric, all of whom have agreed to continue as Phase 2 SWP partners.

Credentials, Capabilities, Experience and Availability of Key Personnel

The Partnership will retain most of its key personnel from Phase 1 activities for the proposed Phase 2 pilots. All key personnel are amply prepared for Phase 2 validation testing by their active roles in the Phase I SWP program. Additional management personnel added for the Phase 2 tasks, the five pilot projects proposed, are key managers and points-of-contact for project site operators. These include **Mike Hirl** of KinderMorgan – SACROC-Claytonville pilot, **Steve Malkewicz** of Resolute – Aneth pilot, **Wilson Groen** of the Navajo Nation Oil and Gas Company – Aneth pilot, **Jim Schlabaugh** of Burlington – San Juan basin ECBM pilot, **Joel Brown**, U.S. Department of Agriculture – Regional terrestrial pilot, and **Joe Hewett**, U.S. Bureau of Land Management – San Juan terrestial pilot. All proposed project personnel available to the degree indicated for the 48-month duration of the project, assuming that the project begins approximately November 1, 2005. Details of the affiliations, credentials, capabilities and experience of key personnel are outlined in the resumes provided in attached file “resumes.doc.”

Project Organization, Structure and Diversity of Abilities

The project is organized within a set of nested and interacting management units that integrates the technical and geographic breadth of the project team. Project vision and overall technical management will be handled by an Executive Steering Committee (ESC) that comprises representatives drawn from each principal Partner. The ESC will also work with the National Energy Technology Lab. (NETL), the

Western Governor's Association and all regional State geological surveys to ensure continuity across State boundaries as the Partnership performs its pilot testing and continued regional characterization.

Similar to Phase 1 operations, core working groups will form, one for each of the five proposed pilot tests, and these working groups will meet frequently. The ESC will meet at least three times per year.

Prior Experience in Project Management

While overall technical management will be addressed by the ESC, day-to-day project management will be handled by the New Mexico Institute of Mining and Technology. Project Manager and PI **Dr. Brian McPherson** has several years experience in research management and is currently PI for the Southwest Regional Partnership on Carbon Sequestration, Phase I, and has managed two other large CO_2 sequestration projects. Utah Co-PI **Dr. Rick Allis** is Director of the Utah Geological Survey, just concluded serving as co-Principal Investigator of a DOE CO_2 sequestration project in the partnership region, and has considerable experience in project management with large teams. Leader of the GIS/Database initiative, **Dr. Dennis Goreham**, manages one of the most recognized GIS centers in the nation (UT AGRC) and Co-chairs the Western Governor's Association Geographic Information Council. Other key management personnel from the Partnership include co-PI **Karen Deike** of the Western Governors' Association, Assistant Project Manager for Field Operations **Dick Benson,** co-PI **Dave Borns** of Sandia National Lab, co-PI **Mark Holtz** of the Texas BEG, co-PI **Bob Siegfried** of GTI, and co-PI **Tarla Peterson** of the University of Utah. Resumes are attached in the file "resumes.doc."

Facilities, Equipment and Materials

The SWP has some of the facilities and equipment necessary for carrying out the required Phase 2 tasks. Otherwise, we have budgeted for all necessary field equipment and vendors required to carry out the proposed pilots and MMV activities. For databases, the Utah Automated Geographic Reference Center (AGRC) will continue to host the Southwest Region's databases. Outreach will be facilitated using the existing outreach and education mechanisms in place via Phase 1 activities, with outreach support offered by Western Governors' Association.

Appendix A – Arizona Regulatory Summary (General)

TITLE 12. NATURAL RESOURCES

CHAPTER 7. OIL AND GAS CONSERVATION COMMISSION

(Authority: A.R.S. § 27-514 et seq.)

ARTICLE 1. OIL, GAS, HELIUM, AND GEOTHERMAL RESOURCES

Section

ARTICLE 2. REPEALED

Article 2, consisting of R12-7-201 through R12-7-221, R12-7-231 through R12-7-234, R12-7-241 through R12-7-246, R12-7-251, R12-7-252, R12-7-261 through R12-7-264, R12-7-271, R12-7-272, R12-7-281, R12-7-291 through R12-7-294, and Appendix 1, repealed effective January 2, 1996 (Supp. 96-1).

ARTICLE 1. OIL, GAS, HELIUM, AND GEOTHERMAL RESOURCES

R12-7-101. Definitions

In this Chapter, unless the context otherwise requires:

"API" means American Petroleum Institute.

"Barrel" means 42 (US) gallons measured at 60° F and atmospheric pressure at sea level.

"BTU" means British thermal unit and represents the quantity of heat required to raise the temperature of 1 pound of water 1° F at or near 39.2° F.

"Condensate" means liquid hydrocarbons recovered at the earth's surface as a result of condensation due to reduced pressure or temperature of petroleum hydrocarbons that exist in a gaseous phase in subsurface reservoir rocks.

"Cubic foot of gas" means the volume of gas contained in 1 cubic foot of space at a standard pressure base of 14.73 pounds per square inch absolute and a standard temperature base of 60° F.

"Gas well" means a well that produces with a gas-oil ratio in excess of 50,000 cubic feet of gas per barrel of oil.

"Injection well" means a well used to inject air, gas, water, or other substance into an underground stratum.

"Mcf" means 1000 cubic feet of gas reported at a pressure base of 14.73 pounds per square inch absolute and a standard temperature base of 60° F.

"Oil well" means a well that produces with a gas-oil ratio less than 50,000 cubic feet of gas per barrel of oil.

"Operator" means any person authorized by an owner to control the day-to-day activities of a well or production or refining facility.

"Shut-in well" means a well that is capable of production in paying quantities, is completed as a producing well, and is not presently being operated.

"Stratigraphic test or core hole test" means drilling a hole for the sole purpose of obtaining geological information.

"Temporarily abandoned well" means a well that is not capable of production in paying quantities and is not presently being operated.

Historical Note

Former B; Former Section R12-7-101 renumbered and amended as Section R12-7-102, former Section R12-7-100 renumbered and amended as Section R12-7-101 effective September 29, 1982 (Supp. 82-5). Amended effective January 2, 1996 (Supp. 96-1). Amended by final rulemaking at 6 A.A.R. 4827, effective December 7, 2000 (Supp. 00-4).

R12-7-102. Repealed

Historical Note

Former 101; Former Section R12-7-102 renumbered and amended as Section R12-7-103, former Section R12-7-101 renumbered and amended as Section R12-7-102 effective September 29, 1982 (Supp. 82-5). Repealed effective January 19, 1994 (Supp. 94-1).

R12-7-103. Bond

A. An operator shall file a performance bond with the Commission prior to approval of a permit to drill a new well, re-enter an abandoned well, or assume responsibility as operator of existing wells. The bond amount shall be $10,000 for a well drilled to a total depth of 10,000 feet or less, $20,000 for a well drilled deeper than 10,000 feet, or $25,000 as a blanket bond to cover all wells and shall be payable to the Oil and Gas Conservation Commission, State of Arizona, and conditioned upon the faithful performance by the operator of the duty to drill each well in a manner to prevent waste, plug each dry or abandoned well, repair each well causing waste or pollution, and maintain and restore the well site.

B. The Commission shall accept a bond in the form of a surety bond, executed by the operator as principal and a corporate surety authorized to do business in Arizona, a certified check, or a certificate of deposit at a federally insured bank authorized to do business in Arizona.

C. Transfer of property does not release the bond. If a property is transferred and the principal desires to be released from the bond, the procedure shall be as follows:

1. The principal on the bond shall notify the Commission in writing of the proposed transfer, giving the location of each well, the date and number of each permit to drill, and the name, address, and telephone number of the proposed transferee.
2. The transferee of any well or of the operation of any well shall declare to the Commission in writing acceptance of the transfer and of the responsibility of each well and shall submit a new bond or bonds unless the transferee's blanket bond applies to the well or wells.
3. When the Commission approves the transfer, the transferor is released from all responsibility with respect to the well or wells, and the Commission shall notify the principal and the bonding company in writing that the transferor's applicable bond or bonds are subject to release.

Historical Note

Former Rule 102; Former Section R12-7-103 renumbered and amended as Section R12-7-104, former Section R12-7-102 renumbered and amended as Section R12-7-103 effective September 29, 1982 (Supp. 82-5). Amended effective January 19, 1994 (Supp. 94-1).

R12-7-104. Application for Permit to Drill

A. Before drilling or re-entering any well or conducting any surface disturbance associated with such activity, the operator shall submit to the Commission an application for permit to drill or re-enter and obtain approval. The complete application package shall contain:

1. An application for permit to drill on a form provided by the Commission, which shall include the operator's name, address, and phone number, and a description of the proposed well and its location;
2. A well and well-site construction plan that meets the requirements of R12-7-108 through R12-7-118;
3. A plat, prepared and certified by a registered surveyor bearing the surveyor's certificate number, on which is shown the exact acreage or legal subdivision allotted to the well as required by R12-7-107, the well's exact location, and its ground-level elevation;
4. An organization report as required by R12-7-194;
5. A performance bond, as required by R12-7-103; and
6. A fee of $25.00 per well.

B. The Commission shall mail to the applicant, within 30 days of receipt of the application required in subsection (A), written notice of administrative completeness or a detailed list of deficiencies. Within 30 days of receipt of all items required in subsection (A), the Commission shall review the application and:

1. Issue a permit to drill, or
2. Provide a written explanation in compliance with A.R.S. § 41-1076 to the applicant if the application is not approved.

C. Time-frames
1. The administrative review period is 30 days. The substantive review period is 30 days. The overall time-frame is 60 days.
2. For the purpose of this subsection, intermediate Saturdays, Sundays, and legal holidays shall be included in the time-frame computation. The last day of the notice period shall be included in the computation unless it is a Saturday, Sunday, or legal holiday.

D. Unless operations are commenced within 180 days after date of approval, the permit to drill shall become null and void unless an extension in writing is granted by the Commission.

E. In case of imminent danger to public safety or of contamination of the environment, the Commission may authorize the drilling of an emergency relief or offset well to reduce the danger or hazard. Within 10 days of commencing an emergency relief or offset well, the operator shall file an application as required in subsection (A). No well drilled under this subsection shall be used for production unless it conforms to the provisions of R12-7-107.

Historical Note

Former Rule 103; Former Section R12-7-104 renumbered and amended as Section R12-7-105, former Section R12-7-103 renumbered and amended as Section R12-7-104 effective September 29, 1982 (Supp. 82-5). Amended effective January 19, 1994 (Supp. 94-1). Amended effective June 6, 1997 (Supp. 97-2).

R12-7-105. Change of Location

A. No operator shall drill a well in a location other than that authorized by the permit issued pursuant to R12-7-104 until the following requirements have been met:
1. If the operator decides to change the location before drilling the well, an amended application for permit to drill shall be filed showing the new location.
2. If it is determined that the location is erroneously described on the permit after drilling has begun, the operator shall obtain a new permit showing the correct location.

B. If the new location is at an authorized point in the approved drilling unit as provided in the initial permit, the application may be made by electronic communication and the Commission may by electronic communication authorize the commencement or continuance of drilling operations. Within ten days after obtaining such authorization, the operator shall file an amended application showing the new location. An amended permit may be issued and the old permit cancelled without payment of additional fee.

C. If the new location is located outside the approved drilling unit covered by the initial permit, no drilling shall be commenced or continued until a new application for permit to drill is filed and approved as required by R12-7-104, including payment of an additional fee.

Historical Note

Former Rule 104; Former Section R12-7-105 renumbered and amended as Section R12-7-106, former Section R12-7-104 renumbered and amended as Section R12-7-105 effective September 29, 1982 (Supp. 82-5). Amended effective January 19, 1994 (Supp. 94-1).

R12-7-106. Identification of Wells, Producing Leases, Tanks, Refineries, Buildings, and Facilities

A. The operator shall mark each drilling, producing, injection, or shut-in well in a conspicuous place with the operator's name, lease name or number, well number, and the legal description of the well's location.

B. The operator shall mark each abandoned well as required in R12-7-127(F).

C. The operator shall mark all tank batteries, gasoline plants, structures, storage buildings, compressors, and compressor buildings, and all other storage or transportation equipment with the operator's name, address, telephone number, lease name or number, and location. All structures within a fenced yard may be identified by a single sign at the principal outside entrance to the yard.

D. The operator of a storage-well facility shall clearly mark each well with the operator's name, lease name or number, and well number. Each outside entrance to the facility shall be marked with the operator's name, address, and one or more emergency response telephone numbers.

E. The operator of a refinery shall mark each facility at each outside entrance with the operator's name, address, and one or more emergency response telephone numbers.

F. Sign lettering shall contrast strongly with the background and be large enough to be legible under normal conditions at a distance of 25 feet. The operator shall preserve these markings and keep them legible and up to date.

Historical Note

Former Rule 105; Former Section R12-7-106 renumbered and amended as Section R12-7-107, former Section R12-7-105 renumbered and amended as Section R12-7-106 effective September 29, 1982 (Supp. 82-5). Amended effective January 19, 1994 (Supp. 94-1).

R12-7-107. Spacing of Wells

A. Every well drilled for oil shall be located on a drilling unit consisting of approximately 80 contiguous surface acres within two governmental quarter-quarter sections or lots having one side in common, upon which there is not located, and of which no part is attributed to, any other well completed in or drilling to, the same pool.
1. In areas not covered by United States Public Land Surveys, the oil drilling unit shall consist of an area bounded by four sides intersecting at angles of not less than 85 degrees or more than 95 degrees. The unit shall contain at least 76 contiguous surface acres and its maximum dimension shall not exceed 3,000 feet.
2. No well drilled for oil shall be located closer than 330 feet to any boundary of the drilling unit or closer than 330 feet to the shortest center line of the drilling unit.
3. No well drilled for oil shall be located within a quarter-quarter section or lot having one side in common with another quarter-quarter section or lot upon which there is located a well completed in or drilling to the same pool.

B. Every well drilled for gas shall be located on a drilling unit consisting of approximately 640 but not less than 600 contiguous surface acres within one governmental section upon which there is not located, and of which no part is attributed to, any other well completed in or drilling to the same pool.
1. In areas not covered by United States Public Land Surveys, the gas drilling unit shall consist of an area bounded by four sides intersecting at angles of not less than 85 degrees or more than 95 degrees. The unit shall contain at least 600 contiguous surface acres and its maximum dimension shall not exceed 8,500 feet.
2. No well drilled for gas shall be located closer than 1,660 feet from any boundary of the drilling unit.

C. Every well drilled for geothermal resources shall be located on a drilling unit approved or as modified by the Commission. The Commission may require modification to minimize well interference and provide the necessary volume of geothermal resources for the intended use, to protect correlative rights, and to protect the environment.

D. If the operator drills a horizontal segment, that horizontal segment shall be located:
1. At least 330 feet from the boundary of the spacing unit in the case of an oil well;
2. At least 1,660 feet from the boundary of the spacing unit in the case of a gas well; and
3. As approved or modified by the Commission in the case of a geothermal well.

E. The Commission may grant exceptions to the regular locations specified in subsections (A), (B), and (C) only after notice and hearing.
1. Applications for exception shall fully state the reasons why the exception is necessary and shall include a plat prepared and certified by a registered surveyor bearing the surveyor's certificate number showing all other completed, drilling, and permitted wells on the property and all adjoining surrounding properties and wells.
2. Exceptions shall be granted only after the operator provides by certified mail a copy of the application to all adjoining lessees, and only after the Commission deter mines in a duly noted public hearing that the application is valid.
3. The Commission may grant an exception location without notice or hearing when topography prohibits drilling at a regular location on the drilling unit.
4. If an existing well's classification changes due to its recompletion or due to a change in the nature of the product being produced, the Commission may approve an irregular location application with supporting data and ten days' notice and hearing, provided that the operator furnish the Commission with proof of mailing of a copy of the application to all operators within a one-mile radius of the acreage to be dedicated.

F. In order to prevent waste, the Commission may, after notice and hearing, fix different spacing requirements and require lesser or greater acreage for drilling units in any specific oil, gas, or geothermal resource pool notwithstanding the provisions of subsections (A), (B), and (C).

G. The Commission may order pooling and integration of interests pursuant to A.R.S. §§ 27-505 and 27-666.

Historical Note

Former Rule 106; Former Section R12-7-107 renumbered and amended as Section R12-7-108, former Section R12-7-106 renumbered and amended as Section R12-7-107 effective September 29, 1982 (Supp. 82-5). Correction, paragraph (1) "No well drilled for oil shall be located within the bounds of a quarter-quarter section or lot . . ." (Supp. 82-6). Amended effective January 19, 1994 (Supp. 94-1).

R12-7-108. Pit for Drilling Mud and Drill Cuttings

A. Each operator shall maintain an adequate supply of drilling mud to confine oil, gas, or water to its native stratum during the drilling of any well and shall provide, before drilling is commenced, an adequate pit, either earthen or portable, for the drilling mud or the accumulation of drill cuttings.

B. An earthen pit used for drilling, deepening, testing, reworking, or fracturing shall be constructed of or sealed with an impervious material and shall be maintained to prevent escape of any contained substance. Earthen pits shall be fenced on all sides at all times.

C. Earthen pits shall be constructed and maintained to prevent the entrance of outside runoff water and the fluid level in earthen pits shall be kept at all times at least 18 inches below the lowest point of the embankment.

D. Any mud contained in an earthen pit shall be water-based and contain no more than one pound per barrel of thinner for each 25 pounds per barrel of barite or hematite. Mud containing chromium lignosulfonate, ferrochrome lignosulfonate or other chromium compounds shall not be used.

E. Drilling mud shall be disposed of by either recycling or commercial off-site disposal. Mud described in subsection (D) may be disposed of by evaporation and subsequent leveling of the pits.

Historical Note

Former Rule 107; Former Section R12-7-108 renumbered and amended as Section R12-7-109, former Section R12-7-107 renumbered and amended as Section R12-7-108 effective September 29, 1982 (Supp. 82-5). Amended effective January 19, 1994 (Supp. 94-1).

R12-7-109. Repealed

Historical Note

Former Rule 108; Former Section R12-7-109 renumbered and amended as Section R12-7-110, former Section R12-7-108 renumbered and amended as Section R12-7-109 effective September 29, 1982 (Supp. 82-5). Repealed effective January 19, 1994 (Supp. 94-1).

R12-7-110. Surface Casing Requirements

A. Surface casing shall be set at a sufficient depth to protect and isolate all known or reasonably estimated freshwater zones and to prevent blowouts or uncontrolled flows. The surface casing shall:
1. Be of sufficient size to permit the use of an intermediate string or strings of casing;
2. Be set in or through an impervious formation and shall be cemented by the pump and plug, displacement, or other method approved by the Commission;
3. Be cemented back to surface either during the primary cement job or by remedial action; and
4. Have API-approved centralizers on the bottom three joints as a minimum.

B. Cement shall be allowed to set a minimum of 12 hours under the lowest necessary pressure before drilling the cementing plugs or initiating tests.

C. Surface casing shall be pressure tested for at least 30 minutes to 70% of internal yield pressure or one psi per foot of casing depth, whichever is less. If a drop of more than 10% of the test pressure should occur, the casing shall be considered defective and corrective measures shall be applied. In wells drilled with cable tools, casing may be tested by bailing the well dry. The hole shall remain satisfactorily dry for one hour before commencing further operations. Results of the above test and any remedial action shall be reported in writing to the Commission within 15 days following the test.

D. The operator of a well shall notify the Commission at least 48 hours before setting surface casing so that a representative of the Commission may witness all or a part of the operations required in this Section.

Historical Note

Former Rule 109; Former Section R12-7-110 renumbered and amended as Section R12-7-111, former Section R12-7-109 renumbered and amended as Section R12-7-110 effective September 29, 1982 (Supp. 82-5). Amended effective January 19, 1994 (Supp. 94-1).

R12-7-111. Intermediate and Production Casing and Tubing Requirements

A. All producing wells shall be completed with production casing set directly above or through the producing interval and cemented by the pump and plug method, or other method approved by the Commission, to protect the zones to be produced. An intermediate string of casing may be required to seal off all potentially productive, lost circulation, and abnormally pressured zones that may be encountered in the well, except those to be produced. The Commission may require casing strings to be cemented from the maximum depth of the casing to at least 50 feet inside the previously run string of casing. For liners, a minimum of 100 feet of overlap between a string of casing and the next larger casing is required.

B. Strings of casing shall stand cemented for at least 12 hours before drilling out the cementing plugs or initiating such tests as the Commission may require.

C. Strings of intermediate and production casing shall be pressure tested to 70% of the manufacturer's rated internal yield pressure or one psi per foot of casing depth, whichever is less. In cases where combination strings utilizing casing of varied grades and weights are used, the above test pressures shall apply to the lowest pressure rated component used. If pressure declines more than 10% in 30 minutes, the casing shall be considered defective and corrective measures shall be applied.

1. In wells drilled with cable tools, casing may be tested by bailing the well dry, in which case the hole shall remain satisfactorily dry for at least one hour before commencing further operations on the well. Results of the above test and any remedial action shall be reported in writing to the Commission within 15 days following the test.

D. All flowing oil wells shall have tubing set as near the bottom as practical with tubing perforations not more than 250 feet above the top of the zone to be produced. Wells may be completed with small-diameter casing, which is generally understood in the industry to be "slim hole" or "tubingless" completions, in lieu of tubing.

E. The operator shall notify the Commission at least 48 hours before setting any casing string so that a representative of the Commission may witness all or a part of the operations required in this Section.

Historical Note

Former Rule 110; Former Section R12-7-111 renumbered and amended as Section R12-7-112, former Section R12-7-110 renumbered and amended as Section R12-7-111 effective September 29, 1982 (Supp. 82-5). Amended effective January 19, 1994 (Supp. 94-1).

R12-7-112. Defective Casing or Cementing

A. The operator shall take immediate steps to correct the casing condition of any well that may cause, or is causing, underground waste of oil, gas, or geothermal resources or contamination of fresh waters. These steps shall restore the integrity of the casing to the standards set in R12-7-110(C) and R12-7-111(C).

B. The operator shall report the corrective actions taken in writing to the Commission within 15 days of the completion of the work. If the condition of the casing cannot be corrected, the well shall be plugged and abandoned in compliance with R12-7-127.

Historical Note

Former Rule 111; Former Section R12-7-112 renumbered and amended as Section R12-7-113, former Section R12-7-111 renumbered and amended as Section R12-7-112 effective September 29, 1982 (Supp. 82-5). Amended effective January 19, 1994 (Supp. 94-1).

R12-7-113. Blowout Prevention and Related Well-control Equipment

A. When drilling in areas where pressures are unknown or high pressures do or are likely to exist, a blowout preventer, control head and related lines, and connections necessary to control the pressures and to keep the well under control at all times shall be installed as soon as the surface casing is set.

B. Upon installation, all ram-type blowout preventers and related equipment shall be pressure tested to the lesser of the manufacturer's full working pressure rating of the equipment, 70% of the minimum internal yield pressure of any casing subject to test, or one psi per foot of the last casing string depth. Annular or bag-type preventers shall be tested to the lesser of 1000 psi or 50% of full working pressure on installation. The blowout preventer and related equipment shall be tested:

1. After each string of casing is set in the well,
2. Not less than once each 14 days from each control station, and
3. Following repairs that require disconnection of any pressure seal in the assembly. Only the component repaired or replaced needs be tested unless alteration or repair occurs at a normal full blowout preventer test period.

C. The operator shall maintain records of the tests required in this Section until the well is completed and shall submit copies of these records to the Commission if required.

Historical Note

Former Rule 112; Former Section R12-7-113 renumbered and amended as Section R12-7-114, former Section R12-7-112 renumbered and amended as Section R12-7-113 effective September 29, 1982 (Supp. 82-5). Amended effective January 19, 1994 (Supp. 94-1).

R12-7-114. Recovery of Casing

Recovery of inside or outside strings of casing is prohibited unless written approval is obtained from the Commission. Approval shall be given only for wells where mudding and plugging operations can be carried out safely and the well abandoned in compliance with R12-7-127.

Historical Note

Former Rule 113; Former Section R12-7-114 renumbered and amended as Section R12-7-115, former Section R12-7-113 renumbered and amended as Section R12-7-114 effective September 29, 1982 (Supp. 82-5). Section repealed, new Section adopted effective January 19, 1994 (Supp. 94-1).

R12-7-115. Deviation of Hole and Directional Drilling

A. No drilling well may be intentionally deviated from its normal vertical course unless the operator shall first file application and obtain approval from the Commission after notice and hearing. The normal vertical course of a well is defined by a tolerance wherein the maximum deviation of the well does not exceed a 100-foot radius from the surface location. Deviation from the vertical for short distances is permitted in the drilling of a well without special approval only to straighten the hole, sidetrack junk, or correct other mechanical difficulties.

B. An application for directional drilling shall include:

1. The name, address, and phone number of the operator;
2. The field name, lease name, well number, state permit number, reservoir name, and county where the proposed well is located;
3. A plat or sketch showing the distance from the surface location to section and lease lines and to the target location within the intended producing interval;
4. The reason for the intentional deviation; and
5. The signature of the operator.

C. The operator of any well capable of production and whose producing interval or any portion thereof is located 330 feet or less in the case of an oil well or 1,660 feet or less in the case of a gas well from the boundary of any drilling unit shall run a directional survey before running the production casing.

D. In order to ensure compliance with this Section, the Commission may require the operator to run a directional survey of any hole at the operator's expense. The Commission may require an operator to run a directional survey of any hole at the request of an offset operator at the expense and risk of the offset operator unless the survey shows that the well is completed at a point outside the drilling unit, or at an unauthorized point.

E. Within 30 days following the completion of a directionally drilled well, the operator shall file with the Commission a complete angular deviation and directional survey of the well obtained by a well survey company.

F. Nothing in these rules shall be interpreted to permit the drilling of any well in such manner that it crosses the drilling unit lines, except by approval obtained after notice and hearing.

Historical Note

Former Rule 114; Former Section R12-7-115 renumbered and amended as Section R12-7-116, former Section R12-7-114 renumbered and amended as Section R12-7-115 effective September 29, 1982 (Supp. 82-5). Amended effective January 19, 1994 (Supp. 94-1).

R12-7-116. Multiple Zone Completions

A. Completions to include production from more than one common source of supply from a single well are prohibited except as authorized by the Commission after notice and hearing. After notice and hearing, the Commission shall maintain a list of zones or reservoirs, by fields, for which multiple completions have been authorized.

B. Operators shall file an application for multiple completion with the Commission and shall demonstrate the method to be used to keep the production streams separate. The application shall be accompanied by:

1. An electrical log or other acceptable log with tops and bottoms of formations or producing zones and perforated intervals shown and marked;
2. A diagrammatic sketch of the multiple completion installation indicating make, type, and setting depths of packer or packers;
3. A plat showing the location of the well and all offset wells and the names and addresses of operators of all leases offsetting acreage dedicated to applicant's well; and
4. Proof of mailing of application for multiple completion to all offset operators.

C. The Commission may approve subsequent applications for multiple completion of the same zones or reservoirs in a field administratively without a hearing, provided that:

1. The applicant can show that the Commission has approved and listed the zones or reservoirs as required in subsection (A);
2. The subsequent application is filed as required in subsection (B); and
3. The Commission receives no protest to the application after a 15-day holding period. A hearing shall be called if a protest is received.

D. Within 15 days of setting the final packer or packers, the operator shall file a report with the Commission identifying the well and its location showing the make, type, and depth set of each packer and the signature of the supervisor of the work. This report shall include the results of a packer leakage test and detail for each separate common source of supply, its stabilized shut-in pressure, producing pressure, and the simultaneous shut-in pressure on each other separate common source of supply. The operator shall notify the Commission at least 48 hours in advance of performing the tests required in this subsection.

E. Every operator of a multi-completed well shall operate, produce, and maintain the well to prevent commingling of production from the separate sources of supply. The Commission may require any multi-completed well to be tested at any time to demonstrate the effectiveness of the separation of sources of supply. These tests may be witnessed by representatives of the Commission and by offset operators.

Historical Note

Former Rule 115; Former Section R12-7-116 renumbered and amended as Section R12-7-117, former Section R12-7-115 renumbered and amended as Section R12-7-116 effective September 29, 1982 (Supp. 82-5). Amended effective January 19, 1994 (Supp. 94-1).

R12-7-117. Artificial Stimulation of Oil and Gas Wells

A. An operator shall report the artificial stimulation of any well to the Commission in writing within 15 days of the stimulation showing the type of stimulation, the amounts and types of materials used, stimulation pressures applied, and the flow and pressure results before and after stimulation.

B. If the artificial stimulation of a well results in any damage to the producing formation, a freshwater formation, casing, or casingseat that permits communication between fluid-bearing zones, the operator shall immediately notify the Commission and proceed with diligence to correct the damage. If the artificial stimulation results in irreparable damage to the well, the operator shall plug and abandon the well pursuant to R12-7-127.

Historical Note

Former Rule 116; Former Section R12-7-117 renumbered and amended as Section R12-7-118, former Section R12-7-116 renumbered and amended as Section R12-7-117 effective September 29, 1982 (Supp. 82-5). Amended effective January 19, 1994 (Supp. 94-1). Amended effective June 5, 1998 (Supp. 98-2).

R12-7-118. Operations in Hydrogen Sulfide Environments

A. When drilling, redrilling, deepening, or plugging back operations in areas where the formations to be penetrated are known to contain or are expected to contain hydrogen sulfide gas (H_2S) in excess of 10 ppm and in areas where the presence or absence or H_2S is unknown, the operator shall contract the services of an approved H_2S safety company to be on location at the known or expected depths.

B. A written contingency plan providing details of actions to be taken to alert and protect operating personnel and members of the public in the event of an accidental release of H_2S gas shall be submitted to the Commission as part of the initial application for a permit to drill or as a sundry notice.

Historical Note

Former Rule 117; Former Section R12-7-118 renumbered and amended as Section R12-7-119, former Section R12-7-117 renumbered and amended as Section R12-7-118 effective September 29, 1982 (Supp. 82-5). Amended effective January 19, 1994 (Supp. 94-1).

R12-7-119. Wellhead and Lease Equipment

A. The operator shall install and maintain valves, fittings, and wellhead connections that

1. Have a rated working pressure equivalent to at least 100% of the calculated or known surface pressure to which they may be subjected from the producing zone;
2. Allow well production, productivity, deliverability, and transient pressure tests;
3. Permit pressures to be obtained on both casing and tubing; and
4. Control the flow of the oil, gas, or geothermal resources on a flowing well.

B. The operator shall produce flowing oil wells into tanks equipped with high-low pressure and high-low level shut-in controls and shall install a safety valve that automatically closes on the wellhead in the event of surface production equipment malfunctions.

C. The operator shall equip artificial lift wells with wellhead safety sensors to shut off the source of power in the event of abnormally high or low flowline pressures.

Historical Note

Former Rule 118; Former Section R12-7-119 renumbered and amended as Section R12-7-120, former Section R12-7-118 renumbered and amended as Section R12-7-119 effective September 29, 1982 (Supp. 82-5). Amended effective January 2, 1996 (Supp. 96-1).

R12-7-120. Notification of Fire, Leaks, Spills, and Blowouts

A. Each operator shall notify the Commission within 24 hours of any fire, break, leak, spill, overflow, or blowout that occurs at any oil, gas, or geothermal drilling, producing, or transportation facility, or at any injection, disposal, or storage facility.

B. Each operator shall file a final written report within 15 days of resolving incidents described in subsection (A) giving the location by quarter-quarter section, township, and range; date and time of occurrence; specific nature and cause of the incident; resultant damage; action taken to correct the situation and prevent its reoccurrence; and losses of hydrocarbons or geothermal resources.

Historical Note

Former Rule 119; Former Section R12-7-120 renumbered and amended as Section R12-7-121, former Section R12-7-119 renumbered and amended as Section R12-7-120 effective September 29, 1982 (Supp. 82-5). Amended effective January 2, 1996 (Supp. 96-1).

R12-7-121. Well Completion and Filing Requirements

A. An operator shall file a completion report with the Commission within 30 days after a well is completed. The completion report shall contain a description of the well and lease, the casing, tubing, liner, perforation, stimulation, and cement squeeze records, and data on the initial production. The operator shall submit other well data to the Commission within 30 days of the date the work is done, including any:

1. Lithologic, mud, or wireline log;
2. Directional survey;
3. Core description and analysis;
4. Stratigraphic or faunal determination;
5. Formation or drill-stem test;
6. Formation fluid analysis; or
7. Other similar information or survey.

B. An operator shall furnish samples of drilled cuttings, at a maximum interval of 10 feet, to the Commission within 30 days after drilling is completed. The operator may furnish samples of continuous core in chips at 1-foot intervals. The operator shall:

1. Wash and dry all samples;
2. For each sample, place approximately 3 tablespoons of the sample in an envelope with the following identifying information: the well from which the sample originates, the location of the well, the Commission's permit number for the well, and the depth at which the sample is taken; and
3. Package sample envelopes in protective boxes and ship prepaid to:

   Oil & Gas Administrator
   Arizona Geological Survey
   416 West Congress, Suite 100
   Tucson, AZ 85701

C. The Commission shall keep all well information required by this Section confidential for 1 year after the drilling is completed unless the operator gives written permission to release the information at an earlier date. The Commission shall provide notice to the operator 60 days before confidential records become subject to public inspection and, at the operator's request, extend the confidential period for 6 months to 2 years if the Commission finds that the operator has demonstrated that release would harm the operator's competitive position with respect to unleased land in the vicinity of the well.

Historical Note

Former Rule 120; Former Section R12-7-121 renumbered and amended as Section R12-7-122, former Section R12-7-120 renumbered and amended as Section R12-7-121 effective September 29, 1982 (Supp. 82-5). Amended effective January 2, 1996 (Supp. 96-1). Amended by final rulemaking at 6 A.A.R. 4827, effective December 7, 2000 (Supp. 00-4).

R12-7-122. Recompletion and Routine Maintenance Operations

A. After a well has been completed, it shall not be deepened, redrilled, plugged back, reworked, or recompleted in a different zone, without prior approval by the Commission of a written application showing the character of the proposed work and the time it will begin. The Commission shall notify the applicant in writing whether the proposed work is approved or disapproved.

B. In the case of an emergency, an application may be made by electronic communication, and the Commission may by electronic communication authorize the work; however, written application required in subsection (A) shall be filed with the Commission within 10 days after emergency authorization is given, even though the work has already been commenced or completed. The Commission shall confirm the emergency authorization in writing upon receipt of the written application.

C. Written approval from the Commission is not required on acidizing, fracturing, and reperforating, or other routine well operations designed to restore or maintain production.

D. Within 15 days following the completion of any work described in this Section, the operator shall file a written report with the Commission identifying the well and fully describing the work performed. If the well is recompleted, a completion report shall be filed as required by R12-7-121.

Historical Note

Former Section R12-7-121 renumbered and amended as Section R12-7-122 effective September 29, 1982 (Supp. 82-5). Amended effective January 2, 1996 (Supp. 96-1).

R12-7-123. Reserved

R12-7-124. Reserved

R12-7-125. Temporarily Abandoned and Shut-in Wells

A. If drilling, injection, or production operations at a well are suspended, or have been suspended for 60 days, an operator shall plug the well under R12-7-127 unless the Commission permits the well to be temporarily abandoned or shut-in. The Commission shall not classify a well as shut-in until the operator submits a completion report under R12-7-121.

B. An operator may temporarily abandon or shut-in a well for up to 5 years if the operator demonstrates to a quorum of the Commission a future beneficial use of the well and submits a Sundry Notice to the Commission containing the following information:
1. Evidence of casing integrity as required in R12-7-112 including a complete description of the current casing, cementing, and perforation record of the well;
2. The stimulation and cement squeeze record and complete data on the results of any well tests performed to date; and
3. All other well data required in R12-7-121(A).

C. Before an approved time-frame for a temporarily abandoned or shut-in well expires, the operator shall return the well to beneficial use under a plan approved by the Commission, permanently plug and abandon the well, or apply for an extension to temporarily abandon or shut-in the well. If the integrity of the well casing is in question, the Commission may require the operator to:
1. Prove casing integrity in accordance with R12-7-112;
2. Plug any well that fails to meet the casing integrity required by R12-7-112; and
3. Re-test the well in accordance with R12-7-150 to continue shut-in status.

D. An operator shall ensure that no work begins on a temporarily abandoned or shut-in well until approved by the Commission. The operator shall give at least 24 hours' notice to the Commission before any work begins. Within 15 days of completing the proposed work, the operator shall file a written report with the Commission fully describing the work performed including a copy of all test rates, pressures, and fluid analyses.

Historical Note

Adopted effective January 2, 1996 (Supp. 96-1). Amended by final rulemaking at 6 A.A.R. 4827, effective December 7, 2000 (Supp. 00-4).

R12-7-126. Application to Plug and Abandon

A. Before abandoning any well, the operator shall submit an application to plug and abandon to the Commission and obtain approval. The application shall set forth the name and location of the well, the mechanical condition of the well, the productive zone and latest production, and a complete description of the proposed work. The plan shall provide for the protection of all formations containing usable-quality water, oil, gas, or geothermal resources.

B. In the case of a drilling well or an emergency, the application may be made by electronic communication, and the Commission may by electronic communication authorize the work; however, the operator shall file a written application within 10 days after the emergency authorization is given even though the work has already been commenced or completed. The Commission shall confirm the emergency authorization in writing upon receipt of the written application.

Historical Note

Former Rule 201; Amended effective September 29, 1982 (Supp. 82-5). Amended effective January 2, 1996 (Supp. 96-1).

R12-7-127. Plugging Methods and Procedures

A. Before abandoning any well, the operator shall submit an application to plug and abandon to the Commission for approval as required in R12-7-126. All down-hole plugging shall be conducted through drill pipe or tubing, unless otherwise approved by the Commission.

B. Open hole
1. A cement plug shall be placed to extend at least 50 feet below the bottom, except as limited by total depth or plugged back total depth, to 50 feet above the top of any zone containing fluid with a potential to migrate, any zone of lost circulation, and any zone containing potentially valuable minerals, including noncommercial hydrocarbons, coal, and oil shale.
2. All freshwater zones shall be plugged with a continuous cement plug which shall extend from at least 50 feet below to at least 50 feet above the freshwater zone, or a 100-foot plug shall be centered across the base of the freshwater zone and a 100-foot plug shall be centered across the top of the freshwater zone.
3. Open hole below the shoe of cemented casing shall be plugged with cement which shall extend from at least 50 feet below to at least 50 feet above the shoe.

C. Cased hole
1. A cement plug shall be placed opposite all open perforations and extend to a minimum of 50 feet below, except as limited by total depth or plugged back total depth, to 50 feet above the perforated interval. In lieu of the cement plug, a bridge plug may be placed within 50 to 100 feet above the open perforations and followed by at least 50 feet of cement.
2. If any casing is cut and recovered, a cement plug shall be placed to extend at least 50 feet above and below the stub.
3. No annular space that extends to the surface shall be left open to the drilled hole below. If this condition exists, a minimum of the top 100 feet of each annulus shall be plugged with cement.

D. Plugging mud having the proper weight and consistency to prevent movement of other fluids into or within the bore hole shall be placed across all intervals not plugged with cement. In the absence of other information at the time plugging is approved, plugging mud shall be made up with a minimum of 15 pounds per barrel of sodium bentonite and a nonfermenting polymer, have a minimum consistency of 9 pounds per gallon, a minimum viscosity of 50 seconds per quart, and mixed with fresh water.

E. A cement surface plug of at least 50 feet shall be placed in the smallest casing which extends to the surface. The top of this plug shall be placed as near the eventual casing cut-off point as possible.

F. The abandoned well shall be marked by a piece of metal pipe not less than 4 inches in diameter securely set in cement and extending at least 4 feet above the general ground level. The well location and identity shall be permanently inscribed as required in R12-7-106(A). An abandoned well location on tilled or otherwise unique land shall be marked in a manner approved by the Commission.

G. The drill site of an abandoned well shall be restored as nearly as possible to its natural state, to the satisfaction of the Commission. All pits shall be filled and all equipment and debris shall be removed from the location.

H. The operator shall notify the Commission at least 48 hours before starting abandonment operations to allow a representative of the Commission to witness the operations required in this Section. To ensure the integrity or placement of any plug, the representative may order the plug to be tested.

I. Within 15 days after the plugging of any well, the operator shall file with the Commission a plugging record setting forth in detail the method used in plugging the well, including the casing record; the size, kind, and depth of plugs used; and the name and depth interval of each formation containing fresh water, oil, gas, or geothermal resources.

J. Seismic shot holes
1. All seismic shot holes shall be plugged and abandoned within 30 days of firing.
2. Seismic shot holes which do not encounter freshwater zones shall be filled with a high-grade bentonite slurry or some other comparable plugging material as approved by the Commission.
3. Seismic shot holes which do encounter freshwater zones shall be plugged with cement in accordance with the applicable provisions of subsections (B) and (D).
4. Seismic shot-hole locations shall be restored in accordance with subsection (G) and the operator shall file a plugging record in accordance with subsection (I).

Historical Note

Former Rule 202; Amended effective September 29, 1982 (Supp. 82-5). Amended effective January 2, 1996 (Supp. 96-1).

R12-7-128. Stratigraphic, Core, and Seismic Holes

A. Any hole drilled for stratigraphic, core, or seismic purposes shall comply with all rules in this Chapter pertaining to the drilling of a well except the spacing provisions of R12-7-107.

B. Each hole drilled for stratigraphic, core, or seismic purposes shall be plugged in accordance with R12-7-126 and R12-7-127. The operator of a stratigraphic or core hole shall submit samples and cores and file a completion report in accordance with R12-7-121.

Historical Note

Former Rule 203; Amended effective September 29, 1982 (Supp. 82-5). Amended effective January 2, 1996 (Supp. 96-1).

R12-7-129. Wells to be Used as Water Wells

A. The landowner, landowner's agent, or lessee may use any well or exploratory hole as a water well provided that:
1. Written approval is obtained from the Arizona Department of Water Resources;
2. The operator plugs the well in accordance with R12-7-127 to a point immediately below the freshwater strata; and
3. The landowner, landowner's agent, or lessee assumes responsibility for the well and compliance with the provisions of A.R.S. Title 45, Chapter 2 in a signed and notarized water-well responsibility form provided by and filed with the Commission.

B. After filing the notarized water-well responsibility form with the Commission, the landowner, landowner's agent, or lessee shall comply with A.R.S. Title 45, Chapter 2 before modification or abandonment of the well.

C. Upon filing the notarized water-well responsibility form with the Commission, the Commission shall notify the bonding company and operator in writing so that the bond may be cancelled or made no longer effective with respect to that well.

Historical Note

Former Rule 204; Amended effective September 29, 1982 (Supp. 82-5). Amended effective January 2, 1996 (Supp. 96-1). Amended by final rulemaking at 8 A.A.R. 3363, effective July 15, 2002 (Supp. 02-3).

R12-7-130. Reserved

R12-7-131. Reserved

R12-7-132. Reserved

R12-7-133. Reserved

R12-7-134. Reserved

R12-7-135. Gas-oil Ratio and Potential Tests

A. Each operator shall conduct a gas-oil ratio test between 5 and 15 days after the completion or recompletion of any well located in a pool which contains both oil and gas. The average daily oil production, the average daily gas production, and the average gas-oil ratio shall be recorded.

B. The results of the gas-oil ratio test shall be reported in writing to the Commission within 15 days after completion of the test.

C. Each operator shall conduct a potential test within 30 days following the completion or recompletion of any well for the production of oil. The results of this test shall be reported in writing to the Commission within 15 days after completion of the test.

Historical Note

Former Rule 301; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-136. Subsurface Pressure Tests and Reservoir Surveys

A. Each operator shall conduct a test, within 30 days after completion, to determine the reservoir pressure on the discovery well of any new pool. The test shall be made after the well has been shut-in for at least 24 hours, and the results shall be reported in writing to the Commission within 15 days after the completion of the test.

B. The Commission may require subsurface pressure measurements on a number of wells in any pool to provide data to determine reservoir characteristics. The survey shall be made by the operator and shall provide a description of the test method and results including fluids, temperature, and pressure data and may require supervision by a qualified agent of the Commission. The results shall be reported in writing to the Commission within 15 days of the completion of the survey.

Historical Note

Former Rule 302; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-137. Commingling of Production from Pools

A. Unless authorized by the Commission, each pool shall be produced as a single common reservoir, with the wells completed, cased, maintained, and operated as the producing media for that pool. Oil production from each pool shall at all times be segregated into separate, identified tanks. The commingling of production from different pools is prohibited, unless authorized by order of the Commission after notice and hearing.

B. The Commission may approve commingling of production upon demonstration by the applicant that such commingling shall not cause waste of reservoir energy or diminish recovery of the resource. Application for approval of commingling shall include the following:
1. Electric or porosity log with tops and bottoms of formations or producing zones and perforated intervals shown and marked;
2. Diagrammatic sketch of the proposed well structure, including make, type and setting depths of packers;
3. The reservoir pressure for each zone or formation pro posed for commingling, the specific gravity and BTU content of the gas if the zone produces gas, and the API gravity and gas-oil ratio of the oil if the zone produces oil;
4. Plat showing the location of the well and all offset wells, and a list of the names and addresses of operators of all leases offsetting the acreage dedicated to the applicant's well;

5. Waiver consenting to the proposed commingling from each offset operator, or in lieu thereof, copies of letters requesting such waiver; and
6. Proof of mailing of notice of application for commingling to all offset operators.

C. The first application for commingling of pools in a field shall be approved by the Commission only after notice and hearing. Subsequent applications, completed as required in subsection (B), for commingling of the same zones in the same field may be approved administratively if, after a 15-day holding period, there are no protests from offsetting operators.

Historical Note

Former Rule 303; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-138. Casinghead Gas

A. All casinghead gas produced and sold or transported away from a lease, except amounts of flare gas, shall be metered and reported monthly in writing to the Commission in standard Mcf and gallons of liquids per Mcf. If the casinghead gas is sold as supply stock for a gasoline plant, the gallons of liquids per Mcf shall be reported. The operator of a lease shall not be required to measure the exact amount of casinghead gas produced and used for fuel purposes in the development and normal operation of the lease.

B. Pending arrangements for disposition of some useful purpose, all casinghead gas that is authorized to be vented shall be burned, and the estimated volume reported monthly as required by R12-7-161.

Historical Note

Former Rule 304; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-139. Use of Vacuum Pumps

A. The use of any device for the purpose of putting a vacuum on any stratum containing oil, gas, or geothermal resources is prohibited unless authorized by the Commission.

B. The Commission may, after notice and hearing, authorize the use of vacuum pumps if the applicant can show that use of the vacuum will not create waste or infringe on correlative rights.

Historical Note

Former Rule 305. Amended effective February 23, 1993 (Supp. 93-1).

R12-7-140. Pollution, Surface Damage, and Noise Abatement

A. An operator of a well, production facility, gasoline plant, gas plant, or pipeline shall conduct operations in a manner that prevents surface or subsurface pollution.

B. An operator shall conduct operations in a manner that prevents oil, gas, salt water, fracturing fluid or any other substance from polluting any surface or subsurface waters.

C. During swabbing and bailing operations or when purging a well, all substances removed from the bore hole shall be placed in a pit or tank and shall not be allowed to pollute any surface or subsurface waters.

D. An operator shall maintain all wellhead connections, surface equipment, lease flow lines, and tank batteries at all times to prevent the escape of oil, gas, produced water, or any other substance.

E. An operator shall report any fire, leak, or blowout to the Commission in accordance with R12-7-120. An operator shall ensure that any pit is constructed and operated in accordance with R12-7-108.

F. An operator shall minimize noise when conducting air drilling operations or when the well is allowed to produce while drilling. An operator shall ensure that the welfare of the operating personnel and the public is not negatively affected by the noise created by the expanding gases.

Historical Note

Former Rule 306. Amended effective February 23, 1993 (Supp. 93-1). Amended by final rulemaking at 8 A.A.R. 3363, effective July 15, 2002 (Supp. 02-3).

R12-7-141. Renumbered

Historical Note

Former Rule 307; Language transferred and amended, see Section R12-7-176 (Supp. 82-5).

R12-7-142. Measurement of Oil

Oil or condensate shall not be transported from a lease until it has been measured. Each transporter shall file a monthly report of the amount of oil or condensate transported from the lease as required by R12-7-185.

Historical Note

Former Rule 308; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-143. Oil Tanks, Fire Walls, and Fire Hazards

A. Oil shall not be stored or retained in an earthen reservoir or an open receptacle. The Commission may require dikes or fire walls to protect life, health, or property. All dikes or fire walls shall be erected and continuously maintained around all permanent oil tanks or batteries that are within the corporate limits of any city, town or village, or where such tanks are closer than 150 feet to any highway or inhabited dwelling, or closer than 1,000 feet to any school or church. The capacity of the dike or firewall shall be 1 1/2 times the capacity of the tank or tanks that it surrounds. The reservoir so formed within the dike shall be kept free from vegetation, water and oil.

B. Anything that might constitute a fire hazard, including potentially flammable items and reckless behavior such as smoking, shall be moved at least 150 feet from the well, tanks, separator, or other equipment.

Historical Note

Former Rule 309. Amended effective February 23, 1993 (Supp. 93-1).

R12-7-144. Reserved

R12-7-145. Reserved

R12-7-146. Reserved

R12-7-147. Reserved

R12-7-148. Reserved

R12-7-149. Reserved

R12-7-150. Capacity Tests of Gas Wells and Geothermal Wells

A. The operator of a producing gas well shall determine its open-flow capacity within 30 days following completion. Additional tests shall be taken as requested by the Commission. When a pipeline connection is available, gas wells shall not be tested by open-flow method, but the open-flow capacity shall be determined by the multipoint or single-point back-pressure test method.

B. The Commission may require tests to determine the quantity and quality of geothermal resources or reservoir energy.

C. The results of the tests required in this Section shall be reported in writing to the Commission within 15 days after the completion of the test.

Historical Note

Former Rule 401; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-151. Measurement of Gas from Gas Wells and Geothermal Resources

A. All gas produced for whatever purpose in gaseous form from gas wells shall be accounted for by metering as approved by the Commission. If the gas is sold, the purchaser shall report the volume purchased as required by R12-7-186. If the gas is delivered to a transportation facility, the transporter shall report the volume transported as required by R12-7-185. The operator shall report the volume produced as required by R12-7-161.

B. Each operator of a geothermal lease shall measure the quantity and quality of all production in accordance with the standard practices, procedures, and specifications generally used in the industry. The operator shall report the production as required in R12-7-161 and the purchaser shall file a report as required in R12-7-186.

Historical Note

Former Rule 402; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-152. Utilization of Gas

A. No gas from any completed gas well shall be:

1. Permitted to escape into the air except for testing when no pipeline connection is available.
2. Used expansively in engines or pumps and then vented, or
3. Used to gas-lift in oil wells unless all gas produced from such gas-lift operations is processed in a gasoline plant, and the residue gas is used in the manufacture of carbon black or for some other profitable use.

B. Utilization of gas in the manufacture of carbon black may be made only if approved by the Commission, after notice and hearing, based on a finding that a more profitable use is not available or will not be available in a reasonable time.

Historical Note

Former Rule 403. Amended effective February 23, 1993 (Supp. 93-1).

R12-7-153. Non-hydrocarbon Gas

The rules of this Chapter shall also apply to helium, carbon dioxide, and any other non-hydrocarbon gas.

Historical Note

Former Rule 404. Amended effective February 23, 1993 (Supp. 93-1).

R12-7-154. Reserved

R12-7-155. Reserved

R12-7-156. Reserved

R12-7-157. Reserved

R12-7-158. Reserved

R12-7-159. Reserved

R12-7-160. Regulation of Production

If the Commission determines that oil, gas, or geothermal resources production in the state is causing waste, the Commission shall limit, allocate, and apportion the total amount of oil, gas, or geothermal resources which may be produced.

Historical Note

Former Rule 501; Amended effective September 29, 1982. See also Section R12-7-170 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-161. Producer's Monthly Report

A. Each operator shall file a producer's monthly report for each producing lease for each calendar month, setting forth the operator's name, each well's lease name or number, well number, state permit number, the actual amounts of oil, gas, water, or geothermal resources produced, the number of days each well produced, and the disposition of the produced oil, gas, water, or geothermal resources. The report shall be filed on or before the 25th day of the next succeeding month.

B. If a well is off production for a period exceeding 30 days, the Commission shall be notified in writing with the reasons given.

Historical Note

Former Rule 502; Amended effective September 29, 1982. See also Section R12-7-171 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-162. Reserved

R12-7-163. Reserved

R12-7-164. Reserved

R12-7-165. Reserved

R12-7-166. Reserved

R12-7-167. Reserved

R12-7-168. Reserved

R12-7-169. Reserved

R12-7-170. Renumbered

Historical Note

Former Rule 601; Language transferred and amended, see Section R12-7-160 (Supp. 82-5).

R12-7-171. Renumbered

Historical Note

Former Rule 602; Language transferred and amended, see Section R12-7-161 (Supp. 82-5).

R12-7-172. Reserved

R12-7-173. Reserved

R12-7-174. Reserved

R12-7-175. Injection Wells Including Enhanced Recovery, Disposal, and Storage Wells

A. The following injection wells used for enhanced recovery, disposal, or storage shall require a permit from the Commission:

1. Class II injection wells
   a. Saltwater disposal wells: wells used to return salt water associated with oil and gas production to the subsurface.
   b. Enhanced oil recovery wells: wells used to inject salt water, gases, enhanced waters, and steam in order to maintain and extend oil production;
   c. Hydrocarbon storage wells: wells used for the underground storage of crude oil, liquified petroleum gas (LPG), and other liquid hydrocarbon products in naturally occurring rock formations.
2. Other injection wells

a. Geothermal injection wells: Class V wells used to reinject groundwater or geothermal fluids that are used in or are associated with the production of geothermal energy;
b. Other wells: wells used for the underground storage of any hydrocarbons or nonhydrocarbons that are gaseous at standard temperature and pressure, wells used to dissolve salt to create a cavity to be used for underground storage, and wells used to dispose of brine produced in the course of creating a solution-mined salt cavity.

B. In addition to being subject to the applicable provisions of this Chapter, the wells listed in subsection (A) shall be subject to the following specific regulation:
1. Injection wells listed in subsections (A)(1)(a) and (b) and (A)(2)(a) shall be regulated by R12-7-176, R12-7-178, and R12-7-179.
2. Injection wells listed in subsections (A)(1)(c) and (A)(2)(b) shall be regulated by R12-7-176, R12-7-178, R12-7-179, R12-7-180, R12-7-181, and R12-7-182.

C. No permits for injection wells other than those described in this Section shall be issued by the Commission.

Historical Note

Adopted effective January 2, 1996 (Supp. 96-1).

R12-7-176. Permits for Injection Wells

A. The injection of any substance into any geologic formation is prohibited unless 1st authorized by the Commission after notice and hearing. The Commission shall give at least 15 days' notice before a hearing is held for drilling a new injection well or for converting an existing well into an injection well. A permit shall not be required for routine well operations pursuant to R12-7-122(C) whose physical effects are confined to the area near the well bore.

B. The application for a permit for an injection well as defined in R12-7-175 shall be prepared in accordance with R12-7-104, shall meet all the applicable requirements of this Chapter, and shall contain the following requirements, where applicable:
1. A plat showing the location of each proposed injection well and the location and status of all wells, including drilling wells and dry holes, within 1/2 mile of the proposed well. The plat shall include the lease boundary lines, the names of the surface and subsurface lessees and owners within 1/2 mile of the injection well or wells, and the name of each offset operator.
2. A geologic study, including:
   a. A contour map drawn on a geologic marker at or near the top of each injection zone in the project area;
   b. A thickness map of each injection zone in the project area;
   c. A geologic cross-section drawn through the site of an injection well in the project area showing structural details, any wells that may be affected by the project, and the location of the base of any freshwater strata, defined as water having 10,000 ppm or less of total dissolved solids, or a statement that no fresh water exists; and
   d. A representative electric log to a depth below the deepest producing zone identifying all geologic units including the injection and confining zones, freshwater aquifers, and oil, gas, or geothermal zones.
3. An engineering study, including:
   a. A statement of the primary purpose of the project;
   b. The characteristics of the injection and confining zones including porosity, permeability, thickness, areal extent, fracture gradient, original and present temperature and pressure, and residual oil, gas, and water saturations;
   c. The reservoir fluid data for each injection zone including oil gravity and viscosity, water quality, and specific gravity of gas;
   d. A description of each injection well's casing, or the proposed casing and cementing program, and the proposed method of testing the casing before use of the injection well. The casing shall be designed and tested in accordance with R12-7-181(C) with respect to the injection zone;
   e. A diagram of the proposed wellhead;
   f. A casing diagram, including cement plugs, and the actual or calculated cement fill behind the casing of all wells within the area affected by the project, including abandoned wells, showing that they will not cause damage to life, health, property, or natural resources;
   g. The well stimulation program if stimulation is planned; and
   h. The planned well-drilling and abandonment program to complete the project, including a flood-pattern map showing all injection, production, and abandoned wells, and unit boundaries.
4. An injection plan, including:
   a. A diagram and plan of the injection facilities;
   b. The maximum surface injection pressure expected during the life of the project and the estimated daily rate of fluid injection, by well. The operator shall provide calculations showing that the maximum injection pressure will not initiate fractures in the confining zone;
   c. A description of the area affected by the volumetric method and by the pressure-buildup method and the radius affected during the life of the project;
   d. The monitoring system or method to be used to ensure that no damage is occurring and that the injection fluid is confined to the permitted injection zone and to the area controlled by the operator;
   e. The method of injection such as casing, tubing, tubing with packer, between strings;
   f. The protective methods to be used on each injection line and well and a contingency plan for well failure or a shut-in period, including a plan for disposition of fluids not injected as a consequence of well failure;
   g. The source and chemical analysis of the injection fluid, and chemical analysis of the water in the injection zone. If the water in the injection zone has 10,000 ppm or less of total dissolved solids, the applicant shall provide evidence of commercial oil or gas producibility of the zone by means of historical production in the field or by log information, core data, and values for the porosity and permeability of the zone; and
   h. The location and depth of each water-source well that will be used in conjunction with the project.
5. Proof of notification to neighboring operators and surface owners within 1/2 mile of the proposed well.
6. Supplementary data as required in R12-7-180 for storage-well projects.
7. Any additional information that the Commission may determine is necessary to adequately clarify the informa-

tion submitted pursuant to R12-7-176(B)(1) through (B)(6).

8. All maps, diagrams, and exhibits required in this subsection shall be clearly labeled as to scale and purpose and shall clearly identify wells, boundaries, zones, contacts, and other relevant data.

C. Permits may be issued for a period up to the operating life of the well with review once every 5 years. Permits may be modified or terminated during their term if the Commission determines that the operator is not in compliance with the requirements of this Chapter.

Historical Note

Former Rule 701; Amended effective September 29, 1982. See also Section R12-7-141 (Supp. 82-5). Amended effective January 2, 1996 (Supp. 96-1).

R12-7-177. Repealed

Historical Note

Former Rule 702; Amended effective September 29, 1982 (Supp. 82-5). Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-178. Notice of Commencement, Discontinuance, and Transfer of Injection Operations

The following provisions apply to all injection projects defined in R12-7-175:

1. The operator shall notify the Commission of the date that injection operations will begin.
2. The operator shall notify the Commission of the date that injection operations will cease and provide the reasons for discontinuing the injection operations.
   a. The temporary abandonment of any injection well shall be in accordance with R12-7-125. Temporarily abandoned injection wells shall meet the testing requirements of R12-7-179(D).
   b. All injection wells shall be plugged and abandoned, in accordance with R12-7-126 and R12-7-127.
3. An injection well shall not be transferred from 1 operator to another without the written approval of the Commission.
   a. The operator shall file the request for transfer of ownership of an injection well in triplicate with the Commission at least 45 days before the proposed transfer date. The request shall include the name, address, and telephone number of the proposed new operator and provide the location and status of each well involved.
   b. The proposed new operator shall file with the Commission an organization report as required in R12-7-194 and bond as required in R12-7-103 before the request for transfer will be considered.
   c. The Commission shall return 1 copy of the request for transfer to the operator and 1 to the proposed new operator within 30 days after receipt of the information required in subsections (3)(a) and (b), designating approval or denial of the transfer of authority to inject for the subject well.
      i. If the proposed transfer is approved, a copy of the order authorizing injection shall be attached to the approved request for transfer.
      ii. If the proposed transfer is denied, the Commission shall return 1 copy of the request to the operator and 1 copy to the proposed operator together with the reasons for the denial and the steps necessary for its approval.

Historical Note

Former Rule 703; Amended effective September 29, 1982 (Supp. 82-5). Amended effective January 2, 1996 (Supp. 96-2).

R12-7-179. Testing and Monitoring of Injection Wells

A. The operator of an injection well shall file a weekly sundry report with the Commission on all drilling, completion, recompletion, and workover operations.

B. The operator of an injection well shall monitor operations to ensure that injection pressure at the wellhead does not exceed the maximum pressure authorized in the permit, and that no injection shall cause movement of injection or formation fluids into an underground source of drinking water.

C. The operator shall keep accurate records of the amount of oil, gas, water, or geothermal resources produced, the volume of substances injected, the average and maximum pressure used for injection, and the nature of the injected fluid. The operator of an enhanced recovery or disposal well shall submit a report as required in R12-7-187. The operator of a storage well shall submit a report as required in R12-7-185.

D. The operator shall run the following pressure or monitoring tests on new injection wells to establish the mechanical integrity of the tubing, casing, and packer. Existing wells being converted to an injection well shall be tested in the same manner and shall maintain the same mechanical integrity as a new well.

1. The casing-tubing annulus above the packer shall be tested upon completion and at least once every 5 years, under the supervision of the Commission, at a pressure equal to the lesser of the maximum authorized injection pressure or 1,000 psi, provided that no testing pressure shall be less than 300 psi. Documentation of the test shall be submitted to the Commission. Test pressures shall be applied for a period of 30 minutes. If a drop of more than 10% of the test pressure should occur, corrective measures shall be applied. If the tubing, casing, or packer cannot be brought up to standard, the well shall be plugged and abandoned in accordance with R12-7-126 and R12-7-127.
2. The Commission may require the operator to run a tracer survey, a temperature log, or a noise log to demonstrate the absence of fluid movement in vertical channels adjacent to the injection well.

E. Mechanical failure or downhole problems which indicate an injection well is not, or may not be, directing the injected fluid into the permitted injection zone may be cause to shut in the well. The operator shall notify the Commission within 24 hours of any such failure or problem. A written notice shall be filed within 5 days of the occurrence, with a plan for testing and repairing the well. If the well cannot be brought up to the standard required in subsection (D), it shall be plugged and abandoned in accordance with R12-7-126 and R12-7-127.

Historical Note

Former Rule 704; Amended effective September 29, 1982 (Supp. 82-5). Amended effective January 2, 1996 (Supp. 96-1).

R12-7-180. Supplementary Requirements for Storage Wells

The application for a storage well as defined in R12-7-175(B)(2) shall be prepared in accordance with R12-7-176 and shall contain the following, where applicable:

1. Information on any oil or gas production within 5 miles of each proposed well;
2. Information on the oil and gas reserves of each storage zone before starting injection, including calculations;

3. A comprehensive plan for disposition of brine and salt produced in the course of creating a solution-mined salt cavity. Cavities shall be designed and constructed in accordance with R12-7-181;
   a. Surface disposition shall be subject to the rules of the Department of Water Resources and the Department of Environmental Quality;
   b. Saltwater disposal wells shall be permitted in accordance with R12-7-176;
   c. Surface brine reservoirs used in the operation of the storage system and disposal reservoirs shall be designed to prevent the contamination of air, fresh water, and soil;
4. A list of proposed surface and subsurface safety devices, tests, and precautions to be taken to ensure safety of the project. The operator shall install a flare or other safety system acceptable to the Commission at or near each brine pit or any other location where escape of gases is likely to occur.

Historical Note

Former Rule 705; Amended effective September 29, 1982 (Supp. 82-5). Amended effective January 2, 1996 (Supp. 96-1).

R12-7-181. Design and Construction of Storage Wells and Cavities

A. Before drilling a storage well for storing liquid or gaseous hydrocarbons, or any other substances under the jurisdiction of the Commission, in an underground cavity, the applicant shall demonstrate to the Commission that the proposed storage will preserve the structural integrity of the host rock, including halite, and the overlying sediments. The evidence presented shall include:
1. An investigation to determine the feasibility of a storage system at the particular site; and
2. An assessment of the stability of each proposed cavity design, particularly with regard to the size, shape and depth of the storage cavity, the amount of separation between storage cavities, and the amount of separation between the storage cavity and the periphery of the host rock.

B. The design of a solution-mined storage system shall be based on site-specific geologic and engineering parameters including type of storage use, location of each cavity, number of cavities, cavity capacity, and maximum development diameter of each cavity. The design shall ensure that project development can be conducted in a reasonable, prudent, and systematic manner and shall stress physical and environmental safety and the prevention of waste. The design and solution mining shall be continually reviewed throughout the construction phase to account for any new subsurface information and shall include provisions for protection from damage caused by hydraulic shock. The original development and operational plans shall be modified, as necessary, to conform with good engineering practice. The design shall incorporate the standards outlined below:
1. The minimum separation between the nearest outer walls of adjacent storage cavities as measured in any direction shall be established considering:
   a. The properties of the host rock;
   b. The elevation of the top and bottom of the adjacent cavities;
   c. Their maximum development diameter relative to the spacing of the cavities; and
   d. Other considerations deemed appropriate for the specific site; however, in no case shall such separation at any time during the storage project be less than 200 feet.
2. The walls of a storage cavity shall be no less than 200 feet from the boundary of the lands included in the storage project on which the chambers are located.
3. If the design involves the intentional subsurface connection between 2 adjacent storage cavities under 1 property (that is, a "U"-tube storage-cavity system), the minimum separation between cavities specified in subsection (B)(1)(d) shall not apply.

C. The borehole shall be dually cased from the surface into the cavity in accordance with R12-7-110 and R12-7-111. At least 2 strings of casing shall be fully cemented from the surface into the host rock either during the primary cement job or by remedial action. The Commission may administratively grant an exception to the requirement for 2 strings of cemented casing if the applicant can show that the exception is reasonable, justified by site-specific geologic or engineering parameters, is no less stringent, and consistent with the intent of these rules regarding physical and environmental safety, conservation of the resource, and the prevention of waste.
1. The final cemented casing string shall have tensile and collapse strengths, as approved by the Commission, for the setting depth and shall be set a minimum of 200 feet into the formation to be used for the storage cavity.
2. The casing seat of the final cemented casing string shall be pressure-tested after drilling at least 10 feet into the formation below the casing seat. The test pressure calculated at the casing seat shall equal the proposed maximum operating pressure at that point and shall not exceed 0.9 psi per foot of depth.
3. After the wellhead has been installed and before products are stored, the system shall be pressure-tested as a unit.
4. All tests required in this subsection shall meet the integrity standards set in R12-7-179(D).

D. Storage facilities in existence prior to June 1, 1978, shall not be required to meet the planning and construction requirements of subsections (B) and (C), except for future expansions or additions.

Historical Note

Adopted effective August 31, 1978 (Supp. 78-4). Amended effective September 29, 1982 (Supp. 82-5). Amended (and subsections (A)(1)(h) through (m) moved to Section R12-7-182) effective January 2, 1996 (Supp. 96-1)

R12-7-182. Operation, Inspection, and Closure of Storage-well Systems

A. The maximum and minimum operating pressures of a storage system shall be determined in consideration of the lithologic characteristics of the host rock. The maximum operating pressure at the shallower of the casing seat or cavity ceiling shall not exceed 0.9 psi per foot of depth.
1. The storage system shall not be subjected to pressures exceeding the maximum operating pressure even for short periods of time, including pressure pulsation peaks and abnormal operating conditions.
2. The wellhead, flowlines, valves, and all related connections shall have a test pressure rating equivalent to 125% of the maximum pressure which could be exerted at the surface. All valves shall be periodically inspected and maintained in good working order.
3. The wellhead and storage system shall be protected with safety devices to prevent pressures exceeding the maximum operating pressure from being exerted on the stor-

age system and to prevent backflow of stored products in the event of flowline rupture.
4. Personnel shall be at either the well or other control sites for the well during injection or withdrawal from any storage well.

B. The flare, as required in R12-7-180(4), shall be burned continuously when a liquified gas or other flammable substance is being injected into a cavern.

C. Each operator of a storage well shall conduct semiannual safety inspections of the operator's facility and file with the Commission a written report on the inspection procedures and results within 5 days following the inspection. The operator shall notify the Commission at least 5 days before an inspection to allow a representative of the Commission to witness the inspection. Inspections shall include, the following:
1. Operation of all manual valves;
2. Operation of all automatic shut-in safety valves, including sounding or alarm devices;
3. Examination of flare system or other safety system installation;
4. Examination of earthen brine pits, tanks, firewalls, and related equipment;
5. Examination of flowlines, manifolds, and related equipment;
6. Examination of warning signs and safety fences;
7. Examination of housekeeping practices including the removal of weeds, used equipment, and debris from the area of operations;
8. The Commission may require additional inspections at any time during regular working hours and upon reasonable notice to the operator.

D. A capacity determination for each storage cavity shall be made and filed with the Commission upon completion of the storage cavity. These determinations shall be verified at least once every 5 years.

E. Safety precaution signs shall be displayed and unauthorized personnel kept out of the storage area. Each storage wellhead shall be visibly marked in accordance with R12-7-106(D). Guard rails shall be installed where the Commission determines it is necessary to ensure safety.

F. Storage wells shall be plugged and abandoned in accordance with R12-7-126 and R12-7-127.

G. If the Commission determines that the continued operation of a storage well or associated facilities, including valves, brine tanks or pits, flares, dehydrators, and loading and docking facilities, would cause unsafe operating conditions, waste, pollution, or contamination of air, fresh water, or soil, or encroachment on adjacent property, the Commission shall order discontinuance of operations of the storage facility or any part thereof until the Commission determines that the project can and will be conducted in a physically and environmentally safe manner.

H. The operator shall notify the Commission within 24 hours of every accident or equipment malfunction which causes loss of life or requires hospitalization of personnel; threatens the public health and safety; pollutes the air, soil, or fresh water; or causes loss of the stored substance. A final written report shall be filed with the Commission in accordance with R12-7-120(B).

I. The Commission may administratively grant exceptions to the guidelines and requirements of this Section if the applicant can show that the exception is reasonable, justified by site-specific geologic or engineering parameters, are no less stringent, and consistent with the intent of these rules regarding physical and environmental safety, conservation of the resource, and the prevention of waste. An applicant may request a hearing pursuant to A.R.S. § 27-517.

Historical Note

Adopted by moving subsections (A)(1)(h) through (m) of R12-7-181 and amending the text effective January 2, 1996 (Supp. 96-1).

R12-7-183. Certificate of Compliance and Authorization to Transport

A. Each producer or operator of any well shall execute under oath and file with the Commission an operator's certificate of compliance and authorization to transport oil, gas, or geothermal resources from lease provided by the Commission for each well.

B. The certificate, when properly executed and approved by the Commission, shall constitute authorization to the pipeline or other transporter to transport oil, gas or geothermal resources from the developed unit named. The Commission may provide written permission for the transportation of production in order to prevent waste, pending execution and approval of the certificate.

C. The certificate shall remain in full force and effect until:
1. The operating ownership of the developed unit changes, or
2. The transporter changes, or
3. The certificate is cancelled by the Commission.

D. When a change occurs in operating ownership of any developed unit, or when a change occurs in the transporter from any developed unit, the operator shall file a new certificate with the Commission within 10 days of the change. With respect to a temporary change in transporter which involves less than the production of one month, the producer may, in lieu of filing a new certificate, notify the Commission and the transporter in writing of the estimated amount of oil, gas, or geothermal resources to be moved by the temporary transporter, and the name of the temporary transporter. The operator shall furnish a copy of the notice to the temporary transporter.

E. The temporary transporter shall not move any greater quantity of oil, gas, or geothermal resources than the estimated amount shown in the notice.

F. Time-frames
1. The Commission shall mail to the producer or operator, within 10 days of receipt of the certificate required in subsection (A), written notice of administrative completeness or a detailed list of deficiencies. Within 10 days of receipt of an administratively complete certificate, the Commission shall approve the certificate or provide a written explanation in compliance with A.R.S. § 41-1076 to the producer or operator if the certificate is not approved. The overall time-frame is 20 days.
2. For the purpose of this subsection, intermediate Saturdays, Sundays, and legal holidays are not included in the time-frame computation.

Historical Note

Former Rule 801; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1). Amended effective June 6, 1997 (Supp. 97-2).

R12-7-184. Recovered Load Oil

Recovered load oil may be run from a lease on which it is recovered only upon approval by the Commission of a certificate for load oil credit and permit to transport recovered load oil showing the source and amount of the load oil. Upon approval, the Commission shall forward one copy to the designated transporter as authority to transport the oil. This rule applies only to oil obtained from a source other than the lease on which it is used.

Historical Note
Former Rule 802; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-185. Transporter's and Storer's Monthly Report

A. Each transporter of oil and condensate shall furnish for each calendar month a report containing information and data respecting stocks of oil and condensate on hand and all movements within the state of oil and condensate by pipeline, trucks, or other conveyances except railroad, from leases to storers or refiners; movements between transporters within the state; movements between storers within the state; movements between refiners within the state; and movements between storers and refiners within the state.

B. Each storer of oil and condensate shall furnish for each calendar month a report containing information and data respecting the storage of oil and condensate within the state.

C. Each storer of natural gas, liquified petroleum gas, or other hydrocarbon or nonhydrocarbon gases in storage wells shall furnish for each calendar month a report containing information and data respecting the storage, including receipts and deliveries, of such products within the state.

D. Transporters and storers shall file reports required in this Section with the Commission on or before the 25th day of the next succeeding month.

Historical Note
Former Rule 803; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-186. Gas or Geothermal Purchaser's Monthly Report

A. Each purchaser or taker of gas in gaseous form or geothermal resources from any well, lease, pool or proration unit shall file for each calendar month a report detailing acquisition and disposition of all gas in gaseous form or geothermal resources purchased or taken during that month.

B. Purchasers and takers shall file reports required in this Section with the Commission on or before the 25th day of the next succeeding month.

Historical Note
Former Rule 804; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-187. Injection Project Report

A. Each operator of an injection project shall furnish for each injection well for each calendar month a report of injection project containing information and data including the lease and well number, the well's state permit number, average injection pressure during the month, amount of fluid in barrels injected during the month, the total amount of fluid injected to date, the source of the injected fluid, and the number of days the injection well was operated during the month.

B. Operators of injection projects shall file reports required in this Section with the Commission on or before the 25th day of the next succeeding month.

Historical Note
Adopted effective February 23, 1993 (Supp. 93-1).

R12-7-188. Refinery Reports

A. Each refiner of oil or condensate shall furnish for each calendar month a refinery monthly report containing information and data respecting oil, condensate and products involved in the refiner's operations during each month.

B. Refiners shall file reports required in this Section with the Commission on or before the 25th day of the next succeeding month.

Historical Note
Former Rule 901; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-189. Repealed

Historical Note
Former Rule 902; Amended effective September 29, 1982 (Supp. 82-5). Repealed effective February 23, 1993 (Supp. 93-1).

R12-7-190. Gasoline Plant Reports

A. Each operator of a gasoline plant, cycling plant, or any other plant at which gasoline, butane, propane, condensate, kerosene, oil or other liquid products are extracted from gas shall furnish for each calendar month a gasoline plant or pressure maintenance plant monthly report containing information and data respecting gas and products involved in the operation of each plant during each month.

B. Operators shall file reports required by this Section with the Commission on or before the 25th day of the next succeeding month.

Historical Note
Former Rule 903; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-191. Reserved

R12-7-192. Books and Records to Substantiate Reports

A. Each operator, producer, transporter, storer, refiner, processor, gasoline or extraction or geothermal generating plant operator, and initial purchaser of oil, gas, or geothermal resources shall make and keep books and records covering operations in Arizona, from which are made and which will substantiate all reports required by the Commission.

B. Books and records required in this Section shall be available for inspection by the Commission for at least a six-year period.

Historical Note
Former Rule 1001; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1).

R12-7-193. Repealed

Historical Note
Former Rule 1002. Amended effective February 23, 1993 (Supp. 93-1). Repealed effective September 22, 1993 (Supp. 93-3).

R12-7-194. Organization Reports

A. Before any person shall engage in any activity covered by this Chapter, that person shall file with the Commission an organization report that includes a statement under oath giving the following information:

1. The name under which the business is being operated or conducted;
2. The name and post office address of the person and the business or businesses engaged in;
3. The plan or organization, and, if a reorganization, the name and address of the previous organization;
4. The state where incorporated, if a foreign corporation, and the name and post office address of the Arizona

agent, together with the date of permit to do business in Arizona; and
5. The names and addresses of the principal officers or partners and the names and addresses of the directors.

B. When a change occurs, as to facts stated in the report filed, a new organization report shall be filed with the Commission within ten days of the change.

Historical Note

Former Rule 1003. Amended effective February 23, 1993 (Supp. 93-1).

R12-7-195. Repealed

Historical Note

Former Rule 1004; Amended effective September 29, 1982 (Supp. 82-5). Amended effective February 23, 1993 (Supp. 93-1). Repealed effective September 22, 1993 (Supp. 93-3).

Appendix 1. Repealed

Historical Note

(For the convenience of the operator, the forms and reports in common use by the United States Geological Survey, and for the purpose for which each form was designed, may be submitted in lieu of similar Commission forms. Commission forms No. 1, 2, 3, 4, and 27 must be used for their designated purpose and no substitutes will be acceptable.) Repealed effective January 2, 1996 (Supp. 96-1).

ARTICLE 2. REPEALED

R12-7-201. Repealed

Historical Note

Former A. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-202. Repealed

Historical Note

Former B. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-203. Repealed

Historical Note

Former Rule G-101. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-204. Repealed

Historical Note

Former Rule G-102. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-205. Repealed

Historical Note

Former Rule G-103. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-206. Repealed

Historical Note

Former Rule G-104. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-207. Repealed

Historical Note

Former Rule G-105. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-208. Repealed

Historical Note

Former Rule G-106. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-209. Repealed

Historical Note

Former Rule G-107. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-210. Repealed

Historical Note

Former Rule G-108. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-211. Repealed

Historical Note

Former Rule G-109. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-212. Repealed

Historical Note

Former Rule G-110. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-213. Repealed

Historical Note

Former Rule G-111. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-214. Repealed

Historical Note

Former Rule G-112. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-215. Repealed

Historical Note

Former Rule G-113. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-216. Repealed

Historical Note

Former Rule G-114. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-217. Repealed

Historical Note

Former Rule G-115. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-218. Repealed

Historical Note

Former Rule G-116. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-219. Repealed

Historical Note

Former Rule G-117. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-220. Repealed

Historical Note

Former Rule G-118. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-221. Repealed

Historical Note
Former Rule G-119. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-222. Reserved

R12-7-223. Reserved

R12-7-224. Reserved

R12-7-225. Reserved

R12-7-226. Reserved

R12-7-227. Reserved

R12-7-228. Reserved

R12-7-229. Reserved

R12-7-230. Reserved

R12-7-231. Repealed

Historical Note
Former Rule G-201. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-232. Repealed

Historical Note
Former Rule G-202. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-233. Repealed

Historical Note
Former Rule G-203. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-234. Repealed

Historical Note
Former Rule G-204. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-235. Reserved

R12-7-236. Reserved

R12-7-237. Reserved

R12-7-238. Reserved

R12-7-239. Reserved

R12-7-240. Reserved

R12-7-241. Repealed

Historical Note
Former Rule G-301. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-242. Repealed

Historical Note
Former Rule G-302. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-243. Repealed

Historical Note
Former Rule G-303. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-244. Repealed

Historical Note
Former Rule G-304. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-245. Repealed

Historical Note
Former Rule G-305. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-246. Repealed

Historical Note
Former Rule G-306. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-247. Reserved

R12-7-248. Reserved

R12-7-249. Reserved

R12-7-250. Reserved

R12-7-251. Repealed

Historical Note
Former Rule G-401. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-252. Repealed

Historical Note
Former Rule G-402. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-253. Reserved

R12-7-254. Reserved

R12-7-255. Reserved

R12-7-256. Reserved

R12-7-257. Reserved

R12-7-258. Reserved

R12-7-259. Reserved

R12-7-260. Reserved

R12-7-261. Repealed

Historical Note
Former Rule G-501. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-262. Repealed

Historical Note
Former Rule G-502. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-263. Repealed

Historical Note
Former Rule G-503. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-264. Repealed

Historical Note
Former Rule G-504. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-265. Reserved

R12-7-266. Reserved

R12-7-267. Reserved

R12-7-268. Reserved

R12-7-269. Reserved

R12-7-270. Reserved

R12-7-271. Repealed

Historical Note
Former Rule G-601. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-272. Repealed

Historical Note
Former Rule G-602. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-273. Reserved

R12-7-274. Reserved

R12-7-275. Reserved

R12-7-276. Reserved

R12-7-277. Reserved

R12-7-278. Reserved

R12-7-279. Reserved

R12-7-280. Reserved

R12-7-281. Repealed

Historical Note
Former Rule G-701. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-282. Reserved

R12-7-283. Reserved

R12-7-284. Reserved

R12-7-285. Reserved

R12-7-286. Reserved

R12-7-287. Reserved

R12-7-288. Reserved

R12-7-289. Reserved

R12-7-290. Reserved

R12-7-291. Repealed

Historical Note
Former Rule G-801. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-292. Repealed

Historical Note
Former Rule G-802. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-293. Repealed

Historical Note
Former Rule G-803. Repealed effective January 2, 1996 (Supp. 96-1).

R12-7-294. Repealed

Historical Note
Former Rule G-804. Repealed effective January 2, 1996 (Supp. 96-1).

Appendix 1. Repealed

Historical Note
Repealed effective January 2, 1996 (Supp. 96-1).

Appendix B – Colorado Regulatory Summary (General)

RULES AND REGULATIONS

DEFINITIONS
(100 Series)

ACT shall mean the Oil and Gas Conservation Act of the State of Colorado.

APPLICANT shall mean the person who institutes a proceeding before the Commission, which it has standing to institute under these rules.

AQUIFER shall mean a geologic formation, group of formations or part of a formation that can both store and transmit ground water. It includes both the saturated and unsaturated zone but does not include the confining layer, which separates two (2) adjacent aquifers.

ASSEMBLY BUILDING shall mean any building or portion of building or structure used for the regular gathering of fifty (50) or more persons for such purposes as deliberation, education, instruction, worship, entertainment, amusement, drinking or dining, or awaiting transport.

AUTHORIZED DEPUTY shall mean a representative of the Director as authorized by the Commission.

BATTERY shall mean the point of collection (tanks) and disbursement (tank, meter, lease automated custody transfer [LACT] unit) of oil or gas from producing well(s).

BARREL shall mean forty-two (42) gallons (U.S.) at sixty degrees fahrenheit (60^{o} F) at atmospheric pressure.

BRADENHEAD TEST AREA shall mean any area designated as a bradenhead test area by the Commission under Rule 207.b.

BUILDING UNIT shall mean a building or structure intended for human occupancy. A dwelling unit is equal to one (1) building unit, every guest room in a hotel/motel is equal to one (1) building unit, and every five thousand (5,000) square feet of building floor area in commercial facilities, and every fifteen thousand (15,000) square feet of building floor area in warehouses, or other similar storage facilities, is equal to one (1) building unit.

CEASE AND DESIST ORDER shall mean an order issued by the Commission pursuant to §34-60-121(5), C.R.S.

CENTRALIZED E&P WASTE MANAGEMENT FACILITY shall mean a facility, other than a commercial disposal facility exclusively regulated by the Colorado Department of Public Health and Environment, that is: (1) used exclusively by one owner or operator; or (2) used by more than one operator under an operating agreement and which receives for collection, treatment, temporary storage, and/or disposal of produced water, drilling fluids, drill cuttings, completion fluids, and any other exempt E&P wastes that are generated from two or more production units or areas or from a set of commonly owned or operated leases. This definition includes the surface storage and disposal facilities that are present at Class II disposal well sites. This definition also includes oil-field naturally occurring radioactive materials (NORM) related storage, decontamination, treatment, or disposal.

COMMERCIAL DISPOSAL WELL FACILITY shall mean a facility whose primary objective is disposal of Class II waste from a third party for financial profit.

COMMISSION shall mean the Oil and Gas Conservation Commission of the State of Colorado.

COMPLETION. An **oil well** shall be considered completed when the first new oil is produced through wellhead equipment into lease tanks from the ultimate producing interval after the production string has been run. A **gas well** shall be considered completed when the well is capable of producing gas through wellhead equipment from the ultimate producing zone after the production string has been run. A **dry hole** shall be considered completed when all provisions of plugging are complied with as set out in these rules. Any well not previously defined as an oil or gas well, shall be considered completed ninety (90) days after reaching total depth. If approved by the Director, a well that requires extensive testing shall be considered completed when the drilling rig is released or six (6) months after reaching total depth, whichever is later.

CORNERING AND CONTIGUOUS UNITS when used in reference to an exception location shall mean those lands which make up the unit(s) immediately adjacent to and toward which a well is encroaching upon established setbacks.

CROP LAND shall mean lands which are cultivated, mechanically or manually harvested, or irrigated for vegetative agricultural production.

CUBIC FOOT of gas shall mean the volume of gas contained in one (1) cubic foot of space at a standard pressure base and a standard temperature base. The standard pressure base shall be fourteen point seventy three (14.73) psia, and the standard temperature base shall be sixty degrees fahrenheit (60°F).

D-J BASIN FOX HILLS PROTECTION AREA shall mean that area of the state consisting of Townships 5 South through Townships 5 North, Ranges 58 West through 70 West, and Township 6 South, Ranges 65 West through 70 West.

DAY shall mean a period of twenty-four (24) consecutive hours.

DEDICATED INJECTION WELL shall mean any well as defined under 40 C.F.R. §144.5 B, 1992 Edition, (adopted by the U.S. Environmental Protection Agency) used for the exclusive purpose of injecting fluids or gas from the surface. The definition of a dedicated injection well does not include gas storage wells.

DESIGNATED AGENT when used herein shall mean the designated representative of any producer, operator, transporter, refiner, gasoline or other extraction plant operator, or initial purchaser.

DESIGNATED OUTSIDE ACTIVITY AREAS shall mean a well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by twenty (20) or more persons on at least forty (40) days in any twelve (12) month period or by at least five hundred (500) or more people on at least three (3) days in any twelve (12) month period.

DIRECTOR shall mean the Director of the Oil and Gas Conservation Commission of the State of Colorado or any member of the Director's staff authorized to represent the Director.

DOMESTIC GAS WELL shall mean a gas well that produces solely for the use of the surface owner. The gas produced cannot be sold, traded or bartered.

DRILLING PITS shall mean those pits used during drilling operations and initial completion of a well, and include:

ANCILLARY PITS used to contain fluids during drilling operations and initial completion procedures, such as circulation pits and water storage pits.

COMPLETION PITS used to contain fluid during initial completion procedures, and not originally constructed for use in drilling operations.

RESERVE PITS used to store drilling fluids for use in drilling operations or to contain E&P waste generated during drilling operations and initial completion procedures.

EDUCATIONAL FACILITY shall mean any building used for legally allowed educational purposes for more than twelve (12) hours per week for more than six (6) persons. This includes any building or portion of building used for licensed day-care purposes for more than six (6) persons.

EMERGENCY ORDER shall mean an order issued by the Commission pursuant to §34-60-108(3), C.R.S.

EMERGENCY SITUATION for purposes of §34-60-121(5), C.R.S., and the rules promulgated thereunder shall mean a fact situation which presents an immediate danger to public health, safety or welfare.

EXPLORATION AND PRODUCTION WASTE (E&P WASTE) shall mean those wastes associated with operations to locate or remove oil or gas from the ground or to remove impurities from such substances, and which are uniquely associated with and intrinsic to oil and gas exploration, development or production operations of which are exempt from regulation under Subtitle C of the Resource Conservation and Recovery Act (RCRA), 42 USC Sections 6921, et. seq. For a waste to be considered an E&P waste, it shall be associated with operations to locate or remove oil or gas from the ground or to remove impurities from such substances and it shall be intrinsic to and uniquely associated with oil and gas exploration, development or production. For natural gas, primary field operations include those production-related activities at or near the wellhead and at the gas plant (regardless of whether or not the gas plant is at or near the wellhead), but prior to transport of the natural gas from the gas plant to market. In addition, uniquely associated wastes derived from the production stream along the gas plant feeder pipelines are considered E&P wastes, even if a change of custody in the natural gas has occurred between the wellhead and the gas plant. In addition, wastes uniquely associated with the operations to recover natural gas from underground storage fields are considered to be E&P waste.

FIELD shall mean the general area which is underlaid or appears to be underlaid by at least one (1) pool; and "field" shall include the underground reservoir or reservoirs containing oil or gas or both. The words "field" and "pool" mean the same thing when only one (1) underground reservoir is involved; however, "field", unlike "pool", may relate to two (2) or more pools.

FINANCIAL ASSURANCE shall mean a surety bond, cash collateral, certificate of deposit, letter of credit, sinking fund, escrow account, lien on property, security interest, guarantee, or other instrument or method in favor of and acceptable to the Commission. With regard to third party liability concerns related to public health, safety and welfare, the term encompasses general liability insurance.

FLOWLINES shall mean those segments of pipe from the wellhead downstream through the production facilities ending at:

In the case of gas lines, the gas metering equipment; or
In the case of oil lines, the oil loading point or LACT unit; or

GAS FACILITY shall mean those facilities that process or compress natural gas after production-related activities which are conducted at or near the wellhead and prior to a point where the gas is transferred to a carrier for transport.

GAS STORAGE WELL means any well drilled for the injection, withdrawal, production, observation, and/or monitoring of natural gas stored in underground formations. The fact that any such well is used incidentally for the production of native gas or the enhanced recovery of native hydrocarbons shall not affect its status as a gas storage well.

GAS WELL shall mean a well, the principal production of which at the mouth of the well is gas, as defined by the Act.

GROUND WATER means subsurface waters in a zone of saturation.

HIGH DENSITY AREA shall mean any tract of land determined to be a high density area in accordance with Rule 603.b.

HOSPITAL, NURSING HOME, BOARD AND CARE FACILITIES shall mean buildings used for the licensed care of more than five (5) in-patients or residents.

INACTIVE WELL shall mean any shut-in well from which no production has been sold for a period of twelve (12) consecutive months; any well which has been temporarily abandoned for a period of six (6) consecutive months; or, any injection well which has not been utilized for a period of twelve (12) consecutive months.

INDIAN LANDS shall mean those lands located within the exterior boundaries of a defined Indian reservation, including allotted Indian lands, in which the legal, beneficial, or restricted ownership of the underlying oil, gas, or coal bed methane or of the right to explore for and develop the oil, gas, or coal bed methane belongs to or is leased from an Indian tribe.

INTERVENOR shall mean a local government intervening solely to raise environmental or public health, safety and welfare concerns in which case the intervention shall be granted of right, or a person who has timely filed an intervention in a relevant proceeding and has demonstrated to the satisfaction of the commission that the intervention will serve the public interest, in which case the person may be recognized as a permissive intervenor at the Commission’s discretion.

JAIL shall mean those structures where the personal liberties of occupants are restrained, including but not limited to, mental hospitals, mental sanitariums, prisons, reformatories.

LAND APPLICATION shall mean the disposal method by which E&P waste is spread upon or sometimes mixed into soils.

LAND TREATMENT shall mean the treatment method by which E&P waste is applied to soils and treated to result in a reduction of hydrocarbon concentration by biodegradation and other natural attenuation processes. Land treatment may be enhanced by tilling, disking, aerating, composting and the addition of nutrients or microbes.

LOCAL GOVERNMENT means a county, home rule or statutory city, town, territorial charter city or city and county, or any special district established pursuant to the Special District Act, §32-1-101, C.R.S. to §32-1-1505, C.R.S.

LOCAL GOVERNMENTAL DESIGNEE means the office designated to receive, on behalf of the local government, copies of all documents required to be filed with the local governmental designee pursuant to these rules.

LOG or WELL LOG shall mean a systematic detailed record of formations encountered in the drilling of a well.

MULTI-WELL PITS shall mean pits used for treatment or disposal of E&P wastes generated from more than one (1) well.

MULTI-WELL SITE shall mean a common well pad from which multiple wells may be drilled to various bottomhole locations.

NON-CROP LAND shall mean all lands which are not defined as crop land, including range land.

OIL AND GAS OPERATIONS means exploration for oil and gas, including the conduct of seismic operations and the drilling of test bores; the siting, drilling, deepening, recompletion, reworking, or abandonment of an oil and gas well, underground injection well, or gas storage well; production operations related to any such well including the installation of flowlines and gathering systems; the generation, transportation, storage, treatment, or disposal of exploration and production wastes; and any construction, site preparation, or reclamation activities associated with such operations.

OIL WELL shall mean a well, the principal production of which at the mouth of the well is oil, as defined by the Act.

ORPHANED SITE shall mean a site, where a significant adverse environmental impact may be or has been caused by oil and gas operations for which no responsible party can be found, or where such responsible party is unwilling or unable to mitigate such impact.

ORPHAN WELL shall mean a well for which no owner or operator can be found, or where such owner or operator is unwilling or unable to plug and abandon such well.

OWNER shall mean the person who has the right to drill into and produce from a pool and to appropriate the oil or gas produced therefrom either for such owner or others or for such owner and others, including owners of a well capable of producing oil or gas, or both.

PIT shall mean any natural or man-made depression in the ground used for oil or gas exploration or production purposes. Pit does not include steel, fiberglass, concrete or other similar vessels which do not release their contents to surrounding soils.

PLUGGING AND ABANDONMENT shall mean the cementing of a well, the removal of its associated production facilities, the removal or abandonment in-place of its flowline, and the remediation and reclamation of the wellsite.

POINT OF COMPLIANCE means one (1) or more points or locations at which compliance with applicable ground water standards established under Water Quality Control Commission Basic Standards for Ground Water, §3.11.4, must be achieved.

POLLUTION means man-made or man-induced contamination or other degradation of the physical, chemical, biological, or radiological integrity of air, water, soil, or biological resource.

The words **POOL, PERSON, OWNER, PRODUCER, OIL, GAS, WASTE, CORRELATIVE RIGHTS and COMMON SOURCE OF SUPPLY** are defined by the Act, and said definitions are hereby adopted in these rules and Regulations. The word "operator" is used in these rules and regulations and accompanying forms interchangeably with the same meaning as the term "owner" except in Rules 301., 325., and 401. where the word "operator" is used to identify the persons designated by the owner or owners to perform the functions covered by those rules.

PRODUCED AND MARKETED as used in the Act, shall mean, when oil shall have left the lease tank battery or when natural gas shall have passed the metering point and entered into the stream of commerce as its first step toward the ultimate consumer.

PRODUCTION FACILITIES shall mean all storage, separation, treating, dehydration, artificial lift, power supply, compression, pumping, metering, monitoring, flowline, and other equipment directly associated with oil wells, gas wells, or injection wells.

PRODUCTION PITS shall mean those pits used after drilling operations and initial completion of a well, including natural gas gathering, processing and storage facility pits, multi-well pits and:

SKIMMING/SETTLING PITS used to provide retention time for settling of solids and separation of residual oil.

PRODUCED WATER PITS used to temporarily store produced water prior to injection for enhanced recovery or disposal, off-site transport, or surface-water discharge.

PERCOLATION PITS used to dispose of produced water by percolation and evaporation through the bottom and/or sides of the pits into surrounding soils.

EVAPORATION PITS used to contain produced waters which evaporate into the atmosphere by natural thermal forces.

PROTESTANT shall mean a person who has timely filed a protest in a relevant proceeding and has demonstrated to the Commission's satisfaction that the person filing the protest would be directly and adversely affected or aggrieved by the Commission's ruling in the proceeding, and that any injury or threat of injury sustained would be entitled to legal protection under the Act.

RELEASE shall mean any unauthorized discharge of E&P waste to the environment over time.

REMEDIATION shall mean the process of reducing the concentration of a contaminant or contaminants in water or soil to the extent necessary to ensure compliance with the allowable concentrations and levels in Table 910-1 and other applicable ground water standards and classifications.

RESERVE PITS shall mean those pits used to store drilling fluids for use in drilling operations or to contain E&P waste generated during drilling operations.

RESPONDENT shall mean a party against whom a proceeding is instituted, or a **PROTESTANT** who protests the granting of the relief sought in the application as provided in Rule 509.

RESPONSIBLE PARTY shall mean a person who conducts an oil and gas operation in a manner which is in contravention of any then-applicable provision of the Act, or of any rule, regulation, or order of the Commission, or of any permit, that threatens to cause, or actually causes, a significant adverse environmental impact to any air, water, soil, or biological resource. **RESPONSIBLE PARTY** includes any person who disposes of any other waste by mixing it with exploration and production waste so as to threaten to cause, or actually cause, a significant adverse environmental impact to any air, water, soil, or biological resource.

SEISMIC OPERATIONS shall mean all activities associated with acquisition of seismic data including but not limited to surveying, shothole drilling, recording, shothole plugging and reclamation.

SENSITIVE AREA is an area vulnerable to potential significant adverse ground water impacts, due to factors such as the presence of shallow economically usable ground water or pathways for communication with deeper economically usable ground water; proximity to surface water, including lakes, rivers, perennial or intermittent streams, creeks, irrigation canals, and wetlands. The procedure for identifying Sensitive Areas is set forth in the Sensitive Area Identification Decision Tree and Guidance Document.

SHUT-IN WELL shall mean a well which is capable of production or injection by opening valves, activating existing equipment or supplying a power source.

SIMULTANEOUS INJECTION WELL shall mean any well in which water produced from oil and gas producing zones is injected into a lower injection zone and such water production is not brought to the surface.

SPECIAL FIELD RULES shall mean those rules promulgated for and which are limited in their application to individual pools or fields within the State of Colorado.

SPECIAL PURPOSE PITS shall mean those pits used in oil and gas operations, including natural gas gathering, processing and storage facility pits, multi-well pits, and:

BLOWDOWN PITS used to collect material resulting from, including but not limited to, the emptying or depressurizating of wells, vessels, or gas gathering systems.

FLARE PITS used exclusively for flaring gas.

EMERGENCY PITS used to contain liquids on a temporary basis due to process upset conditions.

BASIC SEDIMENT/TANK BOTTOM PITS used to temporarily store or treat the extraneous materials in crude oil which may settle to the bottoms of tanks or production vessels and which may contain residual oil.

WORKOVER PITS used to contain liquids during the performance of remedial operations on a producing well in an effort to increase production.

PLUGGING PITS used for containment of fluids encountered during the plugging process.

SPILL shall mean any unauthorized sudden discharge of E&P waste to the environment.

STRATIGRAPHIC WELL means a well drilled for stratigraphic information only. Wells drilled in a delineated field to known productive horizons shall not be classified as "stratigraphic". Neither the term "well" nor "stratigraphic well" shall include seismic holes drilled for the purpose of obtaining geophysical information only.

SUBSURFACE DISPOSAL FACILITY means a facility or system for disposing of water or other oil field wastes into a subsurface reservoir or reservoirs.

TEMPORARILY ABANDONED WELL shall mean a well which is incapable of production or injection without the addition of one or more pieces of wellhead or other equipment, including valves, tubing, rods, pumps, heater-treaters, separators, dehydrators, compressors, piping or tanks.

VOLUNTARY SELF-EVALUATION shall mean a self-initiated assessment, audit, or review, not otherwise expressly required by environmental law, that is performed by any person or entity, for itself, either by an employee or employees employed by such person or entity who are assigned the responsibility of performing such assessment, audit, or review or by a consultant engaged by such person or entity expressly and specifically for the purpose of performing such assessment, audit, or review to determine whether such person or entity is in compliance with environmental laws.

WATERS OF THE STATE mean any and all surface and subsurface waters which are contained in or flow in or through this state, but does not include waters in sewage systems, waters in treatment works of disposal systems, water in potable water distribution systems, and all water withdrawn for use until use and treatment have been completed. Waters of the state include, but are not limited to, all streams, lakes, ponds, impounding reservoirs, wetlands, watercourses, waterways, wells, springs, irrigation ditches or canals, drainage systems, and all other bodies or accumulations of water, surface and underground, natural or artificial, public or private, situated wholly or partly within or bordering upon the state.

WELL when used alone in these Rules and Regulations, shall mean an oil or gas well, a hole drilled for the purpose of producing oil or gas, a well into which fluids are injected, a stratigraphic well, a gas storage well, or a well used for the purpose of monitoring or observing a reservoir.

WELL SITE shall mean the areas which are directly disturbed during the drilling and subsequent operation of, or affected by production facilities directly associated with, any oil well, gas well, or injection well.

WILDCAT (Exploratory) WELL means any well drilled beyond the known producing limits of a pool.

ZONE OF INCORPORATION shall mean the soil layer from the soil surface to a depth of twelve (12) inches below the surface.

ALL OTHER WORDS used herein shall be given their usual customary and accepted meaning, and all words of a technical nature, or peculiar to the oil and gas industry, shall be given that meaning which is generally accepted in said oil and gas industry.

GENERAL RULES

201. EFFECTIVE SCOPE OF RULES AND REGULATIONS

All rules and regulations of a general nature herein promulgated to prevent waste and to conserve oil and gas in the State of Colorado shall be effective throughout the State of Colorado and be in force in all pools and fields except as may be amended, modified, altered or enlarged generally or in specific individual pools or fields by orders heretofore or hereafter issued by the Commission, and except where special field rules apply, in which case the special field rules shall govern to the extent of any conflict.

202. OFFICE AND DUTIES OF DIRECTOR

The office of Director of the Commission is hereby created. It shall be the duty of the Director to aid the Commission in the administration of the Act, as may be required of the Director from time to time and to act as Hearing Officer when so directed by the Commission.

203. OFFICE AND DUTIES OF SECRETARY

The office of Secretary to the Commission is hereby created. The duties of the Secretary shall be as determined from time to time by the Commission.

204. GENERAL FUNCTIONS OF DIRECTOR

The Director and the authorized deputies shall also have the right at all reasonable times to go upon and inspect any oil and/or gas properties, disposal facilities, or transporters facilities and wells for the purpose of making any investigation or tests to ascertain whether the provisions of the Act or these rules or any special field rules are being complied with, and shall report any violation thereof to the Commission.

205. ACCESS TO RECORDS

All producers, operators, transporters, refiners, gasoline or other extraction plant operators and initial purchasers of oil and gas within this state, shall make and keep appropriate books and records covering their operations in the state from which they may be able to make and substantiate the reports required by the Commission. Such books, records and copies of said reports required by the Commission shall be kept on file and available for inspection by the Commission for a period of at least five (5) years. The Director and the authorized deputies shall have access to all well records wherever located. All owners, drilling contractors, drillers, service companies, or other persons engaged in drilling or servicing wells, shall permit the Director, or authorized deputy, at the Director's or their risk, in the absence of negligence on the part of the owner, to come upon any lease, property or well operated or controlled by them, and to inspect the record and operation of such wells and to have access at all times to any and all records of wells; provided, that information so obtained shall be kept confidential and shall be reported only to the Commission or its authorized agents.

206. REPORTS

All producers, operators, transporters, refiners, gasoline and other extraction plant operators and initial purchasers of oil and gas within the state shall from time to time file accurate and complete reports containing such information and covering such periods as the Commission shall require.

207. TESTS AND SURVEYS

a. **Tests and surveys**. When deemed necessary or advisable, the Commission is authorized to require that tests or surveys be made to determine the presence of waste or occurrence of pollution. The Commission, in calling for reports under Rule 206. and tests or surveys to be made as provided in this rule, shall designate the time allowed the operator for compliance, which provisions as to time shall prevail over any other time provisions in these rules.

b. **Bradenhead monitoring**.

(1) The Director shall have authority to designate specific fields or portions of fields as bradenhead test areas within which, on any well, the bradenhead access to the annulus between the production and surface casing, as well as any intermediate casing, shall be equipped with fittings to allow safe and convenient determinations of pressure and fluid flow. Any such proposed designation shall occur by notice describing the proposed bradenhead test area. Such notice shall be given to all operators of record within such area and by publication. The proposed designation, if no protests are timely filed, shall be placed upon the Commission consent agenda for the regular monthly meeting of the Commission following the month in which such notice is given, and shall be approved or heard by the Commission in accordance with Rule 520. Such designation shall be effective immediately, upon approval by the Commission.

(2) All operators within any bradenhead test area shall have thirty (30) days after the effective date of the designation to commence the taking of bradenhead pressure readings in all wells located therein which are equipped for such readings. The operator shall equip any well which is not so equipped within ninety (90) days of the effective date, and within thirty (30) days thereafter the operator shall take the required reading. Such readings shall include the date, time and pressure of each reading, and the type of fluid reported. Such readings shall be taken in bradenhead test areas annually, maintained at the operator's office for a period of five (5) years, and shall be reported to the Director upon written request.

208. CORRECTIVE ACTION

The Commission shall require correction, in a manner to be prescribed or approved by it, of any condition which is causing or is likely to cause waste or pollution; and require the proper plugging and abandonment of any well or wells no longer used or useful in accordance with such reasonable plan as may be prescribed by it.

209. PROTECTION OF COAL SEAMS AND WATER-BEARING FORMATIONS

In the conduct of oil and gas operations each owner shall exercise due care in the protection of coal seams and water-bearing formations as required by the applicable statutes of the State of Colorado.

Special precautions shall be taken in drilling and abandoning wells to guard against any loss of artesian water from the stratum in which it occurs and the contamination of fresh water by objectionable water, oil, or gas. Before any oil or gas well is completed as a producer, all oil, gas and water strata above and below the producing horizon shall be sealed or separated in order to prevent the intermingling of their contents.

210. SIGNS AND MARKERS

The operator shall mark each and every well in a conspicuous place, from the time of initial drilling until final abandonment, as follows:

a. **Drilling and Recompletion Operations**. Directional signs, no less than three (3) and no more than six (6) square feet in size, shall be provided during any drilling or recompletion operation, by the operator or drilling contractor. Such signs shall be at locations sufficient to advise emergency crews where drilling is taking place; at a minimum, such locations shall include (i) the first point of intersection of a public road and the rig access road and (ii) thereafter at each intersection of the rig access route, except where the route to the rig is clearly obvious to uninformed third parties. Signs not necessary to meet other obligations under these rules shall be removed as soon as practicable after the operation is complete.

b. **Permanent Designations**.

(1) **Wells**. Within sixty (60) days after the completion of a well, a permanent sign shall be located at the wellhead, which shall identify the well and provide its legal location, including the quarter quarter section. When no associated battery is present, the additional information required under Rule 210.b.(2) shall be required on the sign.

(2) **Batteries**. Within sixty (60) days after the installation of a battery, a permanent sign shall be located at the battery. At the option of the operator, or at the request of local emergency response authorities, the sign may be placed at the intersection of the lease access road with a public, farm or ranch road if the referenced battery is readily apparent from such location. Such sign, which shall be no less than three (3) square feet and no more than six (6) square feet, shall provide: the name of the operator; a phone number at which the operator can be reached at all times; a phone number for local emergency services (911 where available); the lease name or well name(s) associated with the battery; the public road used to access the site; and, the legal location, including the quarter-quarter section. In lieu of providing the legal location on the permanent sign, it may be stenciled on a tank in characters visible from one hundred (100) feet.

c. **Centralized E&P Waste Management Facilities**. The main point of access to a centralized E&P waste management facility shall be marked by a sign captioned “(operator name) E&P Waste Management Facility”. Such sign, which shall be no less than three (3) square feet and no more than six (6) square feet shall provide: a phone number at which the operator can be reached at all times; a phone number for local emergency services (911 where available); the public road used to access the facility; and the legal location, including quarter quarter section, of the facility.

d. **General sign requirements**. No sign required under this Rule 210. shall be installed at a height exceeding six (6) feet. Operators shall maintain signs in a legible condition, and shall replace damaged or vandalized signs within sixty (60) days. New operators shall update signs within sixty (60) days after change of operator approval is received from the Commission.

211. NAMING OF FIELDS

All oil and gas fields discovered in the state subsequent to the adoption of these rules and regulations shall be named by the Director or at the Director's direction.

212. SAFETY

For safety regulations regarding industry personnel, contact the U.S. Department of Labor, Occupational Safety and Health Administration, Regional Administrator, Colorado Region VIII, 1999 Broadway, Suite 1690, Denver, Colorado 80202, telephone (303) 391-5858. For State Safety regulations regarding public safety see Rules 601-607.

213. FORMS UPON REQUEST

Forms required by the Commission will be furnished upon request. (Please see Procedures and Forms Guidelines)

214. LOCAL GOVERNMENTAL DESIGNEE

Each local government which designates an office for the purposes set forth in the 100 Series shall provide the Commission written notice of such designation, including the name, address and telephone number, facsimile number, electronic mail address, local emergency dispatch and other emergency numbers of the local governmental designee. It shall be the responsibility of such local governmental designee to ensure that all documents provided to the local governmental designee by oil and gas operators and the Commission or the Director are distributed to the appropriate persons and offices.

DRILLING, DEVELOPMENT, PRODUCING AND ABANDONMENT

301. RECORDS, REPORTS, NOTICES-GENERAL

Any written notice of intention to do work or to change plans previously approved must be filed with the Director, and must reach the Director and receive approval before the work is begun, or such approval may be given orally and, if so given, shall thereafter be confirmed to the Director in writing.

In case of emergency, or any situation where operations might be unduly delayed, any notice or information required by these rules and regulations to be given to the Director may be given orally or by wire, and if approval is obtained the transaction shall be promptly confirmed in writing to the Director, as a matter of record.

Immediate notice shall be given to the Director when public health or safety is in jeopardy. Notice shall also be given to the Director of any other significant downhole problem or mechanical failure in any well within ten (10) days.

The owner shall keep on the leased premises, or at the owner's headquarters in the field, or otherwise conveniently available to the Director, accurate and complete records of the drilling, redrilling, deepening, repairing, plugging or abandoning of all wells, and of all other well operations, and of all alterations to casing. These records shall show all the formations penetrated, the content and quality of oil, gas or water in each formation tested, and the grade, weight and size, and landed depth of casing used in drilling each well on the leased premises, and any other information obtained in the course of well operation. Such records on each well shall be maintained by any subsequent owner.

Whenever a person has been designated as an operator by an owner or owners of the lease or well, such an operator may submit the reports as herein required by the Commission.

302. COGCC Form 1. REGISTRATION FOR OIL AND GAS OPERATIONS

a. Prior to the commencement of its operations, all producers, operators, transporters, refiners, gasoline or other extraction plant operators, and initial purchasers who are conducting operations subject to this Act in the State of Colorado, shall, for purposes of the Act, file a Registration For Oil and Gas Operations, Form 1, with the Director in the manner and form approved by the Commission. Any producer, operator, transporter, refiner, gasoline or other extraction plant operator, and initial purchaser conducting operations subject to the Act who has not previously filed a Registration For Oil and Gas Operations, Form 1 shall do so. Any person providing financial assurance for oil and gas operators in Colorado shall file a Form 1 with the Director. All changes of address of the parties required to file a Form 1 shall be immediately reported by submitting a new Form 1.

b. Any party may act on or for the behalf of the owner/operator provided the owner/operator has filed a Designation of Agent, Form 1A. This agent shall remain in effect until it is terminated in writing by the owner/operator. All changes of address of the agent shall be immediately reported by submitting a new Form 1A.

303. COGCC Form 2. APPLICATION FOR PERMIT-TO-DRILL, DEEPEN, RE-ENTER, OR RECOMPLETE, AND OPERATE

a. Before any person shall commence operations for the drilling or re-entry of any well, such person shall file with the Director an application on Form 2 for a permit-to-drill, along with a filing and service fee established by the Commission (see Appendix III), and shall secure the Director's approval before commencement of operations with heavy equipment. The permit-to-drill shall be binding with respect to any conflicting local governmental permit or land use approval process. Wells drilled for stratigraphic information only shall be exempt from paying the filing and service fee. The re-entry of a well in a unitized, storage, or secondary recovery operation is exempt from the provisions of this rule and notice of intent to re-enter a well shall be filed on a Sundry Notice, Form 4.

b. A request to recomplete or deepen a well to a different reservoir shall be filed on an Application for Permit-to-Drill, Form 2, with a filing and service fee established by the Commission (see Appendix III), along with a Sundry Notice, Form 4, detailing the work, and a wellbore diagram.

c. Attached to and part of the Permit-to-Drill, Form 2, as filed shall be a current 8 1/2" by 11" scaled drawing of the entire section(s) containing the proposed well location with the following minimum information:

(1) Dimensions on adjacent exterior section lines sufficient to completely describe the quarter section containing the proposed well shall be indicated. If dimensions are not field measured, state how the dimensions were determined.

(2) For directional drilling into an adjacent section, that section shall also be shown on the location plat and dimensions on exterior section lines sufficient to completely describe the quarter section containing the proposed productive interval and bottom hole location shall be indicated. (Additional requirements related to directional drilling are found in Rule 321.)

(3) For irregular, partial or truncated sections, dimensions will be furnished to completely describe the entire section containing the proposed well.

(4) The field-measured distances from the nearer north/south and nearer east/west section lines shall be measured at ninety (90) degrees from said section lines to the well location and referenced on the plat. For unsurveyed land grants and other areas where an official public land survey system does not exist, the well locations shall be spotted as footages on a protracted section plat using Global Positioning System (GPS) technology and also reported as latitude and longitude in accordance with the requirements set forth below:

A. All GPS data reported to the Commission shall be differentially corrected using base station data or other correction sources. The base station or other correction source shall be identified and reported with the coordinate values.

B. Coordinates shall be reported as latitude and longitude in decimal degrees to an accuracy of at least five (5) decimal places (e.g.; latitude 37.12345 N, longitude 104.45632 W).

C. All data shall be referenced to the North American Datum (NAD) of 1927.

D. The date of the survey shall be reported.

(5) A map legend.

(6) A north arrow.

(7) A scale expressed as an equivalent (e.g. - 1" = 1000').

(8) A bar scale.

(9) The ground elevation.

(10) The basis of the elevation (how it was calculated or its source).

(11) The basis of bearing or interior angles used.

(12) Complete description of monuments and/or collateral evidence found; all aliquot corners used shall be described.

(13) The legal land description by section, township, range, principal meridian, baseline and county.

(14) Operator name.

(15) Well name and well number.

(16) Date of completion of scaled drawing.

(17) All visible improvements within two hundred (200) feet of a wellhead (or, in a high density area within four hundred (400) feet of a wellhead) shall be physically tied in and plotted on the well location plat or on an addendum, with a horizontal distance and approximate bearing from the well location. Visible improvements shall include, but not be limited to, all buildings, publicly maintained roads and trails, major above-ground utility lines, railroads, pipelines, mines, oil wells, gas wells, injection wells, water wells, visible plugged wells, sewers with manholes, standing bodies of water, and natural channels including permanent canals and ditches through which water flows. If there are no visible improvements within two hundred (200) feet of a wellhead (or in a high density area within four hundred (400) feet of a wellhead), it shall be so noted on the Permit-to-Drill, Form 2.

(18) Surface use shall be described within the two hundred (200) foot radius of a wellhead (or in a high density area within the four hundred (400) foot radius of a wellhead).

(19) In addition to the scaled drawing, the applicant shall attach to the Permit-to-Drill, Form 2, an 8½" by 11" vicinity or U.S.G.S. topographic map of at least a three (3) mile radius around the proposed well which clearly shows access from one (1) or more public roads, a map showing surface and mineral lease ownership within two hundred (200) feet of a wellhead (or in a high density area within four hundred (400) feet of a wellhead). Where the applicant is not the lessee, mineral ownership shall be described for the entire drilling and spacing unit.

303.d. Form 2/2A application and copies to local governmental designees. In addition to the above, an applicant filing a Permit-to-Drill, Form 2, shall also attach a completed Form 2A, except that the Form 2A shall not be required on federal or Indian owned surface lands when a Federal 13 Point Surface Use Plan is included. The Form 2A requires the attachment of a minimum of two (2) color photographs; one (1) of the staked location and one (1) of the existing or proposed access road. Each photograph shall be identified by: date taken, well name, location and direction of view. Permit-to-Drill, Form 2, shall be filed with the Director in triplicate for wells on all patented, state and federal surface lands. A single, informational (not official notice) copy of the Permit-to-Drill, Form 2 and Form 2A and all attachments shall be delivered by the applicant to the local governmental designee(s) of the county or municipal corporation within whose jurisdiction the activity is occurring or is proposed to occur at or before the time of filing with the Director. It shall be the responsibility of the Director to promptly provide the local governmental designee(s) with formal notification of the filing of the Permit-to-Drill, Form 2. Such notice is to be sent by facsimile if requested, and, if not, then by first class U.S. Mail. Any comments from the local government designee concerning the Permit-to-Drill, Form 2, and Form 2A as filed shall be provided to the Director and to the applicant in writing within ten (10) days after the date on which the Permit-to-Drill, Form 2 was sent to the local government designee(s) by the Director. The Director shall take no action with respect to the Permit-to-Drill, Form 2, prior to the expiration of the ten (10) day period, except under the circumstances provided for in Rule 303.j(1) and (2), or when the Director has received notice from the local governmental designee(s) waiving the ten (10) day period. Upon written request to the Director received prior to the expiration of the ten (10) day period, the local government designee shall be granted an extension of up to twenty (20) additional days to consider the application. If, prior to the expiration of the comment period provided herein and after participation in an onsite consultation under Rule 306.a.(3), the local governmental designee files an application for hearing on the permit-to-drill, Form 2, under Rule 503.b.(6), alleging significant impacts on public health, safety and welfare, including the environment, the director shall withhold the issuance of such permit and the provisions of Rule 303.k. shall apply.

e. **Well sites and access roads in wetlands.** In the event that an operator acquires an Army Corps of Engineers permit pursuant to 33 U.S.C.A. §1342 and 1344 of the Water Pollution and Control Act (Section 404 of the federal Clean Water Act) for construction of a wellsite, access road, or production facility, the operator shall so indicate on the Form 2A.

f. **Revisions to Form 2/2A.** Prior to approval of the Form 2/2A, minor revisions or requested information may be provided by contacting the COGCC staff. After approval, any substantive changes shall be submitted for approval on a Form 2/2A. A Sundry Notice, Form 4, shall be submitted when non-substantive revisions are made after approval, and no additional fee shall be imposed.

g. **Incomplete applications.** Applications for permit-to-drill which are submitted without the necessary attachments, the proper signature or the required information shall be considered incomplete and shall not be approved. The COGCC staff shall notify the applicant in not more than thirty (30) days of permit application receipt of such inadequacies. The applicant shall then have thirty (30) days from the date which they were contacted to correct and/or provide requested information for that well, otherwise the permit application shall be considered withdrawn and the fee shall not be refunded.

h. **Permit expiration.** If operations are not commenced on the permitted well within one (1) year after date of approval, the permit shall become null and void. The Director shall not approve extensions to applications for Permit-to-Drill, Form 2.

i. **Permits in areas pending Commission hearing.** The Director may withhold the issuance of a permit and the granting of approval of any Permit-to-Drill, Form 2, for any well or proposed well that is located in an area for which an application has been filed, or which the Commission has sought, by its own motion, to establish drilling units or to designate any tract of land as a high density area, in which case the hearing thereon shall be held at the next meeting of the Commission at which time the matter can be legally heard.

j. **Special circumstances for permit issuance without notice or consultation.** The Director may issue a permit at any time in the event that an operator files a sworn statement and demonstrates therein to the Director's satisfaction that:

(1) The operator had the right or obligation under the terms of an existing contract to drill a well; and the owner or operator has a leasehold estate or a right to acquire a leasehold estate under said contract which will be terminated unless the operator is permitted to immediately commence the drilling of said well; or

(2) Due to exigent circumstances (including a recent change in geological interpretation), significant economic hardship to a drilling contractor will result or significant economic hardship to an operator in the form of drilling standby charges will result.

In the event the Director issues a permit under this rule, the operator shall not be required to meet obligations to surface owners and local governmental designees under Rules 303.d., 305.b.(1) & (3), and 306.a. The Director shall report permits granted in such manner to the Commission at regularly scheduled monthly hearings.

k. **Withholding Permit-to-Drill, Form 2, approval.** The Director may withhold the issuance of a permit and the granting of approval of any Permit-to-Drill, Form 2, for any proposed well when, based on information supplied by a surface owner or by staff analysis, and where appropriate as confirmed by an onsite inspection, the Director has reasonable cause to believe that a proposed well location raises significant concerns regarding potential significant adverse impacts to public health, safety and welfare, including the environment. If a request is made by a local governmental designee under Rules 303.d. and 503.b.(6), such application shall be granted and the director shall withhold issuance of the permit-to-drill, Form 2, unless the local government has been disqualified from making such request under Rule 501.b. Any hearing granted pursuant to this rule shall be expedited and the matter shall be heard at the next scheduled commission hearing, and all parties shall be deemed to have waived any notice requirements to the contrary. In the event such approval is not granted, when requested by the operator, the Director shall ask the Commission to issue an emergency order under Rule 502.a. suspending approval of the Permit-to-Drill for such well and setting the matter for the next hearing. The Director shall use best efforts to notify the applicant, local governmental designee, surface owner and other interested parties as applicable of such request in order that such parties may participate in the Commission's emergency consideration of the matter

l. **Reclassification of stratigraphic well.** If a test for productivity is made in a stratigraphic well, the well must be reclassified as a well drilled for oil or gas and is subject to all of the rules and regulations for a well drilled for oil or gas, including filing of reports and mechanical logs.

304. FINANCIAL ASSURANCE REQUIREMENTS

Prior to drilling or assuming the operations for a well an operator shall provide financial assurance in accordance with the 700 Series rules. When an operator's existing wells are not in compliance with the 700 Series, the Director may withhold action on an Application for Permit-to-Drill, Form 2, until such time as a hearing on the permit application is held by the Commission. Such hearing shall be held at the next regularly scheduled Commission hearing at which time the matter can be legally heard.

305. NOTICES OF OIL AND GAS OPERATIONS

a. The provisions of this Rule 305. shall not be applicable on federal or Indian owned surface lands.

b. **Notices.**

(1) **Notice of drilling.** Before an operator shall commence operations for the drilling of any well, such operator shall evidence its intention to conduct such operations by giving the surface owner and local governmental designee written notice thereof as provided in subparagraph c. below. Such notice of drilling shall be mailed or hand delivered to the surface owner not less than thirty (30) days prior to the date of estimated commencement of operations with heavy equipment as set forth in the notice and shall be mailed to the local governmental designee not less than thirty (30) days prior to the date of estimated commencement of operations with heavy equipment as set forth in the notice. Operators shall retain a record of such notice of drilling for a minimum of one (1) year. Such written notice also shall be posted on or near the proposed drillsite at least thirty (30) days prior to commencement of operations with heavy equipment. If notice for the commencement of operations is waived by the surface owner under this rule, the local governmental designee notice under this Rule 305.b. shall be received no later than the business day preceding commencement of operations with heavy equipment. The operator shall confirm that the surface owner notice requirements of this Rule 305.b. have been completed or waived before the Director approves an Application for Permit-to-Drill, Form 2.

(2) **Notice of subsequent well operations.** Before an operator shall commence subsequent well operations, such operator shall evidence its intention to conduct such operations by giving the surface owner

written notice thereof in accordance with paragraph c. below. **Subsequent well operations** shall mean those operations that will materially impact surface areas beyond the existing access road or well site for any well, including operations such as fracturing or recompletion of the well but shall not include routine service and maintenance operations including but not limited to the changing of pumps. The notice of subsequent operations shall be mailed or hand delivered not less than seven (7) days prior to the date of estimated commencement of operations with heavy equipment as set forth in the notice.

(3) **Notice during irrigation season.** If a well is to be drilled on irrigated crop lands between March 1 and October 31, the operator, in addition to meeting the consultation requirements of Rule 306., shall contact the surface owner, or at the request of the surface owner, the tenant at least fourteen (14) days prior to the commencement of surface activities by the operator and arrange to coordinate drilling operations to avoid unreasonable interference with irrigation plans and activities.

(4) **Final reclamation notice.** The following notice requirements shall apply only to final reclamation operations commenced more than thirty (30) days after the completion of a well.

A. Not less than thirty (30) days before any final reclamation operations are to take place pursuant to Rule 1004., the operator shall notify the surface owner in accordance with paragraph c. below. Final reclamation operations shall mean those reclamation operations to be undertaken when a well is to be plugged and abandoned or when production facilities are to be permanently removed.

B. Not less than seven (7) days before any final reclamation operations are to take place, the operator shall notify the Director on a Sundry Notice, Form 4.

c. **Notice requirements.** As to notices to be given pursuant to this Rule 305., included with each such notice shall be the following:

(1) The estimated date that the operations for which notice is being given are to commence.

(2) The name of the operator and the name, address and phone number of the individual representing the operator who can be contacted concerning the proposed operations.

(3) The legal description (or plat) indicating the quarter quarter section upon which the operations will be conducted.

(4) A statement that the surface owner has responsibility for notifying any affected tenant of the proposed operations.

(5) With respect to the notices of drilling, the notice mailed or hand delivered to the surface owner shall also include a return addressed, postage prepaid postcard upon which surface owners may request their preference with respect to the consultation requirement under Rule 306., including the preference to appoint a tenant for consultation. If the surface owner appoints a tenant for consultation, that person's name, address, and telephone number must be provided to the operator by the surface owner on the postcard.

(6) A copy of the Commission's informational brochure for surface owners, containing the rules pertaining to notice of oil and gas operations and opportunities for consultation thereon, as well as the rules of procedure for filing complaints and making applications for hearing. The brochure shall provide contact information for the Commission's main office, field offices and website, and shall describe the services and information available to the public, including access to a listing of local governmental designees. The brochure shall contain a prominent disclaimer advising surface owners to obtain legal advice as may be appropriate to their particular circumstances.

d. **Identifying surface owner.** In determining the identity and address of a surface owner for the purpose of giving all notices under this Rule 305., the records of the assessor for the county in which the lands are situated may be relied upon.

e. **Tenants.** With respect to notices given under this Rule 305., it shall be the responsibility of the notified surface owner to give notice of the proposed operation to the tenant farmer, lessee or other party that may own or have an interest in any crops or surface improvements that could be affected by such proposed operation.

f. **Waiver.** Any and all of the surface owner notice requirements set forth in this Rule 305. may be waived by the affected surface owner at any time. Any and all local governmental designee notice requirements set forth in this Rule 305. may be waived by the affected local governmental designee(s) at any time.

306. CONSULTATION.

In locating roads, production facilities and well sites, and in preparation for reclamation and final abandonment, the operator shall use its best efforts to consult in good faith with the affected surface owner, or the surface owner's appointed tenant as provided for in Rule 305. Consultation with local governmental designees is addressed in Rule 306.a. (3) below. The following shall apply to each such consultation:

a. **Drilling consultation.** The good faith effort to consult shall occur at a time mutually agreed to by the parties prior to the commencement of operations with heavy equipment upon the lands of the surface owner. The operator shall confirm that the surface owner consultation requirements of this Rule 306. have been completed or waived before the Director approves an Application for Permit-to-Drill, Form 2.

(1) **Information provided by operator.** When consulting with the surface owner or appointed tenant, the operator shall furnish a description or diagram of the proposed drilling location; dimensions of the well site; and, if known, the location of associated production or injection facilities, pipelines, roads and any other areas to be used for oil and gas operations (if not previously furnished to such surface owner or if different from what was previously furnished).

(2) **Good faith consultation.** Such good faith consultation shall allow the surface owner or appointed tenant the opportunity to provide comments to the operator regarding preferences for the timing of oil and gas operations and preferred locations for wells and associated facilities.

(3) **Local government consultation.** Local governments which have appointed a local governmental designee and have indicated to the Director a desire for onsite consultation shall be given an opportunity to engage in such consultation concerning the location of roads, production facilities and well sites prior to the commencing of operations with heavy equipment.

b. **Final reclamation consultation.** In preparing for final reclamation and plugging and abandonment, the operator shall use its best efforts to consult in good faith with the affected surface owner (or the tenant when the surface owner has requested that such consultation be made with the tenant). Such good faith consultation shall allow the surface owner (or appointed tenant) the opportunity to provide comments concerning preference for timing of such operations and all aspects of final reclamation.

c. **Tenants.** Operators shall have no obligation to consult with tenant farmers, lessees, or any other party ("tenant") that may own or have an interest in any crops or surface improvements that could be affected by the proposed operation unless the surface owner appoints such tenant for such purposes. Nothing shall prevent the surface owner from including the tenant during the consultation.

d. **Waiver.** The requirement to consult with the surface owner under this Rule 306. may be waived by the affected surface owner or the surface owner's appointed tenant at any time.

307. COGCC Form 4. SUNDRY NOTICES AND REPORTS ON WELLS

The Sundry Notice, Form 4, is a multipurpose form which shall be used by an operator to request approval from or provide notice to the Director as required by rule or when no other specific form exists, i.e., well name or number change. The rules requiring the use of the Sundry Notice, Form 4, are listed in Appendix I.

308A. COGCC Form 5. DRILLING COMPLETION REPORT

Within thirty (30) days of the setting of production casing, the plugging of a dry hole, the deepening or sidetracking of a well, or any time the wellbore configuration is changed, the operator shall transmit to the Director the Drilling Completion Report, Form 5, and one (1) copy of all logs run, be they mechanical, mud, or other. Additionally, if drill stem tests, core analyses, or directional surveys are run, they shall be submitted at the same time and together with this completion report. All Sections 1 - 22 (if applicable) and the attachment checklist shall be completely filled out.

Within thirty (30) days of the suspension of commenced drilling activities prior to reaching total depth, the operator shall file a Drilling Completion Report, Form 5, notifying the Director of the date of such suspension of drilling activity stating the reason for suspension and the anticipated date and method of resumption of drilling, showing the details of all work performed to date. In cases of an uncompleted well, the initial Drilling Completion Report, Form 5, shall state "preliminary" at the top of the form. A supplementary Form 5 shall be submitted within thirty (30) days of reaching total depth.

308B. COGCC Form 5A. COMPLETED INTERVAL REPORT

The Completed Interval Report, Form 5A, shall be submitted within thirty (30) days of completing a formation (successful or not), when a formation is temporarily abandoned or permanently abandoned, for a recompletion, reperforation or restimulation, or when a formation is commingled.

In order to resolve completed interval information uncertainties, the Director may require an operator to submit a Completed Interval Report, Form 5A.

308C. CONFIDENTIALITY

Upon submittal of a Sundry Notice, Form 4, request by the operator, completion reports, including Drilling Completion Reports, Form 5 and Completed Interval Reports, Form 5A, and mechanical logs of exploratory or wildcat wells shall be marked "confidential" by the Director and kept confidential for six (6) months after the date of completion, unless the operator gives written permission to release such logs at an earlier date.

309. COGCC Form 7. OPERATOR'S MONTHLY PRODUCTION REPORT

Each producer or operator of an oil or gas well shall file with the Commission, within forty-five (45) days after the month in which production occurs, a report on Operator's Monthly Production Report, Form 7, containing all information required by said form. In addition, all fluids produced during the initial testing and completion shall be reported on Operator's Monthly Production Report, Form 7 within forty-five (45) days after the month in which testing and completion occurs.

310A. COGCC Form 8. MILL LEVY

On or before March 1, June 1, September 1 and December 1 of each year, every producer or purchaser, whichever disburses funds directly to each and every person owning a working interest, a royalty interest, an overriding royalty interest, a production payment and other similar interests from the sale of oil or natural gas subject to the charge imposed by §34-60-122 (1) (a) C.R.S., 1973, as amended, shall file a return with the Director showing by operator, the volume of oil, gas or condensate produced or purchased during the preceding calendar quarter, including the total consideration due or received at the point of delivery. No filing shall be required when the charge imposed is zero mill ($0.0000) per dollar value.

The Levy shall be an amount fixed by order of the Commission. The levy amount may, from time to time, be reduced or increased to meet the expenses chargeable against the oil and gas conservation fund. The present charge imposed, as of July 1, 2002, is one and one tenth mill ($0.0011) per dollar value.

310B. COGCC Form 8A. ENVIRONMENTAL RESPONSE FUND LEVY

On or before March 1, June 1, September 1 and December 1 of each year, every producer or purchaser, whichever disburses funds directly to each and every person owning a working interest, a royalty interest, an overriding royalty interest, a production payment and other similar interests from the sale of oil or natural gas subject to the charge imposed by §34-60-122 (1) (b) C.R.S., 1973, as amended, shall file a Form 8A, Environmental Response Fund report with the Director showing the total volume of oil, gas or condensate produced or purchased during the preceding calendar quarter, including the total consideration due or received at the point of delivery from all leases listed on the corresponding mill levy, Form 8. No filing shall be required when the surcharge imposed is zero.

The Environmental Response Fund surcharge shall be an amount fixed by order of the Commission. The surcharge amount may, from time to time, be reduced or increased to meet the expenses chargeable against the oil and gas Environmental Response Fund. As of October 1, 1996, the surcharge shall be zero mill ($0.0000) on the dollar.

311. COGCC Form 6. WELL ABANDONMENT REPORT

Notice shall be given to the Director, and approval obtained in advance of the time the operator expects to abandon a well on Form 6. When filing an intent to abandon, the form shall be completed and attachments included to fully describe the proposed operations. This includes the proposed depths of mechanical plugs and casing cuts, the proposed depths and volumes of all cement plugs, the amount, size and depth of casing and junk to be left in the well, the volume and weight of fluid to be left in the wellbore and the nature and quantities of any other materials to be used in the plugging. If the well is not plugged within six (6) months of intent approval a new intent shall be filed.

Within thirty (30) days after abandonment, the Well Abandonment Report, Form 6, shall be filed with the Director. The abandonment details shall include an account of the manner in which the abandonment or plugging work was performed. Additionally, plugging verification reports detailing all procedures are required. A Plugging Verification Report shall be submitted for each person or contractor actually setting the plugs. The Well Abandonment Report, Form 6, and the Plugging Verification Reports shall detail the depths of mechanical plugs and casing cuts, the depths and volumes of all cement plugs, the amount, size and depth of casing and junk left in the well, the volume and weight of fluid left in the wellbore and the nature and quantities of any other materials used in the plugging. Plugging Verification Reports shall conform with the operator's report and both shall show that plugging procedures are at least as extensive as those approved by the Director. When filing a subsequent report of abandonment, the entire form shall be completed except for the second block, background information. (See Rule 319 for well abandonment requirements and procedures.)

312. COGCC Form 10. CERTIFICATE OF CLEARANCE AND/OR CHANGE OF OPERATOR

a. Each operator of any oil or gas well completed after April 30, 1956, shall file with the Director, within thirty (30) days after initial sale of oil or gas a Certificate of Clearance and/or Change of Operator, Form 10, in accordance with the instructions appearing on such form, for each well producing oil or gas or both oil and gas. A Certificate of Clearance shall be filed for any well from which oil, gas or other hydrocarbon is being produced.

A Certificate of Clearance shall be filed within thirty (30) days should the producing formation(s), the oil transporter (first purchaser) and/or the gas gatherer (first purchaser) change. In addition, within fifteen (15) days of an operator change for any well, a Change of Operator, Form 10, shall be filed with a filing and service fee as set by the Commission. (See Appendix III)

b. Each operator of a Class II injection well shall file a new Certificate of Clearance and/or Change of Operator, Form 10 with the Director within fifteen (15) days of the transfer of ownership.

c. Whenever there shall occur a change in the producer or operator filing the certificate under Rule 312.a. hereof, or whenever there shall occur a change of transporter from any well within the state, a new Certificate of Clearance and/or Change of Operator, Form 10 shall be executed and filed within fifteen (15) days in accordance with the instructions appearing on such form. In the case of temporary use of oil for well treating or stimulating purposes, no new form need be executed. In the case of other temporary change in transporter involving the production of less than one (1) month, the producer or operator may, in lieu of filing a new certificate, notify the Commission and the transporter authorized by the certificate on file with the Commission by letter of the estimated amount to be moved by the temporary transporter and the name of such temporary transporter. A copy of such notice shall also be furnished such temporary transporter.

d. In no instance shall the temporary transporter move any quantity greater than the estimated amount shown in said notice.

e. The certificate, when properly executed and approved by the Commission, shall constitute authorization to the pipeline or other transporter to transport the authorized volume from the well named therein; provided that this section shall not prevent the production or transportation in order to prevent waste, pending execution and approval of said certificate. Permission for the transportation of such production shall be granted in writing to the producer and transporter.

f. The certificate shall remain in force and effect until:

(1) The producer or operator filing the certificate is changed; or
(2) The transporter is changed; or
(3) The certificate is canceled by the Commission.

g. A copy of each Certificate of Clearance and/or Change of Operator, Form 10 to be filed hereunder shall be sent by the Director to those local governmental designees who so request.

h. It is the operator's responsibility to mail approved copies of the Certificate of Clearance and/or Change of Operator, Form 10, to the transporter and/or gatherer for each well listed.

313. COGCC Form 11. MONTHLY REPORT OF GASOLINE OR OTHER EXTRACTION PLANTS

All operators of gasoline or other extraction plants shall make monthly reports to the Director on Form 11. Such forms shall contain all information required thereon and shall be filed with the Director on or before the twenty-fifth (25th) day of each month covering the preceding month.

314. COGCC Form 17. BRADENHEAD TEST REPORT

Results of bradenhead tests, as required by Rule 207.b., shall be submitted to the Director within ten (10) days of completion. A wellbore diagram shall be submitted if not previously submitted or if the wellbore configuration has changed. If sampled, then the results of any gas and liquid analysis shall be submitted.

315. REPORT OF RESERVOIR PRESSURE TEST

Where the Director believes it is necessary to prevent waste, protect correlative rights, or prevent a significant adverse impact, the Director may require subsurface pressure measurements. Whenever such measurements are made, results shall be reported on Sundry Notice, Form 4, within twenty (20) days after completion of tests, or submitted on any company form approved by the Director containing the same information.

316A. COGCC Form 14. MONTHLY REPORT OF FLUIDS INJECTED

Except for fluids involved with fracturing, acidizing or other similar treatment elsewhere required to be reported on a Completed Interval Report, Form 5A, all operators engaged in the injection of fluids into any formation in dedicated injection wells shall file monthly with the Commission a detailed account of such operation on Form 14, or any company form containing the same information previously approved by the Director. Types of chemicals used to treat injection water, as well as the date of initial fluid injection for new injection wells, are to be reported on said form under Remarks. The type and amount of fluids received from transporters shall be included on the report. Operators of simultaneous injection wells shall, by March 1 of each year, report to the Director the calculated injected volume for the previous year by month on Form 14. Operators of gas storage projects shall, by March 1 of each year, report to the Director the amount of gas injected and withdrawn for the previous year and the amount of gas remaining in the reservoir as of December 31 of that year.

316B. COGCC Form 21. MECHANICAL INTEGRITY TEST

Results of mechanical integrity tests of injection wells or shut-in wells shall be submitted on Form 21, within thirty (30) days after the test. A pressure chart shall accompany this report. Not less than ten (10) days prior to the performance of any mechanical integrity test, the Director shall be notified, in writing, of the scheduled date on which the test will be performed. The form shall be completely filled out except for Part II, which is required only if the well is a permitted or pending injection well.

317. GENERAL DRILLING RULES

Unless altered, modified, or changed for a particular field or formation upon hearing before the Commission the following shall apply to the drilling or deepening of all wells.

a. **Blowout preventer equipment ("BOPE")**. The operator shall take all necessary precautions for keeping a well under control while being drilled or deepened. BOPE, if any, shall be indicated on the Application for Permit to Drill, Form 2, as well as any known subsurface conditions (e.g. under or over-pressured formations). The working pressure of any BOPE shall exceed the anticipated surface pressure to which it may be subjected, assuming a partially evacuated hole with a pressure gradient of 0.22 psi/ft. (For BOPE requirements in high density areas see Rule 603.b(4)B. For statewide BOPE specification, inspection, operation and testing requirements see Rule 603.f.)

(1) The Director shall have the authority to designate specific areas, fields or formations as requiring certain BOPE. Any such proposed designation shall occur by notice describing the area, field or formation in question and shall be given to all operators of record within such area or field and by publication. The proposed designation, if no protest is timely filed, shall be placed on the Commission consent agenda for its next regularly scheduled meeting following the month in which such notice was given. The matter shall be approved or heard by the Commission in accordance with Rule 520. Such designation shall be effective immediately upon approval by the Commission, except as to any previously approved Permit to Drill, Form 2.

(2) The Director shall have the authority, outside areas designated pursuant to Rule 317.a.(1), to condition approval of any Application for Permit to Drill by requiring BOPE which the Director determines to be necessary for keeping the well under control. Should the operator object to such condition of approval, the matter shall be heard at the next regularly scheduled meeting of the Commission, subject to the notice requirements of Rule 507.

b. **Bottom hole location**. Unless authorized by the provisions of Rule 321., all wells shall be so drilled that the horizontal distance between the bottom of the hole and the location at the top of the hole shall be at all times a practical minimum.

c. **Requirement to post permit at the rig and provide spud notice**. A copy of the approved Application for Permit to Drill, Deepen, Re-enter, or Recomplete and Operate, Form 2, shall be posted in a conspicuous place on the drilling rig or workover rig. A notice shall be provided to the Director on a Sundry Notice, Form 4, no later than five (5) days following the spudding of a well. The Director may apply a condition of approval for Application for Permit to Drill, Deepen, Re-enter, or Recomplete and Operate, Form 2 requiring not less than twenty-four (24) hours nor more than seventy-two (72) hours verbal or written notice prior to spud.

d. **Casing program to protect hydrocarbon horizons and ground water.** The casing program adopted for each well must be so planned and maintained as to protect any potential oil or gas bearing horizons penetrated during drilling from infiltration of injurious waters from other sources, and to prevent the migration of oil, gas or water from one (1) horizon to another, that may result in the degradation of ground water. A Sundry Notice, Form 4, including a detailed work plan and a wellbore diagram, shall be submitted and approved by the Director prior to any routine or planned casing repair operations. During well operations, prior verbal approval for unforseen casing repairs followed by the filing of a Sundry Notice, Form 4, after completion of operations shall be acceptable.

e. **Surface casing where subsurface conditions are unknown**. In areas where pressure and formations are unknown, sufficient surface casing shall be run to reach a depth below all known or reasonably estimated utilizable domestic fresh water levels and to prevent blowouts or uncontrolled flows and shall be of sufficient size to permit the use of an intermediate string or strings of casings. Surface casing shall be set in or through an impervious formation and shall be cemented by pump and plug or displacement or other approved method with sufficient cement to fill the annulus to the top of the hole, all in accordance with reasonable requirements of the Director. In the D-J Basin Fox Hills Protection Area surface casing will be set in accordance with Rule 317A. (See also subparagraph g.).

f. **Surface casing where subsurface conditions are known**. In wells drilled in areas where subsurface conditions have been established by drilling experience, surface casing size, at the owner's option, shall be set and cemented to the surface by the pump and plug or displacement or other approved method at a depth and in a manner sufficient to protect all fresh water and to ensure against blowouts or uncontrolled flows. In the D-J Basin Fox Hills Protection Area surface casing will be set in accordance with Rule 317A. (See also subparagraph g.).

g. **Alternate aquifer protection by stage cementing**. In areas where fresh water aquifers are of such depth as to make it impractical or uneconomical to set the full amount of surface casing necessary to comply fully with the requirement to cover or isolate all fresh water aquifers as required in subparagraph e. and f., the owner may, at its option, comply with this requirement by stage cementing the intermediate and/or production string so as to accomplish the required result. If unanticipated fresh water aquifers are encountered after setting the surface pipe they shall be protected or isolated by stage cementing the intermediate and/or production string with a solid cement plug extending from fifty (50) feet below each fresh water aquifer to fifty (50) feet above said fresh water aquifer or by other methods approved by the Director in each case. In the D-J Basin Fox Hills Protection Area any stage cementing shall occur only in accordance with Rule 317A. If the stage cement is not circulated to surface, a temperature log or cement bond log shall be run to determine the top of the stage cement to ensure aquifers are protected.

h. **Surface and intermediate casing cementing**. The operator shall ensure that all surface and intermediate casing cement required under this rule shall be of adequate quality to achieve a minimum compressive strength of three hundred (300) psi after twenty-four (24) hours and eight hundred (800) psi after seventy-two (72) hours measured at ninety-five degrees fahrenheit (95°F) and at eight hundred (800) psi. All surface casing shall be cemented with a continuous column from the bottom of the casing to the surface. After thorough circulation of the wellbore, cement shall be pumped behind the intermediate casing to at least two hundred (200) feet above the top of the shallowest known production horizon and as required in 317.g. Cement placed behind the surface and intermediate casing shall be allowed to set a minimum of eight (8) hours, or until three hundred (300) psi calculated compressive strength is developed, whichever occurs first, prior to commencing drilling operations. If the surface casing cement level falls below the surface, to the extent safety or aquifer protection is compromised, remedial cementing operations shall be performed.

i. **Production casing cementing**. The operator shall ensure that all cement required under this rule placed behind production casing shall be of adequate quality to achieve a minimum compressive strength of at least three hundred (300) psi after twenty-four (24) hours and eight hundred (800) psi after seventy-two (72) hours measured at ninety-five degrees fahrenheit (95°F) and at eight hundred (800) psi. After thorough circulation of a wellbore, cement shall be pumped behind the production casing two hundred (200) feet above the top of the shallowest known producing horizon. All fresh water aquifers which are exposed below the surface casing shall be cemented behind the production casing. All such cementing around an aquifer shall consist of a continuous cement column extending from at least fifty (50) feet below the bottom of the fresh water aquifer which is being protected to at least fifty (50) feet above the top of said fresh water aquifer. Cement placed behind the production casing shall be allowed to set seventy-two (72) hours, or until eight hundred (800) psi calculated compressive strength is developed, whichever occurs first, prior to the undertaking of any completion operation.

j. **Production casing pressure testing**. The installed production casing shall be adequately pressure tested for the conditions anticipated to be encountered during completion and production operations.

k. **Protection of aquifers and production stratum and suspension of drilling operations before running production casing**. In the event drilling operations are suspended before production string is run, the Commission shall be notified immediately and the owner shall take adequate and proper precautions to assure that no alien water enters oil or gas strata, nor potential fresh water aquifers during such suspension period or periods. If alien water is found to be entering the production stratum or to be causing significant adverse environmental impact to fresh water aquifers during completion testing or after the well has been put on production, the condition shall be promptly remedied.

l. **Flaring of gas during drilling and notice to local emergency dispatch**. Any gas escaping from the well during drilling operations shall be, so far as practicable, conducted to a safe distance from the well site and burned. The operator shall notify the local emergency dispatch as provided by the local governmental designee of any such flaring. Such notice shall be given prior to the flaring if the flaring can be reasonably anticipated, and in all other cases as soon as possible but in no event more than two (2) hours after the flaring occurs.

m. **Protection of productive strata during deepening operations**. If a well is deepened for the purpose of producing oil and gas from a lower stratum, such deepening to and completion in the lower stratum shall be conducted in such a manner as to protect all upper productive strata.

n. **Requirement to evaluate disposal zones for hydrocarbon potential**. If a well is drilled as a disposal well then the disposal zone shall be evaluated for hydrocarbon potential. The proposed hydrocarbon evaluation method shall be submitted in writing and approved by the Director prior to implementation. The productivity results shall be submitted to the Director upon completion of the well.

o. **Requirement to log well**. For all new drilling operations, the operator shall be required to run a minimum of a resistivity log with gamma-ray or other petrophysical log(s) approved by the Director that adequately describe the stratigraphy of the wellbore. This log and all other logs run shall be submitted with the Well Completion or Recompletion Report and Log, Form 5. Open hole logs shall be run to adequately verify setting depth of surface casing and aquifer coverage. These requirements shall not apply to the unlogged open hole completion intervals, or to wells in which no open hole logs are run.

p. **Remedial cementing during recompletion.** The Director may apply a condition of approval for Application for Permit to Drill, Deepen, Re-enter, or Recomplete and Operate, Form 2, to require remedial cementing during recompletion operations consistent with the provisions for protecting aquifers and hydrocarbon bearing zones in this Rule 317.

317A. SPECIAL DRILLING RULES - D-J BASIN FOX HILLS PROTECTION AREA

The following special drilling rules shall apply to wells in the D-J Basin Fox Hills Protection Area:

a. **Surface Casing - Minimum Requirements for Well Control**. In all wells drilled within the D-J Basin Fox Hills Protection Area, surface casing shall be run to a minimum depth of five percent (5%) of the projected total depth to which the well is to be drilled, provided that in no event shall the surface casing be run to a depth less than two hundred (200) feet. The Director may, on a case-by-case basis, grant variances in this five percent (5%) requirement where the Director finds that the well is a development well in which pressures can be accurately predicted and finds that, based upon those predictions, the five percent (5%) requirement should be varied to achieve effective well control. In all cases, however, the actual depth at which the surface casing is set shall be calculated to position the casing seat to a depth within a competent formation (preferably shale) which will contain the maximum pressure to which the casing will be exposed during normal drilling operations.

b. **Surface Casing - Aquifer Protection**. For purposes of aquifer protection, surface casing must be set as follows in wells which are not exploratory wells:

(1) Surface casing shall be run to a depth at least fifty (50) feet below the Fox Hills transition zone in wells drilled within Townships 5 South through 5 North, Ranges 65 West through 70 West or within Townships 3 North through 5 North, Range 64 West.

(2) With respect to Townships 5 South through 5 North, Ranges 58 West through 63 West, Townships 5 South through 2 North, Range 64 West; and Township 6 South, Ranges 65 West through 70 West, in all wells located within one (1) mile of a permitted producing water well, surface casing shall be set to a depth sufficient to protect the deepest permitted producing water well within such one (1) mile area. Said depth shall be at least fifty (50) feet below the depth of the base of the aquifer from which said deepest water well is producing, or fifty (50) feet below the base of the Fox Hills Transition Zone if such deepest water well produces from the Fox Hills Aquifer.

Upon the request of the operator, the Director (or the Commission upon appeal) may grant a variance to the requirements of this subparagraph b. upon a showing to the Director, or the Commission upon appeal, that the variance does not violate the basic intent of said requirements. For such variance purpose, the basic intent of said requirements is stated to be to provide reasonable aquifer protection for the water well(s) which are permitted by the State of Colorado Division of Water Resources and are currently producing in the area potentially affected by the oil or gas well to be drilled.

c. **Exploratory Wells**. For purposes of the D-J Basin Fox Hills Protection Area only, the term exploratory well means any well:

(1) Which targets the classically demonstrated zones with limited geographic extent such as channel, bar, valley fill and levee type sandstones that were deposited prior to the x-bentonite time stratigraphic event; or

(2) Which can be demonstrated to be separated from a known producing horizon by a dry hole; or

(3) Which can be demonstrated to be targeted to a horizon which is geologically separate from the producing horizon in an offsetting producing well, or

(4) Which the Director, or the Commission upon appeal, may define as an exploratory well by variance, it being the basic intent of this definition that the requirements of subparagraph b. not operate to discourage the drilling of high risk wells.

318. LOCATION OF WELLS

All wells drilled for oil or gas to a common source of supply shall have the following setbacks:

a. **Wells deeper than 2,500 feet in depth**. A well to be drilled in excess of two thousand five hundred (2,500) feet in depth shall be located not less than six hundred (600) feet from any lease line, and shall be located not less than one thousand two hundred (1,200) feet from any other producible or drilling oil or gas well when drilling to the same common source of supply, unless authorized by order of the Commission upon hearing.

b. **Wells less than 2,500 feet in depth**. A well to be drilled to less than a depth of two thousand five hundred (2,500) feet below the surface shall be located not less than two hundred (200) feet from any lease line, and not less than three hundred (300) feet from any other producible oil or gas well, or drilling well, in said source of supply, except that only one producible oil or gas well in each such source of supply shall be allowed in each governmental quarter-quarter section unless an exception under Rule 318.c. is obtained.

c. **Exception locations.** The Director may grant an operator's request for a well location exception to the requirements of this rule or any order because of geologic, environmental, topographic or archaeologic conditions, irregular sections, a surface owner request, or for other good cause shown, provided that a waiver or consent signed by the lease owner toward whom the well location is proposed to be moved, agreeing that said well may be located at the point at which the operator proposes to drill the well and where correlative rights are protected. If the operator of the proposed well is also the operator of the drilling unit or unspaced offset lease toward which the well is proposed to be moved, waivers shall be obtained from the mineral interest owners under such lands. If waivers cannot be obtained from all parties and no party objects to the location, the operator may apply for a variance under Rule 502.b. If a party or parties object to a location and cannot reach an agreement, the operator may apply for a Commission hearing on the exception location.

d. **Exemptions to Rule 318**.

(1) This rule shall not apply to authorized secondary recovery projects.

(2) This rule shall apply to fracture or crevice production found in shale, except from fields previously exempted from this rule.

(3) In a unit operation, approved by federal or state authorities, the rules herein set forth shall not apply except that no well in excess of two thousand five hundred (2,500) feet in depth shall be located less than six hundred (600) feet from the exterior or interior (if there be one) boundary of the unit area and no well less than two thousand five hundred (2,500) feet in depth below the surface shall be located less than two hundred (200) feet from the exterior or interior (if there be one) boundary of the unit area unless otherwise authorized by the order of the Commission after proper notice to owners outside the unit area.

e. **Wells located near a mine**. No well drilled for oil or gas shall be located within two hundred (200) feet of a shaft or entrance to a coal mine not definitely abandoned or sealed, nor shall such well be located within one hundred (100) feet of any mine shaft house, mine boiler house, mine engine house, or mine fan; and the location of any proposed well shall insure that when drilled it will be at least fifteen (15) feet from any mine haulage or airway.

318A. GREATER WATTENBERG AREA SPECIAL WELL LOCATION RULE

a. The Greater Wattenberg Area ("GWA") is defined to include those lands from and including Townships 2 South to 7 North and Ranges 61 West to 69 West, 6^{th} P.M. In GWA, operators may utilize the following described drilling locations to drill or twin a well, deepen a well, or recomplete a well and to commingle any or all of the Cretaceous Age formations from the base of the Dakota to the surface ("GWA wells"):

(1) A square with sides four hundred (400) feet in length, the center of which is the center of any quarter/quarter section; and,

(2) A square with sides eight hundred (800) feet in length, the center of which is the center of any quarter section.

b. Any GWA well in existence prior to the effective date of this rule, which is not located as described above, may also be utilized for deepening to or recompletion in any Cretaceous Age formation, and for the commingling of production therefrom.

c. Where an existing well cannot be utilized for deepening or recompletion, for reasons including, but not limited to, differing ownership or wellbore limitations, any new, twinned well shall be located as close to such existing well as is practicable, consistent with sound engineering practice.

d. This rule does not alter the size or configuration of drilling units for GWA wells in existence prior to its effective date. Where deemed necessary an operator for purposes of allocating production, such operator may allocate production to an expanded drilling unit with respect to a particular Cretaceous Age formation consistent with the provisions of this rule.

e. This rule shall not serve to bar the granting of relief to owners who file an application alleging abuse of their correlative rights to the extent that such owners can demonstrate that their opportunity to produce the Cretaceous Age formations from the drilling locations herein authorized does not provide an equal opportunity to obtain their just and equitable share of oil and gas from such formations.

f. Subject to paragraph d. above, this rule supersedes all prior Commission drilling and spacing orders affecting the GWA wells. Well location exceptions to this rule shall be subject to the provisions of Rule 318.c.

319. ABANDONMENT

The requirements for abandoning a well shall be as follows:

a. **Plugging**

(1) A dry or abandoned well, seismic, core, or other exploratory hole, must be plugged in such a manner that oil, gas, water, or other substance shall be confined to the reservoir in which it originally occurred. Any cement plug shall be a minimum of fifty (50) feet in length and shall extend a minimum of fifty (50) feet above each zone to be protected. The material used in plugging, whether cement, mechanical plug, or some other equivalent method approved in writing by the Director, must be placed in the well in a manner to permanently prevent migration of oil, gas, water, or other substance from the formation or horizon in which it originally occurred. The preferred plugging cement slurry is that recommended by the American Petroleum Institute (API) Environmental Guidance Document: Well Abandonment and Inactive Well Practices for U.S. Exploration and Production Operations, i.e., a neat cement slurry mixed to API standards. However, pozzolan, gel and other approved extenders may be used if the operator can document, to the Director's satisfaction, that the slurry design will achieve a minimum compressive strength of three hundred (300) psi after twenty-four (24) hours and eight hundred (800) psi after seventy-two (72) hours measured at ninety-five (95) degrees fahrenheit and at eight hundred (800) psi.

(2) The operator shall have the option as to the method of placing cement in the hole by (a) dump bailer, (b) pumping a balanced cement plug through tubing or drill pipe, (c) pump and plug, or (d) equivalent method approved by the Director prior to plugging. Unless prior approval is given, all wellbores will have water, mud or other approved fluid between all plugs.

(3) No substance of any nature or description other than normally used in plugging operations shall be placed in any well at any time during plugging operations. All final reports of plugging and abandonment shall be submitted on a Well Abandonment Report, Form 6, and accompanied by a job log or cement verification report from the plugging contractor specifying the type of fluid used to fill the wellbore, type and slurry volume of API Class cement used, date of work, and depth the plugs were placed.

(4) In order to protect the fresh water strata, no surface casing shall be pulled from any well unless authorized by the Director.

(5) All abandoned wells shall have a plug or seal placed at the surface of the ground or the bottom of the cellar in the hole in such manner as not to interfere with soil cultivation or other surface use. The top of the pipe must be sealed with either a cement plug and a screw cap, or cement plug and a steel plate welded in place or by other approved method, or in the alternative be marked with a permanent monument which shall consist of a piece of pipe not less than four (4) inches in diameter and not less than ten (10) feet in length, of which four (4) feet shall be above the general ground level, the remainder to be embedded in cement or to be welded to the surface casing.

(6) The operator must obtain approval from the Director of the plugging method prior to plugging, and shall notify the Director of the estimated time and date the plugging operation of any well is to commence, and identify the depth and thickness of all known sources of ground water. For good cause shown, the Director may require that a cement plug be tagged if a cement retainer or bridge plug is not used. If requested by the operator, the Director shall furnish written follow-up documentation for a requirement to tag cement plugs.

(7) **Wells Used for Fresh Water**. When the well, seismic, core, or other exploratory hole to be plugged may safely be used as a fresh water well, and such utilization is desired by the landowner, the well need not be filled above the required sealing plug set below fresh water; provided that written authority for such use is secured from the landowner and, in such written authority, the landowner assumes the responsibility to plug the well upon its abandonment as a water well in accordance with these rules. Such written authority and assumption of responsibility shall be filed with the Commission, provided further that the landowner furnish a copy of the permit for a water well approved by the Division of Water Resources.

b. **Shut-in and Temporary Abandonment**.

(1) A well may be shut-in or temporarily abandoned when completed, upon approval of the Director, for a period not to exceed six (6) months provided the hole is cased or left in such a manner as to prevent migration of oil, gas, water or other substance from the formation or horizon in which it originally occurred. All shut-in or temporarily abandoned wells shall be closed to the atmosphere with a swedge and valve or packer, or other approved method. The well sign shall remain in place. If an operator requests shut-in or temporary

abandonment status in excess of six (6) months the operator shall state the reason for requesting such extension and state plans for future operation. A Sundry Notice, Form 4, or other form approved by the Director, shall be submitted annually stating the status of the well and plans for future operation. The Director shall submit copies of any Sundry Notice, Form 4, to the local governmental designees who so requests.

(2) The manner in which the well is to be maintained should be reported to the Commission, and bonding requirements, as provided for in Rule 304., kept in force until such time as the well is permanently abandoned.

(3) A well which has ceased production or injection or is incapable of production or injection shall be abandoned within six (6) months thereafter unless the time is extended by the Director upon application by the owner. The application shall indicate why the well is shut-in and future plans for utilization. In the event the well is covered by a blanket bond, the Director may require an individual plugging bond on the shut-in or temporarily abandoned well. Gas storage wells are to be considered active at all times unless physically plugged.

(4) In addition to the requirements of Rule 325., an injection well that is shut-in or temporarily abandoned shall have a mechanical integrity test performed within two (2) years after the shut-in date in order to be retained in shut-in or temporarily abandoned status.

(5) If an injection well which has been shut-in or temporarily abandoned is determined not to have mechanical integrity as a result of any test required by the Commission rules and regulations, it must, within six (6) months following such a test, be either repaired and pass a mechanical integrity test or be plugged and abandoned.

320. LIABILITY

The owner and operator of any well drilled for oil or gas production or injection purposes, or any seismic, core, or other exploratory holes, whether cased or uncased, shall be liable and responsible for the plugging thereof in accordance with the rules and regulations of the Commission regardless of whether the cost of such plugging and abandonment exceeds the amount of security as set forth in Rule 304.

321. DIRECTIONAL DRILLING

If an operator intends to drill a horizontal or deviated wellbore utilizing controlled directional drilling methods, other than whipstocking due to hole conditions, the plans shall accompany an application for Permit-to-Drill, Form 2. In addition to the information required on the plat in Rule 303.c., the plat shall also show the surface and bottom hole location. If the surface location is in a different section than the bottom hole location, a plat depicting each section is required. Additionally, the proposed directional survey including two (2) wellbore deviation plots, one depicting the plan view and one depicting the side view, shall accompany the application.

Within thirty (30) days of completion the operator shall submit a Drilling Completion Report, Form 5, according to Rule 308., with a copy of the directional survey coordinate listing and the wellbore deviation plots (plan and side views). The survey data shall be provided in a single analysis report with sufficient detail to determine the location of the wellbore from the base of the surface casing to the kick off point and from that point to total depth.

Any changes to an approved Application for Permit-to-Drill, Form 2, shall be submitted and approved on a Sundry Notice, Form 4, prior to implementation. Any request to change either the surface or bottom hole location shall be accompanied by a new proposed directional plan, an updated plat and updated wellbore deviation plots (plan and side view).

322. COMMINGLING

The commingling of production from multiple formations or wells is encouraged in order to maximize the efficient use of wellbores and to minimize the surface disturbance from oil and gas operations. Commingling may be conducted at the discretion of an operator, unless the Commission has issued an order or promulgated a rule excluding specific wells, geologic formations, geographic areas, or field from commingling in response to an application filed by a directly and adversely affected or aggrieved party or on the Commission’s own motion.

This rule supercedes the procedural requirements to establish commingling and allocation contained in any Commission order as of the effective date of this rule, but does not supersede any allocation made under such order.

323. OPEN PIT STORAGE OF OIL OR HYDROCARBON SUBSTANCES

Storage of oil or any other produced liquid hydrocarbon substance in earthen pits or reservoirs is considered to constitute waste, except in emergencies where such substances cannot be otherwise contained. In such cases, these substances must be reclaimed and such storage eliminated as soon as practicable after the emergency is controlled, unless special permission to delay or continue is obtained from the Director.

324A. POLLUTION

a. The operator shall take precautions to prevent significant adverse environmental impacts to air, water, soil, or biological resources to the extent necessary to protect public health, safety and welfare, by using cost-effective and technically feasible measures to protect environmental quality and to prevent the unauthorized discharge or disposal of oil, gas, E&P waste, chemical substances, trash, discarded equipment or other oil field waste.

b. No operator, in the conduct of any oil or gas operation shall perform any act or practice which shall constitute a violation of water quality standards or classifications established by the Water Quality Control Commission for waters of the state, or any point of compliance established by the Director pursuant to Rule 324D. The Director may establish one (1) or more points of compliance for any event of pollution, which shall be complied with by all parties determined to be a responsible party for such pollution.

c. No owner, in the conduct of any oil or gas operation, shall perform any act or practice which shall constitute a violation of any comprehensive plan adopted by the Air Quality Control Commission for the prevention, control and abatement of pollution of the air of the state.

d. No injection shall be authorized pursuant to Rule 325. or Rule 401. unless the person applying for authorization to conduct the injection activities demonstrates that those activities will not result in the presence in an underground source of drinking water of any physical, chemical, biological or radiological substance or matter which may cause a violation of any primary drinking water regulation in effect as of July 12, 1982 and found at 40 C.F.R. Part 142, as amended, or may otherwise adversely affect the health of persons. An underground source of drinking water is an aquifer or its portion:

(1) A. Which supplies any public water system; or

B. Which contains a sufficient quantity of ground water to supply a public water system; and

i. Currently supplies drinking water for human consumption; or
ii. Contains fewer than ten thousand (10,000) milligrams per liter total dissolved solids; and

(2) Which is not an exempted aquifer.

e. No person shall accept water produced from oil and gas operations, or other oil field waste for disposal in a commercial disposal facility, without first obtaining a Certificate of Designation from the County in which such facility is located, in accord with the regulations pertaining to solid waste disposal sites and facilities as promulgated by the Colorado Department of Public Health and Environment.

324B. EXEMPT AQUIFERS

a. **Criteria for aquifer exemption.** An aquifer or a portion thereof may be designated by the Director or the Commission as an exempted aquifer, in connection with the filing of an application pursuant to Rule 325. or Rule 401. if it meets the following criteria:

(1) It does not currently serve as a source of drinking water; and either subparagraph (2) or (3) below apply:

(2) It cannot now and will not in the future serve as a source of drinking water because:

A. It is mineral, hydrocarbon or geothermal energy producing, or can be demonstrated by a person filing an application pursuant to Rule 324. or Rule 401. to contain minerals or hydrocarbons that considering their quantity and location are expected to be commercially producible; or

B. It is situated at a depth or location which makes recovery of water for drinking water purposes economically or technologically impractical; or

C. It is so contaminated that it would be economically or technologically impractical to render the water fit for human consumption;

(3) The total dissolved solids content of the ground water is more than three thousand (3,000) and less than ten thousand (10,000) milligrams per liter and it is not reasonably expected to supply a public water system.

b. **Aquifer exemption public notice.** If an aquifer exemption is required as part of an injection permit process, the injection well applicant shall apply for an aquifer exemption. This application shall contain data and information which show that applicable aquifer exemption criteria set forth in Rule 324B.a. are met. After evaluation of the application and prior to designating an aquifer or a portion thereof as an exempted aquifer, the Director shall publish a notice of proposed designation in a newspaper of general circulation serving the area where the aquifer is located. The notice shall identify such aquifer or portion thereof which the Director proposes to designate as exempted, and shall state that any person who can make a showing to the Director that the requested designation does not meet the critera set forth in Rule 324B.a.

c. **Evaluation of written requests for public hearing.** Written requests for a public hearing before the Commission shall be reviewed and evaluated by the Director in consultation with the applicant to determine if the criteria set forth in Rule 324B.a. have been met. If, within thirty (30) days after publication of the notice, the Commission receives a hearing request for which the Director determines the criteria set forth in Rule 324B.a. have not been met, the Commission shall hold such a hearing in accordance with the provisions of §34-60-108, C.R.S., 1973, as amended, and shall make a final determination regarding designation.

d. **Aquifer exemption designation**. If, within thirty (30) days after publication of the notice described in subparagraph b. above, the Commission does not receive a hearing request or receives a hearing request for which the Director determines the criteria set forth in Rule 324B.a. have been met, said aquifer or portion thereof shall be considered exempted thirty (30) days after publication of the notice.

324C. QUALITY ASSURANCE FOR CHEMICAL ANALYSIS

For the purpose of application for a permit for all wells authorized under Rule 325. and Rule 401., collection and analysis of water samples must comply with the Commission's approved quality assurance project plan.

324D. CRITERIA TO ESTABLISH POINTS OF COMPLIANCE

In determining a point of compliance, the Director shall take into consideration recommendations of the operator or any responsible party or parties, if applicable, including technical and economic feasibility, together with the following factors:

a. The classified use established by the Water Quality Control Commission, for any ground water or surface water which will be impacted by contamination. If not so classified, the Director shall consider the quality, quantity, potential economic use and accessibility of such water;

b. The geologic and hydrologic characteristics of the site, such as depth to ground water, ground water flow, direction and velocity, soil types, surface water impacts, and climate;

c. The toxicity, mobility, and persistence in the environment of contaminants released or discharged from the site;

d. Established wellhead protection areas;

e. The potential of the site as an aquifer recharge area; and

f. The distance to the nearest permitted domestic water well or public water supply well completed in the same aquifer affected by the event.

g. The distance to the nearest permitted livestock or irrigation water well completed in the same aquifer affected by the event.

325. UNDERGROUND DISPOSAL OF WATER

a. No person shall commence operations for the underground disposal of water, or any other fluids, into a Class II well, or any well regulated by the Commission, nor shall any person commence construction of such a well, without having first obtained written authorization for such operations from the Director. Persons wishing to obtain authorization to conduct underground disposal activities shall file with the Director an Underground Injection Formation Permit Application, Form 31 and an Injection Well Permit Application, Form 33. If the disposal well is to be drilled, this application shall be submitted concurrently with the Application for Permit-to-Drill, Form 2, along with a service and filing fee to be determined by the Commission. (See Appendix III)

b. **Withholding approval of underground disposal of water.** The Director may withhold the issuance of a permit and the granting of approval of any Underground Injection Formation Permit Application, Form 31 and any Injection Well Permit Application, Form 33 for any proposed disposal well when the Director has reasonable cause to believe that the proposed disposal well could result in a significant adverse impact on the environment or public health, safety and welfare. In the event such approval is not granted, the Director shall immediately advise the operator and bring the matter to the Commission at its next regularly scheduled hearing.

c. The application for a dedicated injection well shall include the following information:

(1) The name, description and depth of the formation into which water is to be injected, and all underground sources of drinking water which may be affected by the proposed operation. A water analysis of the injection formation (if the total dissolved solids of the injection formation is determined to be less than ten thousand (10,000) milligrams per liter, the aquifer must be exempted in accordance with Rule 324B.). The fracture pressure or fracture gradient of the injection formation.

(2) A base plat covering the area within one-quarter (1/4) mile of the proposed disposal well showing location of the proposed disposal well or wells and the location of all oil and gas wells, domestic and irrigation wells of public record and the identification of all oil and gas wells currently producing from the proposed injection zone within one-half (1/2) mile of the disposal zone. The names, addresses and holdings of all surface and mineral owners as defined in §34-60-103 (7), C.R.S., within one-quarter (1/4) mile of the proposed disposal well or wells, or all owners of record in the field if a field-wide system is proposed. These owners shall be specifically outlined and identified on the base plat. A list of all domestic an irrigation wells of public record, within one-quarter mile of the proposed disposal well or wells, including their location and depth. (This information may be obtained at the Colorado Division of Water Resources.) Remedial action shall be required for any well within one-quarter (1/4) mile of the proposed disposal well or wells, which the applicant may or may not operate and a plan for the performance of any such remedial work. A copy of all plans and specifications for the system and its appurtenances.

(3) A resistivity log, run from the bottom of the surface casing to total depth of the disposal well or wells or any well within one (1) mile together with a log from that well that can be correlated with the injection well. If the disposal well is to be drilled, a description of the typical stratigraphic level of the disposal formation in the disposal well or wells, and any other available logging or testing data, on the disposal well or wells.

(4) A full description of the casing in the disposal well or wells. This shall include any information available on any remedial cement work performed to any casing string. This shall also include a schematic drawing showing all casing strings with cement volumes and tops, existing or as proposed, plug back total depth, depth of any existing open or squeezed perforations, setting depths of any bridge plugs existing or proposed, planned perforations in the injection zone, tubing and packer size and setting depth. A diagram of the surface facility showing all pipelines and tanks associated with the system. A listing of all leases connected directly by pipelines to the system.

(5) A listing of all sources of water, by lease and well, to be injected shall be submitted on a Source of Produced Water for Disposal, Form 26.

(6) Any proposed stimulation program.

(7) The estimated minimum and maximum amount of water to be injected daily with anticipated injection pressures. Maximum injection pressure will be set by the Director upon approval.

(8) The names and addresses of those persons notified by the applicant, as required by subparagraph i of this rule.

d. The application for a simultaneous injection well shall include the following:

(1) The name, description and depth of the formation into which water is to be injected, and all underground sources of drinking water which may be affected by the proposed operation. A water analysis of the injection formation (if the total dissolved solids of the injection formation is determined to be less than ten thousand (10,000) milligrams per liter, the aquifer must be exempted in accordance with Rule 324B.); a water analysis from the producing formation; and the fracture pressure or fracture gradient of the injection formation.

(2) A base plat covering the area within one-quarter (1/4) mile of the proposed well showing the location of the proposed well or wells and the location of all oil and gas wells, domestic and irrigation wells of public record and the identification of all oil and gas wells currently producing from the proposed injection zone within one-half (1/2) mile of the disposal zone and the names, addresses and holdings of all mineral owners as defined in §34-60-103 (7), C.R.S., within one-quarter (1/4) mile of the proposed disposal well or wells, or all owners of record in the field if a field-wide system is proposed. These owners shall be specifically outlined and identified on the base plat. Remedial action shall be required for any well within one-quarter (1/4) mile of the proposed well or wells in which the injection zone is not adequately confined. The applicant shall include information regarding the need for remedial action on any well(s) penetrating the injection zone within one-quarter (1/4) mile of the proposed disposal well or wells, which the applicant may or may not operate and a plan for the performance of any such remedial work and a copy of all plans and specifications for the system and its appurtenances.

(3) A resistivity log, run from the bottom of the surface casing to total depth of the disposal zone or such log from a well within one (1) mile together with a log from that well that can be correlated with the simultaneous injection well. If the simultaneous injection well is to be drilled, a description of the typical stratigraphic level of the injection formation in the simultaneous injection well or wells, and any other available logging or testing data, on the simultaneous injection well or wells.

(4) A full description of the casing in the simultaneous injection well or wells. This shall include any information available on any remedial cement work performed to any casing string. This shall also include a schematic drawing showing all casing strings with cement volumes and tops, existing or as proposed, plug back total depth, depth of any existing open or squeezed perforations, setting depths of any bridge plugs existing or proposed, planned perforations in the injection zone, downhole pump setting depth and any tubing and or packer size and setting depth.

(5) Any proposed stimulation program.

(6) The estimated amount of water to be injected daily.

(7) Downhole pump specifications, together with a calculation of maximum discharge pressure created under proposed wellbore configuration. Downhole pump configurations shall be designed to inject below the injection zone fracture gradient.

(8) The names and addresses of those persons notified by the applicant, as required by subparagraph j. of this rule.

The following rules shall apply to both dedicated injection well and simultaneous injection well applications.

e. **Mechanical integrity testing requirement**. Prior to application approval, the proposed disposal well must satisfactorily pass a mechanical integrity test in accordance with Rule 326.

f. **Centralized and commercial disposal well requirements.** Prior to application approval, the appurtenant centralized and commercial disposal well operations shall comply with the requirements of Rules 704. and 908.

g. **Multiple well applications**. Application may be made to include the use of more than one (1) disposal well on the same lease, or on more than one (1) lease. Wherever feasible and applicable, the application shall contemplate a coordinated plan for the entire field.

h. The designated operator of a unitized or cooperative project shall execute the application.

i. Notice of the application for a dedicated injection well shall be given by the applicant by registered or certified mail or by personal delivery, to each surface owner and owner as defined in §34-60-103(7), C.R.S., within one-quarter (1/4) mile of the proposed well or wells and to owners and operators of oil and gas wells producing from the injection zone within one-half (1/2) mile of the disposal well or to owners of cornering and contiguous units where injection will occur into the producing zones, whichever is the greater distance.

j. Notice of the application for a simultaneous injection well shall be given by the applicant by registered or certified mail or by personal delivery, to each owner as defined in §34-60-103(7), C.R.S., within one-quarter (1/4) mile of the proposed well or wells and to owners and operators of oil and gas wells producing from the injection zone within one-half (1/2) mile of the disposal well or to owners of cornering and contiguous units where injection will occur into the producing zones, whichever is the greater distance.

k. A copy of the notice of application shall be included with the disposal application filed with the Commission, and the applicant shall certify that notice by registered or certified mail or by personal delivery, to each of the owners specified in subparagraphs i. and j., has been accomplished.

l. **Notice of application requirements**. The notice shall describe the proposed operation and shall state that any person who would be directly and adversely affected or aggrieved by the authorization of the underground disposal into the proposed injection zone may file, within fifteen (15) days of notification, a written request for a public hearing before the Commission, provided such request meets the protest requirements specified in subparagraph m. of this rule. The notice shall also state that additional information on the operation of the proposed disposal well may be obtained at the Commission office.

m. **Evaluation of written requests for public hearing**. Written requests for public hearing before the Commission by a person, notified in accordance with subparagraphs i. and j. of this rule, who may be directly and adversely affected or aggrieved by the authorization of the underground disposal into the proposed injection zone, shall be reviewed and evaluated by the Director in consultation with the applicant. Written protests shall specifically provide information on:

(1) Possible conflicts between the injection zone's proposed disposal use and present or future use as a source of drinking water or present or future use as a source of hydrocarbons, or

(2) Operations at the well site which may affect potential and current sources of drinking water.

n. **Dedicated injection well public notice**. The Director shall publish a notice of the proposed disposal permit for dedicated injection wells in a newspaper of general circulation serving the area where the well(s) is (are) located. The notice shall briefly describe the disposal application and include legal location, proposed injection zone, depth of injection and other relevant information. Comment period on the proposed disposal application shall end thirty (30) days after date of publication. If any data, information, or arguments submitted during the public comment period appear to raise substantial questions concerning potential impacts to the environment, public health, safety and welfare raised by the proposed disposal well permit the Director may request that the Commission hold a hearing.

o. **Injection application deadlines**. If all of the data or information necessary to approve the disposal application has not been received within six (6) months of the date of receipt, the application will be withdrawn from consideration. However, for good cause shown, a ninety (90) day extension may be granted, if requested prior to the date of expiration.

326. MECHANICAL INTEGRITY TESTING

For the purpose of this rule, a mechanical integrity test of a well is a test designed to determine if: there is a significant leak in the casing, tubing, or packer of the well, and there is significant fluid movement into an underground source of drinking water through vertical channels adjacent to the wellbore.

a. Injection Wells - A mechanical integrity test shall be performed on all injection wells.

(1) The mechanical integrity test shall include one (1) of the following tests to determine whether significant leaks are present in the casing, tubing, or packer;

A. A pressure test with liquid or gas at a pressure of not less than three hundred (300) psi or the minimum injection pressure, whichever is greater, and not more than the maximum injection pressure; or

B. The monitoring and reporting to the Director, on a monthly basis for sixty (60) consecutive months, of the average casing-tubing annulus pressure, following an initial pressure test; or

C. In lieu of A. and B. any equivalent test or combinations of tests approved by the Director.

(2) The mechanical integrity test shall include one (1) of the following tests to determine whether there are significant fluid movements in vertical channels adjacent to the well bore:

A. Cementing records which shall only be valid for injection wells in existence prior to July 1, 1986;

B. Tracer surveys;

C. Cement bond log or other acceptable cement evaluation log;

D. Temperature surveys; or

E. In lieu of A.-D., any other equivalent test or combination of tests approved by the Director.

(3) No person shall inject fluids into a new injection well unless a mechanical integrity test on the well has been performed and supporting documents including Mechanical Integrity Test, Form 14B, submitted and approved by the Director. Verbal approval may be granted for continuous injection following the test.

(4) Following the performance of the initial mechanical integrity test required by subparagraph (3), additional mechanical integrity tests shall be performed on each type of injection well as follows:

A. **Dedicated injection well.** As long as it is used for the injection of fluids, mechanical integrity tests shall be performed at the rate of not less than one (1) test every five (5) years. The first five (5) year period shall commence on the date the initial mechanical integrity test is performed.

B. **Simultaneous injection well.** No additional tests will be required after the initial mechanical integrity test.

(5) Following the performance of the initial mechanical integrity test required by subparagraph (3), additional mechanical integrity tests shall be performed on each well, as long as it is used for the injection of fluids, at the rate of not less than one (1) test every five (5) years. The first five (5) year period shall commence on the date the initial mechanical integrity test is performed.

b. **Shut-in Wells** - All shut-in wells shall pass a mechanical integrity test.

(1) A mechanical integrity test shall be performed on each shut-in well within two (2) years of the initial shut-in date. A mechanical integrity test shall be performed on each shut-in well on five (5) year intervals from the date the initial mechanical integrity test was performed. If, at any time, surface equipment is removed or the well becomes incapable of production, a mechanical integrity test must be performed within thirty (30) days. The mechanical integrity test for a shut-in well shall be:

A. Isolation of the wellbore with a bridge plug or similar approved isolating device set one hundred (100) feet or less above the highest perforations and a pressure test with liquid or gas at a pressure of not less than three hundred (300) psi surface pressure or any equivalent test or combination of tests approved by the Director.

B. Following the performance of the initial mechanical integrity test for shut-in wells, additional tests, other than the five (5) year interval test, may be required.

c. Not less than ten (10) days prior to the performance of any mechanical integrity test required by this rule, any person required to perform the test shall notify the Director, in writing, of the scheduled date on which the test will be performed.

d. All wells shall maintain mechanical integrity. All wells which lack mechanical integrity shall be repaired or plugged and abandoned within six (6) months of failing a mechanical integrity test or of a determination through any other means that the well lacks mechanical integrity, and the well site reclaimed in accordance with Rule 1004.a. All injection wells which fail a mechanical integrity test, or which are determined through any other means to lack mechanical integrity, shall be shut-in immediately.

327. LOSS OF WELL CONTROL

The operator shall take all reasonable precautions, in addition to fully complying with Rule 317. to prevent any oil, gas or water well from blowing uncontrolled and shall take immediate steps and exercise due diligence to bring under control any such well, and shall report such occurrence to the Director as soon as practicable, but no later than twenty four (24) hours following the incident. Within fifteen (15) days after all occurrences the operator shall submit a written report giving all details. The Director shall maintain these written reports in a central file.

328. MEASUREMENT OF OIL

The volume of production of oil shall be computed in terms of barrels of clean oil on the basis of properly calibrated meter measurements or tank measurements of oil-level differences, made and recorded to the nearest one-quarter (1/4) inch of one hundred percent (100%) capacity tables, subject to the following corrections:

a. **Correction for Impurities.** The percentage of impurities (water, sand and other foreign substances not constituting a natural component part of the oil) shall be determined to the satisfaction of the Director, and the observed gross volume of oil shall be corrected to exclude the entire volume of such impurities.

b. **Temperature Correction.** The observed volume of oil corrected for impurities shall be further corrected to the standard volume of sixty degrees fahrenheit (60°F). in accordance with A.S.T.M. D-1250 Table 7, or any revisions thereof and any supplements thereto or any close approximation thereof approved by the Director.

c. **Gravity Determination.** The gravity of oil at sixty degrees fahrenheit (60°F) shall be determined in accordance with A.S.T.M. D-1250 Table 5, or any revisions thereof and any supplements thereto or any close approximation thereof approved by the Director.

329. MEASUREMENT OF GAS

Production of gas of all kinds shall be measured by meter unless otherwise agreed to by the Director. For computing volume of gas to be reported to the Commission, the standard pressure base shall be fourteen point seventy-three (14.73) psia, regardless of atmospheric pressure at the point of measurement, and the standard temperature base shall be sixty degrees fahrenheit (60°F). All volumes of gas to be reported to the Commission shall be adjusted by computation to these standards, regardless of pressures and temperatures at which the gas was actually measured, unless otherwise authorized by the Director.

330. MEASUREMENT OF PRODUCED AND INJECTED WATER

a. The volume of produced water shall be computed and reported in terms of barrels on the basis of properly calibrated meter measurements or tank measurements of water-level differences, made and recorded to the nearest one-quarter (1/4) inch of one hundred percent (100%) capacity tables. If measurements are based on oil/water ratios, the oil/water ratio must be based on a production test performed during the last calendar year. Other equivalent methods for measurement of produced water may be approved by the Director.

b. The volume of water injected into a Class II dedicated injection well shall be computed and reported in terms of barrels on the basis of properly calibrated meter measurements or tank measurements of water-level differences, made and recorded to the nearest one-quarter (1/4) inch of one hundred percent (100%) capacity tables. If water is transported to an injection facility by means other than direct pipeline, measurement of water is required by a properly calibrated meter.

c. The volume of water injected and produced in simultaneous injection wells shall be computed and reported in terms of barrels on the basis of calculated pump volumes, on the basis of properly calibrated meter measurements, or on the basis of a produced gas to water ratio based on an annual production test.

331. VACUUM PUMPS ON WELLS

The installation of vacuum pumps or other devices for the purpose of imposing a vacuum at the wellhead or on any oil or gas bearing reservoir may be approved by the Director upon application therefore, except as herein provided. The application shall be accompanied by an exhibit showing the location of all wells on adjacent premises and all offset wells on adjacent lands, and shall set forth all material facts involved and the manner and method of installation proposed. Notice of the application shall be given by the applicant by registered or certified mail, or by delivering a copy of the application to each producer within one-half (1/2) mile of the installation.

In the event no producer within one-half (1/2) mile of the installation or the Commission itself files written objection or complaint to the application within fifteen (15) days of the date of application, then the application shall be approved, but if any producer within one-half (1/2) mile of said installation or the Commission itself files written objection within fifteen (15) days of the date of application, then a hearing shall be held as soon as practicable.

332. USE OF GAS FOR ARTIFICIAL GAS LIFTING

Gas may be used for artificial gas lifting of oil where all such gas returned to the surface with the oil is used without waste. Where the returned gas is not to be so used, the use of gas for artificial gas lifting of oil is prohibited unless otherwise specifically ordered and authorized by the Commission upon hearing.

333. SEISMIC OPERATIONS

a. **COGCC Form 20, Notice of Intent to Conduct Seismic Operations**. Seismic operations require an approved Form 20 which shall be submitted to the Director prior to commencement of shothole drilling or recording operations. An informational copy of the Form 20 shall be filed by the operator with the local governmental designee at or before the time of filing with the Director. Any change of plans or line locations may be implemented without Director approval provided that after such change is performed, the Director shall receive written notice of the change within five (5) days.

A map shall be included with the notice. This map shall be at a scale of at least 1:48,000 showing sections, townships and ranges and providing the location of the proposed seismic lines, including source and receiver line locations.

The Notice of Intent to Conduct Seismic Operations, Form 20, shall be in effect for six (6) months from the date of approval. An extension of time may be granted upon written request submitted prior to the expiration date.

b. **Surface owner consultation.** Prior to the commencement of any seismic operations, a good faith effort shall be made to consult with all surface owners of the lands included in the seismic project area.

c. **Exploration requiring the drilling of shotholes**:

(1) **Explosive storage.** All explosives shall be legally and safely stored and accounted for in magazines when not in use in accordance with relevant regulations of the Alcohol, Tobacco and Firearms Division of the Federal Department of the Treasury.

(2) **Blasting safety setbacks.** Blasting shall be kept a safe distance from occupied buildings, water wells or springs, unless by special written permission of the surface owner or lessee, according to the following minimum setback distances:

CHARGES IN LBS. GREATER THAN	CHARGES IN LBS. UP TO AND INCLUDING	MINIMUM SETBACK DISTANCE IN FEET
0	2	200
2	5	300
5	6	360
6	7	420
7	8	480
8	9	540
9	10	600
10	11	649
11	12	696
12	13	741
13	14	784
14	15	825
15	16	864
16	17	901
17	18	936
18	19	969
19	20	1000
20		1320

(3) Prior to any shothole drilling, the operator shall contact the Utility Notification Center of Colorado at 1-800-922-1987.

(4) **Drilling and plugging.** The following guidelines shall be used to plug shotholes unless the operator can demonstrate that another method will provide adequate protection to ground water quality and movement and long-term land stability:

A. Any slurry, drilling fluids, or cuttings which are deposited on the surface around the seismic hole shall be raked or otherwise spread out to at least within one (1) inch of the surface, such that the growth of the natural grasses or foliage shall not be impaired.

B. All shotholes shall be preplugged or anchored to prevent public access if not immediately shot. In the event the preplug does not hold, seismic holes shall be properly plugged and abandoned as soon as practical after the shot has been fired. However, a fired hole shall not be left unplugged for more than thirty (30) days without approval of the Director. In no event shall shotholes be left open, but shall be covered with a tin hat or other similar cover until they are properly plugged. The hats shall be imprinted with the seismic contractor's name or identification number or mark.

C. The hole shall be filled to a depth of approximately three (3) feet below ground level by returning the cuttings to the hole and tamping the returned cuttings to ensure the hole is not bridged. A non-metallic perma-plug either imprinted or tagged with the operator name or the identification number or mark described in the notice of intent shall be set at a depth of three (3) feet, and the remaining hole shall be filled and tamped to the surface with cuttings and native soil. A sufficient mound of native soil shall be left over the hole to allow for settling.

D. When non-artesian water is encountered while drilling seismic shotholes, the holes shall be filled from the bottom up with a high grade coarse ground bentonite to ten (10) feet above the static water level or to a depth of three (3) feet from the surface; the remaining hole shall be filled and tamped to the surface with cuttings and native soil, unless the operator otherwise demonstrates that use of another suitable plugging material may be substituted for bentonite without harm to ground water resources.

E. If artesian flow (water rising above the depth at which encountered) is encountered in the drilling of any seismic hole, cement or high grade coarse ground bentonite shall be used to seal off the water flow with the selected material placed from the bottom of the hole to the surface or at least fifty (50) feet above the top of the water-bearing material, thereby preventing cross-flow between aquifers, erosion or contamination of fresh water supplies. Said holes shall be plugged immediately.

d. **COGCC Form 20A, Completion Report for Seismic Operations**. A Form 20A shall be submitted to the Director within sixty (60) days after completion of the project. The report shall include: maps (with a scale not less than 1:48,000) showing the location of all receiver lines, energy source lines and any shotholes. Shotholes encountering artesian flow shall be indicated on the map.

If the program included any shotholes, then the completion report shall be accompanied by the following:

(1) a certification by the party responsible for plugging the holes that all shotholes are plugged as prescribed by these rules and approved by the Director, and

(2) the latitude and longitude of each shothole location. Latitude and longitude values shall be referenced to the NAD 1927 and reported in decimal degrees to an accuracy of at least five (5) decimal places (e.g.; latitude 37.12345 N, longitude 104.45632 W), or reported in other form as approved by the Director. If GPS technology is utilized to determine the latitude and longitude, all GPS data shall meet the requirements set forth in Rule 303.c.(4)a. through d.

e. **Bonding Requirements.** The company submitting the Notice of Intent to Conduct Seismic Operations, Form 20, shall file financial assurance in accordance with Rule 705. prior to the commencement of operations. The bond shall remain in effect until a request is made by the company to release the bond for the following reasons:

(1) The shotholes have been properly plugged and abandoned, and source and receiver lines have been reclaimed in accordance with this Rule 333., and

(2) There are no outstanding complaints received from surface owners that have not been investigated by the Director and addressed as provided for in Rule 522.

f. **Reclamation requirements.** Upon completion of seismic operations the surface of the land shall be restored as nearly as practicable to its original condition at the commencement of seismic operations. Appropriate reclamation of disturbed areas will vary depending upon site specific conditions and may include compaction alleviation and revegetation. All flagging, stakes, cables, cement, mud sacks or other materials associated with seismic operations shall be removed.

334. PUBLIC HIGHWAYS AND ROADS

All persons subject to the Act and these rules and regulations while using public highways or roads shall be subject to the State Vehicles and Traffic Laws pursuant to Title 42, C.R.S. and the State Highway and Roads Laws, Title 43, C.R.S., pertaining to the use of public highways or roads within the state.

335. COGCC Form 15. PIT CONSTRUCTION REPORT/PERMIT

A Pit Construction Report/Permit, Form 15, shall be submitted for approval by the Director in accordance with Rule 903.

336. COGCC Form 18. COMPLAINT FORM

Any party who wishes to file a complaint regarding oil and gas operations is encouraged to submit a Form 18. The Director shall investigate any complaint and determine what, if any, action shall be taken in accordance with Rule 522.

337. COGCC Form 19. SPILL/RELEASE REPORT

All spills and releases of E&P waste exceeding five (5) barrels shall be reported on a Spill/Release Report, Form 19. Form 19 shall be filed with the Director pursuant to the reporting requirements in Rule 906.

338. COGCC Form 24. SOIL ANALYSIS REPORT

Soil Analysis Report, Form 24, shall be submitted where soil composition data is required, in accordance with Rule 910.

339. COGCC Form 25. WATER ANALYSIS REPORT

Water Analysis Report, Form 25, shall be submitted where water quality data is required, in accordance with Rule 910.

340. COGCC Form 27. SITE INVESTIGATION AND REMEDIATION WORKPLAN

Site Investigation and Remediation Workplan, Form 27, shall be submitted when required in accordance with Rule 909.

UNIT OPERATIONS, ENHANCED RECOVERY PROJECTS, AND STORAGE OF LIQUID HYDROCARBONS

401. AUTHORIZATION

a. No person shall perform any enhanced recovery operations, cycling or recycling operations including the extraction and separation of liquid hydrocarbons from natural gas in connection therewith, or operations for the storage of gaseous or liquid hydrocarbons, nor shall any person carry on any other method of unit or cooperative development or operation of a field or a part of either, without having first obtained written authorization from the Commission to perform the aforementioned activities or operations. No person shall commence construction of a well for use in either enhanced recovery operations or for storage of gaseous or liquid hydrocarbons without having first obtained written authorization from the Commission to do so. These provisions shall not apply to existing gas storage projects or to projects that have received approval of the Federal Energy Regulatory Commission; provided however, that a copy of such application and approval shall be submitted to the Commission and made a part of their records.

b. Persons wishing to obtain such authorization shall file an application for authorization with the Commission. The application may be filed by any one (1) or more of the parties involved, or by the operator of the project for which authorization is sought. The application shall include the following:

(1) A plat showing the area involved, together with the well or wells, including drilling wells, dry and abandoned wells located thereon, all properly designated. If the plan of operation involves injection of fluids for enhanced recovery operations, or storage of liquid hydrocarbons, such plat shall show the names of owners of record within one-quarter (1/4) mile of the injection well or wells indicating whether they are surface owners, mineral interest owners, or working interest owners. The application shall also include information regarding the need for remedial action on wells penetrating the injection zone within one-quarter (1/4) mile of each injection well and a plan for the performance of any such remedial work.

(2) A full description of the particular operation for which authorization is required.

(3) Copies of the unit or co-operative agreement and operating agreement, unless these agreements have already been provided to the Commission.

(4) Where injection of fluids for enhanced recovery operations or storage of liquid hydrocarbons is proposed, the application shall also contain:

A. The name, description, thickness and depth of the following formations: those from which wells are producing or having produced; those which will receive any fluids to be injected; those capable of limiting the movement of any fluids to be injected;

B. The name and the depth to the bottom of all underground sources of drinking water which may be affected by the proposed activity or operation;

C. A resistivity log, run from the bottom of the surface casing to total depth of the injection well or wells, or a resistivity log of any well within one (1) mile together with a log from that well that can be correlated with a similar log of the injection well. If the injection well is to be drilled, a description of the typical stratigraphic level of the injection formation and any other available logging or testing data;

D. A description of the casing of the injection well or wells or the proposed casing program, including a schematic drawing of the surface and subsurface construction details of the system and a full description of cement jobs already in place or proposed;

E. A statement specifying the type of fluid to be injected, chemical analysis of the fluid to be injected, the source of the fluid, the estimated amounts to be injected daily, the anticipated injection pressures, water analysis of receiving formation, any available data on the compatibility of the fluid with the receiving formations and known or calculated fracture gradient (maximum authorized surface injection pressure will be set by the Director);

F. A description of any proposed stimulation program;

G. The name and address of the operator or operators of the project and those persons notified by the applicant.

(5) This rule does not apply to gas storage projects in existence on August 18, 1986.

402. NOTICE AND DATE OF HEARING

Upon the filing of any application, the Commission shall issue notice thereof, as provided by the Act and these regulations. Said application shall be set for public hearing at such time as the Commission may fix.

403. ADDITIONAL NOTICE

If injection of fluids is proposed by said application, in addition to the notice required by the Act, a copy of such application shall be given in person or by first class mail to each owner of record of the reservoir involved within one-quarter (1/4) mile of the proposed intake well or wells. Such delivery, whether in person or by mail, shall take place on or before the date the application is filed. An affidavit shall be attached to the application showing the parties to whom the notice has been given and their addresses.

404. CASING AND CEMENTING OF INJECTION WELLS

Wells used for injection of fluids into the producing formation shall be cased with safe and adequate casing or tubing so as to prevent leakage, and shall be so set or cemented that damage will not be caused to oil, gas or fresh water resources. (Each injection well must satisfactorily pass a mechanical integrity test in accord with Rule 326. prior to injection.)

405. NOTICE OF COMMENCEMENT AND DISCONTINUANCE OF INJECTION OPERATIONS

The following provisions shall apply to all injection projects whether or not they are approved by the Commission:

a. Immediately upon the commencement of injection operations, the operator shall notify the Commission of the injection date.

b. Within ten (10) days after the discontinuance of injection operations the operator shall notify the Commission of the date of such discontinuance and the reasons therefore.

c. When any well in an approved enhanced recovery unit operation is converted to or from an injection status, notice shall be given on a Sundry Notice, Form 4, within thirty (30) days.

d. Before any intake well shall be plugged, notice shall be given to the Commission by the owner of said well, and the same procedure shall be followed in the plugging of such well as is provided for the plugging of oil and gas wells.

RULES OF PRACTICE AND PROCEDURE

501. APPLICABILITY OF RULES OF PRACTICE AND PROCEDURE

a. These rules shall be known and designated as "Rules of Practice and Procedure before the Oil and Gas Conservation Commission of the State of Colorado," and shall apply to all proceedings before the Commission. These rules shall be liberally construed to secure just, speedy, and inexpensive determination of all issues presented to the Commission.

b. Notwithstanding any provision of these rules, the Commission shall, upon its own motion or upon the motion of a party to a proceeding, act to prohibit or terminate any abuse of process by an applicant, protestant, intervenor, witness or party offering a statement pursuant to Rule 510. in a proceeding. Such action may include, but is not limited to, summary dismissal of an application, protest, intervention or other pleading; limitation or prohibition of harassing or abusive testimony; and finding a party in contempt. Grounds for such action include, but are not limited to, the use of the Commission's procedures for reasons of obstruction and delay; misrepresentation in pleadings or testimony; or, other inappropriate or outrageous conduct.

c. Any rule, regulation, or final order of the Commission shall be subject to judicial review in accordance with the provisions of the Administrative Procedure Act, §§24-4-101 to 108, C.R.S., and any other applicable provisions of law.

502. PROCEEDINGS NOT REQUIRING THE FILING OF AN APPLICATION

a. **Commission's own motion.** The Commission may, on its own motion, initiate proceedings upon any questions relating to conservation of oil and gas or the conduct of oil and gas operations in the State of Colorado, or to the administration of the Act, by notice of hearing or by issuance of an emergency order without notice of hearing. Such emergency order shall be effective upon issuance and shall remain effective for a period not to exceed fifteen (15) days. Notice of an emergency order shall be given as soon as possible after issuance.

b. **Variances.**

(1) Variances to any Commission rules, regulations, or orders may be granted in writing by the Director without a hearing upon written request by an operator to the Director, or by the Commission after hearing upon application. The operator or the applicant requesting the variance shall make a showing that it has complied with the specific requirements contained in these rules to secure a variance, if any, and that the requested variance will not violate the basic intent of the Oil and Gas Conservation Act.

(2) No variance to the rules and regulations applicable to the Underground Injection Control Program shall be granted by the Director without consultation with the U.S. Environmental Protection Agency, Region VIII, Waste Water Management Division Director.

(3) The Director shall report any variances granted at the monthly Commission hearing following the date on which such variance was granted.

503. ALL OTHER PROCEEDINGS COMMENCED BY FILING AN APPLICATION

a. All proceedings other than those initiated by the Commission or variance requests submitted for Director approval shall be commenced by filing with the Commission the original and nine (9) copies of a typewritten or printed petition which shall be titled "application." Whenever possible, the application shall also be submitted on compatible electronic media. The application shall set forth in reasonable detail the relief requested and the legal and factual grounds for such relief. The original of the application shall be executed by a person with authority to do so on behalf of the applicant and the contents thereof shall be verified by a party with sufficient knowledge to confirm the facts contained therein. Each application shall be accompanied by a docket fee established by the Commission (See Appendix III), except applications seeking an order finding violation or an emergency order.

b. Applications to the Commission may be filed by the following applicants:

(1) For purposes of applications for the creation of drilling units, applications for additional wells within existing drilling units, other applications for modifications to existing drilling unit orders, or applications for exceptions to Rule 318., only those owners within the proposed drilling unit, or within the existing drilling unit to be affected by the application, may be applicants.

(2) For purposes of applications for involuntary pooling orders made pursuant to §34-60-116, C.R.S., only those persons who own an interest in the mineral estate of the tracts to be pooled may be applicants.

(3) For purposes of applications for unitization made pursuant to §34-60-118, C.R.S., only those persons who own an interest in the mineral estate underlying the tract or tracts to be unitized may be applicants.

(4) For purposes of seeking an order finding violation, only the Director or a party who made a complaint under Rule 522. may be an applicant.

(5) For purposes of seeking a variance from the Commission, only the operator, mineral owner, surface owner or tenant of the lands which will be affected by such variance, other state agencies, any local government within whose jurisdiction the affected operation is located, or any person who may be directly and adversely affected or aggrieved if such variance is not granted, may be an applicant.

(6) For purposes of seeking a hearing on a permit-to-drill, Form 2, under Rules 303.d. and 303.k., the relevant local government shall be the applicant, and the hearing shall be conducted in similar fashion as is specified in Rule 508.j., k and l. with respect to a public issues hearing. It shall be the burden of the local government applicant to bring forward evidence sufficient for the commission to make the preliminary findings specified in subsection j of Rule 508. at the outset of such hearing.

(7) For purposes of seeking relief or a ruling from the Commission on any other matter not described in (1) through (6) above, only persons who can demonstrate that they are directly and adversely affected or aggrieved by the conduct of oil and gas operations or an order of the Commission and that their interest is entitled to legal protection under the act may be an applicant.

c. Applications subject to the requirements for local public forums under Rule 508.a. shall be accompanied by a proposed plan (the "Proposed Plan") to address protection of the environment, public health, safety, and welfare and a description of the current surface occupancy/use. The Proposed Plan shall include the rules and regulations of the Commission as they are applied to oil and gas operations in the application lands along with any procedures or conditions the applicant will voluntarily follow to address the protection of the environment, public health, safety, and welfare.

d. No later than seven (7) days after the application is filed, the applicant shall submit to the Commission a certificate of service demonstrating that the applicant served a copy of the application on all persons entitled to notice pursuant to these rules by mailing a copy thereof, first-class postage prepaid, to the last known mailing address of the person to be served, or by personal delivery. The applicant shall at the same time submit to the Commission a list of all persons entitled to notice pursuant to these rules on compatible electronic media. If the applicant is unable to submit an electronic media list of persons noticed the applicant shall submit a written list of persons noticed no later than seven (7) days after the application is filed.

e. The applicant shall enjoy a rebuttable presumption that it has properly served notice on persons entitled to notice of the proceedings by demonstrating through certification or testimony that notice was provided pursuant to Rules 507. and 508.

f. In order to continue to receive copies of the pleadings filed in a specific proceeding a party who receives notice of the application shall file with the Secretary a protest or intervention in accordance with these rules.

g. Subsequent to the initiation of a proceeding, all pleadings filed by any party shall be offered by filing with the Secretary the original and nine (9) copies bearing the cause number assigned to such proceeding. Each pleading shall include the certificate of the party filing the pleading that the pleading has been served on all persons who have filed a protest or intervention in accordance with these rules, by mailing a copy thereof, first-class postage prepaid, to the last known mailing address of the person to be served, or by personal delivery.

504. DOCKET NUMBER OF PROCEEDINGS

When a proceeding is initiated the Secretary of the Commission shall assign it a new docket number and enter on a separate page of a docket provided for such purpose, the proceeding with the date of the filing of the application, or the date of the entry of the Commission order, initiating such proceeding. All subsequent pleadings shall be assigned the same docket number and shall be noted with the date of filing upon the docket page or continued docket page, for such proceeding, as the case may be.

505. REQUIREMENT OF PUBLIC HEARING

Before the Commission adopts any rule, regulation, or enters any order, or amendment thereof, or grants any variance pursuant to Rule 502., the Commission shall hold a public hearing, scheduled in accordance with Rule 506., at such time and place as may be prescribed by the Commission. Any party shall be entitled to be heard as provided in these rules and regulations. The foregoing shall not apply to the issuance of an emergency order, notice of alleged violation, or cease and desist order.

506. HEARING DATE/CONTINUANCE

a. All applications shall be filed no later than fifty (50) days in advance of the hearing date for which the applicant proposes the matter be docketed provided the docket has not been filled by the Secretary. The Secretary shall have the discretion to accept applications later than fifty (50) days prior to the hearing date, subject to docket availability and the notice requirements of Rules 507. and 508. The Secretary shall grant the first request by an applicant for a continuance of any matter three (3) business days before the scheduled hearing, provided that a protest has not been filed. For contested matters the Secretary shall have the discretion to grant any motion for continuance stipulated to by the applicant and any protestants or intervenors. The Secretary shall notify the Commission of any continuances granted at the next regularly scheduled Commission meeting. The Commission may at any time direct the Secretary to discontinue granting continuances in any matter. In all other cases, requests for continuance shall be reviewed by the Commission before approval or denial. When a continuance request is heard by the Commission the moving party shall demonstrate good cause in order for the Commission to grant the continuance.

b. In all rulemaking proceedings, hearings shall be held in accordance with Rule 529.

c. The Commission may for good cause cancel or continue any hearing to another date by issuing written notice at any time prior to the close of the record, or by announcement at hearing. Good cause shall include, but shall not be limited to, the Commission's acknowledgment that it will not have sufficient time at any regularly scheduled meeting to hear any matter. Any continuance of a hearing shall not extend the filing deadline for the filing of protests or interventions in accordance with Rule 509., unless the application is amended, or as otherwise allowed by the Commission.

d. When a Commission hearing is scheduled for multiple days the Secretary may estimate the time and date that a given matter may be heard by the Commission. The Commission may change, at its discretion, the proposed hearing docket, including the time or date of any scheduled hearing. It shall be the responsibility of the participating party and its attorney to be present when the Commission hears the matter.

507. NOTICE FOR HEARING

a. **General notice provisions**

(1) When any proceeding has been initiated, the Commission shall cause notice of such proceeding to be given to all persons specified in the relevant sections of Rules 507.b. and 507.c. at least twenty (20) days in advance of any Commission hearing at which the matter will first be heard. Notice shall be provided in accordance with the requirements of §34-60-108(4), C.R.S.

(2) The applicant shall assume the cost for publication, and if the number of notices exceeds one hundred (100), responsibility for mailing the notices.

(3) The Secretary shall give notice to any person who has filed a request to be placed on the Commission hearing notice list, and paid the annual fee therefor. Notice by publication or notice provided pursuant to the hearing notice list shall not confer interested party status on any person.

b. **Notice for specific applications**

(1) **Applications affecting drilling units.** For purposes of applications for the creation of drilling units, applications for additional wells within existing drilling units or other applications for modifications of or exceptions to existing drilling unit orders (except for applications for well exception locations to existing orders which are addressed in subsection 4 of this rule) notice of the application shall be served on the owners within the proposed drilling unit or within the existing drilling unit to be affected by the applications.

(2) **Applications for involuntary pooling.** For purposes of applications for involuntary pooling orders made pursuant to §34-60-116, C.R.S., notice of the application shall be served on those persons who own any interest in the mineral estate of the tracts to be pooled, except owners of an overriding royalty interest.

(3) **Applications for unitization.** For purposes of applications for unitization made pursuant to §34-60-118, C.R.S., notice of the application shall be served on those persons who own any interest in the mineral estate underlying the tract or tracts to be unitized and the owners within one-half (1/2) mile of the tract or tracts to be unitized.

(4) **Applications changing certain well location setbacks**. For purposes of applications that change the permitted minimum setbacks for established drilling and spacing units, notice of the application shall be served on those owners of contiguous or cornering tracts who may be affected by such change.

(5) **Applications for well location exception.** For purposes of applications made for exceptions to Rule 318., exceptions to legal locations within drilling and spacing units, or for an exception location to an existing order, notice of the application shall be served on the owners of any contiguous or cornering tract toward which the well location is proposed to be moved, provided that when the applicant owns any interest covering such tract, the person who owns the mineral estate underlying the tract covered by such lease shall also be notified. If there is more than one owner within a single drilling unit and the owners have designated a party as the operator on their behalf, notice shall be presumed sufficient if served upon the designated operator of the affected formation.

(6) **Orders related to violations.** With respect to the resolution of a Notice of Alleged Violation (NOAV) through an Administrative Order by Consent (AOC), and to applications for an Order Finding Violation (OFV), notice shall be provided to the complainant and by publication in accordance with §34-60-108(4), C.R.S.

c. **Notice to local government.** For purposes of intervention pursuant to Rule 509. notice shall also be given to the local governmental designee of applications made under sections (1), (3) and (4) of this Rule at the same time that notice is provided to the Commission.

508. LOCAL PUBLIC FORUMS, HEARINGS ON APPLICATIONS FOR INCREASED WELL DENSITY AND PUBLIC ISSUES HEARINGS.

a. Applicability of rule. Applications that would result in more than one (1) well site or multi-well site per forty (40) acre nominal governmental quarter-quarter section or that request approval for additional wells that would result in more than one (1) well site or multi-well site per forty (40) acre nominal governmental quarter-quarter section, within existing drilling units, not previously authorized by Commission order (together an “application for increased well density”) shall be subject to the provisions of this Rule 508.

b. **Local public forum.**

(1) The rules and regulations of the Oil and Gas Conservation Commission as they are applied to oil and gas operations are expected to adequately address impacts to the environment and public health, safety and welfare which may be raised by an application for increased well density.

(2) A local public forum may however be convened to consider potential issues related to the environment or public health, safety, and welfare that may be raised by an application for increased well density that may not be completely addressed by these rules or the Proposed Plan submitted with the application to address protection of the environment, public health, safety, and welfare as described in Rule 503.c.

A. A local public forum shall be convened on the Commission’s own motion, or upon request from a local governmental designee or the applicant.

B. A local public forum may be convened at the Director’s discretion, or upon receipt of a request for a local public forum from a citizen of the county(ies) in which the application area is situated, after the Director’s consideration of the following factors:

(i) The size of the application area and the number and density of surface locations requested;

(ii) The population density of the application area;

(iii) The distribution of Indian, federal and fee lands within the application area;

(iv) The level of current or past public interest in increased well density in the vicinity of the application area;

(v) Whether the application is limited to the deepening or recompletion of existing wells, or directional drilling from existing surface locations, or;

(vi) Whether the application is limited to an exploratory unit formed for involuntary pooling purposes.

(3) The Director shall notify the local governmental designee of any application for increased well density no later than five (5) days after receipt of such application. If the local governmental designee elects to require a local public forum it shall notify the Director of its decision within five (5) days of receipt of notice of the application.

(4) The Director shall notify the applicant of any decision to convene a local public forum no later than ten (10) days after receipt of the application.

c. **Local public forums on federal and Indian lands.**

(1) If the surface and the minerals of the application area are comprised in their entirety of federal or Indian lands no local public forum shall be convened because potential impacts to the environment or public health, safety, and welfare on such lands are subject to federal or tribal requirements. All proceedings on any application for increased well density on federal or Indian lands shall be conducted to comply with the obligations contained in any intergovernmental or tribal memoranda of understanding governing the conduct of oil and gas operations on federal or Indian lands.

(2) If the application area is comprised in part of federal or Indian lands, the Director shall consult with the appropriate federal or Indian authorities before scheduling any public forum on the application. Insofar as the application includes federal or Indian lands, proceedings thereon shall be conducted in accordance with this rule and any obligations contained in any intergovernmental or tribal memoranda of understanding governing the conduct of oil and gas operations on federal or Indian lands.

(3) The Director shall notify the appropriate federal and Indian authorities of any local public forum to be convened to evaluate an application area that includes federal or Indian lands. Federal or Indian participation in the local public forum may include without limitation presentation of the most recent applicable resource management plan(s) and any environmental assessment(s) or environmental impact statement(s) that cover or include all or any portion of the application area.

d. **Notice of the local public forum.**

(1) Within five (5) days from the date the applicant receives notice from the Director that a local public forum shall be convened, the applicant shall submit to the Director a list of the surface owners within the application area. In determining the identity and address of a surface owner for the purpose of giving all notices under this rule the records of the assessor for the county in which the lands are situated may be relied upon.

(2) At least twenty (20) days before the date of the local public forum the Director shall mail to the listed surface owners notice thereof.

(3) Within ten (10) days of receipt of an application for increased well density the Director shall, by regular or electronic mail or by facsimile copy, provide to the local governmental designee(s) notice of the local public forum or notice that based on the factors in Rule 508.b.(2).B. above the Director will not conduct a local public forum.

(4) At least ten (10) days before the date of the local public forum the Director shall publish notice thereof in a newspaper of general circulation in the count(ies) where the application lands are located.

(5) The notice for the local public forum shall state that the forum is being conducted to consider any issues raised by the application that may affect the environment or public health, safety, and welfare that are not addressed by the rules or the Proposed Plan.

(6) Within five (5) days of receipt of an application for increased well density, the Director shall post a description of such application on the COGCC Internet web page.

e. **Timing and location of the local public forum.**

(1) As soon as practicable after publication of notice, but at least ten (10) days prior to the scheduled Commission hearing on the application, the Director shall conduct the local public forum at a location

reasonably proximate to the lands affected by the application. In the alternative, if the hearing is to be held at a location reasonably proximate to the lands affected by the application, the local public forum shall be replaced by the presentation of statements in accordance with Rule 510 during the hearing on the application.

(2) The Director shall immediately notify the applicant of the scheduled time and location of the local public forum.

(3) To the extent practicable, the local public forum shall be scheduled to accommodate the Director or the Director's designee, the participants and the applicant.

(4) If the application area is comprised of lands located in more than one jurisdiction the Director shall coordinate the local public forum to provide for a single forum at a reasonable location proximate to the lands affected by the application.

f. **Conduct of the local public forum.**

(1) A COGCC Hearing Officer shall preside over the local public forum. The COGCC Hearing Officer shall provide to the participants an explanation of the purpose of the local public forum and how the Commission may use the information obtained from the local public forum. The purpose of the local public forum is to address the sufficiency of the rules or the Proposed Plan with respect to protection of the environment or public health, safety, and welfare.

(2) The conduct of the local public forum shall be informal, and participants shall not be required to be sworn, represented by attorneys, or subjected to cross examination.

(3) Attendance or participation at the local public forum by a Commissioner shall not constitute a violation of Rule 515.

(4) The applicant shall participate in the local public forum and present information related to the application.

(5) The Director shall create a record of the local public forum by video-tape, audio-tape or by court reporter. Such record shall be made available to all Commissioners for review prior to the hearing on the application, and may be relied upon in making a decision to convene a public issues hearing.

g. The local public forum shall be conducted to allow elected officials, local government personnel and citizens to express concerns not completely addressed by the rules or the Proposed Plan or make statements regarding the potential impacts from increased well density that relate to the environment or public health, safety, and welfare. Issues raised in the local public forum may include the following:

(1) Impact to local infrastructure;

(2) Impact to the environment;

(3) Impact to wildlife;

(4) Impact to ground water resources;

(5) Potential reclamation impact; and

(6) Other impact to public health, safety and welfare.

The local public forum shall be limited to matters that are within the jurisdiction of the Commission.

h. **Report to the Commission.** At the conclusion of the local public forum the presiding officer shall prepare and submit to the Commission a report of the proceedings. A copy of the report shall be made available, no later than five (5) days prior to the hearing on the application, to the Commissioners, the applicant, any affected local government and the public and shall be posted to the COGCC Internet web page. The report on the local public forum presented to the Commission shall be included in the administrative record for the application taking into consideration the nature of the local public forum process.

i. **Conduct of the hearing on the application.**

(1) The hearing on the application shall be conducted in accordance with Rule 528.

(2) The Commission shall approve or deny the application based solely on the application's technical merits in accordance with §34-60-116, C.R.S.

(3) The presiding officer for any local public forum shall present to the Commission the report of the local public forum.

(4) At the conclusion of the hearing on the application the Commission shall consider and decide whether to convene a public issues hearing based on the local public forum or statements made under Rule 510., and any motions to intervene, and the Commission may:

A.Approve the application without condition;

B.Approve the application with conditions based on the technical testimony presented at the hearing on the application;

C. Approve the application, and with the applicant's consent, attach to the order on the application conditions the Commission determines are necessary to address issues related to the environment or public heath, safety or welfare;

D. Approve the application and stay its effective date to convene a public issues hearing in accordance with Rule 508.j.

E.Deny the Application.

(5) If the Commission orders a public issues hearing it shall set the public issues hearing for the next regularly scheduled Commission meeting, unless the applicant requests at a prehearing conference, and the Commission agrees, to convene the public issues hearing immediately following the hearing on the application.

(6) If the Commission orders a public issues hearing it shall set the public issues hearing for the next regularly scheduled Commission meeting.

j. **Public issues hearing**

Upon a request by an applicant, protestant, or intervener, or on the Commission's own motion, a public issues hearing shall be convened provided the Commission makes the following preliminary findings:

(1) That the public issues raised by the application reasonably relate to potential significant adverse impacts to the environment or public health, safety and welfare that are within the Commission's jurisdiction to remedy; and

(2) That the potential impacts were not adequately addressed by:

A. In the case of an application for increased well density, the application or the Proposed Plan; or

B. In the case of an application for permit-to-drill, by such permit.

(3) That the potential impacts are not adequately addressed by the rules and regulations of the Commission.

k. **Conduct of the public issues hearing:**

(1) The rules and regulations of the Commission shall apply to all participants in the public issues hearing.

(2) The public issues hearing shall be conducted, to the extent practicable, in accordance with Rule 528.

(3) After the public issues hearing the Commission may attach conditions to its order to protect the environment from significant adverse impacts or to protect public health safety and welfare as are warranted by the relevant testimony, and that are not otherwise addressed by these rules and regulations and the Proposed Plan. In addition, the Commission may without limitation:

A. Direct the applicant to amend its Proposed Plan for Commission review and approval for all or a portion of the application area to address specific issues related to the environment or public health, safety and welfare, including any identified impacts of increased well density within all or a portion of the application area, rather than on a single well basis.

B. Include in any order a provision to allow the Director discretion to attach specific conditions to individual well permits as the Commission determines are reasonable and necessary to protect the environment or public health, safety, and welfare.

(4) Any plan or conditions imposed by Commission order that would affect federal or Indian lands sall take into account conditions imposed by the federal or Indian authorities and any federal environmental analysis in order to facilitate regulatory consistency and minimize duplicative regulatory efforts.

(5) Any plan or conditions imposed shall take into account cost effectiveness and technical feasibility, and shall not be applied to prevent the drilling of new wells per se.

I. The Director and the commission shall use best efforts to comply with the provisions of this Rule 508., however, any deviation from this rule shall not give rise to a challenge to Commission action on the local public forum, the application for increased well density, or the public issues hearing.

509. PARTICIPATION IN ADJUDICATORY PROCEEDINGS

a. The applicant and persons that have filed with the Commission a timely and proper protest or intervention pursuant to this rule shall have the right to participate formally in any adjudicatory proceeding. In the case of a local government, intervention shall be granted by right and without fee solely to raise environmental or public health, safety, and welfare concerns.

(1) The protest or intervention shall be filed with the Secretary, and served on the applicant and its counsel at least ten (10) business days prior to the first hearing date on the matter.

(2) Description of affected interest:

A. A protest shall include information to demonstrate that the person is a protestant under these rules in order for the protest to be accepted by the Commission.

B. A local government intervening as a matter of right shall include in the intervention information describing the environmental or public health, safety and welfare concerns raised by the application. When an intervention is filed by any local government or person on an application subject to Rule 508.a., information on the following shall be included:

i. That the public issues raised by the application reasonably relate to potential significant adverse impacts to the environment or public health, safety and welfare that are within the Commission’s jurisdiction to remedy; and

ii. That the potential impacts were not adequately addressed by the application or by the Proposed Plan; and

iii. That the potential impacts are not adequately addressed by the rules and regulations of the Commission.

C. A party desiring to intervene by permission of the Commission shall include in the intervention information to demonstrate why the intervention will serve the public interest, in which case granting the intervention shall be at the Commission's sole discretion. The Commission, at its discretion, may limit the scope of the permissive intervenor’s participation at the hearing.

(3) The pleading shall include:

A. A general statement of the factual or legal basis for the protest or intervention,

B. The relief requested;

C. A description of the intended presentation including a list of proposed witnesses;

D. A time estimate to hear the protest or intervention; and

E. A certificate of service attesting that the pleading has been served, at least ten (10) business days prior to the first hearing date on the matter, on the applicant and any other party which has filed a protest or intervention in the proceeding. If the pleading is served by mail the party filing the pleading shall provide a facsimile copy of the pleading to the applicant and other persons who have filed a proper protest or intervention in the matter on or before the final date for protest or intervention. If for any reason the party filing the pleading is not able to furnish a copy of the pleading to the applicant and the other persons who have filed a proper protest or intervention on or before the final date for protest or intervention, the party filing the pleading shall so notify the Secretary, the applicant and the other parties to the proceeding.

b. The Secretary or the Director may require any additional information necessary pursuant to these rules to ensure the application, protest or intervention is complete on its face.

c. Any person shall have the right to participate in an adjudicatory proceeding by making a 510. statement in accordance with these rules.

d. All pleadings filed pursuant to this rule shall be submitted with an original and nine (9) copies, and shall be accompanied by a docket fee established by the Commission (see Appendix III). The docket fee shall be refunded if an intervention is denied. In cases of extreme hardship, the docket fee may be refunded at the discretion of the Commission.

e. **Participation at the hearing:**

(1) Adjudicatory hearings shall be conducted in accordance with Rule 528. and any applicable prehearing orders of the Commission, or its designated Hearing Officer.

(2) Testimony and cross-examination by a protestant or intervenor shall be limited to those issues that reasonably relate to the interests that the protestant or intervenor seeks to protect, and which may be adversely affected by an order of the Commission.

510. STATEMENTS AT HEARING

a. Any person may make an oral statement or submit a written statement at any hearing that relates to the proceeding before the Commission. The Commission, at its discretion, may limit the length of any oral statement or restrict repetitive statements. In an adjudicatory hearing, an oral statement shall not be accepted into the record unless:

(1) The statement is made under oath, and

(2) The parties to the hearing are allowed to cross-examine the maker of the statement.

b. The Commission, at its discretion, may accept a sworn written statement into the record with due regard to the fact the statement was not subject to cross-examination.

c. The parties to the hearing shall have the right to object to inclusion of any statement under this Rule 510. into the record. The Commission shall note the objection for the record. If the Commission accepts the basis for excluding the 510. statement from the record the substance of the statement shall not be considered by the Commission in making a decision on the matter at issue.

511. APPLICATION PROCEDURE

a. Upon the filing of an application, the Secretary shall set the matter for hearing and ensure that notice is given.

b. If the matter is uncontested, the applicant may request, and the Director may recommend approval on the basis of the merits of the verified application and the supporting exhibits. If the Director does not recommend approval of the application without hearing, the applicant may request an administrative hearing on the application. For purposes of this rule an uncontested matter shall mean any application that is not subject to a protest or an intervention objecting to the relief requested in the application.

c. If the application is contested, the Commission or the Director, at their discretion, may direct the parties to engage in a prehearing conference in accordance with Rule 527. A prehearing conference may result in a continuance of the hearing, or bifurcation of hearing issues as determined by the Director, Hearing Officer or Hearing Commissioner.

512. COMMISSION MEMBERS REQUIRED FOR HEARINGS AND/OR DECISIONS

Four (4) members of the Commission constitute a quorum for the transaction of business. Testimony may be taken and oath or affirmation administered by any member of the Commission.

513. RESERVED

514. JUDICIAL REVIEW

Any Commission order constitutes final agency action for the purpose of judicial review, except as may otherwise be specified under these rules. The statutory time period for filing a notice of appeal from any Commission decision shall commence on the date the order is mailed or served.

515. EX PARTE COMMUNICATIONS

a. The following provisions shall be applied in any adjudicatory proceeding before the Commission or a Hearing Officer.

(1) No person shall make or knowingly cause to be made to any member of the Commission or a Hearing Officer, an ex parte communication concerning the merits of a proceeding which has been noticed for hearing.

(2) No Commissioner or Hearing Officer shall make or knowingly cause to be made to any interested person an ex parte communication concerning the merits of a proceeding which has been noticed for hearing.

(3) A Commissioner or Hearing Officer who receives, or who makes or knowingly causes to be made, a communication prohibited by this rule shall place on the public record of a proceeding:

A. All such written communications and any responses thereto;

B. Memoranda stating the substance of any such oral communications and any responses thereto.

(4) Upon receipt of a communication knowingly made or knowingly caused to be made by a person in violation of this Rule, the Commission or a Hearing Officer may require the person to show cause why their claim or interest in the proceeding should not be dismissed, denied, or otherwise adversely affected on account of such violation.

b. Oral or written communication with individual Commission members is permissible in a rulemaking proceeding. If such information is relied upon in final decision making it shall be made part of the record by the Commission. After the rulemaking record is closed new information that is intended for the rulemaking record shall be presented to the Commission as a whole upon approval of a request to reopen the rulemaking record.

c. This rule shall not limit the right to challenge a decision of the Commission or a Hearing Officer on the grounds of bias or prejudice due to any ex parte communication.

516. STANDARDS OF CONDUCT

a. The purpose of this rule is to ensure that the Commission's decisions are free from personal bias and that its decision making processes are consistent with the concept of fundamental fairness. The provisions of this rule are in addition to the requirements for Commission members set forth in Title 24, Article 18, Section 108.5 of the Colorado Revised Statutes. This rule should be construed and applied to further the objectives of fair and impartial decision making. To achieve these standards Commissioners and Hearing Officers should:

(1) Discharge their responsibilities with high integrity.

(2) Respect and comply with the law. Their conduct, at all times, should promote public confidence in the integrity and impartiality of the Commission.

(3) Not lend the prestige of the office to advance their own private interests, or the private interests of others, nor should they convey, or permit others to convey, the impression that special influence can be brought to bear on them.

b. **Conflicts of interest.** A conflict of interest exists in circumstances where a Commissioner or Hearing Officer has a personal or financial interest that prejudices that Commissioner's or Hearing Officer's ability to participate objectively in an official act.

(1) A Commissioner or a Hearing Officer shall disclose the basis for a potential conflict of interest to the Commission and others in attendance at the hearing before any discussion begins or as soon thereafter as the conflict is perceived. A conflict of interest may also be raised by other Commissioners, the applicant, any protestant or intervenor, or any member of the public.

(2) In response to an assertion of a conflict of interest, a Commissioner may withdraw or the Director may designate an alternate Hearing Officer. If the Commissioner does not agree to withdraw, the other Commissioners, after discussion and comments from any member of the public, shall vote on whether a conflict of interest exists. Such vote shall be binding on the Commissioner disclosing the conflict.

(3) In determining whether there is a conflict of interest that warrants withdrawal the Commission members or Hearing Officer shall take the following into consideration:

A. Whether the official act will have a direct economic benefit on a business or other undertaking in which the Commissioner or Hearing Officer has a direct or substantial financial interest.

B. Whether the potential conflict will result in the Commissioner or Hearing Officer not being capable of judging a particular controversy fairly on the basis of its own circumstances.

C. Whether the potential conflict will result in the Commissioner or Hearing Officer having an unalterable closed mind on matters critical to the disposition of the proceeding.

c. **Discharge of duties.** In the performance of their official duties, the Commission shall apply the following standards:

(1) To be faithful to and constantly strive to improve their competence in regulatory principles, and to be unswayed by partisan interests, public clamor or fear of criticism.

(2) To maintain order and decorum in the proceedings before them.

(3) To be patient, dignified and courteous to litigants, witnesses, lawyers and others with whom the Commission deals in an official capacity, and to require similar conduct of attorneys, staff and others subject to their direction and control.

(4) To afford to every person who is legally interested in a proceeding, or their attorney, full right to be heard according to law.

(5) To diligently discharge their administrative responsibilities, maintain professional confidence in Commission administration and facilitate the performance of the administrative responsibilities of other staff officials.

517. REPRESENTATION AT ADMINISTRATIVE AND COMMISSION HEARINGS

a. Natural persons may appear on their own behalf and represent themselves at hearings before the Commission and persons allowed to make oral or written statements may do so without counsel. Pro se participants shall be subject to these rules and regulations.

b. Except as provided in a. and c. of this rule, representation at hearings before the Commission shall be by attorneys licensed to practice law in the State of Colorado, and provided that any attorney duly admitted to practice law in a court of record of any state or territory of the United States or in the District of Columbia, but not admitted to practice in Colorado, who appears at a hearing before the Commission may, upon motion, be admitted for the purpose of that hearing only, if that attorney has associated for purposes of that hearing with any attorney who:

(1) Is admitted to practice law in Colorado;

(2) Is a resident or maintains a law office within Colorado; and

(3) Is personally appearing with the applicant in the matter and in all proceedings connected with it.

The resident attorney shall continue in the case unless other resident counsel is submitted. Any notice, pleading, or other paper may be served upon the resident attorney with the same effect as if personally served on the non-resident attorney within this state. Resident counsel shall be present before the Commission unless otherwise ordered by the Commission.

c. The Commission has the discretion to allow representation by a corporate officer or director of a community organization, a closely held corporation, a citizens' group duly authorized under Colorado law, or if a limited liability corporation, the member/manager in the following circumstances:

(1) Where the agency is adopting a rule of future effect;

(2) Local public forums;

(3) When an individual is appearing on behalf of a closely held corporation as provided in §13-1-127, C.R.S.;

d. Unless a non-attorney is appearing pro se or pursuant to §13-1-127, C.R.S., or the Director is participating pursuant to Rule 528.c., a non-attorney shall not be permitted to examine or cross-examine witnesses, make objections or resist objections to the introduction of testimony, or make legal arguments.

e. At administrative hearings before the Director, attorneys shall not be required.

518. SUBPOENAS

The Commission may, through the Secretary, issue subpoenas requiring attendance of witnesses and the production of books, papers, and other instruments to the same extent and in the same manner and in accordance with the procedure provided in the Colorado Rules of Civil Procedure which authorize issuance of subpoenas by Clerks of District Courts. A party seeking a subpoena shall submit the form of the subpoena to the Secretary for execution. Upon execution, the party requesting the subpoena has the responsibility to serve the subpoena in accordance with the Rules of Civil Procedure. Upon receipt of an objection to any subpoena issued by the Commission, the Commission has the discretion to limit the scope of the subpoena to matters that are within the scope of the Commission's jurisdiction under the Act.

519. APPLICABILITY OF COLORADO COURT RULES AND ADMINISTRATIVE NOTICE.

a. The Commission adopts the rules of practice and procedure contained in the Colorado Rules of Civil Procedure insofar as the same may be applicable and not inconsistent with the rules herein set forth.

b. In general, the rules of evidence applicable before a trial court without a jury shall be applicable, providing that such rules may be relaxed, where, by so doing, the ends of justice will be better served.

(1) To promote uniformity in the admission of evidence, the Commission, to the extent practical, shall observe and conform to the Colorado rules of evidence applicable in civil non-jury cases in the district courts of Colorado.

(2) When necessary to ascertain facts affecting substantial rights of the parties to a proceeding, the Commission may receive and consider evidence not admissible under the rules of evidence, if the evidence

possesses probative value commonly accepted by reasonable and prudent persons in the conduct of their affairs.

(3) Informality in any proceeding or in the manner of taking testimony shall not invalidate any Commission order, decision, rule or regulation.

c. **Administrative notice.** The Commission may take administrative notice of:

(1) Constitutions and statutes of any state and of the United States;

(2) Rules, regulations, official reports, decisions, and orders of state and federal administrative agencies;

(3) Decisions and orders of federal and state courts;

(4) Reports and other documents in the files of the Commission;

(5) Matters of common knowledge and undisputed technical or scientific fact;

(6) Matters that may be judicially noticed by a Colorado district court in a civil non-jury case; and

(7) Matters within the expertise of the Commission.

520. TIME OF HEARINGS AND HEARING AGENDA

a. Regular hearings will be held before the Commission on such days as may be set by the Commission.

b. The Secretary shall place on the consent agenda those matters recommended by a Hearing Officer for approval, those matters in which an Administrative Order by Consent (AOC) has been negotiated, and those uncontested matters for which a decision has been requested based on the verified application.

(1) The consent agenda shall be voted on without deliberation and without the necessity of reading the individual items, except any Commissioner may request clarification from the Director for any matter on the consent agenda.

(2) Any Commissioner may remove a matter from the consent agenda prior to voting thereon.

(3) Any matter removed from the consent agenda shall be heard at the end of the remaining agenda, if practicable and agreeable to the applicant, or, if not, scheduled for hearing at the next regularly scheduled meeting of the Commission.

521. RESERVED

522. PROCEDURE TO BE FOLLOWED REGARDING ALLEGED VIOLATIONS

a. **Notice of Alleged Violation.**

(1) A complaint requesting that the Director issue a Notice of Alleged Violation (NOAV) may be made by the mineral owner, surface owner or tenant of the lands upon which the alleged violation took place, by other state agencies, by the local government within whose boundaries the lands are located upon which the alleged violation took place, or by any other person who may be directly and adversely affected or aggrieved as a result of the alleged violation.

(2) Oral complaints shall be confirmed in writing. Persons making a complaint are encouraged to submit a Complaint Form, Form 18.

(3) If the Director, on the Director's own initiative or based on a complaint, has reasonable cause to believe that a violation of the Act, or of any rule, regulation, or order of the Commission, or of any permit issued by the Director, has occurred, the Director shall cause the operator to voluntarily remedy the violation, or shall issue a NOAV to the operator. Reasonable cause requires, at least, physical evidence of the alleged violation, as verified by the Director.

(4) If the Director, after investigating a complaint made in accordance with this Rule 522.a.(1), decides not to issue a NOAV, the complainant may file an application to the Commission pursuant to Rule 503.b.(4), requesting the Commission enter an Order Finding Violation (OFV) in accordance with this rule.

(5) **NOAV process**

A. A NOAV issued by the Director shall be served on the operator's designated agent, or on the operator if no agent has been designated, by personal delivery or by certified mail, return receipt requested.

B. The NOAV shall not be placed on the Commission docket, except as part of an application filed pursuant to subparagraph c. of this rule.

C. The NOAV does not constitute final agency action for purposes of judicial appeal.

D. The NOAV shall identify the statute, rule, regulation, order, permit or permit condition subject to Commission jurisdiction allegedly violated and the facts alleged to constitute the violation. The NOAV may propose appropriate corrective action and an abatement schedule, if any, that the Director elects to require. The NOAV shall also describe the penalty, if any, which the Director may propose, to be recommended in accordance with Rule 523.

b. **Resolution of a Notice of Alleged Violation.**

(1) Informal procedures to resolve issues raised by a NOAV with the Director are encouraged. Such procedures may include, but are not limited to, meetings, phone conferences and the exchange of information. If, as a result of such procedures, the Director determines that no violation has occurred, the Director shall revoke the NOAV in writing and shall provide a copy of the written notification to the complainant, if any.

(2) NOAVs may be resolved by written agreement of the operator and the Director as to the appropriate corrective action and abatement schedule, a copy of which shall be provided by the Director to the complainant, if any. Such agreements do not require Commission approval and shall not be placed on the Commission docket, except at the request of the operator.

(3) NOAVs which are not resolved by written agreement for correction and abatement or which recommend the imposition of a penalty may be provisionally resolved by negotiation between the operator and the Director. If such negotiations result in a proposed agreement, an Administrative Order By Consent (AOC) containing such agreement shall be prepared and noticed for review and approval by the Commission. The Director may propose the terms for an AOC directly to the alleged violator. Upon Commission approval, the AOC shall become a final order, and the agreed penalty imposed. The AOC shall be placed on the consent agenda and Commission approval may be granted without hearing, unless a protest thereto is filed. Unless the operator so agrees, such AOC shall not constitute an admission of the alleged violation.

(4) The Director shall advise the complainant of any informal procedures used to facilitate resolution of the NOAV. A complainant may object to the proposed resolution by AOC. At the Director's discretion the AOC may be reviewed and modified based on the complainant's concerns, with the consent of the operator. If the complainant objects to the Director's final decision to revoke or settle the NOAV, the complainant shall have the right to file with the Commission an application for an Order Finding Violation (OFV). Such application shall be filed within forty-five (45) days of the Director's decision and shall be served on the Director and the operator.

c. **Order Finding Violation.**

(1) If the operator contests the NOAV, as to the existence of the violation, the appropriate corrective action and abatement schedule, or as to any proposed penalty, the Director shall make application to the Commission for an OFV and shall place the matter on the next available Commission docket, providing that at least twenty (20) days notice of such application is provided to the operator.

(2) If the Director decides not to issue a NOAV, the Commission may conduct a hearing to consider whether to issue an OFV upon twenty (20) days notice to the affected operator under the following circumstances:

A. On the Commission's own initiative if it believes that the Director has failed to enforce a provision of statute, rule, regulation, order, permit or permit condition subject to Commission jurisdiction.

B. On the application of a complainant pursuant to Rule 503.b.(4), provided that such complainant has first made a written request to the Director to issue an NOAV and the Director has determined in writing not to do so. An application by a complainant shall be filed within forty-five (45) days of the Director's written determination.

(3) Upon an operator's request a settlement conference shall be held with the Director no less than five (5) days before the hearing on an OFV. If an agreement is reached, an AOC containing such agreement shall be prepared and noticed for review and approval by the Commission, at its discretion. Upon such approval, the AOC shall become a final order, and the agreed penalty shall be imposed. Such approval may be granted without hearing, unless a hearing thereon is requested by a complainant. Unless the operator so agrees, such AOC shall not constitute an admission of the alleged violation.

(4) A hearing to consider whether to issue an OFV shall be a de novo proceeding, unless the parties stipulate as to the facts, or as to the appropriate corrective action and abatement schedule, in which case the hearing may be accordingly limited.

(5) The Director is always a necessary party to a hearing on an OFV. The operator against which an OFV is sought is always a necessary party but need not present a case. Any person, which is not the applicant for an OFV, but whose complaint initiated the enforcement proceeding, shall be granted intervenor status if so requested, pursuant to Rule 509., except that the filing fee shall be waived.

d. **Cease and Desist Orders.**

(1) The Commission or the Director may issue a cease and desist order whenever an operator fails to take corrective action required by final AOC or OFV.

(2) Whenever the Commission has evidence that a violation of any provision of the Act, any rule, permit, or order of the Commission has occurred under circumstances deemed to constitute an emergency situation, the Commission or the Director may issue a cease and desist order. If the order is entered by the Director it shall be immediately reported to the Commission for review and approval. Such order shall be considered a final order for purposes of judicial review.

(3) The order shall be served by personal delivery or by certified mail, return receipt requested, or by confirmed facsimile copy followed by a copy provided by certified mail, return receipt requested, to the operator's designated agent, or on the operator if no agent has been designated, for service of process and shall state the provision alleged to have been violated, the facts alleged to constitute the violation, the time by which the acts or practices cited are required to cease, and any corrective action the Commission or the Director elects to require of the operator. Any protest by an operator to a cease and desist order issued by the Director shall automatically stay the effective date of the order, in which case the order shall not be considered final for purposes of judicial review until such protest is heard.

(4) In the event an operator fails to comply with a cease and desist order, the Commission may request the attorney general to bring suit pursuant to §34-60-109, C.R.S.

523. PROCEDURE FOR ASSESSING FINES

a. **Fines.** An operator who violates any provision of the Act or any rule, permit, or order issued by the Commission shall be subject to a fine which shall be imposed only by order of the Commission, after hearing, or by an AOC approved by the Commission. All fines shall be calculated using the base fine amount for the particular violation as set forth in the fine schedule in subparagraph c. of this Rule 523., subject to the following:

(1) The Commission may in its discretion find that each day a violation exists constitutes a separate violation; however, no fine for any single violation shall exceed one thousand dollars ($1,000) per day.

(2) All fines shall be subject to adjustment based upon the factors listed in subparagraph d. of this Rule 523.

(3) For a violation which does not result in significant waste of oil and gas resources, damage to correlative rights, or a significant adverse impact on public health, safety or welfare, the maximum penalty for any single violation shall not exceed ten thousand dollars ($10,000) regardless of the number of days of such violation.

(4) Fines for violations for which no base fine is listed shall be determined by the Commission at its discretion subject to subparagraphs (1), (2), and (3) of this Rule 523.a.

b. **Voluntary disclosure.** Any operator who conducts a voluntary self-evaluation as defined in the 100 Series of the rules and makes a voluntary disclosure to the Director of a significant adverse impact on the environment or of a failure to obtain or comply with any necessary permits, shall enjoy a rebuttable presumption against the imposition of a fine for any violation relating to such impact or failure, under the following conditions:

(1) The disclosure is made promptly after the operator learns of the violation as a result of the voluntary self-evaluation;

(2) The operator making the disclosure cooperates with the Director regarding investigation of the issue identified in the disclosure; and

(3) The operator making the disclosure has achieved or commits to achieve compliance within a reasonable time and pursues compliance with due diligence.

The Commission shall deny the presumption against the imposition of fines only, if, after hearing, it finds that any of the preceding conditions have not been met, or that the use of this process was engaged in for fraudulent purposes.

c. Base fine schedule. The following table sets forth the base fine for violation of the rules listed.

RULE NUMBER	BASE FINE
205	$500
206	$500
207	$500
208	$500
209	$1000
210	$250

RULE NUMBER	BASE FINE
401	$500
403	$250
404	$1000
405	$250

RULE NUMBER	BASE FINE
602	$1000
603	$1000
604	$1000
605	$750
606A	$750
606B	$750
607	$750

RULE NUMBER	BASE FINE
703	$1000
704	$1000
705	$1000
706	$1000
707	$1000
708	$1000
709	$1000
711	$1000

RULE NUMBER	BASE FINE
301	$1000
302	$500
303	$1000
305	$1000
306	$1000
307	$250
308	$500
309	$500
310	$500
311	$250
312	$250
313	$250
314A	$250
315	$250
316A	$500
316B	$1000
317	$1000
317A	$1000
318	$1000
319	$1000
320	$1000
321	$500
322	$500
323	$1000
324	$1000
325	$1000
326	$1000
327	$1000
328	$500
329	$500
330	$500
331	$500

RULE NUMBER	BASE FINE
802	$1000
803	$250
804	$250

RULE NUMBER	BASE FINE
1002	$1000
1003	$1000
1004	$1000

RULE NUMBER	BASE FINE
1101	$1000
1102	$1000
1103	$1000

RULE NUMBER	BASE FINE
332	$500
333	$1000

RULE NUMBER	BASE FINE
901	$1000
902	$1000
903	$1000
904	$1000
905	$1000
906	$1000
907	$1000
908	$1000
909	$1000
910	$1000
911	$1000
912	$1000

d. **Adjustment.** The fine may be increased or decreased by application of the aggravating and mitigating factors set forth below.

Aggravating factors.

(1) The violation was intentional or reckless.

(2) The violation had a significant negative impact, or threat of significant negative impact on the environment or on public health, safety, or welfare.

(3) The violation resulted in significant waste of oil and gas resources.

(4) The violation had a significant negative impact on correlative rights of other parties.

(5) The violation resulted in or threatened to result in significant loss or damage to public or private property.

(6) The violation involved recalcitrance or recidivism upon the part of the violator.

(7) The violation involved intentional false reporting or recordkeeping.

(8) The violation resulted in economic benefit to the violator, including the economic benefit associated with noncompliance with the applicable rule, in which case the amount of such benefit may be taken into consideration.

Mitigating factors.

(1) The violator self-reported the violation.

(2) The violator demonstrated prompt, effective and prudent response to the violation, including assistance to any impacted parties.

(3) The violator cooperated with the Commission, or other agencies with respect to the violation.

(4) The cause(s) of the violation was outside of the violator's reasonable control and responsibility, or is customarily considered to be force majeure.

(5) The violator made a good faith effort to comply with applicable requirements prior to the Commission learning of the violation.

(6) The cost of correcting the violation reduced or eliminated any economic benefit to the operator.

(7) The operator has demonstrated a history of compliance with Commission rules, regulations and orders.

e. **Public projects.** In lieu of or in reduction of fine amounts, an AOC may provide for the initiation of or participation in operator projects which are beneficial to the environment or public health, safety and welfare, and the Commission encourages AOCs which so provide.

f. **Payment of fines.** An operator against whom the Commission enters an order to pay a fine must pay the amount due within thirty (30) days of the effective date of the order, unless the Commission grants a longer period or unless the operator files for judicial appeal, in which event payment of the penalty shall be stayed pending resolution of such appeal. An operator's obligations to comply with the provisions of a Commission order requiring compliance with the Act, a permit condition or these rules and regulations shall not be stayed pending resolution of an appeal unless the stay is ordered by the court.

524. DETERMINATION OF RESPONSIBLE PARTY

In all cases it shall be the burden of the Director to present sufficient evidence to the Commission to determine responsible party status.

a. A hearing may be initiated on the Commission's own motion, upon application, or at the request of the Director to decide responsible party status upon at least twenty (20) days notice to the potentially responsible parties.

b. Operators shall provide to the Director such information as the Director may reasonably require in making such determination.

c. The Commission shall make the determination under this section without regard to any contractual assignments of liability or other legal defenses between parties.

d. An operator shall enjoy a rebuttable presumption against mitigation liability under §34-60-124 (7), C.R.S., for ongoing significant adverse environmental impacts where the violation which led to such impacts was committed by a predecessor operator and where the operator has conducted an environmental investigation, with reasonable due diligence, of the environmental condition of the particular asset or activity and such investigation did not reveal such significant adverse environmental impacts. The failure to report any condition which is causing such impacts, upon subsequent knowledge by the operator, shall negate the rebuttable presumption against mitigation liability.

e. Where multiple persons are determined to be responsible parties, they shall share in the mitigation liability in proportion to their respective shares of production, respective periods of ownership or respective contributions to the problem, or any other factors as may serve the interests of fairness.

f. The determination of responsible party status and mitigation liability shall require a showing that the responsible party conducted operations that have resulted in or have threatened to cause a significant adverse environmental impact to any air, water, soil or biological resource based on the conduct of oil or gas operations in contravention of any then applicable historic provisions of the Act or rules, whether or not the Commission has entered an order finding violation.

525. PERMIT-RELATED PENALTIES

a. If the Commission determines, after a hearing, that an operator failed to perform any required corrective action/abatement or failed to comply with a cease and desist order issued by the Director or the Commission with regard to violation of a permit provision, the Commission may issue an order suspending, modifying or revoking the permit authorizing the operation. The order shall provide the condition(s) which must be met by the operator for reinstatement of the permit. An operator which is subject to an order that suspends, modifies or revokes a permit shall continue the affected operations only for the purpose of bringing them into compliance with the permit or modified permit and shall do so under the supervision of the Director. Once the condition for reinstatement has been met to the satisfaction of the Director and any fine not subject to judicial review or appeal has been paid, the Director shall inform the Commission, and the Commission, if in agreement, shall reinstate the permit.

b. Whenever the Commission or the Director has evidence that an operator is responsible for a pattern of violation of any provision of the Act, or of any rule, permit, or order of the Commission, the Commission or the Director shall issue a notice to such operator to appear for a hearing before the Commission. If the Commission finds, after such hearing, that a knowing and willful pattern of violation exists, it may issue an order which shall prohibit the issuance of any new permits to such operator. When such operator demonstrates to the satisfaction of the Commission that it has brought each of the violations into compliance and that any fine not subject to judicial review or appeal has been paid, such order denying new permits shall be vacated.

526. ADMINISTRATIVE HEARINGS IN UNCONTESTED MATTERS

a. As to applications where there has been no protest or intervention filed with the Commission in accordance with Rule 509., and where the Director has not recommended approval based on the content of the verified application and supporting exhibits, the application may be heard administratively prior to or on the date of the scheduled Commission hearing. The date and time of the administrative hearing shall be scheduled for the mutual convenience of the applicant and the Hearing Officer. The administrative hearing may be conducted prior to the protest or intervention date but no order shall be entered by the Commission until it has fully considered any timely and properly filed protest or intervention.

b. One or more duly appointed Hearing Officers may hear the application at the administrative hearing. Administrative hearings shall proceed informally in a meeting format. The applicant may present its case using exhibits and witnesses. All witnesses shall be sworn. At the conclusion of the administrative hearing, the Hearing Officer shall make a decision concerning approval or denial of the application and so inform the applicant. The Hearing Officer shall put such decision in a written report to the Commission containing findings of fact, conclusions of law, if any, and a recommended order. If the Hearing Officer recommends denial or qualified approval of the application, the applicant shall be entitled to a hearing de novo at the next scheduled hearing of the Commission.

c. The Commission may appoint Hearing Officers from the Commission staff for the purpose of hearing uncontested matters, presiding at local public forums or otherwise representing the Commission. The service of the Hearing Officers shall be at the Director’s discretion.

527. PREHEARING PROCEDURES FOR CONTESTED ADJUDICATORY PROCEEDINGS BEFORE THE COMMISSION

a. The Commission encourages the use of prehearing conferences between parties to a contested matter in order to facilitate settlement, narrow the issues, identify any stipulated facts, resolve any other pertinent issues, and reduce the hearing time before the Commission. A prehearing conference shall be conducted at the direction of the Commission or the Director upon receipt of a protest or an intervention, or upon the request of the applicant or any person who has filed a protest or intervention. For matters in which a staff analysis has been prepared, the Director shall participate in the prehearing conference to advise the parties of the content of the preliminary staff analysis. The prehearing conference shall be conducted under the following general guidelines.

b. The Director, a Hearing Officer or Hearing Commissioner shall preside over any prehearing conference and rule on preliminary matters in any proceeding pending before the Commission.

c. The Secretary shall notify the applicant and any person who has filed a protest or intervention of the prehearing conference, and shall direct the attorneys for the parties, and pro se parties, to appear in order to expedite the hearing or settle issues, or both.

d. All parties shall be prepared to discuss all procedural and substantive issues, and shall be authorized to make binding commitments on all procedural matters.

e. Preparation should include advance study of all materials filed and materials obtained through discovery.

f. Failure of any person to attend the prehearing conference, after being notified of the date, time and place, shall be a waiver of any objection and shall be deemed to be a concurrence to any agreement reached, or to any order or ruling made at the prehearing conference.

g. A prehearing statement may be required of any party.

h. At any prehearing conference, the following matters may be considered:

(1) Offers of settlement or designation of issues;

(2) Simplification of and establishment of a list or summary of the issues;

(3) Bifurcation of issues for hearing purposes;

(4) Admissions as to, or stipulations of, facts not remaining in dispute or the authenticity of documents;

(5) Limitation of the number of fact and expert witnesses;

(6) Limitation on methods and extent of discovery, and a discovery schedule;

(7) Disposition of procedural motions; and

(8) Other matters raised by the parties, the Commission, or presiding officer.

i. At any prehearing conference, the following information may be required:

(1) An exchange and acceptance of service of exhibits proposed to be offered in evidence, and establishment of a list of exhibits to be offered;

(2) Establishment of a list of witnesses to be called and anticipated testimony times; and

(3) A timetable for the completion of discovery, if discovery is allowed.

j. The parties shall reduce to writing any agreement reached or orders issued at a prehearing conference which shall be filed with the presiding officer, who shall enter a decision approving or disapproving it, or recommend modification as a condition for approval. An agreement which is disapproved shall be privileged and inadmissible as evidence in any Commission proceeding.

j. It is the intent of this rule that a prehearing order shall be binding upon the participating parties.

k. Subsequent to the prehearing conference and prior to the hearing on a contested matter, the parties shall each prepare and submit to the Hearing Officer a recommended order for the Commission to consider for adoption at the time of hearing.

528. CONDUCT OF ADJUDICATORY HEARINGS.

a. **Contested applications.** Every party shall have the right to present its case by oral and/or documentary evidence. The following shall be the order of presentation unless otherwise established by the Commission at the hearing:

(1) Determination of whether any Commission members have a conflict of interest;

(2) Presentation of any prehearing order;

(3) Presentation of any motions and disposition of procedural matters;

(4) Presentation of the stipulation, if any;

(5) Opening statement by the applicant;

(6) Opening statements by the respondent (and intervener, if any);

(7) Presentation of the case-in-chief by the applicant;

(8) Presentations by respondent (and intervener, if any);

(9) Presentation of statements under Rule 510., if any;

(10) Presentation of staff analysis, if requested by the Commission.

(11) Rebuttal by the applicant;

(12) Rebuttal by the respondent (and intervenor, if any);

(13) Closing statement by the applicant;

(14) Closing statements by the respondent (and intervenor, if any).

(15) Rebuttal closing statement by the applicant.

(16) Upon motion and for good cause shown, the Commission may permit surrebuttal.

(17) Closing of the record.

b. **Uncontested applications not approved administratively.** For uncontested applications not approved administratively pursuant to Rule 526., the applicant may present evidence in support of its application to the Commission. The order of presentation shall be as follows, unless otherwise established by the Commission at the hearing:

(1) Determination of whether any Commission members have a conflict of interest;

(2) Presentation of staff analysis, if requested by the Commission. The Commission, at its discretion, or upon request of the Director may defer staff testimony until all of the evidence has been presented.

(3) Presentation of the case-in-chief by the applicant;

(4) Closing statement by the applicant.

(5) Closing of the record.

c. **Enforcement hearings.** In order to assure that all parties against whom a fine or penalty may be imposed are afforded due process of law, the Commission shall, at any hearing, permit the Director or the complainant pursuant to Rule 522.b.(4) to present evidence and argument and to conduct cross-examination required for a full disclosure of the facts. The enforcement matter shall be heard by the Commission de novo unless the operator waives its right to a de novo hearing prior to or at the Commission hearing. The order of presentation in a hearing for an enforcement matter shall be as follows, unless otherwise established by the Commission at the hearing:

(1) Determination of whether any Commission members have a conflict of interest;

(2) Opening statements by all parties;

(3) Presentation by the Director;

(4) Presentation by any complainant under Rule 522.b.(4).;

(5) Presentation by the operator;

(6) Rebuttal by the Director;

(7) Rebuttal by the respondent;

(8) Closing statements by the parties;

(9) Finding regarding existence of violation;

(10) If the Commission first determines by a preponderance of the evidence that a violation or violations exist, presentation by the Director of any recommended fine or permit-related penalty, and/or recommended corrective action/abatement to be taken by the operator;

(11) Response by any complainant under Rule 522.b.(4).;

(12) Presentation of statements under Rule 510., if any;

(13) Response by the operator;

(14) Rebuttal by the Director; and

(15) Closing statements by all parties;

(16) Closing of the record.

d. **Closing of record.** At the conclusion of closing statements, the record shall be closed to the presentation of any further evidence, testimony, or statements, except as such may occur in response to questions from the Commission.

e. **Witnesses.** Each witness shall take an oath or affirmation before testifying. After a witness has testified, the applicant, the protestant or participating intervenors and any Commissioner may cross-examine that witness in the order established by the chairperson of the Commission.

f. Where two or more protestants or intervenors have substantially similar interests and positions, the Commission may limit cross-examination or argument on motions and objections to fewer than all the intervenors. The Commission may also limit testimony to avoid undue delay, waste of time or needless presentation of cumulative evidence.

g. **Commission findings and order.** After due consideration of written and oral statements, the testimony, and the arguments presented at hearing, the Commission shall make its findings and order, based upon evidence in the record and, as appropriate, consistent with the Act and any rule, permit, or order made pursuant thereto.

529. PROCEDURES FOR RULEMAKING PROCEEDINGS

a. **Institution of rulemaking.** The Commission may institute rulemaking on its motion or in response to an application filed by any person.

b. **Applications for rulemaking.** Any person may petition the Commission to initiate rulemaking. All applications for rulemaking shall contain the following information:

(1) The name, address, and telephone number of the person requesting the rulemaking;

(2) A copy of the rule proposed in the application and a general statement of the reasons for the requested rule; and

(3) A proposed statement of the basis and purpose for the rule.

c. **Notice of proposed rulemaking.** All rulemaking hearings of the Commission shall be noticed by publication in the Colorado Register not less than twenty (20) days and not more than sixty (60) days prior to the hearing.

d. **Time for rulemaking.** The rulemaking hearing shall not be held until the expiration of six (6) months from the date of application unless the Commission, in its discretion, decides that an earlier hearing is appropriate.

e. **Development of proposed rules.** Prior to the notice of proposed rulemaking, the Commission or Director may use informal procedures to gather information, including, but not limited to, public forums, investigation by Commission staff, and formation of rulemaking teams. Commissioners may participate in such informal proceedings.

f. **Content of notice.** The notice shall state the time, date, place, and general subject matter of the hearing to be held. It may include a statement indicating whether an informal public meeting will be held, the time, date, place, and general purpose of the meeting, any special procedures the Commission deems appropriate for the particular rulemaking proceeding and a statement encouraging public participation. The notice shall state that the proposed regulations will be available upon request from the office of the Commission, the date of availability, and any fee. The notice shall include a short and plain statement which summarizes the intended action and states generally the basis and purpose of the rule.

g. **The rulemaking hearing.** The Commission shall hold a formal public hearing before promulgating any rules or regulations. At that hearing, the Commission shall afford any person an opportunity to submit data, views or arguments. The Commission may limit such testimony or presentation of evidence at its discretion and may prohibit repetitive, irrelevant or harassing testimony.

h. **Conduct of rulemaking hearings.**

(1) The Commission encourages any person to participate at rulemaking hearings. The times at which the public may participate will be determined at the discretion of the Commission. The Commission may, at its discretion, limit the amount of time a person may use to comment or make public statements. Oaths shall not be required for public participation.

(2) The Commission encourages witnesses to make plain, brief, and simple statements of their positions. It also encourages submittal of written statements prior to hearing, with only an oral summary of such a statement at the hearing.

(3) The order of presentation at a rulemaking hearing shall be as established by the Commission at the hearing.

(4) The Commission has the discretion to continue rulemaking hearings by announcement at the rulemaking hearing without republication of the proposed rule.

530. INVOLUNTARY POOLING PROCEEDINGS

a. An application for involuntary pooling pursuant to §34-60-116, C.R.S. may be filed at any time a nonconsenting owner within the drilling unit refuses to agree to bear his proportionate share of the costs and risks of drilling and operating the well. As used herein a nonconsenting owner shall mean an owner in the area to be pooled who, after at least thirty (30) days written notice of the following information does not elect in writing to consent to participate in the cost of the well concerning which the pooling order is sought:

(1) The location and objective depth of the well.

(2) The estimated drilling and completion cost of the well.

(3) The estimated spud date for the well or range of time within which spudding is to occur.

(4) An authority for expenditure prepared by the operator and containing the information required above, together with additional information deemed appropriate by the operator shall satisfy this obligation.

b. In determining whether a reasonable offer to lease has been tendered under §34-60-116(7)(d), C.R.S., the Commission shall consider the lease terms listed below for the drilling and spacing unit in the application and for all cornering and contiguous units that are under the proposed lease:

(1) Date of lease and primary term or offer with acreage in lease;

(2) Annual rental per acre;

(3) Bonus payment or evidence of its non-availability;

(4) Mineral interest royalty;

(5) Such other lease terms as may be relevant.

SAFETY REGULATIONS

601. INTRODUCTION

The rules and regulations in this section are promulgated to protect the health, safety and welfare of the general public during the drilling, completion and operation of oil and gas wells and producing facilities. They do not apply to parties or requirements regulated under the Federal Occupational Safety and Health Act of 1970 (See Rule 212.).

602. GENERAL

The training and action of employees, as well as proper location and operation of equipment is an important part of any safety program. While this section is general in nature, it is considered a basic part of the foundation of any safety program.

a. Employees shall be familiarized with these rules and regulations as provided herein as they relate to their function in their respective jobs. Each new employee should have their job outlined, explained and demonstrated.

b. Unsafe and potentially dangerous conditions as defined by these rules, should be reported immediately by employees to the supervisor in charge and shall be remedied as soon as practical. Any accident involving injury to wellsite personnel or to a member of the general public which requires hospitalization, or significant damage to equipment or the wellsite shall be reported to the Oil and Gas Conservation Commission as soon as practicable, but in no event later than twenty-four (24) hours after the accident.

Where unsafe or potentially dangerous conditions exist, the owner or operator shall respond as directed by an agency with demonstrated authority to do so (such as sheriff, fire district director, etc.).

c. Vehicles of persons not involved in drilling, production, servicing, or seismic operations shall be located a minimum distance of one hundred (100) feet from the wellbore, or a distance equal to the height of the derrick or mast, whichever is greater. Equivalent safety measures shall be taken where terrain, location or other conditions do not permit this minimum distance requirements.

d. Existing wells are exempt from the provisions of these regulations as they relate to the location of the well.

e. Existing producing facilities shall be exempt from the provisions of these regulations with respect to minimum distance requirements and setbacks unless they are found by the Director to be unsafe.

f. Self-contained sanitary facilities shall be provided during drilling operations and at any other similarly staffed oil and gas operations facility.

603. DRILLING AND WELL SERVICING OPERATIONS AND HIGH DENSITY AREA RULES

a. **Statewide setbacks**. Subparagraph (1) below shall apply to all areas of the state except as provided under subparagraphs b. and e. of this rule. Subparagraph (2) below shall apply to all areas of the state.

(1) At the time of initial drilling of the well, the wellhead shall be located a distance of one hundred fifty (150) feet or one and one-half (1-1/2) times the height of the derrick, whichever is greater, from any occupied building, public road, major above ground utility line or railroad.

(2) A well shall be a minimum distance of one hundred fifty (150) feet from a surface property line. An exception may be granted by the Director if it is not feasible for the operator to meet this minimum distance requirement and a waiver is obtained from the offset surface owner(s). An exception request letter stating the reasons for the exception shall be submitted to the Director and accompanied by a signed waiver(s) from the offset surface owner(s). Such waiver shall be written and filed in the county clerk and recorder's office and with the Director.

b. **High density area rules for building units**. A high density area shall be determined at the time the well is permitted on a well-by-well basis by calculating the number of occupied building units within the seventy-two (72) acre area defined by a one thousand (1000) foot radius from the wellhead or production facility. If thirty-six (36) or more actual or platted building units (as defined in the 100 Series rules) are within the one thousand (1000) foot radius or eighteen (18) or more building units are within any semi-circle of the one thousand (1000) foot radius (i.e., an average density of one (1) building unit per two (2) acres), it shall be deemed a high density area. If platted building units are used to determine the density, then fifty percent (50%) of said platted units shall have building units under construction or constructed.

c. **High density area rules for other facilities.** If an educational facility, assembly building, hospital, nursing home, board and care facility, or jail is located within one thousand (1000) feet of a wellhead or production facility, high density area rules shall apply.

d. **Designated outside activity area.** The Commission, upon application and hearing, shall determine the appropriate boundary and setbacks for a designated outside activity area as defined in the 100 Series rules. The minimum setback from the boundary of the designated outside activity area shall be three hundred fifty (350) feet.

e. The following rules shall apply in high density and designated outside activity areas:

(1) **Provisions for encroaching development**. If, by virtue of subsequent future surface development, an area becomes a high density area, subparagraphs (2), (3), (7) and (14) shall not apply to the operator.

(2) **Setbacks for wellheads**. At the time of initial drilling of the well, the wellhead location shall be not less than three hundred fifty (350) feet from any building unit, educational facility, assembly building, hospital, nursing home, board and care facility, or jail.

(3) **Setbacks for production equipment**. At the time of initial installation, production tanks and/or associated on-site production equipment shall be located not less than three hundred fifty (350) feet from any building unit, and, if requested by the local governmental designee, production tanks shall be located five hundred (500) feet from an educational facility, assembly building, hospital, nursing home, board and care facility, jail or designated outside activity area. However, such five hundred (500) foot setback shall be decreased to the maximum achievable setback if five hundred (500) feet would extend beyond the area on which the operator has a legal right to place or construct such facilities. Should the operator object to such five hundred (500) foot setback for any reason, a variance hearing shall be conducted at the next regularly scheduled meeting of the Commission, subject to the notice requirements of Rule 507.

(4) A. **Blowout preventer equipment ("BOPE") for high density area drilling operations**. Blowout prevention equipment for drilling operations shall consist of (at a minimum):

i. Rig with kelley double ram with blind ram and pipe ram;
annular preventer or a rotating head

ii. Rig without kelley double ram with blind ram and pipe ram

Mineral Management certification or Director approved training for blowout prevention shall be required for at least one (1) person at the wellsite during drilling operations.

B. **BOPE testing for high density area drilling operations**. Upon initial rig-up and at least once every thirty (30) days during drilling operations thereafter, pressure testing of the casing string and each component of the blowout prevention equipment including flange connections shall be performed to seventy percent (70%) of working pressure or seventy percent (70%) of the internal yield of casing, whichever is less. Pressure testing shall be conducted and the documented results shall be retained by the operator for inspection by the Director for a period of one (1) year. Activation of the pipe rams for function testing shall be conducted on a daily basis when practicable.

C. **Pit level indicators**. Pit level indicators shall be used.

D. **Drill stem tests**. Closed chamber drill stem tests shall be allowed in high density areas. All other drill stem tests shall require approval by the Director.

(5) A. **BOPE for well servicing operations**. Adequate blowout prevention equipment shall be used on all well servicing operations.

B. Backup stabbing valves shall be required on well servicing operations during reverse circulation. Valves shall be pressure tested before each well servicing operation using both low pressure air and high pressure fluid.

(6) **Location requirement exceptions and waivers**. Exceptions to the location requirements set out in subparagraphs (2) and (3) above shall be granted by the Director if the Director determines that Rule 318. has been complied with and that a copy of waivers from each person owning an occupied building or building permitted for construction within three hundred fifty (350) feet of the proposed location is submitted as part of

the Permit to Drill, Form 2, and that the proposed location complies with all other safety requirements of the rules and regulations.

(7) **Fencing requirements**. At the time of initial installation, if a wellsite falls within a high density area, all pumps, pits, wellheads and production facilities shall be adequately fenced to restrict access by unauthorized persons. For security purposes, all such facilities and equipment used in the operation of a completed well shall be surrounded by a fence six (6) feet in height, constructed in conformance with local written standards so long as the material is non-combustible and allows for adequate ventilation, and the gate(s) shall be locked.

(8) **Control of fire hazards**. Any material not in use that might constitute a fire hazard shall be removed a minimum of twenty-five (25) feet from the wellhead, tanks and separator. Any electrical equipment installations inside the bermed area shall comply with API RP 500 classifications and comply with the current national electrical code as adopted by the State of Colorado.

(9) **Loadlines**. In high density areas, all loadlines shall be bullplugged or capped.

(10) **Removal of surface trash**. All surface trash, debris, scrap or discarded material connected with the operations of the property shall be removed from the premises or disposed of in a legal manner.

(11) **Guy line anchors**. All guy line anchors left buried for future use shall be identified by a marker of bright color not less than four (4) feet in height and not greater than one (1) foot east of the guy line anchor.

(12) **Berm construction**. All newly installed or replaced berms in high density areas, in the absence of remote impounding, shall be constructed around crude oil and condensate storage tanks and shall enclose an area sufficient to contain one hundred fifty percent (150%) of the largest single tank. No more than two (2) crude oil and condensate storage tanks shall be located within a single berm. Berms shall be inspected at regular intervals and containment integrity maintained. Refer to American Petroleum Institute Recommended Practices - D16.

(13) **Tank specifications**. All newly installed or replaced crude oil and condensate storage tanks in high density areas shall be designed, constructed, and maintained in accordance with National Fire Protection Association's latest edition (NFPA 30). The operator shall maintain written records verifying proper design, construction, and maintenance, and shall make these records available for inspection by the Director.

(14) **Access roads**. If a wellsite falls within a high density area at the time of construction, all leasehold roads shall be constructed to accommodate local emergency vehicle access requirements, and shall be maintained in a reasonable condition.

(15) **Well site cleared**. Within ninety (90) days after a well is plugged and abandoned, the well site shall be cleared of all non-essential equipment, trash, and debris. For good cause shown, an extension of time may be granted by the Director.

(16) **Identification of plugged and abandoned wells in high density areas**. The operator shall identify the location of the wellbore with a permanent monument as specified in Rule 319.a.(5). The operator shall also inscribe or imbed the well number and date of plugging upon the permanent monument.

(17) **Development from existing well pads**. Where possible, operators shall provide for the development of multiple reservoirs by drilling on existing pads or by multiple completions or commingling in existing wellbores (see Rule 322.). If any operator asserts it is not possible to comply with, or requests relief from, this requirement, the matter shall be set for hearing by the Commission and relief granted as appropriate.

f. **Statewide rig floor safety valve requirements**. When drilling or well servicing operations are in progress on a well where there is any indication the well will flow hydrocarbons, either through prior records or present conditions, there shall be on the rig floor a safety valve with connections suitable for use with each size and type of tool joint or coupling being used on the job.

g. **Statewide static charge requirements**. Rig substructure, derrick, or mast shall be designed and operated to prevent accumulation of static charge.

h. **Statewide well servicing pressure check requirements**. Prior to initiating well servicing operations, the well shall be checked for pressure and steps taken to remove pressure or operate safely under pressure before commencing operations.

i. **Statewide well control equipment and other safety requirements**. Well control equipment and other safety requirements are:

(1) When there is any indication that a well will flow, either through prior records, present well conditions, or the planned well work, blowout prevention equipment shall be installed in accordance with Rule 317. or any special orders of the Commission.

(2) Blowout prevention equipment when required by Rule 317. shall be in accordance with API RP 53: Recommended Practices for Blowout Prevention Equipment Systems, or amendments thereto.

(3) While in service, blowout prevention equipment shall be inspected daily and a preventer operating test shall be performed on each round trip, but not more than once every twenty-four (24) hour period. Notation of operating tests shall be made on the daily report.

(4) All pipe fittings, valves and unions placed on or connected with blowout prevention equipment, well casing, casinghead, drill pipe, or tubing shall have a working pressure rating suitable for the maximum anticipated surface pressure and shall be in good working condition as per generally accepted industry standards.

(5) Blowout prevention equipment shall contain pipe rams that enable closure on the pipe being used. The choke line(s) and kill line(s) shall be anchored, tied or otherwise secured to prevent whipping resulting from pressure surges.

(6) Pressure testing of the casing string and each component of the blowout prevention equipment, if blowout prevention equipment is required, shall be conducted prior to drilling out any string of casing except conductor pipe. The minimum test pressure shall be five hundred (500) psi, and shall hold for fifteen (15) minutes without pressure loss in order for the casing string to be considered serviceable. Upon demand the operator shall provide to the commissioner the pressure test evidence. Drilling operations shall not proceed until blowout prevention equipment is tested and found to be serviceable.

(7) If the blind rams are closed for any purpose except operational testing, the valves on the choke lines or relief lines below the blind rams should be opened prior to opening the rams to bleed off any trapped pressure.

(8) All rig employees shall have adequate understanding of and be able to operate the blowout prevention equipment system. New employees shall be trained in the operations of blowout prevention equipment system as soon as practicable to do so.

(9) Drilling contractors shall place a sign or marker at the point of intersection of the public road and rig access road.

(10) The number of the public road to be used in accessing the rig along with all necessary emergency numbers shall be posted in a conspicuous place on the drilling rig.

j. **Statewide equipment, weeds, waste, and trash requirements**. All locations, including wells and surface production facilities, shall be kept free of the following: equipment, vehicles, and supplies not necessary for use on that lease; weeds; rubbish, and other waste material. The burning or burial of such material on the premises may be subject to other applicable laws. In addition, material may be burned or buried on the premises only with the prior written consent of the surface owner.

k. **Statewide equipment anchoring requirements**. All equipment at drilling and production sites in geological hazard and floodplain areas shall be anchored to the extent necessary to resist flotation, collapse, lateral movement or subsidence.

604. PRODUCTION FACILITIES

a. **Crude Oil Tanks**.

(1) Atmospheric tanks used for crude oil storage shall be built in accordance with the following standards as applicable:

A. Underwriters Laboratories, Inc., No. UL-142, "Standard for Steel Above Ground Tanks for Flammable and Combustible Liquids"

B. American Petroleum Institute Standard No. 650, "Welded Steel Tanks for Oil Storage"

C. American Petroleum Institute Standard No. 12B, “Bolted Tanks for Storage of Production Liquids"

D. American Petroleum Institute Standard No. 12D, "Field Welded Tanks for Storage of Production Liquids" or

E. American Petroleum Institute Standard No. 12F, "Shop Welded Tanks for Storage of Production Liquids".

(2) Tanks shall be located at least two (2) diameters or three hundred fifty (350) feet, whichever is smaller, from the boundary of the property on which it is built. Where the property line is a public way the tanks shall be two thirds (2/3) of the diameter from the nearest side of the public way or easement.

A. Tanks less than three thousand (3,000) barrels capacity shall be located at least three (3) feet apart.

B. Tanks three thousand (3,000) or more barrels capacity shall be located at least one-sixth (1/6) the sum of the diameters apart. When the diameter of one (1) tank is less than one-half (1/2) the diameter of the adjacent tank, the tanks shall be located at least one-half (1/2) the diameter of the smaller tank apart.

(3) At the time of installation, tanks shall be a minimum of two hundred (200) feet from residences, normally occupied buildings, or well defined normally occupied outside areas.

(4) Berms shall be constructed around tanks in the absence of remote impounding. Both methods shall enclose an area with sufficient volume to contain the entire contents of the largest tank in the enclosure. Berms shall be inspected at regular intervals and maintained in good condition. When a berm is provided around tanks no potential ignition sources shall be installed inside that area.

(5) Tanks shall be a minimum of seventy-five (75) feet from a fired vessel or heater-treater.

(6) Tanks shall be a minimum of fifty (50) feet from a separator, well test unit or other non-fired equipment.

(7) Tanks shall be a minimum of seventy-five (75) feet from a compressor with a rating of two hundred (200) horsepower, or more.

(8) Tanks shall be a minimum of seventy-five (75) feet from a wellhead.

(9) Gauge hatches on atmospheric tanks used for crude oil storage shall be closed at all times when not in use.

(10) Vent lines from individual tanks shall be joined and ultimate discharge shall be directed away from the loading racks and fired vessels in accord with API RP 12R-1.

(11) During hot oil treatments on tanks containing thirty-five (35) degree or higher API gravity oil, hot oil units shall be located a minimum of one hundred (100) feet from any tank being serviced.

b. **Fired Vessel, Heater-Treater**.

(1) Fired vessels (FV) including heater-treaters (HT) shall be minimum of fifty (50) feet from separators or well test units.

(2) FV-HT shall be a minimum of fifty (50) feet from a lease automatic custody transfer unit (LACT).

(3) FV-HT shall be a minimum of forty (40) feet from a pump.

(4) FV-HT shall be a minimum of seventy-five (75) feet from a well.

(5) At the time of installation, FV-HT shall be a minimum of two hundred (200) feet from residences occupied buildings, or well defined normally occupied outside areas.

(6) Vents on pressure safety devices shall terminate in a manner so as not to endanger the public or adjoining facilities. They shall be designed so as to be clear and free of debris and water at all times.

c. **Special Equipment**. Under unusual circumstances special equipment may be required to protect public safety. The Director shall determine if such equipment should be employed to protect public safety and if so, require the operator to employ same. If the operator or the affected party does not concur with the action taken, the Director shall bring the matter before the Commission at public hearing.

(1) All wells located within one hundred fifty (150) feet of a residence(s), normally occupied buildings, or well defined normally occupied outside area(s), shall be equipped with an automatic control valve that will shut the well in when a sudden change of pressure, either a rise or drop, occurs. Automatic control valves shall be designed so they fail safe.

(2) Pressure control valves required in subparagraph a. shall be activated by a secondary gas source supply, and shall be inspected at least every three (3) months to assure they are in good working order and the secondary gas supply has volume and pressure sufficient to activate the control valve.

(3) All pumps, pits, and producing facilities shall be adequately fenced to prevent access by unauthorized persons when the producing site or equipment is easily accessible to the public and poses a physical or health hazard.

(4) Sign(s) shall be posted at the boundary of the producing site where access exists, identifying the operator, lease name, location, and listing a phone number, including area code, where the operator may be reached at all times unless emergency numbers have been furnished to the county commission or it's designee.

d. **Mechanical Conditions**. All valves, pipes and fittings shall be securely fastened, inspected at regular intervals and maintained in good mechanical condition.

e. **Buried or partially buried tanks, vessels or structures.** Buried or partially buried tanks, vessels, or structures used for storage of E&P waste shall be properly designed, constructed and installed in a manner to contain materials safely. Such vessels shall be tested for leaks after installation and maintained, repaired or replaced to prevent spills or releases of E&P waste.

605. RESERVED

606A. FIRE PREVENTION AND PROTECTION

a. Gasoline-fueled engines shall be shut down during fueling operations if the fuel tank is an integral part of the engine.

b. Handling, connecting and transfer operations involving liquefied petroleum gas (LPG) shall conform to the requirements of the State Oil Inspector.

c. Flammable liquids storage areas within any building or shed shall:

(1) Be adequately vented to the outside air;

(2) Have two (2) unobstructed exits leading from the building in different directions if the building is in excess of five hundred (500) square feet.

(3) Be maintained with due regard to fire potential with respect to housekeeping and materials storage;

(4) Be identified as a hazard and appropriate warning signs posted;

d. Flammable liquids shall not be stored within fifty (50) feet of the wellbore, except for the fuel in the tanks of operating equipment or supply for injection pumps. Where terrain and location configuration do not permit maintaining this distance, equivalent safety measures should be taken.

e. Liquefied petroleum gas (LPG) tanks larger than two hundred fifty (250) gallons and used for heating purposes, shall be placed as far as practical from and parallel to the adjacent side of the rig or wellbore as terrain and location configuration permit. Installation shall be consistent with provisions of NFPA 58, "Standards for the Storage and Handling of Liquid Petroleum Gases".

f. Smoking shall be prohibited at or in the vicinity of operations which constitute a fire hazard and such locations shall be conspicuously posted with a sign, "No Smoking" or "Open Flame". Matches and all smoking equipment may not be carried into "No Smoking" areas.

g. No source of ignition shall be permitted in an area where smoking has been prohibited unless it is first determined to be safe to do so by the supervisor in charge or the designated representative.

h. Open fires, transformers, or other sources of ignition shall be permitted only in designated areas located at a safe distance from the wellhead or flammable liquid storage areas.

i. Only approved heaters for Class I Division 2 areas, as designated by API RB 500B, shall be permitted on or near the rig floor. The safety features of these heaters shall not be altered.

j. Combustible materials such as oily rags and waste shall be stored in covered metal containers.

k. Material used for cleaning shall have a flash point of not less than one hundred degrees fahrenheit (100°F). For limited special purposes, a lower flash point cleaner may be used when it is specifically required and should be handled with extreme care.

l. Firefighting equipment shall not be tampered with and shall not be removed for other than fire protection and firefighting purposes and services. A firefighting water system may be used for wash down and other utility purposes so long as its firefighting capability is not compromised. After use, water systems must be properly drained or properly protected from freezing.

m. An adequate amount of fire extinguishers and other firefighting equipment shall be suitably located, readily accessible, and plainly labeled as to their type and method of operation.

n. Fire protection equipment shall be periodically inspected and maintained in good operating condition at all times.

o. Firefighting equipment shall be readily available near all welding operations. When welding, cutting or other hot work is performed in locations where other than a minor fire might develop, a person shall be designated as a fire watch. The area surrounding the work shall be inspected at least one (1) hour after the hot work is completed.

p. Portable fire extinguishers shall be tagged showing the date of last inspection, maintenance or recharge. Inspection and maintenance procedures shall comply with the latest edition of the National Fire Protection Association's publication NFPA 10.

q. Personnel shall be familiarized with the location of fire control equipment such as drilling fluid guns, water hoses and fire extinguishers and trained in the use of such equipment. They shall also be familiar with the procedure for requesting emergency assistance as terrain and location configuration permit. Installation shall be consistent with provisions of NFPA 58, "Standards for the Storage and Handling of Liquefied Petroleum Gases".

606B. AIR AND GAS DRILLING

a. Drilling compressors (air or gas) shall be located at least one hundred twenty five (125) feet from the wellbore and in a direction away from the air or gas discharge line.

b. The air or gas discharge line shall be laid in as nearly as a straight line as possible from the wellbore and be a minimum of one hundred fifty (150) feet in length. The line shall be securely anchored.

c. A pilot flame shall be maintained at the end of the air or gas discharge line at all times when air, gas, mist drilling, or well testing is in progress.

d. All combustible material shall be kept at least one hundred (100) feet away from the air and gas discharge line and burn pit.

e. The air line from the compressors to the standpipe shall be of adequate strength to withstand at least the maximum discharge pressure of the compressors used, and shall be checked daily for any evidence of damage or weakness.

f. Smoking shall not be allowed within seventy-five (75) feet of the air and gas discharge line and burn pit.

g. All operations associated with the drilling, completion or production of a well shall be subject to the Colorado Air Quality Control Act, §25-7-101, C.R.S.

607. HYDROGEN SULFIDE GAS

a. When well servicing operations take place in zones known to contain at or above one hundred (100) ppm hydrogen sulfide gas, as measured in the gas stream, the operator shall file a hydrogen sulfide drilling operations plan (United States Department of the Interior, Bureau of Land Management, Onshore Order No. 6, November 23, 1990).

b. When proposing to drill a well in areas where hydrogen sulfide gas in excess of one hundred (100) ppm can reasonably be expected to be encountered, the operator shall submit as part of the Application for Permit to Drill, Form 2, a hydrogen sulfide drilling operations plan (United States Department of the Interior, Bureau of Land Management, Onshore Order No. 6, November 23, 1990).

c. Any gas analysis indicating the presence of hydrogen sulfide gas shall be reported to the Commission and the local governmental designee.

FINANCIAL ASSURANCE AND ENVIRONMENTAL RESPONSE FUND

701. SCOPE

The rules in this series pertain to the provision of financial assurance by operators to ensure the performance of certain obligations imposed by the Oil and Gas Conservation Act (the Act), §34-60-106 (3.5), (11), (12) and (17) C.R.S., as well as the use of the Environmental Response Fund (ERF), §34-60-124 C.R.S., as a mechanism to plug and abandon orphan wells, perform orphaned site reclamation, and remediation, and to conduct other authorized environmental activities.

702. GENERAL

Operators are required to provide financial assurance to the Commission to demonstrate that they are capable of fulfilling the obligations imposed by the Act, as described in this series. Except as otherwise specified herein, a surety bond, in a form and from a company acceptable to the Commission, is an approved method of providing financial assurance. Any other method of providing financial assurance identified in §34-60-106(B), C.R.S., shall be submitted to the Commission for approval, and shall be equivalent to the protection provided by a surety bond and may require detailed Commission review on an ongoing basis, including the use of third party consultants, the reasonable expense for which shall be charged to the operator proposing such alternative financial assurance.

a. When the Director has reasonable cause to believe that the Commission may become burdened with the costs of fulfilling the statutory obligations described herein because an operator has demonstrated a pattern of non-compliance with oil and gas regulations in this or other states, because special geologic, environmental, or operational circumstances exist which make the plugging and abandonment of particular wells more costly, or due to other special and unique circumstances, the Director may petition the Commission for an increase in any individual or blanket financial assurance required in this series.

b. The requirements of this series do not apply to situations where financial assurance has been provided to federal or Indian agencies for operations regulated solely by such agencies.

703. SURFACE OWNER PROTECTION

Operators shall provide financial assurance to the Commission, prior to commencing any operations with heavy equipment, to protect surface owners who are not parties to a lease, surface use or other relevant agreement with the operator from unreasonable crop loss or land damage caused by such operations. The determination that crop loss or land damage is unreasonable shall be made by the Commission after the affected surface owner has filed an application in accordance with the 500 Series rules. Financial assurance for the purpose of surface owner protection shall not be required for operations conducted on state lands when a bond has been filed with the State Board of Land Commissioners.

The financial assurance required by this section shall be in the amount of two thousand dollars ($2,000) per well for non-irrigated land, or five thousand dollars ($5,000) per well for irrigated land. In lieu of such individual amounts, operators may submit statewide, blanket financial assurance in the amount of twenty five thousand dollars ($25,000).

704. CENTRALIZED E&P WASTE MANAGEMENT FACILITIES

An operator which makes application for an offsite, centralized E&P waste management facility shall, upon approval and prior to commencing construction, provide to the Commission financial assurance in the amount of fifty thousand dollars ($50,000) to ensure the proper reclamation, closure and abandonment of such facility. This section does not apply to underground injection wells and multi-well pits covered under Rules 706. and 707.

705. SEISMIC OPERATIONS

Any operator submitting a Notice of Intent to Conduct Seismic Operations, Form 20, shall, prior to commencing such operations, provide financial assurance to the Commission in the amount of twenty five thousand dollars ($25,000) statewide blanket financial assurance to ensure the proper plugging and abandonment of any shot holes and any necessary surface reclamation.

706. SOIL PROTECTION AND PLUGGING AND ABANDONMENT

Prior to commencing the drilling of a well, an operator shall provide financial assurance to the Commission to ensure the protection of the soil and the proper plugging and abandonment of the well in accordance with the 300 Series of drilling regulations, the 900 Series of E&P waste management, the 1000 Series of reclamation regulations, and the 1100 Series of flowline regulations. The financial assurance required by this section shall be in the amount of five thousand dollars ($5,000) per well. In lieu of such individual amount, an operator may submit statewide blanket financial assurance in the amount of thirty thousand dollars ($30,000) for the drilling and operation of less than one hundred (100) wells, or one hundred thousand dollars ($100,000) for the drilling and operation of one hundred (100) or more wells.

707. INACTIVE WELLS

a. To the extent that an operator's inactive well count exceeds such operator's financial assurance amount divided by five thousand dollars ($5,000), such additional wells shall be considered "excess inactive wells". For each excess inactive well, an operator's required financial assurance amount under Rule 706. shall be increased by five thousand dollars ($5,000). This requirement shall be modified or waived if the Commission approves a plan submitted by the operator for reducing such additional financial assurance requirement, for returning wells to production in a timely manner, or for plugging and abandoning such wells on an acceptable schedule.

In determining whether such plan is acceptable, the Commission shall take into consideration such factors as: the number of excess inactive wells; the cost to plug and abandon such wells; the proportion of such wells to the total number of wells held by the operator; any business reason the operator may have for shutting-in or temporarily abandoning such wells; the extent to which such wells may cause or have caused a significant adverse environmental impact; the financial condition of the operator; the capability of the operator to manage such plan in an orderly fashion; and the availability of plugging and abandonment services. If an increase in financial assurance is ordered pursuant to this subsection, the operator may, at its option and in compliance with these 700 Series rules, submit new financial assurance or supplement its existing financial assurance.

b. Operators shall identify and list any shut-in or temporarily abandoned wells on their monthly production/injection report. In addition, when equipment is removed from a well so as to render it temporarily abandoned, operators shall file a Sundry Notice, Form 4, with the Commission within thirty (30) days describing such activity.

c. Any person, other than the operator, who causes equipment from a well to be removed so as to render it temporarily abandoned shall, prior to conducting such activity, file a notice of intent to remove equipment and receive the approval of the Director. The Director may condition such approval on concurrent plugging and abandonment of the well or on provision of the financial assurance required of operators in this series.

708. PUBLIC HEALTH, SAFETY AND WELFARE

All operators shall maintain general liability insurance coverage for property damage and bodily injury to third parties in the minimum amount of five hundred thousand dollars ($500,000) per occurrence. Operators with wells or production facilities located in "high density areas" as defined in Rule 603.b. shall maintain such coverage in the minimum amount of one million dollars ($1,000,000) per occurrence. Such policies shall include the Commission as a "certificate holder" so that the Commission may receive advance notice of cancellation.

709. FINANCIAL ASSURANCE

All financial assurance provided to the Commission pursuant to this Series shall remain in place until such time as the Director determines an operator has complied with the statutory obligations described herein, or until such time the Director determines a successor-in-interest has filed satisfactory replacement financial assurance, at which time the Director shall provide written approval for release of such financial assurance. Whenever an operator fails to fulfill any statutory obligation described herein, and the Commission undertakes to expend funds to remedy the situation, the Director shall make application to the Commission for an order calling or foreclosing the operator's financial assurance.

a. Operators and third party providers of financial assurance shall be served with a copy of such application pursuant to Rule 503. and shall be accorded an opportunity to be heard thereon. Any third party provider of financial assurance which subsequently fails to comply with a Commission order to make such financial assurance available shall be considered an unacceptable provider of any new financial assurance to operators in Colorado, until such time as it applies for and receives an order of reinstatement. This provision shall be stayed by the filing of a judicial appeal. In addition, the Commission may institute suit to recover such monies.

b. If an operator's financial assurance is called or foreclosed by the Commission, the called or foreclosed amount shall be deposited in the Environmental Response Fund to be expended by the Director for the purposes referenced in Rule 701., and an overhead recovery fee of ten percent (10%) of the funds expended by the Director as direct costs shall be charged against any excess of the financial assurance over such costs.

Any remainder of such financial assurance after such cost recovery shall be returned to its provider. In no circumstances will the liability of a third party provider of financial assurance exceed the face amount of such financial assurance.

c. If an operator's financial assurance is called or foreclosed by the Commission, such operator's Certificates of Clearance, Form 10, are forthwith suspended and no sales of gas or oil shall be allowed, except as may be allowed by the Commission order, until such time as the operator's financial assurance has been replaced or restored.

710. ENVIRONMENTAL RESPONSE FUND

It is the intent of the Commission that an Environmental Response Fund (ERF) "emergency reserve" of unobligated funds be maintained in the amount of one million dollars ($1,000,000), which may be used in accordance with the Act and Rule 701.

711. NATURAL GAS GATHERING, NATURAL GAS PROCESSING AND UNDERGROUND NATURAL GAS STORAGE FACILITIES

Operators of natural gas gathering, natural gas processing, or underground natural gas storage facilities shall be required to provide statewide blanket financial assurance to ensure compliance with the 900 Series rules in the amount of fifty thousand dollars ($50,000), or in an amount voluntarily agreed to with the Director, or in an amount to be determined by order of the Commission. Operators of small systems gathering or processing less than five (5) MMSCFD may provide individual financial assurance in the amount of five thousand dollars ($5,000).

AESTHETIC AND NOISE CONTROL REGULATIONS

801. INTRODUCTION

The rules and regulations in this section are promulgated to control aesthetics and noise impacts during the drilling, completion and operation of oil and gas wells and production facilities. Any Colorado county, home rule or statutory city, town, territorial charter city or city and county may, by application to the Commission, seek a determination that the rules and regulations in this section, or any individual rule or regulation, shall not apply to oil and gas activities occurring within the boundaries, or any part thereof, of any Colorado county, home rule or statutory city, town, territorial charter city or city and county, such determination to be based upon a showing by any Colorado county, home rule or statutory city, town, territorial charter city or city and county that, because of conditions existing therein, the enforcement of these rules and regulations is not necessary within the boundaries of any Colorado county, home rule or statutory city, town, territorial charter city or city and county for the protection of public health, safety and welfare.

802. NOISE ABATEMENT

a. Oil and gas operations, including gas facility operations, shall comply with the following maximum permissible noise levels for the predominant land use existing in the zone in which the operation occurs. Any operation involving pipeline or gas facility installation or maintenance, the use of a drilling rig, completion rig, workover rig, or stimulation is subject to the maximum permissible noise levels for industrial zones. In the hours between 7:00 a.m. and the next 7:00 p.m. the noise levels permitted below may be increased ten (10) db(A) for a period not to exceed fifteen (15) minutes in any one (1) hour period.

ZONE	7:00 am to next 7:00 pm	7:00 pm to next 7:00 am
Residential	55 db(A)	50 db(A)
Commercial	60 db(A)	55 db(A)
Light industrial	70 db(A)	65 db(A)
Industrial	80 db(A)	75 db(A)

The following provide guidance for the measurement of sound levels from oil and gas operations:

(1) If there are no occupied building units impacted, sound levels shall be measured at a distance of twenty-five (25) feet or more from the property line radiating the noise. Sound levels at occupied building units shall be measured as near as practicable to the exterior edge of the occupied building unit closest to the area radiating the noise.

(2) Sound level meters shall be equipped with wind screens, and readings taken when the wind velocity at the time and place of measurement is not more than five (5) miles per hour.

(3) Sound level measurements shall be taken four (4) feet above ground level.

(4) Sound levels shall be determined by averaging measurements made over a fifteen (15) minute sample duration.

(5) In all sound level measurements, the existing ambient noise level from all other sources in the encompassing environment at the time and place of such sound level measurement shall be considered to determine the contribution to the sound level by the oil and gas operation(s).

b. Exhaust from all engines, motors, coolers and other mechanized equipment shall be vented in a direction away from all occupied buildings to the extent practicable.

c. In high density areas all facilities within four hundred (400) feet of occupied buildings with engines or motors which are not electrically operated shall be equipped with quiet design mufflers or equivalent. All mufflers shall be properly installed and maintained in proper working order.

803. LIGHTING

To the extent practicable, site lighting shall be directed downward and internally so as to avoid glare on public roads and occupied buildings within seven hundred (700) feet.

804. VISUAL IMPACT MITIGATION

Production facilities constructed or substantially repainted after May 30, 1992 which are observable from any public highway shall be painted with uniform, non-contrasting, non-reflective color tones, (similar to the Munsell Soil Color Coding System) and with colors matched to but slightly darker than the surrounding landscape.

901. INTRODUCTION

a. **General.** The rules and regulations of this series establish the permitting, construction, operating and closure requirements for pits, methods of E&P waste management, procedures for spill/release response and reporting, and sampling and analysis for remediation activities. The 900 Series rules are applicable only to E&P waste, as defined in §34-60-103(4.5), C.R.S., or other solid waste where the Colorado Department Of Public Health And Environment ("CDPHE") has allowed remediation and oversight by the Commission.

b. **COGCC reporting forms.** The reporting required by the rules and regulations of this series shall be made on forms provided by the Director. Alternate forms may be used where equivalent information is supplied and the format has been approved by the Director.

c. **Additional requirements.** Whenever the Director has reasonable cause to believe that an operator, in the conduct of any oil or gas operation, is performing any act or practice which threatens to cause or causes a violation of Table 910-1 and with consideration of water quality standards or classifications established by the Water Quality Control Commission ("WQCC") for waters of the state, the Director may impose additional requirements, including but not limited to, sensitive area determination, sampling and analysis, remediation, monitoring, permitting and the establishment of points of compliance. Any action taken pursuant to this Rule shall comply with the provisions of Rules 324A. through D. and the 500 Series rules.

d. **Alternative compliance methods.** Operators may propose for prior approval by the Director alternative methods for determining the extent of contamination, sampling and analysis, or alternative cleanup goals using points of compliance or risk-based approaches.

e. **Sensitive area determination.** Operators shall make a sensitive area determination using the Sensitive Area Determination Decision Tree, Figure 901-1 to evaluate the potential for impact to ground water and submit data evaluated and analysis used in the determination to the Director for the following operations or remediation activities:

(1) Construction of drilling pits designed for use with fluids containing hydrocarbon concentrations exceeding 20,000 parts per million ("ppm") total petroleum hydrocarbon ("TPH") or chloride concentrations at total well depth exceeding 15,000 ppm.

(2) Construction of production and special purpose pits;

(3) Construction of centralized E&P waste management facilities;

(4) Management and remediation of spills/releases exceeding twenty (20) barrels net loss of E&P waste; or

(5) When the operator or Director has data that indicate an impact or threat of impact to ground water.

f. Sensitive area operations. **Operations in sensitive areas shall incorporate adequate measures and controls to prevent significant adverse environmental impacts and ensure compliance with the allowable concentrations and levels in Table 910-1, with consideration to WQCC standards and classifications. Unlined production and special purpose pits in sensitive areas are generally not approved.**

902. PITS - GENERAL AND SPECIAL RULES

a. Pits used for exploration and production of oil and gas shall be constructed and operated to protect the waters of the state from significant adverse environmental impacts from E&P waste, except as permitted by applicable laws and regulations.

b. Topsoil and subsoil removed in the construction of the pit shall be segregated and stockpiled in a manner described in Rule 1002. and used for reclamation of the site.

c. Pits shall be constructed and operated to provide for a minimum of two (2) feet of freeboard between the top of the pit wall and the fluid level of the pit.

d. Any accumulation of oil in a pit shall be removed within twenty-four (24) hours of discovery. This requirement is not applicable to properly permitted and properly fenced or netted skim pits.

e. Where necessary to protect public health, safety and welfare or to prevent significant adverse environmental impacts resulting from access to a pit by wildlife, migratory birds, domestic animals, or members of the general public, operators shall install appropriate netting or fencing.

f. **Multi-well pits.** Production and special purpose pits used for treatment or disposal of E&P waste generated from more than one well may be permitted in accordance with Rule 903. as a multi-well pit, subject to Director approval.

g. Unlined drilling pits shall not be constructed on fill material.

h. Produced water shall be treated in accordance with Rule 907. before being placed in a production pit.

903. PIT PERMITTING/REPORTING REQUIREMENTS

a. Drilling pits, production pits, and special purpose pits shall be permitted or reported as follows:

(1) Pit Construction Report/Permit, Form 15, shall be submitted for prior Director approval for the following:

A. Drilling pits designed for use with fluids containing hydrocarbon concentrations exceeding 20,000 ppm TPH or chloride concentrations at total well depth exceeding 15,000 ppm in sensitive areas or 50,000 ppm outside sensitive areas.

B. Production pits and unlined special purpose pits in sensitive areas.

C. Unlined production pits and special purpose pits outside sensitive areas, excluding those pits permitted in accordance with Rule 903.a.(2).B.

(2) Pit Construction Report/Permit, Form 15, shall be submitted within thirty (30) days after construction for the following:

A. Lined production pits outside sensitive areas.

B. Unlined production pits outside sensitive areas receiving produced water at an average daily rate of five (5) or less barrels per day calculated on a monthly basis for each month of operation.

C. Lined special purpose pits.

D. Flare pits where there is no risk of condensate accumulation.

(3) Pit Construction Report/Permit, Form 15, shall not be required for drilling pits using water-based bentonitic drilling fluids with concentrations of TPH and chloride below those referenced in Rule 903.a.(1).A.

b. The Pit Construction Report/Permit, Form 15, shall be completed in accordance with the instructions in Appendix I. Failure to complete the form in full may result in delay of approval or return of form.

c. The Director shall endeavor to review any properly completed Pit Construction Report/Permit, Form 15, within thirty (30) days after receipt. In order to allow adequate time for pit permit approval, operators should submit required Form 15 pit construction permit requests for approval with an Application for Permit to Drill, Form 2. The Director may condition permit approval upon compliance with additional terms, provisions or requirements necessary to protect the waters of the state, public health, or the environment.

904. PIT LINING REQUIREMENTS AND SPECIFICATIONS

a. Pit lining requirements. The following pits shall be lined:

(1) Drilling pits designed for use with fluids containing hydrocarbon concentrations exceeding 20,000 ppm TPH or chloride concentrations at total well depth exceeding 15,000 ppm in sensitive areas or 50,000 ppm outside sensitive areas.

(2) Production pits in sensitive areas.

(3) Special purpose pits, except emergency pits constructed during initial response to spills/releases, or flare pits where there is no risk of condensate accumulation.

(4) Skim pits.

b. The following specifications shall apply to pits that are required to be lined:

(1) Materials used in lining pits shall be impervious, weather resistant and resistant to deterioration when in contact with hydrocarbons, aqueous acids, alkali, fungi or other substances in the produced water.

(2) Soil liners shall have a minimum thickness of six (6) inches after compaction, shall cover the entire bottom and interior sides of the pit, and shall be constructed so that the hydraulic conductivity of the liner shall not exceed 1.0 X 10^{-6} cm/sec. Bentonite liners shall be constructed to provide equivalent protection. Operators shall perform post-construction tests either in a laboratory or in the field. All test results shall be filed with the Director.

(3) Synthetic or fabricated liners shall have a minimum thickness of twelve (12) mils and shall be resistant to deterioration by ultraviolet light, weathering, chemicals, punctures and tearing, and designed for the life of the well. The foundation for the liner shall be constructed to prevent punctures from soils or other materials beneath the liner. The synthetic or fabricated liner shall cover the bottom and interior sides of the pit with the edges secured with at least a twelve (12) inch deep anchor trench around the pit perimeter.

(4) In Sensitive Areas, the Director may require a leak detection system for the pit or other equivalent protective measures, including but not limited to, increased record-keeping requirements, monitoring systems and underlying gravel fill sumps and lateral systems. In making such determination, the Director shall consider the surface and subsurface geology, the use and quality of potentially-affected ground water, the quality of the produced water, and the hydraulic conductivity of the surrounding soils and the type of liner.

905. CLOSURE OF PITS, AND BURIED OR PARTIALLY BURIED PRODUCED WATER VESSELS.

a. Unlined production and special purpose pits, except emergency pits constructed during initial response to spills/releases, shall be closed in accordance with an approved Site Investigation and Remediation Workplan, Form 27. The workplan shall be submitted for prior Director approval and shall include a description of the proposed investigation and remediation activities in accordance with Rule 909.

b. Lined pits and buried or partially buried produced water vessels:

(1) Operators shall ensure that soils and ground water meet the allowable concentrations of Table 910-1.

(2) **Pit evacuation.** Prior to backfilling and site reclamation, E&P waste shall be treated or disposed in accordance with Rule 907.

(3) Liners shall be disposed as follows:

A. **Synthetic liner disposal.** On irrigated crop land, liner material shall be removed and disposed in accordance with applicable solid waste rules. On non-irrigated crop land and on non-crop land, liner material may be left in place with surface owner approval.

B. **Constructed soil liners.** Constructed soil liner material may be removed for treatment or disposal, or, where left in place, the material shall be ripped and mixed with native soils in a manner to alleviate compaction and prevent an impermeable barrier to infiltration and ground water flow.

c. **Discovery of a spill/release during closure**. When a spill/release is discovered during closure operations operators shall report the spill/release on the Spill/Release Report, Form 19, in accordance with Rule 906. Leaking pits and buried or partially buried produced water vessels shall be closed and remediated in accordance with Rules 909. and 910.

d. **Emergency pits**. Emergency pits constructed during initial response to contain and mitigate spills/releases shall not be subject to lining requirements. These pits shall be closed and remediated in accordance with Rule 906.

e. **Unlined drilling pits.** Unlined drilling pits shall be closed and reclaimed in accordance with the 1000 Series rules.

906. SPILLS AND RELEASES

a. **General.** Spills/releases of E&P waste, including produced fluids shall be controlled and contained immediately upon discovery. Impacts resulting from spills/releases shall be investigated and cleaned up as soon as practicable.

The Director may require additional activities to prevent or mitigate threatened or actual significant adverse environmental impacts on any air, water, soil or biological resource, or to the extent necessary to ensure compliance with the allowable concentrations and levels in Table 910-1, with consideration to WQCC ground water standards and classifications.

b. **Reporting.**

(1) Spills/releases of E&P waste or produced fluid exceeding five (5) barrels, including those contained within unlined berms, shall be reported on COGCC Spill/Release Report Form, 19. Such report shall include information relating to initial mitigation, site investigation and remediation, and shall be submitted to the Director within ten (10) days of discovery of the spill/release.

(2) In addition, spills/releases which exceed twenty (20) barrels of an E&P waste shall be verbally reported to the Director within twenty-four (24) hours of discovery.

(3) In addition, spill/releases of any size which impact or threaten to impact any waters of the state, residence or occupied structure, livestock or public byway, shall be verbally reported to the Director as soon as practicable after discovery.

c. **Surface owner notification and consultation.** The operator shall make good faith efforts to notify and consult with the surface owner prior to commencing operations to remediate E&P waste from a spill/release in an area not being utilized for oil and gas operations.

d. **Remediation of spills/releases**.

(1) **Remediation workplan.** When threatened or actual significant adverse environmental impacts on any air, water, soil or biological resource from a spill/release exists or when necessary to ensure compliance with the allowable concentrations and levels in Table 910-1, with consideration to WQCC ground water standards and classifications, the Director may require operators to submit a Site Investigation and Remediation Workplan, Form 27.

(2) **Remediation requirements.** Spills/releases shall be remediated to meet the allowable concentrations in Table 910-1. Spills/releases exceeding twenty (20) barrels net loss of E&P waste shall be remediated in accordance with Rules 909. and 910.

e. **Spill/release prevention.**

(1) **Secondary containment.** Secondary containment shall be constructed or installed around tanks containing crude oil, condensate or produced water with greater than 10,000 milligrams per liter (mg/l) total dissolved solids (TDS). Operators are also subject to crude oil tank and containment requirements under Rules 603. and 604. This requirement shall not apply to water tanks with a capacity of one hundred (100) barrels or less.

(2) **Spill/release evaluation.** Operators shall determine the cause of a spill/release, and to the extent practicable, shall implement measures to prevent spills/releases due to similar causes in the future. For reportable spills, operators shall submit this information to the Director on the Spill/Release Report, Form 19 within ten (10) days after discovery of the spill/release.

907. MANAGEMENT OF E&P WASTE

a. **General requirements.**

(1) **Operator obligations.** Operators shall ensure that E&P waste is properly stored, handled, transported, treated, recycled or disposed to prevent threatened or actual significant adverse environmental impacts to air, water, soil or biological resources or to the extent necessary to ensure compliance with the allowable concentrations and levels in Table 910-1, with consideration to WQCC ground water standards and classifications.

(2) E&P waste management activities shall be conducted, and facilities constructed and operated, to protect the waters of the state from significant adverse environmental impacts from E&P waste, except as permitted by applicable laws and regulations.

(3) **Reuse and recycling.** To encourage and promote waste minimization, operators may propose plans for managing E&P waste through beneficial use, reuse and recycling by submitting a written management plan to the Director for approval. Such plans shall describe the proposed use of the waste, method of waste treatment, product quality assurance, and shall include a copy of any certification or authorization that may be required by other laws.

b. **Waste transportation.**

(1) E&P waste, when transported off-site within Colorado for treatment or disposal, shall be transported to facilities authorized by the Director or waste disposal facilities approved to receive E&P waste by the CDPHE.

(2) **Waste generator requirements.** Generators of E&P waste shall maintain, for not less than three (3) years, copies of each invoice, bill or ticket and such other records as necessary to document the following information from a transporter or disposal site, describing the disposal of E&P waste from each location:

A. The date of the transport;

B. The identity of the waste generator;

C. The identity of the waste transporter;

D. The location of the waste pickup site;

E. The type and volume of waste; and

F. The name and location of the treatment or disposal site.

Such records shall be made available for inspection by the Director during normal business hours and copies thereof shall be furnished to the Director upon request.

c. **Produced water.**

(1) **Treatment of produced water.** Produced water shall be treated prior to placement in a production pit to prevent crude oil and condensate from entering the pit.

(2) **Produced water disposal.** Produced water may be disposed as follows:

A. Injection into a Class II well, permitted in accordance with Rule 325.;

B. Evaporation/percolation in a properly permitted lined or unlined pit;

C. Disposal at permitted commercial facilities; or

D. Disposal by roadspreading on lease roads outside sensitive areas for produced waters with less than 5,000 mg/l TDS when authorized by the surface owner. Roadspreading shall not result in pooling or runoff of produced waters and the adjacent soils shall meet the allowable concentrations in Table 910-1.

E. Discharging into state waters, in accordance with the Water Quality Control Act and the rules and regulations promulgated thereunder. Produced water discharged pursuant to this subsection (2)E. may be put to beneficial use in accordance with applicable state statutes and regulations governing the use and administration of water.

(3) **Produced water reuse and recycling.** Produced water may be reused for enhanced recovery, drilling, and other uses in a manner consistent with existing water rights and in consideration of water quality standards and classifications established by the WQCC for waters of the state, or any point of compliance established by the Director pursuant to Rule 324D.

(4) **Mitigation.** Water produced during operation of an oil or gas well may be used to provide an alternate domestic water supply to surface owners within the oil or gas field, in accordance with all applicable laws, including, but not limited to, obtaining the necessary approvals from the WQCD for constructing a new "waterworks," as defined by section 25-1-107(1)(X)(II)(A), C.R.S. Any produced water not so used shall be disposed of in accordance with subsection (2) or (3). Provision of produced water for domestic use within the meaning of this subsection (4) shall not constitute an admission by the operator that the well is dewatering or

impacting any existing water well. The water produced shall be to the benefit of the surface owner within the oil and gas field and may not be sold for profit or traded.

d. **Drilling fluids.**

(1) **Drilling pit fluid recycling.** Drilling pit contents may be recycled to another drilling pit consistent with Rule 903.

(2) **Drilling fluids treatment and disposal.** Drilling fluids may be treated or disposed as follows:

A. Injection into a Class II well permitted in accordance with Rule 325.;

B. Disposal at a commercial solid waste disposal facility; or

C. Land treatment or land application at a centralized E&P waste management facility permitted in accordance with Rule 908.

(3) **Additional authorized disposal of water-based bentonitic drilling fluids.** Water-based bentonitic drilling fluids may be disposed as follows:

A. Drying and burial in drilling pits on non-crop land; or

B. Land application as follows:

i. **Applicability.** Acceptable methods of land application include, but are not limited to, production facility construction and maintenance, lease and farm road maintenance, or lining of stock ponds and irrigation ditches.

ii. **Land application requirements**. The average thickness of water-based bentonitic drilling fluid waste applied shall be no more than three (3) inches prior to incorporation. The waste shall be applied to prevent ponding or erosion and shall be incorporated as a beneficial amendment into the native soils as soon as practicable. The resulting concentrations shall not exceed those in Table 910-1.

iii. **Surface owner approval.** Operators shall obtain written authorization from the surface owner prior to land application of water-based bentonitic drilling fluids.

iv. **Operator obligations**. Operators with control and authority over the wells from which the water-based bentonitic drilling fluid wastes are obtained retain responsibility for the land application operation, and shall diligently cooperate with the Director in responding to complaints regarding land application of water-based bentonitic drilling fluids.

v. **Approval.** Prior Director approval is not required for reuse of water-based bentonitic drilling fluids for land application as a soil amendment or lining material.

e. **Oily waste.** Oily waste includes those materials containing crude oil, condensate or other hydrocarbon-containing E&P waste, such as soil, frac sand, drilling fluids, workover fluids, pit sludge, tank bottoms, pipeline pigging wastes, and natural gas gathering, processing and storage wastes.

(1) Oily waste may be treated or disposed as follows:

A. Disposal at a commercial solid waste disposal facility;

B. Land treatment onsite or with prior written surface owner approval, offsite land treatment; or

C. Land treatment at a centralized E&P waste management facility permitted in accordance with Rule 908.

(2) Land treatment requirements:

A. Free oil shall be removed from the oily waste prior to land treatment.

B. Oily waste shall be spread evenly to prevent pooling, ponding or runoff.

C. Contamination of ground water or surface water shall be prevented.

D. Biodegradation shall be enhanced by disking, tilling, aerating, addition of nutrients, microbes, water or other amendments, as appropriate.

E. Land-treated oily waste incorporated in place shall not exceed the allowable concentrations in Table 910-1.

F. When a threatened or significant adverse environmental impact from onsite land treatment exists, the Director may require operators to submit a Site Investigation And Remediation Workplan, Form 27. Treatment shall thereafter be completed in accordance with the workplan and Rules 909. and 910.

G. When land treatment occurs in an area not being utilized for oil and gas operations, operators shall obtain prior written surface owner approval.

908. CENTRALIZED E&P WASTE MANAGEMENT FACILITIES

a. **Applicability.** Operators may establish non-commercial, centralized E&P waste management facilities for the treatment, disposal, recycling or beneficial reuse of E&P waste. This rule applies only to non-commercial facilities, which means the operator does not represent itself as providing E&P waste management services to third parties, except as part of a unitized area or joint operating agreement or in response to an emergency. Centralized facilities may include components such as land treatment or land application sites, pits and recycling equipment.

b. **Permit requirements.** An application for permit including the following information shall be submitted to the Director for prior approval along with a filing and service fee established by the Commission (Appendix III):

(1) The name, address, phone and fax number of the operator, and a designated contact person.

(2) The name, address and phone number of the surface owner of the site, if not the operator, and the written authorization of such surface owner.

(3) The legal description of the site.

(4) A general topographic, geologic and hydrologic description of the site, including immediately adjacent land uses, a topographic map of a scale no less than 1:24,000 showing the location, and the average annual precipitation and evaporation rates at the site.

(5) Centralized facility siting requirements.

A. A site plan showing drainage patterns and any diversion or containment structures, and facilities such as roads, fencing, tanks, pits, buildings, and other construction details.

B. Scaled drawings of entire sections containing the proposed facility. The field measured distances from the nearer north or south and nearer east or west section lines shall be measured at ninety (90) degrees from said section lines to facility boundaries and referenced on the drawing. A survey shall be provided including a complete description of established monuments or collateral evidence found and all aliquot corners.

C. Appropriate measures to limit access to the centralized facility by wildlife, domestic animals, and members of the general public shall be implemented.

D. Centralized facilities shall have a fire lane of at least ten (10) feet in width around the active treatment areas and within the perimeter fence. In addition, a buffer zone of at least ten (10) feet shall be maintained within the perimeter fire lane.

E. Surface water diversion structures, including, but not limited to, berms and ditches, shall be constructed to accommodate a one hundred (100) year, twenty four (24) hour event.

(6) **Waste profile.** For each type of waste, the amounts to be received and managed by the facility shall be estimated on a monthly average basis. For each waste type to be treated, a characteristic waste profile shall be completed.

(7) F**acility design and engineering.** Facility design and engineering data, including plans and elevations, design basis, calculations, and process description.

(8) **Operating plan.** An operating plan, including, but not limited to, a detailed description of the method of treatment, loading rates, application of nutrients and soil amendments, dust and moisture control, sampling, inspection and maintenance, emergency response, record-keeping, site security, hours of operation, and final disposition of waste. Where treated waste will be beneficially reused, a description of reuse and method of product quality assurance shall be included.

(9) **Ground water monitoring.**

A. The Director may require ground water monitoring for the purpose of preventing and mitigating threatened or actual significant adverse environmental impact or to ensure compliance with the allowable concentrations and levels in Table 910-1, with consideration to WQCC standards and classifications by establishing points of compliance.

B. Where monitoring is required, the direction of flow, ground water gradient and quality of water shall be established by the installation of a minimum of three (3) monitor wells, including an up-gradient well and two (2) down-gradient wells that will serve as points of compliance, or other methods authorized by the Director.

c. **Permit approval**. The Director shall endeavor to approve or deny the properly completed permit within thirty (30) days after receipt and may condition permit approval as necessary to prevent any threatened or actual significant adverse environmental impact on air, water, soil or biological resources or to the extent necessary to ensure compliance with the allowable concentrations and levels in Table 910-1, with consideration to WQCC ground water standards and classifications.

d. **Financial assurance.** The operator of a land treatment facility shall submit for the Director's approval such financial assurance as required by Rule 704.

e. **Facility modifications.** Throughout the life of the facility the operator shall submit proposed modifications to the facility design, operating plan, permit data, or permit conditions to the Director for prior approval.

f. **Annual permit review.** To ensure compliance with permit conditions and the 900 Series rules, the facility permit shall be subject to an annual review by the Director.

g. **Closure.** A preliminary plan for closure shall be submitted with the centralized facility permit. A Site Investigation and Remediation Workplan, Form 27 shall be submitted sixty (60) days prior to closure for approval by the Director. The workplan shall describe the final closure plan.

h. Operators may be subject to local requirements for zoning and construction of facilities and shall provide copies of notifications to local governments or other agencies to the Director.

909. SITE INVESTIGATION, REMEDIATION AND CLOSURE

a. **Applicability.** This section applies to the closure and remediation of pits other than drilling pits constructed pursuant to Rule 903.a.(3).; investigation, reporting and remediation of spills/releases; permitted waste management facilities including treatment facilities; plugged and abandoned wellsites; sites impacted by E&P waste management practices; or other sites as designated by the Director.

b. **General site investigation and remediation requirements.**

(1) **Sensitive Area Determination.** Operators shall complete a sensitive area determination in accordance with Rule 901.e.

(2) **Sampling and analyses.** Samples and analysis of soil and ground water shall be conducted in accordance with Rule 910. to determine the horizontal and vertical extent of any contamination in excess of the allowable concentrations in Table 910-1.

(3) **Management of E&P waste.** E&P waste shall be managed in accordance with Rule 907.

(4) **Pit evacuation**. Prior to backfilling and site reclamation, E&P waste shall be treated or disposed in accordance with Rule 907. and the 1000 Series rules.

(5) **Remediation.** Remediation shall be performed in a manner to mitigate, remove or reduce contamination that exceeds the allowable concentrations in Table 910-1 in order to ensure protection of public health, safety and welfare, and to prevent and mitigate significant adverse environmental impacts. Soil that does not meet allowable concentrations in Table 910-1 shall be remediated. Ground water that does not meet allowable concentrations in Table 910-1 shall be remediated in accordance with a Site Investigation and Remediation Workplan, Form 27.

(6) **Reclamation.** Remediation sites shall be reclaimed in accordance with the 1000 Series rules for reclamation.

c. **Site Investigation And Remediation Workplan, Form 27.** Operators shall prepare and submit for prior Director approval a Site Investigation and Remediation Workplan, Form 27 for the following operations and remediation activities:

(1) Unlined pit closure when required by Rule 905.

(2) Remediation of spills/releases in accordance with Rule 906.

(3) Land treatment of oily waste in accordance with Rule 907.e.(2).F.

(4) Closure of centralized E&P waste management facilities in accordance with Rule 908.g.

(5) Remediation of impacted ground water in accordance with Rule 910.b.(4).

d. **Multiple sites.** Remediation of multiple sites may be submitted on a single workplan with prior Director approval.

e. **Closure.**

(1) Remediation and reclamation shall be complete upon compliance with the allowable concentrations in Table 910-1, or upon compliance with an approved workplan.

(2) **Notification of completion.** Within thirty (30) days after conclusion of site remediation and reclamation activities operators shall provide the following notification of completion:

A. Operators conducting remediation operations in accordance with Rule 909.b. shall submit to the Director a Site Investigation and Remediation Workplan, Form 27, containing information sufficient to demonstrate compliance with these rules.

B. Operators conducting remediation under an approved workplan shall submit to the Director, by adding or attaching to the original workplan, information sufficient to demonstrate compliance with the workplan.

f. **Release of financial assurance.** Financial assurance required by Rule 706. may be held by the Director until the required remediation of ground water impacts is completed in accordance with the approved workplan, or until cleanup goals are met.

910. ALLOWABLE CONCENTRATIONS AND SAMPLING FOR SOIL AND GROUND WATER

a. **Soil and ground water allowable concentrations.** The allowable concentrations for soil and ground water are in Table 910-1. Ground water standards and analytical methods are derived from the ground water standards and classifications established by WQCC.

b. **Sampling and analysis.**

(1) **Existing workplans.** Sampling and analysis for sites subject to an approved workplan shall be conducted in accordance with the workplan and the sampling and analysis requirements described in this rule.

(2) **Methods for sampling and analysis.** Sampling and analysis for site investigation or confirmation of successful remediation shall be conducted to determine the nature and extent of impact and confirm compliance with appropriate allowable concentrations.

A. **Field analysis.** Field measurements and field tests shall be conducted using appropriate equipment, calibrated and operated according to manufacturer specifications, by personnel trained and familiar with the equipment.

B. **Sample collection.** Samples shall be collected, preserved, documented, and shipped using standard environmental sampling procedures in a manner to ensure accurate representation of site conditions.

C. **Laboratory analytical methods.** Laboratories shall analyze samples using standard methods (such as EPA SW-846 or API RP-45) appropriate for detecting the target analyte. The method selected shall have detection limits less than or equal to the allowable concentrations in Table 910-1.

D. **Background sampling.** Samples of comparable, nearby, non-impacted, native soil, ground water or other medium may be required by the Director for establishing background conditions.

(3) **Soil sampling and analysis.**

A. **Applicability.** If soil contamination is suspected or known to exist as a result of spills/releases or E&P waste management, representative samples of soil shall be collected and analyzed in accordance with this rule.

B. **Sample collection.** Samples shall be collected from areas most likely to have been impacted, and the horizontal and vertical extent of contamination shall be determined. The number and location of samples shall be appropriate to the impact.

C. **Sample analysis.** Soil samples shall be analyzed for contaminants listed in Table 910-1 as appropriate to assess the impact or confirm remediation.

D. **Reporting.** Soil Analysis Report, Form 24 shall be used when the Director requires results of soil analyses.

E. **Soil impacted by produced water.** For impacts to soil due to produced water, samples from comparable, nearby non-impacted, native soil shall be collected and analyzed for purposes of establishing background soil conditions including pH and electrical conductivity (EC). Where EC of the impacted soil exceeds the allowable level in Table 910-1, the sodium adsorption ratio (SAR) shall also be determined.

F. **Soil impacted by hydrocarbons.** For impacts to soil due to hydrocarbons, samples shall be analyzed for TPH.

(4) **Ground water sampling and analysis.**

A. **Applicability.** Operators shall collect and analyze representative samples of ground water in accordance with these rules under the following circumstances:

i. Where ground water contamination is suspected or known to exceed the allowable concentrations in Table 910-1;

ii. Where impacted soils are in contact with ground water; or

iii. Where impacts to soils extend down to the high water table.

B. **Sample collection.** Samples shall be collected from areas most likely to have been impacted, downgradient or in the middle of excavated areas. The number and location of samples shall be appropriate to determine the horizontal and vertical extent of the impact. If the concentrations in Table 910-1 are exceeded, the direction of flow and a ground water gradient shall be established, unless the extent of the contamination and migration can otherwise be adequately determined.

C. **Sample analysis.** Ground water samples shall be analyzed for benzene, toluene, ethylbenzene, xylene, and API RP-45 constituents, or other parameters appropriate for evaluating the impact.

D. **Reporting.** Water Analysis Report, Form 25 shall be used when the Director requires results of water analyses.

E. **Impacted ground water.** Where ground water contaminants exceed the allowable concentrations listed in Table 910-1, operators shall notify the Director, and submit to the Director for prior approval a Site Investigation and Remediation Workplan, Form 27, for the investigation, remediation, or monitoring of ground water to meet the required allowable concentrations.

911. PIT, BURIED OR PARTIALLY BURIED PRODUCED WATER VESSEL, BLOWDOWN PIT, AND BASIC SEDIMENT/TANK BOTTOM PIT MANAGEMENT REQUIREMENTS PRIOR TO DECEMBER 30, 1997.

a. **Applicability.** This rule applies to the management, operation, closure and remediation of drilling, production and special purpose pits, buried or partially buried produced water vessels, blowdown pits, and basic sediment/tank bottom pits put into service prior to December 30, 1997 and unlined skim pits put into service prior to July 1, 1995. For pits constructed after December 30, 1997 and skim pits constructed after July 1, 1995, operators shall comply with the requirements contained in Rules 901. through 910.

b. **Inventory.** Operators were required to submit to the Director no later than December 31, 1995, an inventory identifying production pits, buried or partially buried produced water vessels, blowdown pits, and basic sediment/tank bottom pits that existed on June 30, 1995. The inventory required operators to provide the facility name, a description of the location, type, capacity and use of pit/vessel, whether netted or fenced, lined or unlined, and where available, water quality data. Operators who have failed to submit the required inventory are in continuing violation of this rule.

c. **Sensitive area determination.**

(1) For unlined production and special purpose pits constructed prior to July 1, 1995 and not closed by December 30, 1997, operators were required to determine whether the pit was located within a sensitive area in accordance with the Sensitive Area Determination Decision Tree, Figure 901-1, (now Rule 901.e.), and submit data evaluated and analysis used in the determination to the Director on a Sundry Notice, Form 4.

(2) For steel, fiberglass, concrete, or other similar produced water vessels that were buried or partially buried and located in sensitive areas prior to December 30, 1997, operators were required to test such vessels for integrity, unless a monitoring or leak detection system was put in place.

d. The following permitting/reporting requirements applied to pits constructed prior to December 30, 1997:

(1) A Sundry Notice, Form 4, including the name, address, and phone number of the primary contact person operating the production pit for the operator, the facility name, a description of the location, type, capacity and use of pit, engineering design, installation features and water quality data, if available, was required for the following:

A. Lined production pits and lined special purpose pits constructed after July 1, 1995.

B. Unlined production pits constructed prior to July 1, 1995 which are lined in accordance with Rule 905. by December 30, 1997.

(2) An Application For Permit For Unlined Pit, Form 15 was required for the following:

A. Unlined production pits and special purpose pits in sensitive areas constructed prior to July 1, 1995, and not closed by December 30, 1997.

B. Unlined production pits outside sensitive areas constructed after July 1, 1995 and not closed by December 30, 1997.

(3) An Application For Permit For Unlined Pit, Form 15 and a variance under Rule 904.e.(1). (repealed, now Rule 502.b.) was required for unlined production pits and unlined special purpose pits in sensitive areas constructed after July 1, 1995.

(4) A Sundry Notice, Form 4 was required for unlined production pits outside sensitive areas receiving produced water at an average daily rate of five (5) or less barrels per day calculated on a monthly basis for each month of operation constructed prior to December 30, 1997.

e. The Director may have established points of compliance for unlined production pits and special purpose pits and for lined production pits in sensitive areas constructed after July 1, 1995.

f. **Closure requirements.**

(1) Operators of production or special purpose pits existing on July 1, 1995 which were closed before December 30, 1997, were required to submit a Sundry Notice, Form 4, within thirty (30) days of December 30, 1997. The Sundry Notice, Form 4 shall include a copy of the existing pit permit, if a permit was obtained and a description of the closure process.

(2) Pits closed prior to December 30, 1997 were required to be reclaimed in accordance with the 1000 Series rules. Pits closed after December 30, 1997 shall be closed in accordance with the 900 Series rules and reclaimed in accordance with the 1000 Series rules.

(3) Operators of steel, fiberglass, concrete or other similar produced water vessels buried or partially buried and located in sensitive areas were required to repair or replace vessels and tanks found to be leaking. Operators shall repair or replace vessels and tanks found to be leaking. Operators shall submit to the Director a Sundry Notice, Form 4, describing the integrity testing results and action taken within thirty (30) days of December 30, 1997.

(4) Closure of pits and steel, fiberglass, concrete or other similar produced water vessels, and associated remediation operations conducted prior to December 30, 1997 are not subject to Rules 905., 906., 907., 909. and 910.

912. VENTING OR FLARING NATURAL GAS

a. The unnecessary or excessive venting or flaring of natural gas produced from a well is prohibited.

b. Except for gas flared or vented during an upset condition, well maintenance, well stimulation flowback, purging operations, or a productivity test, gas from a well shall be flared or vented only after notice has been given and approval obtained from the Director on a Sundry Notice, Form 4, stating the estimated volume and content of the gas. The notice shall indicate whether the gas contains more than one (1) ppm of hydrogen sulfide. If necessary to protect the public health, safety or welfare, the Director may require the flaring of gas.

c. Gas flared, vented or used on the lease shall be estimated based on a gas-oil ratio test or other equivalent test approved by the Director, and reported on Operator's Monthly Production Report, Form 7.

d. Prior to flaring of any gas, operators shall construct a special purpose pit in compliance with Rule 903.

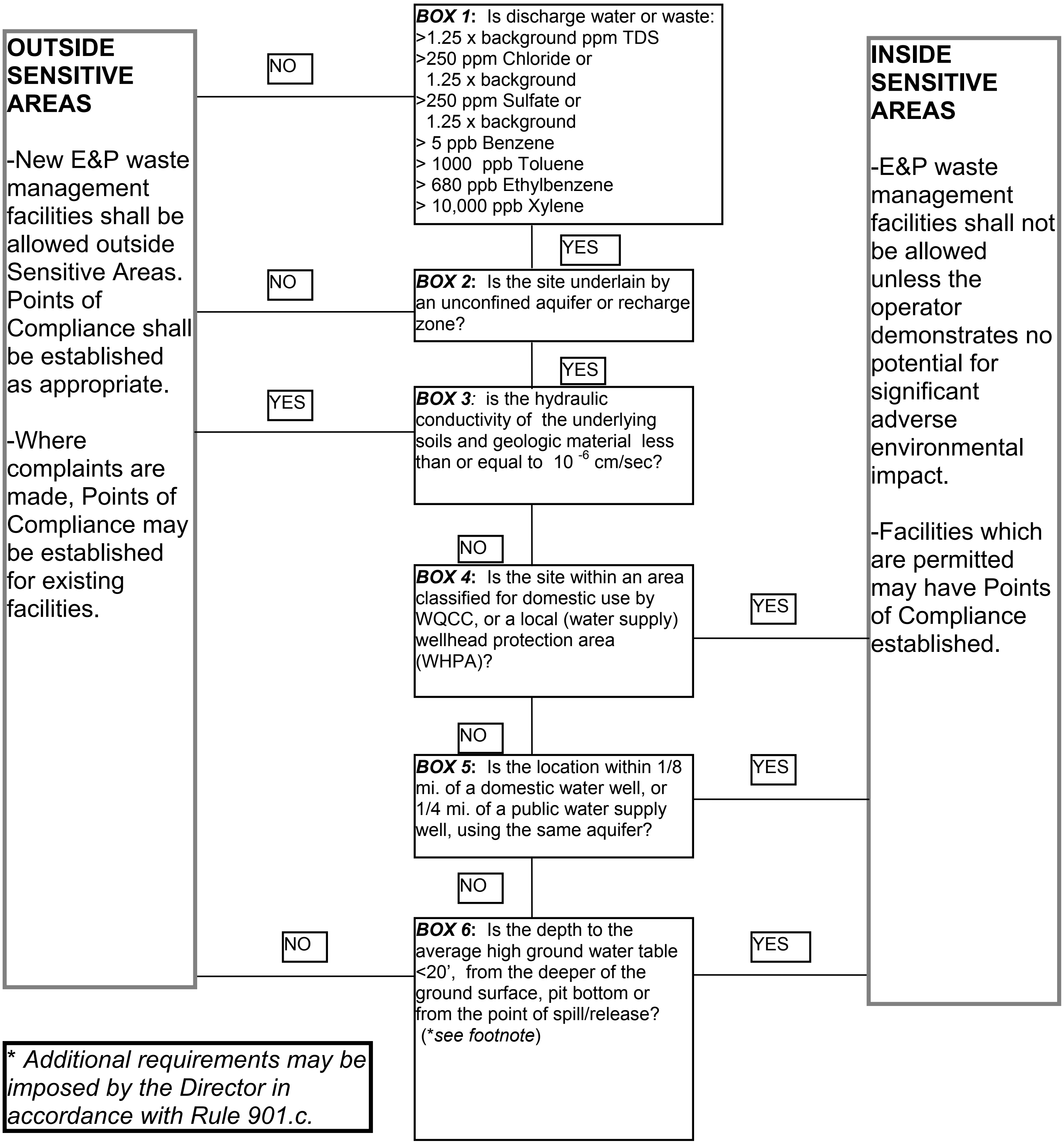
e. Operators shall notify the local emergency dispatch or the local governmental designee of any natural gas flaring. Notice shall be given prior to flaring when flaring can be reasonably anticipated, or as soon as possible but in no event more than two (2) hours after the flaring occurs.

Table 910-1
ALLOWABLE CONCENTRATIONS AND LEVELS

Contaminant of concern	Allowable concentrations
Organics in Soil: EPA Method 8015 (modified)	
TPH-Non-Sensitive Area	10,000 mg/kg
TPH-Sensitive Area	1,000 mg/kg
Organics in Ground Water: EPA Method 8020 [1]	
Benzene	5 μg/l [1]
Toluene	1,000 μg/l [1]
Ethylbenzene	680 μg/l [1]
Xylene	10,000 μg/l [1]
Inorganics in Soils[4]	
Electrical Conductivity (EC)	<4 mmhos/cm or 2x background
Sodium Adsorption Ratio (SAR)	<12
pH	6-9
Inorganics in Ground Water	
Total Dissolved Solids (TDS)	<1.25 x background [1]
Chlorides	<1.25 x background [1]
Sulfates	<1.25 x background [1]
Total Metals in Soils: EPA Method 3050[4]	
Arsenic	41 mg/kg [2]
Barium (LDNR True Total Barium)	180,000 mg/kg [2]
Boron (Hot Water Soluble)	2 mg/l [2]
Cadmium	26 mg/kg [2]
Chromium	1,500 mg/kg [2]
Copper	750 mg/kg [2]
Lead	300 mg/kg [2]
Mercury	17 mg/kg [2]
Molybdenum	[3]
Nickel	210 mg/kg [2]
Selenium	[3]
Silver	100 mg/kg [2]
Zinc	1,400 mg/kg [2]

1 Concentrations taken from CDPHE-WQCC
2 Concentrations taken from API Metals Guidance: Maximum Soil Concentrations
3 Concentrations are dependent on site-specific conditions
4 Consideration shall be given to background levels in native soils

Figure 901-1
SENSITIVE AREA DETERMINATION
Decision Tree



RECLAMATION REGULATIONS

1001. INTRODUCTION

a. **General.** The rules and regulations of this series establish the proper reclamation of the land and soil affected by oil and gas operations and ensure the protection of the topsoil of said land during such operations. The surface of the land shall be restored as nearly as practicable to its condition at the commencement of drilling operations.

b. **Additional requirements.** Notwithstanding the provisions of the 1000 Series rules, when the Director has reasonable cause to believe that a proposed oil and gas operation could result in a significant adverse environmental impact on any air, water, soil, or biological resource, the Director shall conduct an onsite inspection and may request an emergency meeting of the Commission to address the issue.

c. **Surface owner waiver of 1000 Series rules.** The Commission shall not require compliance with Rules 1002., 1003., 1004.a., b., or c.(1), (2), or (3), if the operator can demonstrate to the Director's or the Commission's satisfaction that compliance with such rules is not necessary to protect the public health, safety and welfare, including prevention of significant adverse environmental impacts, and that the operator has entered into an agreement with the surface owner regarding topsoil protection and reclamation of the land. Absent bad faith conduct by the operator, penalties may only be imposed for non-compliance with a Commission order issued after a determination that, notwithstanding such agreement, compliance is necessary to protect public health, safety and welfare. Prior to final reclamation approval as to a specific well, the operator shall either comply with the rules or obtain a variance under Rule 502.b. This rule shall not have the effect of relieving an operator from compliance with the 900 Series rules.

1002. SITE PREPARATION

a. Effective June 1, 1996:

(1) **Fencing of drill sites and access roads on crop lands.** During drilling operations on crop lands, when requested by the surface owner, the operator shall delineate each drillsite and access road on crop lands constructed after such date by berms, single strand fence or other equivalent method in order to discourage unnecessary surface disturbance.

(2) **Fencing of reserve pit when livestock is present.** During drilling operations where livestock is in the immediate area and is not fenced out by existing fences, the operator, at the request of the surface owner, will install a fence around the reserve pit.

(3) **Fencing of well sites.** Subsequent to drilling operations, where livestock is in the immediate area and is not fenced out by existing fences, the operator, at the request of the surface owner, will install a fence around the wellhead, pit and production equipment to prevent livestock entry.

b. **Soil removal and segregation.**

(1) **Soil removal and segregation on crop land.** As to all excavation operations undertaken after June 1, 1996 on crop land, the operator shall separate and store the various A, B, and C soil horizons separately from one another and mark or document stockpile locations to facilitate subsequent reclamation. When separating soil horizons, the operator shall segregate horizons based upon noted changes in physical characteristics such as color, texture, density or consistency. On crop land below the C horizon, the soil horizons shall also be segregated based on the above noted physical characteristics. Segregation will be performed to the extent practicable to a depth of six (6) feet or bedrock, whichever is shallower.

(2) **Soil removal and segregation on non crop land.** As to all excavation operations undertaken after July 1, 1997 on non crop land, the operator shall separate and store the A soil horizon or the top six (6) inches, whichever is deeper, and mark or document stockpile locations to facilitate subsequent reclamation. When separating the A soil horizon, the operator shall segregate the horizon based upon noted changes in physical characteristics such as color, texture, density or consistency.

(3) **Horizons too rocky or too thin.** When the soil horizons are too rocky or too thin for the operator to practicably segregate, then the topsoil shall be segregated to the extent possible and stored. Too rocky shall mean that the soil horizon consists of greater than thirty five percent (35%) by volume rock fragments larger than ten (10) inches in diameter. Too thin shall mean soil horizons that are less than six (6) inches in thickness. The operator shall segregate remaining soils on crop land to the extent practicable to a depth of three (3) feet below the ground surface or bedrock, whichever is shallower, based upon noted changes in

physical characteristics such as color, texture, density or consistency and such soils shall be stockpiled to avoid loss and mixing with other soils.

c. **Protection of soils.** All stockpiled soils shall be protected from degradation due to contamination, compaction and, to the extent practicable, from wind and water erosion during drilling and production operations.

d. **Drill pad location.** The drilling location shall be designed and constructed to provide a safe working area while reasonably minimizing the total surface area disturbed. Consistent with applicable spacing orders and well location orders and regulations, in locating drill pads, steep slopes shall be avoided when reasonably possible. The drill pad site shall be located on the most level location obtainable that will accommodate the intended use. Deep vertical cuts and steep long fill slopes shall be constructed to the least percent slope practical.

e. **Surface disturbance minimization.** In order to reasonably minimize land disturbances and facilitate future reclamation, well sites, production facilities and access roads shall be located, constructed and maintained so as to reasonably control dust, minimize erosion, alteration of natural features and removal of surface materials.

f. **Access roads.** Existing roads shall be used to the greatest extent practicable to avoid erosion and minimize the land area devoted to oil and gas operations. Where feasible and practicable, operators are encouraged to share access roads in developing a field. Where feasible and practicable, roads shall be routed to complement other land usage. To the greatest extent practicable, all vehicles used by the operator, contractors, and other parties associated with the well shall not travel outside of the original access road boundary. Repeated or flagrant instance(s) of failure to restrict lease access to lease roads which result in unreasonable land damage or crop losses shall be subject to a penalty under Rule 523.

1003. INTERIM RECLAMATION

a. General. Debris and waste materials other than de minimis amounts, including, but not limited to, concrete, sack bentonite and other drilling mud additives, sand, plastic, pipe and cable, as well as equipment associated with the drilling, re-entry or completion operations shall be removed. All E&P waste shall be handled according to the 900 Series rules. All pits, cellars, rat holes, and other bore holes unnecessary for further lease operations, excluding the drilling pit, will be backfilled as soon as possible after the drilling rig is released to conform with surrounding terrain. On crop land, if requested by the surface owner, temporary guy line anchors shall be removed as soon as reasonably possible after the completion rig is released. When permanent guy line anchors are installed, it shall not be mandatory to remove them. When permanent guy line anchors are installed on cropland, care shall be taken to minimize disruption of cultivation, irrigation, or harvesting operations. If requested by the surface owner or its representative, the anchors shall be specifically marked, in addition to the marking required below, so as to facilitate farming operations. All guy line anchors left buried for future use shall be identified by a marker of bright color not less than four (4) feet in height and not greater than one (1) foot east of the guy line anchor. Material may be burned or buried on the premises only with the prior written consent of the surface owner, and with prior written notice to the surface tenant. Such burning or burial may be prohibited by other applicable law.

b. **Interim reclamation of areas no longer in use.** All disturbed areas affected by drilling or subsequent operations, except areas reasonably needed for production operations, shall be reclaimed as early and as nearly as practicable to their original condition and shall be maintained to control dust and minimize erosion. As to crop lands, if subsidence occurs in such areas additional topsoil shall be added to the depression and the land shall be re-leveled as close to its original contour as practicable. Interim reclamation shall occur no later than three (3) months on crop land or twelve (12) months on non-crop land after such operations unless the Director extends the time period because of conditions outside the control of the operator.

c. **Compaction alleviation.** All areas compacted by drilling and subsequent oil and gas operations which are no longer needed following completion of such operations shall be cross-ripped. On crop land, such compaction alleviation operations shall be undertaken when the soil moisture at the time of ripping is below thirty-five percent (35%) of field capacity. Ripping shall be undertaken to a depth of eighteen (18) inches unless and to the extent bed rock is encountered at a shallower depth.

d. **Drilling pit closure.** As part of interim reclamation, drilling pits shall be closed in the following manner:

(1) Drilling pit closure on crop land. On crop land water-based bentonitic drilling fluids, except *de minimis* amounts, shall be removed from the drilling pit and disposed of in accordance with the 900 Series rules. Drilling pit reclamation, including the disposal of drilling fluids and cuttings, shall be performed in a manner so as to not result in the formation of an impermeable barrier. Any cuttings removed from the pit for drying shall be returned to the pit prior to backfilling, and no more than *de minimis* amounts may be incorporated into the

surface materials. After the drilling pit is sufficiently dry, the pit shall be backfilled. The backfilling of the drilling pit shall be done to return the soils to their original relative positions.

(2) **Drilling pit closure on non-crop land.** All drilling fluids shall be disposed of in accordance with the 900 Series rules. After the drilling pit is sufficiently dry, the pit shall be backfilled. Materials removed from the pit for drying shall be returned to the pit prior to the backfilling. No more than de minimis amounts may be incorporated into the surface materials. The backfilling of the drilling pit will be done to return the soils to their original relative positions so that the muds and associated solids will be confined to the pit and not squeezed out and incorporated in the surface materials.

(3) **Minimum cover.** On crop lands, a minimum of three (3) feet of backfill cover shall be applied over any remaining drilling pit contents. As to both crop lands and non-crop lands, during the two (2) year period following drilling pit closure, if subsidence occurs over the closed drilling pit location additional topsoil shall be added to the depression and the land shall be re-leveled as close to its original contour as practicable.

e. **Restoration and revegetation.** When a well is completed for production, all disturbed areas no longer needed will be restored and revegetated as soon as practicable.

(1) **Revegetation of crop lands.** All segregated soil horizons removed from crop lands shall be replaced to their original relative positions and contour, and shall be tilled adequately to re-establish a proper seedbed. The area shall be treated if necessary and practicable to prevent invasion of undesirable species and noxious weeds, and to control erosion. Any perennial forage crops that were present before disturbance shall be re-established.

(2) **Revegetation of non-crop lands.** All segregated soil horizons removed from non-crop lands shall be replaced to their original relative positions and contour as near as practicable to achieve erosion control and long-term stability, and shall be tilled adequately in order to establish a proper seedbed. The disturbed area then shall be reseeded in the first favorable season. Reseeding with species consistent with the adjacent plant community is encouraged. In the absence of an agreement between the operator and the affected surface owner as to what seed mix should be used, the operator shall consult with a representative of the local soil conservation district to determine the proper seed mix to use in revegetating the disturbed area. In an area where an operator has drilled or plans to drill multiple wells, in the absence of an agreement between the operator and the affected surface owner, the operator may rely upon previous advice given by the local soil conservation district in determining the proper seed mixes to be used in revegetating each type of terrain upon which operations are to be conducted.

f. **Weed control.** During drilling, production, and reclamation operations, all disturbed areas shall be kept reasonably free of noxious weeds and undesirable species as practicable.

1004. FINAL RECLAMATION OF WELL SITES AND ASSOCIATED PRODUCTION FACILITIES

a. Well sites and associated production facilities. Upon the plugging and abandonment of a well, all pits, mouse and rat holes and cellars shall be backfilled. All debris, abandoned gathering line risers and flowline risers, and surface equipment shall be removed within three (3) months of plugging a well. All access roads to plugged and abandoned wells and associated production facilities shall be closed, graded and recontoured. Culverts and any other obstructions that were part of the access road(s) shall be removed. Well locations, access roads and associated facilities shall be reclaimed. As applicable, compaction alleviation, restoration, and revegetation of well sites, associated production facilities, and access roads shall be performed to the same standards as established for interim reclamation under Rule 1003. Material may be burned or buried on the premises only with the prior written consent of the surface owner, and with prior written notice to the surface tenant. Such burning or burial shall be subject to applicable state and local law. All such reclamation work shall be completed within three (3) months on crop land and twelve (12) months on non-crop land after plugging a well or final closure of associated production facilities. The Director may grant an extension where unusual circumstances are encountered, but every reasonable effort shall be made to complete reclamation before the next local growing season.

b. **Production and special purpose pit closure.** The operator shall comply with the 900 Series rules for the removal or treatment of E&P waste remaining in a production or special purpose pit before the pit may be closed for final reclamation. After any remaining E&P waste is removed or treated, all such pits must be backfilled to return the soils to their original relative positions. As to both crop lands and non-crop lands, if subsidence occurs over closed pit locations, additional topsoil shall be added to the depression and the land shall be re-leveled as close to its original contour as practicable.

c. **Final reclamation threshold for release of financial assurance.** Successful reclamation of the well site and access road will be considered completed when:

(1) On crop land, reclamation has been performed as per Rules 1003. and 1004., and observation by the Director over two growing seasons has indicated no significant unrestored subsidence.

(2) On non-crop land, reclamation has been performed as per Rules 1003. and 1004., and the total cover of live perennial vegetation, excluding noxious weeds, provides sufficient soils erosion control as determined by the Director through a visual appraisal. The Director shall consider the total cover of live perennial vegetation of adjacent or nearby undisturbed land, not including overstory or tree canopy cover, having similar soils, slope and aspect of the reclaimed area.

(3) Disturbances resulting from flow line installations shall be deemed adequately reclaimed when the disturbed area is reasonably capable of supporting the pre-disturbance land use.

(4) A Sundry Notice, Form 4, has been submitted by the operator which describes the final reclamation procedures and any mitigation measures associated with final reclamation performed by the operator, and

(5) A final reclamation inspection has been completed by the Director, there are no outstanding compliance issues relating to Commission rules, regulations, orders, permit conditions or the act, and the Director has notified the operator that final reclamation has been approved.

FLOWLINE REGULATIONS

1101. INSTALLATION AND RECLAMATION

a. **Material**.

(1) After June 1, 1996, materials for pipe and components shall be:

A. Able to maintain the structural integrity of the flowline under temperature, pressure, and other conditions that may be anticipated;

B. Compatible with the material to be transported.

C. A tracer line or location device will be placed adjacent to or in the trench of all buried nonmetallic flowlines to facilitate the location of such pipelines.

b. **Design**. Each component of a flowline shall be designed to prevent failure from corrosion and be able to withstand anticipated operating pressures and other loadings without impairment of its serviceability. The pipe shall have sufficient wall thickness or be installed with adequate protection to withstand anticipated external pressures and loads that will be imposed on the pipe after installation.

c. **Cover**.

(1) All installed flowlines shall have cover sufficient to protect them from damage. On crop land, all flowlines installed after June 1, 1996 shall have a minimum cover of three (3) feet.

(2) Where an underground structure, geologic, economic or other uncontrollable condition prevents flowlines from being installed with minimum cover, or when there is an agreement between the surface owner and the operator, the line may be installed with less than minimum cover or above ground.

d. **Excavation, backfill and reclamation**.

(1) When flowlines cross crop lands, unless waived by the surface owner, the operator shall segregate topsoil while trenching, and trenches shall be backfilled so that the soils will be returned to their original relative positions and contour. This requirement to segregate and backfill topsoil shall not apply to trenches which are twelve (12) inches or less in width. Reasonable efforts shall be made to run flowlines parallel to crop irrigation rows on flood irrigated land.

(2) On crop lands and non-crop lands, flowline trenches will be maintained in order to correct subsidence and reasonably minimize erosion. Interim and final reclamation, including revegetation, shall be performed in accordance with the applicable 1000 Series rules.

e. **Pressure testing**.

(1) Before operating a segment of flowline installed after June 1, 1996, it must be tested to maximum anticipated operating pressure. In conducting tests, each operator shall ensure that reasonable precautions are taken to protect its employees and the general public. The testing may be conducted using well head pressure sources and well bore fluids, including natural gas. Such pressure tests shall be repeated once each calendar year to maximum anticipated operating pressure, and operators shall maintain records of such testing for Commission inspection for at least three (3) years.

(2) Flowline segments operating at less than fifteen (15) psig are excepted from pressure testing requirements.

1102. OPERATIONS, MAINTENANCE, AND REPAIR

a. **Maintenance**.

(1) Each operator shall take reasonable precautions to prevent failures, leakage and corrosion of flowlines.

(2) Whenever an operator discovers any condition that could adversely affect the safe and proper operation of its flowline, it shall correct it within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator shall not operate the affected part of the system until it has corrected the unsafe condition.

b. **Flowline repair**.

(1) Each operator shall, in repairing its flowlines, ensure that the repairs are made in a safe manner and are made so as to prevent injury to persons and damage to property.

(2) No operator shall use any pipe, valve, or fitting in repairing flowline facilities unless the components meet the installation requirements of this section.

c. **Flowline marking**.

(1) In designated high density areas, and where crossing public rights-of-way or utility easement, a marker shall be installed and maintained to identify the location of flowlines installed after June 1, 1996.

(2) The following must be written legibly on a background of sharply contrasting color on each line marker:

"Warning", "Caution" or "Danger" followed by the words "gas (or name of natural gas or petroleum transported) pipeline" in letters at least one (1) inch high with one-quarter (1/4) inch stroke and the name of the operator and the telephone number where the operator can be reached at all times.

d. **One Call participation**. As to flowlines, and any other pipeline over which the Commission has jurisdiction, installed after June 1, 1996, each operator shall participate in Colorado's One Call notification system, the requirements of which are established by §9-1.5-101., C.R.S. et seq.

1103. ABANDONMENT

Each flowline abandoned in place must be disconnected from all sources and supplies of natural gas and petroleum, purged of liquid hydrocarbons, depleted to atmospheric pressure, and cut off three (3) feet below ground surface, or the depth of the flowline, whichever is less and sealed at the ends. This requirement shall also apply to compressor or gas plant feeder pipelines upon decommissioning or closure of a portion or all of a compressor station or gas plant.

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TITLE 19 NATURAL RESOURCES & WILDLIFE
CHAPTER 15 OIL AND GAS
PART 1 GENERAL PROVISIONS AND DEFINITIONS
TITLE 19 NATURAL RESOURCES & WILDLIFE
CHAPTER 15 OIL AND GAS
PART 1 GENERAL PROVISIONS AND DEFINITIONS

19.15.1.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department, Oil Conservation Division, 2040 S. Pacheco, Santa Fe, New Mexico 87505
[2-1-96; 19.15.1.1 NMAC - Rn, 19 NMAC 15.A.1, 5-15-01]

19.15.1.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico.
[2-1-96; 19.15.1.2 NMAC - Rn, 19 NMAC 15.A.2, 5-15-01]

19.15.1.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the Oil and Gas Act which grants the oil conservation division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights, and the disposition of wastes resulting from oil and gas operations.
[2-1-96; 19.15.1.3 NMAC - Rn, 19 NMAC 15.A.3, 5-15-01]

19.15.1.4 DURATION: Permanent
[2-1-96; 19.15.1.4 NMAC - Rn, 19 NMAC 15.A.4, 5-15-01]

19.15.1.5 EFFECTIVE DATE: February 1, 1996.
[2-1-96; 19.15.1.5 NMAC - Rn, 19 NMAC 15.A.5, 5-15-01]

19.15.1.6 OBJECTIVE: To set forth general provisions and definitions pertaining to the authority of the oil Conservation division and the oil conservation commission pursuant to the Oil and Gas Act, NMSA 1978, Sections 70-2-1 through 70-2-38.
[2-1-96; 19.15.1.6 NMAC - Rn, 19 NMAC 15.A.6, 5-15-01]

19.15.1.7 DEFINITIONS:

A. Definitions beginning with the letter “A”.

(1) Abate or abatement shall mean the investigation, containment, removal or other mitigation of water pollution.

(2) Abatement plan shall mean a description of any operational, monitoring, contingency and closure requirements and conditions for the prevention, investigation and abatement of water pollution.

(3) Adjoining spacing units are those existing or prospective spacing units in the same pool(s) that are touching at a point or line the spacing unit that is the subject of the application.

(4) Adjusted allowable shall mean the allowable production a well or proration unit receives after all adjustments are made.

(5) Allocated pool is one in which the total oil or natural gas production is restricted and allocated to various wells therein in accordance with proration schedules.

(6) Allowable production shall mean that number of barrels of oil or standard cubic feet of natural gas authorized by the division to be produced from an allocated pool.

(7) Aquifer shall mean a geological formation, group of formations, or a part of a formation that is capable of yielding a significant amount of water to a well or spring.

B. Definitions beginning with the letter “B”.

(1) Back allowable shall mean the authorization for production of any shortage or underproduction resulting from pipeline proration.

(2) Background shall mean, for purposes of ground-water abatement plans only, the amount of ground-water contaminants naturally occurring from undisturbed geologic sources or water contaminants occurring from a source other than the responsible person's facility. This definition shall not prevent the director from requiring abatement of commingled plumes of pollution, shall not prevent responsible persons from seeking contribution or other legal or equitable relief from other persons, and shall not preclude the director from exercising enforcement authority under any applicable statute, regulation or common law.

(3) Barrel shall mean 42 United States gallons measured at 60 degrees fahrenheit and atmospheric pressure at the sea level.

(4) Barrel of oil shall mean 42 United States gallons of oil, after deductions for the full amount of basic sediment, water and other impurities present, ascertained by centrifugal or other recognized and customary test.

(5) Below-grade tank shall mean a vessel, excluding sumps and pressurized pipeline drip traps, where any portion of the sidewalls of the tank is below the surface of the ground and not visible.

(6) Berm shall mean an embankment or ridge constructed for the purpose of preventing the movement of liquids, sludge, solids, or other materials.

(7) Bottom hole or subsurface pressure shall mean the gauge pressure in pounds per square inch under conditions existing at or near the producing horizon.

(8) Bradenhead gas well shall mean any well producing gas through wellhead connections from a gas reservoir which has been successfully cased off from an underlying oil or gas reservoir.

C. Definitions beginning with the letter “C”.

(1) Carbon dioxide gas shall mean noncombustible gas composed chiefly of carbon dioxide occurring naturally in underground rocks.

(2) Casinghead gas shall mean any gas or vapor or both gas and vapor indigenous to and produced from a pool classified as an oil pool by the division. This also includes gas-cap gas produced from such an oil pool.

(3) Commission shall mean the oil conservation commission.

(4) Common purchaser for natural gas shall mean any person now or hereafter engaged in purchasing from one or more producers gas produced from gas wells within each common source of supply from which it purchases.

(5) Common purchaser for oil shall mean every person now engaged or hereafter engaging in the business of purchasing oil to be transported through pipelines.

(6) Common source of supply. See pool.

(7) Condensate shall mean the liquid recovered at the surface that results from condensation due to reduced pressure or temperature of petroleum hydrocarbons existing in a gaseous phase in the reservoir.

(8) Contiguous shall mean acreage joined by more than one common point, that is, the common boundary must be at least one side of a governmental quarter-quarter section.

(9) Conventional completion shall mean a well completion in which the production string of casing has an outside diameter in excess of 2.875 inches.

(10) Correlative rights shall mean the opportunity afforded, as far as it is practicable to do so, to the owner of each property in a pool to produce without waste his just and equitable share of the oil or gas, or both, in the pool, being an amount, so far as can be practically determined, and so far as can be practicably obtained without waste, substantially in the proportion that the quantity of recoverable oil or gas, or both, under such property bears to the total recoverable oil or gas, or both, in the pool, and for such purpose to use his just and equitable share of the reservoir energy.

(11) Cubic feet of gas or standard cubic foot of gas, for the purpose of these rules, shall mean that volume of gas contained in one cubic foot of space and computed at a base pressure of 10 ounces per square inch above the average barometric pressure of 14.4 pounds per square inch (15.025 psia), at a standard base temperature of 60 degrees fahrenheit.

D. Definitions beginning with the letter “D”.

(1) Deep pool shall mean a common source of supply which is situated 5000 feet or more below the surface.

(2) Depth bracket allowable shall mean the basic oil allowable assigned to a pool and based on its depth, unit size, or special pool rules, which, when multiplied by the market demand percentage factor in effect, will determine the top unit allowable for the pool.

(3) Director shall mean the director of the oil conservation division of the New Mexico energy, minerals and natural resources department.

(4) Division shall mean the oil conservation division of the New Mexico energy, minerals and natural resources department.

E. Definitions beginning with the letter "E".

(1) Exempted aquifer shall mean an aquifer that does not currently serve as a source of drinking water, and which cannot now and will not in the foreseeable future serve as a source of drinking water because: is hydrocarbon producing;

(a) it is hydrocarbon producing;

(b) it is situated at a depth or location which makes the recovery of water for drinking water purposes economically or technologically impractical; or,

(c) it is so contaminated that it would be economically or technologically impractical to render that water fit for human consumption.

(2) Existing spacing unit is a spacing unit containing a producing well.

F. Definitions beginning with the letter "F".

(1) Facility shall mean any structure, installation, operation, storage tank, transmission line, access road, motor vehicle, rolling stock, or activity of any kind, whether stationary or mobile.

(2) Field means the general area which is underlaid or appears to be underlaid by at least one pool; and field also includes the underground reservoir or reservoirs containing such crude petroleum oil or natural gas, or both. The words field and pool mean the same thing when only one underground reservoir is involved; however, field unlike pool may relate to two or more pools.

(3) Fresh water (to be protected) includes the water in lakes and playas, the surface waters of all streams regardless of the quality of the water within any given reach, and all underground waters containing 10,000 milligrams per liter (mg/1) or less of total dissolved solids (TDS) except for which, after notice and hearing, it is found there is no present or reasonably foreseeable beneficial use which would be impaired by contamination of such waters. The water in lakes and playas shall be protected from contamination even though it may contain more than 10,000 mg/1 of TDS unless it can be shown that hydrologically connected fresh ground water will not be adversely affected.

G. Definitions beginning with the letter "G".

(1) Gas lift shall mean any method of lifting liquid to the surface by injecting gas into a well from which oil production is obtained.

(2) Gas-oil ratio shall mean the ratio of the casinghead gas produced in standard cubic feet to the number of barrels of oil concurrently produced during any stated period.

(3) Gas-oil ratio adjustment shall mean the reduction in allowable of a high gas oil ratio unit to conform with the production permitted by the limiting gas-oil ratio for the particular pool during a particular proration period.

(4) Gas transportation facility shall mean a pipeline in operation serving gas wells for the transportation of natural gas, or some other device or equipment in like operation whereby natural gas produced from gas wells connected therewith can be transported or used for consumption.

(5) Gas well shall mean a well producing gas or natural gas from a gas pool, or a well with a gas-oil ratio in excess of 100,000 cubic feet of gas per barrel of oil producing from an oil pool.

(6) Ground water shall mean interstitial water which occurs in saturated earth material and which is capable of entering a well in sufficient amounts to be utilized as a water supply.

H. Definitions beginning with the letter "H".

(1) Hazard to public health exists when water which is used or is reasonably expected to be used in the future as a human drinking water supply exceeds at the time and place of such use, one or more of the numerical standards of Subsection A of 20.6.2.3103 NMAC, or the naturally occurring concentrations, whichever is higher, or if any toxic pollutant as defined at Subsection VV of 20.6.2.7 NMAC affecting human health is present in the water. In determining whether a release would cause a hazard to public health to exist, the director shall investigate and consider the purification and dilution reasonably expected to occur from the time and place of release to the time and place of withdrawal for use as human drinking water.

(2) High gas-oil ratio proration unit shall mean a unit with at least one producing oil well with a gas-oil ratio in excess of the limiting gas-oil ratio for the pool in which the unit is located.

I. Definitions beginning with the letter "I".

(1) Illegal gas shall mean natural gas produced from a gas well in excess of the allowable determined by the division.

(2) Illegal oil shall mean crude petroleum oil produced in excess of the allowable as fixed by the division.

(3) Illegal product shall mean any product of illegal gas or illegal oil.

(4) Inactive well shall be a well which is not being utilized for beneficial purposes such as production, injection or monitoring and which is not being drilled, completed, repaired or worked over.

(5) Injection or input well shall mean any well used for the injection of air, gas, water, or other fluids into any underground stratum.

J. Reserved.

K. Reserved.

L. Definitions beginning with the letter "L".

(1) Limiting gas-oil ratio shall mean the gas-oil ratio assigned by the division to a particular oil pool to limit the volumes of casinghead gas which may be produced from the various oil producing units within that particular pool.

(2) Load oil is any oil or liquid hydrocarbon which has been used in remedial operation in any oil or gas well.

(3) Log or well log shall mean a systematic detailed and correct record of formations encountered in the drilling of a well.

M. Definitions beginning with the letter "M".

(1) Marginal unit shall mean a proration unit which is incapable of producing top unit allowable for the pool in which it is located.

(2) Market demand percentage factor shall mean that percentage factor of 100 percent or less as determined by the division at an oil allowable hearing, which, when multiplied by the depth bracket allowable applicable to each pool, will determine the top unit allowable for that pool.

(3) Mineral estate is the most complete ownership of oil and gas recognized in law and includes all the mineral interests and all the royalty interests.

(4) Mineral interest owners are owners of an interest in the executive rights, which are the rights to explore and develop, including oil and gas lessees (i.e., "working interest owners") and mineral interest owners who have not signed an oil and gas lease.

(5) Minimum allowable shall mean the minimum amount of production from an oil or gas well which may be advisable from time to time to the end that production will repay reasonable lifting cost and thus prevent premature abandonment and resulting waste.

(6) Multiple completion (combination) shall mean a multiple completion in which two or more common sources of supply are produced through a combination of two or more conventional diameter casing strings cemented in a common well-bore, or a combination of small diameter and conventional diameter casing strings cemented in a common well-bore, the conventional diameter strings of which might or might not be a multiple completion (conventional).

(7) Multiple completion (conventional) shall mean a completion in which two or more common sources of supply are produced through one or more strings of tubing installed within a single casing string, with the production from each common source of supply completely segregated by means of packers.

(8) Multiple completion (tubingless) shall mean completion in which two or more common sources of supply are produced through an equal number of casing strings cemented in a common well-bore, each such string of casing having an outside diameter of 2.875 inches or less, with the production from each common source of supply completely segregated by use of cement.

N. Definitions beginning with the letter "N".

(1) Natural gas or gas shall mean any combustible vapor composed chiefly of hydrocarbons occurring naturally in a pool classified by the division as a gas pool.

(2) Non-aqueous phase liquid shall mean an interstitial body of liquid oil, petroleum product, petrochemical, or organic solvent, including an emulsion containing such material.

(3) Non-marginal unit shall mean a proration unit which is capable of producing top unit allowable for the pool in which it is located, and to which has been assigned a top unit allowable.

O. Definitions beginning with the letter "O".

(1) Official gas-oil ratio test shall mean the periodic gas-oil ratio test made by order of the division by such method and means and in such manner as prescribed by the division.

(2) Oil, crude oil, or crude petroleum oil shall mean any petroleum hydrocarbon produced from a well in the liquid phase and which existed in a liquid phase in the reservoir.

(3) Oil field wastes shall mean those wastes produced in conjunction with the exploration, production, refining, processing and transportation of crude oil and/or natural gas and commonly collected at field storage, processing, disposal, or service facilities, and waste collected at gas processing plants, refineries and other processing or transportation facilities.

(4) Oil well shall mean any well capable of producing oil and which is not a gas well as defined herein.

(5) Operator shall mean any person who, duly authorized, is in charge of the development of a lease or the operation of a producing property, or who is in charge of the operation or management of a facility.

(6) Overage or overproduction shall mean the amount of oil or the amount of natural gas produced during a proration period in excess of the amount authorized on the proration schedule.

(7) Owner means the person who has the right to drill into and to produce from any pool, and to appropriate the production either for himself or for himself and another.

P. Definitions beginning with the letter "P".

(1) Penalized unit shall mean a proration unit to which, because of an excessive gas-oil ratio, an allowable has been assigned which is less than top unit allowable for the pool in which it is located and also less than the ability of the well(s) on the unit to produce.

(2) Person shall mean an individual or any other entity including partnerships, corporation, associations, responsible business or association agents or officers, the state or a political subdivision of the state or any agency, department or instrumentality of the United States and any of its officers, agents or employees.

(3) Pit shall mean any surface or sub-surface impoundment, man-made or natural depression, or diked area on the surface. Excluded from this definition are berms constructed around tanks or other facilities solely for the purpose of safety and secondary containment.

(4) Playa lake shall mean a level or nearly level area that occupies the lowest part of a completely closed basin and that is covered with water at irregular intervals, forming a temporary lake.

(5) Pool means any underground reservoir containing a common accumulation of crude petroleum oil or natural gas or both. Each zone of a general structure, which zone is completely separated from any other zone in the structure, is covered by the word "pool" as used herein. "Pool" is synonymous with "common source of supply" and with "common reservoir."

(6) Potential shall mean the properly determined capacity of a well to produce oil, or gas, or both, under conditions prescribed by the division.

(7) Pressure maintenance shall mean the injection of gas or other fluid into a reservoir, either to maintain the existing pressure in such reservoir or to retard the natural decline in the reservoir pressure.

(8) Produced water shall mean those waters produced in conjunction with the production of crude oil and/or natural gas and commonly collected at field storage, processing, or disposal facilities including but not limited to: lease tanks, commingled tank batteries, burn pits, LACT units, and community or lease salt water disposal systems and which may be collected at gas processing plants, pipeline drips and other processing or transportation facilities.

(9) Producer shall mean the owner of a well or wells capable of producing oil or natural gas or both in paying quantities.

(10) Product means any commodity or thing made or manufactured from crude petroleum oil or natural gas, and all derivatives of crude petroleum oil or natural gas, including refined crude oil, crude tops, topped crude, processed crude petroleum, residue from crude petroleum, cracking stock, uncracked fuel oil, treated crude oil, fuel oil, residuum, gas oil, naphtha, distillate, gasoline, kerosene, benzene, wash oil, lubricating oil, and blends or mixtures of crude petroleum oil or natural gas or any derivative thereof.

(11) Proration day shall consist of 24 consecutive hours which shall begin at 7 a.m. and end at 7 a.m. on the following day. The language in this paragraph is different than that which was filed 02-28-97 (effective

(12) Proration month shall mean the calendar month which shall begin at 7 a.m. on the first day of such month and end at 7 a.m. on the first day of the next succeeding month.

(13) Proration period shall mean for oil the proration month and for gas the twelve-month period which shall begin at 7 a.m. on January 1 of each year and end at 7 a.m. on January 1 of the succeeding year or other period designated by general or special order of the division.

(14) Proration schedule shall mean the order of the division authorizing the production, purchase, and transportation of oil, casinghead gas, and natural gas from the various units of oil or of natural gas in allocated pools.

(15) Proration unit is the area in a pool that can be effectively and efficiently drained by one well as determined by the division or commission (See NMSA 1978 Section 70-2-17.B) as well as the area assigned to an individual well for the purposes of allocating allowable production pursuant to a prorationing order for the pool. A proration unit will be the same size and shape as a spacing unit. All proration units are spacing units but not all spacing units are proration units.

(16) Prospective spacing unit is a hypothetical spacing unit that does not yet have a producing well.

Q. Reserved.

R. Definitions beginning with the letter "R".

(1) Recomplete shall mean the subsequent completion of a well in a different pool from the pool in which it was originally completed.

(2) Regulated naturally occurring radioactive material (regulated NORM) shall mean naturally occurring radioactive material (NORM) contained in any oil-field soils, equipment, sludges or any other materials related to oil-field operations or processes exceeding the radiation levels specified in 20.3.14.1403 NMAC.

(3) Release shall mean all breaks, leaks, spills, releases, fires or blowouts involving crude oil, produced water, condensate, drilling fluids, completion fluids or other chemical or contaminant or mixture thereof, including oil field wastes and natural gases to the environment.

(4) Remediation plan shall mean a written description of a program to address unauthorized releases. The plan may include appropriate information, including assessment data, health risk demonstrations, and corrective action(s). The plan may also include an alternative proposing no action beyond the submittal of a spill report.

(5) Responsible person shall mean the owner or operator who must complete division approved corrective action for pollution from releases.

(6) Royalty interest owners are owners of an interest in the non-executive rights including lessors, royalty interest owners and overriding royalty interest owners. Royalty interests are non-cost bearing.

S. Definitions beginning with the letter "S".

(1) Secondary recovery shall mean a method of recovering quantities of oil or gas from a reservoir which quantities would not be recoverable by ordinary primary depletion methods.

(2) Shallow pool shall mean a pool which has a depth range from 0 to 5000 feet.

(3) Shortage or underproduction shall mean the amount of oil or the amount of natural gas during a proration period by which a given proration unit failed to produce an amount equal to that authorized in the proration schedule.

(4) Shut-in shall be the status of a production well or an injection well which is temporarily closed down, whether by closing a valve or disconnection or other physical means.

(5) Shut-in pressure shall mean the gauge pressure noted at the wellhead when the well is completely shut in, not to be confused with bottom hole pressure.

(6) Significant modification of an abatement plan shall mean a change in the abatement technology used excluding design and operational parameters, or relocation of 25% or more of the compliance sampling stations, for any single medium, as designated pursuant to Subsection E, Paragraph (4), Subparagraph (b), Subsubparagraph (iv) of Section 19.15.5.19 NMAC.

(7) Spacing unit is the area allocated to a well under a well spacing order or rule. Under the Oil & Gas Act, NMSA 1978, Section 70-2-12.B(10), the commission has the power to fix spacing units without first creating proration units. See *Rutter & Wilbanks Corp. v. Oil Conservation Comm'n*, 87 NM 286 (1975). This is the area designated on division form C-102.

(8) Subsurface water shall mean ground water and water in the vadose zone that may become ground water or surface water in the reasonably foreseeable future or may be utilized by vegetation.

T. Definitions beginning with the letter "T".

(1) Tank bottoms shall mean that accumulation of hydrocarbon material and other substances which settles naturally below crude oil in tanks and receptacles that are used in handling and storing of crude oil, and which accumulation contains in excess of two (2%) percent of basic sediment and water; provided, however, that with respect to lease production and for lease storage tanks, a tank bottom shall be limited to that volume of the tank in which it is contained that lies below the bottom of the pipeline outlet thereto.

(2) Temporary abandonment shall be the status of a well which is inactive and has been approved for temporary abandonment in accordance with the provisions of these rules.

(3) Top unit allowable for gas shall mean the maximum number of cubic feet of natural gas, for the proration period, allocated to a gas producing unit in an allocated gas pool.

(4) Top unit allowable for oil shall mean the maximum number of barrels for oil daily for each calendar month allocated on a proration unit basis in a pool to non-marginal units. The top unit allowable for a pool shall be determined by multiplying the applicable depth bracket allowable by the market demand percentage factor in effect.

(5) Treating plant shall mean any plant constructed for the purpose of wholly or partially or being used wholly or partially for reclaiming, treating, processing, or in any manner making tank bottoms or any other waste oil marketable.

(6) Tubingless completion shall mean a well completion in which the production string of casing has an outside diameter of 2.875 inches or less.

U. Definitions beginning with the letter "U".

(1) Underground source of drinking water shall mean an aquifer which supplies water for human consumption or which contains ground water having a total dissolved solids concentration of 10,000 mg/1 or less and which is not an exempted aquifer.

(2) Unit of proration for gas shall consist of such multiples of 40 acres as may be prescribed by special pool rules issued by the division.

(3) Unit of proration for oil shall consist of one 40-acre tract or such multiples of 40-acre tracts as may be prescribed by special pool rules issued by the division.

(4) Unorthodox well location shall mean a location which does not conform to the spacing requirements established by the rules and regulations of the division.

V. Definitions beginning with the letter "V". Vadose zone shall mean unsaturated earth material below the land surface and above ground water, or in between bodies of ground water.

W. Definitions beginning with the letter "W".

(1) Waste, in addition to its ordinary meaning, shall include:

(a) underground waste as those words are generally understood in the oil and gas business, and in any event to embrace the inefficient, excessive, or improper use or dissipation of the reservoir energy, including gas energy and water drive, of any pool, and the locating, spacing, drilling, equipping, operating, or producing, of any well or wells in a manner to reduce or tend to reduce the total quantity of crude petroleum oil or natural gas ultimately recovered from any pool, and the use of inefficient underground storage of natural gas;

(b) surface waste as those words are generally understood in the oil and gas business, and in any event to embrace the unnecessary or excessive surface loss or destruction without beneficial use, however caused, of natural gas of any type or in any form, or crude petroleum oil, or any product thereof, but including the loss or destruction, without beneficial use, resulting from evaporation, seepage, leakage, or fire, especially such loss or destruction incident to or resulting from the manner of spacing, equipping, operating or producing a well or wells, or incident to or resulting from the use of inefficient storage or from the production of crude petroleum oil or natural gas, in excess of the reasonable market demand;

(c) the production of crude petroleum oil in this state in excess of the reasonable market demand for such crude petroleum oil; such excess production causes or results in waste which is prohibited by the Oil and Gas Act; the words "reasonable market demand" as used herein with respect to crude petroleum oil, shall be construed to mean the demand for such crude petroleum oil, for reasonable current requirements for current consumption and use within or outside of the state, together with the demand of such amounts as are reasonably necessary for building up or maintaining reasonable storage reserves of crude petroleum oil or the products thereof, or both such crude petroleum oil and products;

(d) the non-ratable purchase or taking of crude petroleum oil in this state; such non-ratable taking and purchasing causes or results in waste, as defined in Subparagraphs (a), (b), and (c) of this definition and causes waste by violating Section 70-2-16 of the Oil and Gas Act;

(e) the production in this state of natural gas from any gas well or wells, or from any gas pool, in excess of the reasonable market demand from such source for natural gas of the type produced or in excess of the capacity of gas transportation facilities for such type of natural gas; the words "reasonable market demand," as used herein with respect to natural gas, shall be construed to mean the demand for natural gas for reasonable current requirements, for current consumption and for use within or outside the state, together with the demand for such amounts as are necessary for building up or maintaining reasonable storage reserves of natural gas or products thereof, or both such natural gas and products.

(2) Water shall mean all water including water situated wholly or partly within or bordering upon the state, whether surface or subsurface, public or private, except private waters that do not combine with other surface or subsurface water.

(3) Water contaminant shall mean any substance that could alter if released or spilled the physical, chemical, biological or radiological qualities of water. "Water contaminant" does not mean source, special nuclear or by-product material as defined by the Atomic Energy Act of 1954.

(4) Watercourse shall mean any lake bed, or gully, draw, stream bed, wash, arroyo, or natural or human-made channel through which water flows or has flowed.

(5) Water pollution shall mean introducing or permitting the introduction into water, either directly or indirectly, of one or more water contaminants in such quantity and of such duration as may with reasonable probability injure human health, animal or plant life or property, or to unreasonably interfere with the public welfare or the use of property.

(6) Well blowout shall mean a loss of control over and subsequent eruption of any drilling or workover well or the rupture of the casing, casinghead, or wellhead or any oil or gas well or injection or disposal well, whether active or inactive, accompanied by the sudden emission of fluids, gaseous or liquids, from the well.

(7) Wellhead protection area shall mean the area within 200 horizontal feet of any private, domestic fresh water well or spring used by less than five households for domestic or stock watering purposes or within1000 horizontal feet of any other fresh water well or spring. Wellhead protection areas shall not include areas around water wells drilled after an existing oil or natural gas waste storage, treatment, or disposal site was established.

(8) Wetlands shall mean those areas that are inundated or saturated by surface or groundwater at a frequency and duration sufficient to support, and under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil conditions in New Mexico. Constructed wetlands used for wastewater treatment purposes are not included in this definition.

(9) Working interest owners are the owners of the operating interest under an oil and gas lease who have the exclusive right to exploit the oil & gas minerals. Working interests are cost bearing.

[1-5-50…2-1-96; A, 7-15-96; Rn, 19 NMAC 15.A.7.1 through 7.84, 3-15-97; A, 7-15-99; 19.15.1.7 NMAC - Rn, 19 NMAC 15.A.7, 5-15-001; A, 3/31/04]

19.15.1.8-10 [RESERVED]

19.15.1.11 SCOPE OF RULES:

A. The following rules of statewide application have been adopted by the commission to conserve the natural resources of the state of New Mexico, to prevent waste, to protect correlative rights, to protect public health and the environment and to otherwise implement the Oil and Gas Act, NMSA 1978, Section 70-2-1 through 70-2-38.

B. Orders, including special pool orders (formerly referred to as "special pool rules and regulations"), of the division or the commission may be issued when required and shall prevail against rules if in conflict with them.

[1-1-50...2-1-96; A, 7-15-99; 19.15.1.11 NMAC - Rn, 19 NMAC 15.A.11, 5-15-01]

19.15.1.12 ENFORCEMENT OF STATUTES AND RULES:

The division is charged with the duty and obligation of enforcing all rules and statutes of the state of New Mexico relating to the conservation of oil and gas including the protection of public health and the environment. However, it shall be the responsibility of all the owners or operators to obtain information pertaining to the regulation of oil and gas before operations begin.

[1-1-50...2-1-96; A, 7-15-99; 19.15.1.12 NMAC - Rn, 19 NMAC 15.A.12, 5-15-01]

19.15.1.13 GENERAL OPERATIONS/WASTE PROHIBITED:

A. The production or handling of crude petroleum oil or natural gas of any type or in any form, or the handling of products thereof, in such a manner or under such conditions or in such amount as to constitute or result in waste is hereby prohibited.

B. All operators, contractors, drillers, carriers, gas distributors, service companies, pipe pulling and salvaging contractors, treating plant operators or other persons shall at all times conduct their operations in or related to the drilling, equipping, operating, producing, plugging and abandonment of oil, gas, injection, disposal, and storage wells or other facilities in a manner that will prevent waste of oil and gas, the contamination of fresh waters and shall not wastefully utilize oil or gas, or allow either to leak or escape from a natural reservoir, or from wells, tanks, containers, pipe or other storage, conduit or operating equipment.

[1-1-50...2-1-96; 19.15.1.13 NMAC - Rn, 19 NMAC 15.A.13, 5-15-01]

19.15.1.14 UNITED STATES GOVERNMENT LEASES:

Operator shall file or cause to be filed with the division copies of "application for permit to drill, deepen or plug back," (BLM form no. 3160-3), "sundry notices and reports on wells," (BLM form no. 3160-5), and "well completion or recompletion report and log," (BLM form no. 3160-4), as approved by the bureau of land management for wells on U.S. government land.

[1-1-50...2-1-96; 19.15.1.14 NMAC - Rn, 19 NMAC 15.A.14, 5-15-01]

19.15.1.15 CLASSIFYING AND DEFINING POOLS:

The division will determine whether a particular well or pool is a gas or oil well, or a gas or oil pool, as the case may be, and from time to time classify and reclassify wells and name pools accordingly, and will determine the limits of any pool or pools producing crude petroleum oil or natural gas and from time to time redetermine such limits.

[1-1-50...2-1-96; 19.15.1.15 NMAC - Rn, 19 NMAC 15.A.15, 5-15-01]

19.15.1.16 FORMS UPON REQUEST:

Forms for written notices, requests and reports required by the division will be furnished upon request.

[1-1-50...2-1-96; 19.15.1.16 NMAC - Rn, 19 NMAC 15.A.16, 5-15-01]

19.15.1.17 AUTHORITY TO COOPERATE WITH OTHER AGENCIES:

The division may from time to time enter into arrangements with state and federal governmental agencies, industry

committees and individuals, with respect to special projects, services and studies relating to conservation of oil and gas and the associated protection of fresh waters.
[1-1-50...2-1-96; 19.15.1.17 NMAC - Rn, 19 NMAC 15.A.17, 5-15-01]

19.15.1.18 [RESERVED.]
[9-23-85; 9-1-89...2-1-96; 19.15.1.18 NMAC - Rn, 19 NMAC 15.A.18, 5-15-01; Repealed, 5-28-04]

19.15.1.19 PREVENTION AND ABATEMENT OF WATER POLLUTION:

A. Purpose

(1) The purpose of this rule are to:

(a) Abate pollution of subsurface water so that all ground water of the state of New Mexico which has a background concentration of 10,000 mg/L or less TDS, is either remediated or protected for use as domestic, industrial and agricultural water supply, and to remediate or protect those segments of surface waters which are gaining because of subsurface-water inflow, for uses designated in the water quality standards for interstate and intrastate surface waters in New Mexico (20.6.4 NMAC); and

(b) Abate surface-water pollution so that all surface waters of the state of New Mexico are remediated or protected for designated or attainable uses as defined in the water quality standards for interstate and intrastate surface waters in New Mexico (20.6.4 NMAC).

(2) If the background concentration of any water contaminant exceeds the standard or requirement of Section 19.15.1.19 NMAC, Subsection B, Paragraphs (1), (2) or (3) pollution shall be abated by the responsible person to the background concentration.

(3) The standards and requirements set forth in of Section 19.15.1.19 NMAC, Subsection B, Paragraphs (1), (2) or (3) are not intended as maximum ranges and concentrations for use, and nothing herein contained shall be construed as limiting the use of waters containing higher ranges and concentrations.

B. Abatement standards and requirements

(1) The vadose zone shall be abated so that water contaminants in the vadose zone will not with reasonable probability contaminate ground water or surface water, in excess of the standards in Paragraphs (2) and (3) below, through leaching, percolation, or other transport mechanisms, or as the water table elevation fluctuates.

(2) Ground-water pollution at any place of withdrawal for present or reasonably foreseeable future use, where the TDS concentration is 10,000 mg/L or less, shall be abated to conform to the following standards:

(a) Toxic pollutant(s) as defined in 20.6.2.7 NMAC shall not be present; and

(b) The standards of 20.6.2.3103 NMAC shall be met.

(3) Surface-water pollution shall be abated to conform to the water quality standards for interstate and intrastate surface waters in New Mexico 20.6.4 NMAC.

(4) Subsurface-water and surface-water abatement shall not be considered complete until eight (8) consecutive quarterly samples, or an alternate lesser number of samples approved by the director, from all compliance sampling stations approved by the director meet the abatement standards of Paragraphs (1), (2) and (3) above. Abatement of water contaminants measured in solid-matrix samples of the vadose zone shall be considered complete after one-time sampling from compliance stations approved by the director.

(5) Technical infeasibility

(a) If any responsible person is unable to fully meet the abatement standards set forth in Paragraphs (1) and (2) above using commercially accepted abatement technology pursuant to an approved abatement plan, he may propose that abatement standards compliance is technically infeasible. Technical infeasibility proposals involving the use of experimental abatement technology shall be considered at the discretion of the director. Technical infeasibility may be demonstrated by a statistically valid extrapolation of the decrease in concentration(s) of any water contaminant(s) over the remainder of a twenty (20) year period, such that projected future reductions during that time would be less than 20% of the concentration(s) at the time technical infeasibility is proposed. A statistically valid decrease cannot be demonstrated by fewer than eight (8) consecutive quarters. The technical infeasibility proposal shall include a substitute abatement standard(s) for those contaminants that is/are technically feasible. Abatement standards for all other water contaminants not demonstrated to be technically infeasible shall be met.

(b) In no event shall a proposed technical infeasibility demonstration be approved by the director for any water contaminant if its concentration is greater than 200% of the abatement standard for the contaminant.

(c) If the director cannot approve any or all portions of a proposed technical infeasibility demonstration because the water contaminant concentration(s) is/are greater than 300% of the abatement standard(s) for each contaminant, the responsible person may further pursue the issue of technical infeasibility by filing a petition with the division seeking approval of alternate abatement standard(s) pursuant to Paragraph (6) below.

(6) Alternative abatement standards

(a) At any time during or after the submission of a stage 2 abatement plan, the responsible person may file a petition seeking approval of alternative abatement standard(s) for the standards set forth in Paragraphs (1) and (2) above. The division may approve alternative abatement standard(s) if the petitioner demonstrates that:

(i) either: compliance with the abatement standard(s) is/are not feasible, by the maximum use of technology within the economic capability of the responsible person; or there is no reasonable relationship between the economic and social costs and benefits (including attainment of the standard(s) set forth in Subsection B of Section 19.15.1.19 NMAC to be obtained, and

(ii) the proposed alternative abatement standard(s) is/are technically achievable and cost-benefit justifiable; and

(iii) compliance with the proposed alternative abatement standard(s) will not create a present or future hazard to public health or undue damage to property.

(b) The petition shall be in writing, filed with the division environmental bureau chief. The petition may include a transport, fate and risk assessment in accordance with accepted methods, and other information as the petitioner deems necessary to support the petition. The petition shall:

(i) state the petitioner's name and address;

(ii) state the date of the petition;

(iii) describe the facility or activity for which the alternate abatement standard(s) is sought;

(iv) state the address or description of the property upon which the facility is located;

(v) describe the water body or watercourse affected by the release;

(iv) identify the abatement standard from which petitioner wishes to vary;

(vii) state why the petitioner believes that compliance with the regulation will impose an unreasonable burden upon his activity;

(viii) identify the water contaminant(s) for which alternative standard(s) is/are proposed;

(ix) state the alternative standard(s) proposed;

(x) identify the three-dimensional body of water pollution for which approval is sought;

(xi) state the extent to which the abatement standard(s) set forth in Subsection B of 19.15.1.19 NMAC is/are now, and will in the future be, violated.

(c) The division environmental bureau chief shall review the petition and, within sixty (60) days after receiving the petition, shall submit a written recommendation to the director to approve, approve subject to conditions, or disapprove any or all of the proposed alternative abatement standard(s). The recommendation shall include the reasons for the division environmental bureau chief's recommendation. The division environmental bureau chief shall submit a copy of the recommendation to the petitioner by certified mail.

(d) If the division environmental bureau chief recommends approval, or approval subject to conditions, of any or all of the proposed alternative abatement standard(s), the division shall hold a public hearing on those standards. If the division environmental bureau chief recommends disapproval of any or all of the proposed alternative abatement standard(s), the petitioner may submit a request to the director, within fifteen (15) days after receipt of the recommendation, for a public hearing on those standards. If a timely request for hearing is not submitted, the recommended disapproval shall become a final decision of the director and shall not be subject to review.

(e) If the director grants a public hearing, the hearing shall be conducted in accordance with division hearing procedures.

(f) Based on the record of the public hearing, the division shall approve, approve subject to condition, or disapprove any or all of the proposed alternative abatement standard(s). The division shall notify the petitioner by certified mail of its decision and the reasons therefore.

(7) Modification of abatement standards. If applicable abatement standards are modified after abatement measures are approved, the abatement standards are modified after abatement measures are approved, the abatement standards that are in effect at the time that abatement measures are approved shall be the abatement standards for the duration of the abatement action, unless the director determines that compliance with those standards may with reasonable probability create a present or future hazard to public health or the environment. In any appeal of the director's determination that additional actions are necessary, the director shall have the burden of proof.

C. Abatement plan required

(1) Unless otherwise provided by Section 19.15.1.19 NMAC all responsible persons who are abating, or who are required to abate, water pollution in excess of the standards and requirements set forth in Subsection B of Section 19.15.1.19 NMAC shall do so pursuant to an abatement plan approved by the director. When an abatement plan has been approved, all actions leading to and including abatement shall be consistent with the terms and conditions of the abatement plan.

(2) In the event of a transfer of the ownership, control or possession of a facility for which an abatement plan is required or approved, where the transferor is a responsible person, the transferee also shall be considered a responsible person for the duration of the abatement plan, and may jointly share the responsibility to conduct the actions required by Section 19.15.1.19 NMAC with other responsible persons. The transferor shall notify the transferee in writing, at least thirty (30) days prior to the transfer, that abatement plan has been required or approved for the facility, and shall deliver or send by certified mail to the director a copy of such notification together with a certificate or other proof that such notification has in fact been received by the transferee. The transferor and transferee may agree to a designated responsible person who shall assume the responsibility to conduct the actions required by Section 19.15.1.19 NMAC. The responsible persons shall notify the director in writing if a designated responsible person is agreed upon. If the director determines that the designated responsible person has failed to conduct the actions required by Section 19.15.1.19 NMAC, the director shall notify all responsible persons of this failure in writing and allow them thirty (30) days, or longer for good cause shown, to conduct the required actions before setting a show cause hearing requiring those responsible persons to appear and show cause why they should not be ordered to comply, a penalty should not be assessed, a civil action should not be commenced in district court or any other appropriate action should not be taken by the division.

(3) If the source of the water pollution to be abated is a facility that operated under a discharge plan, the director may require the responsible person(s) to submit a financial assurance plan which covers the estimated costs to conduct the actions required by the abatement plan. Such a financial assurance plan shall be consistent with any financial assurance requirements adopted by the division.

D. Exemptions from abatement plan requirement

(1) Except a provided in Paragraph (2) below, Subsections C and E do not apply to a person who is abating water pollution:

(a) from an underground storage tank, under the authority of the underground storage tank regulations (Title 20, Chapter 5) adopted by the New Mexico environmental improvement board, or in accordance with the New Mexico Ground Water Protection Act;

(b) under the authority of the U.S. environmental protection agency pursuant to either the Federal Comprehensive Environmental Response, Compensation and Liability Act, and amendments, or the Resource Conservation and Recovery Act;

(c) pursuant to the hazardous waste management regulations (20.4.1 NMAC) adopted by the New Mexico environmental improvement board;

(d) under the authority of the U.S. nuclear regulatory commission or the U.S. department of energy pursuant to the Atomic Energy Act;

(e) under the authority of a ground-water discharge plan approved by the director, provided that such abatement is consistent with the requirements and provisions of Section 19.15.1.19 NMAC, Subsections A, B and E, Paragraphs (3) and (4), and Subsections F and K.

(f) under the authority of a letter of understanding, settlement agreement or administrative order on consent or other agreement signed by the director or his designee prior to **(insert effective date of rule),** 1997, provided that abatement is being performed in full compliance with the terms of the letter of understanding, settlement agreement or administrative order or other agreement on consent; and

(g) on an emergency basis, or while abatement plan approval is pending, or in a manner that will likely result in compliance with the standards and requirements set forth in Subsection B within one year after notice is required to be given pursuant to Subsection B of 19.15.3.116 NMAC provided that the division does not object to the abatement action.

(2) If the director determines that abatement of water pollution subject to Section 19.15.1.19 NMAC, Subsection D, Paragraph (1) will not met the standards of Section 19.15.1.19 NMAC, Subsection B, Paragraphs (2) and (3) or that additional action is necessary to protect health, welfare, environment or property, the director may notify a responsible person, by certified mail, to submit an abatement plan pursuant to Section 19.15.1.19 NMAC, Subsections C and E, Paragraph (1). The notification shall state the reasons for the director's determination. In any appeal of the director's determination under this Paragraph, the director shall have the burden of proof.

E. Abatement plan proposal

(1) Except as provided for in Subsection D of 19.15.1.19 NMAC a responsible person shall, within sixty (60) days of receipt of written notice from the director that an abatement plan is required, submit an abatement plan proposal to the director for approval. Stage 1 and stage 2 abatement plan proposals may be submitted together. For good cause shown, the director may allow for a total of one hundred and twenty (120) days to prepare and submit the abatement plan proposal.

(2) Voluntary abatement

(a) any person wishing to abate water pollution in excess of the standards and requirements set forth in Subsection B of Section 19.15.1.19 NMAC may submit a stage 1 abatement plan proposal to the director for approval. Following approval by the director of a final site investigation report prepared pursuant to stage 1 of an abatement plan, any person may submit a stage 2 abatement plan proposal to the director for approval.

(b) Following approval of a stage 1 or stage 2 abatement plan proposal under E(2)(a) above, the person submitting the approved plan shall be a responsible person under Section 19.15.1.19 NMAC for the purpose of performing the approved stage 1 or stage 2 abatement plan. Nothing in Section 19.15.1.19 NMAC shall preclude the director from applying Subsection D of 19.15.3.116 NMAC to a responsible person if applicable.

(3) Stage 1 abatement plan. The purpose of stage 1 of the abatement plan shall be to design and conduct a site investigation that will adequately define site conditions, and provide the data necessary to select and design an effective abatement option. Stage 1 of the abatement plan may include, but not necessarily be limited to, the following information depending on the media affected, and as needed to select and implement an expeditious abatement option:

(a) Descriptions of the site, including a site map, and of site history including the nature of the release that caused the water pollution, and a summary of previous investigations;

(b) Site investigation work plan to define:

(i) site geology and hydrogeology, the vertical and horizontal extent and magnitude of vadose-zone and ground-water contamination, subsurface hydraulic conductivity, transmissivity, storativity, and rate and direction of contaminant migration, inventory of water wells inside and within one (1) mile from the perimeter of the three-dimensional body where the standards set forth in Subsection B, Paragraph (2) are exceeded, and location and number of such wells actually or potentially affected by the pollution; and

(ii) surface-water hydrology, seasonal stream flow characteristics, groundwater/surface-water relationships, the vertical and horizontal extent and magnitude of contamination and impacts to surface water and stream sediments. The magnitude of contamination and impacts on surface water may be, in part, defined by conducting a biological assessment of fish, benthic macro invertebrates and other wildlife populations. Seasonal ariations should be accounted for when conducting these assessments.

(c) Monitoring program, including sampling stations and frequencies, for the duration of the abatement plan that may be modified, after approval by the director, as additional sampling stations are created;

(d) Quality assurance plan, consistent with the sampling and analytical techniques listed in Subsection B of 20.6.2.3107 NMAC and with 20.6.4.13 NMAC of the water quality standards for interstate and intrastate surface waters in New Mexico 20.6.4 NMAC, for all work to be conducted pursuant to the abatement plan;

(e) A schedule for all stage 1 abatement plan activities, including the submission of summary quarterly progress reports, and the submission, for approval by the director, of a detailed final site investigation report; and

(f) Any additional information that may be required to design and perform an adequate site investigation.

(4) Stage 2 abatement plan

(a) Any responsible person shall submit a stage 2 abatement plan proposal to the director for approval within sixty (60) days, or up to one hundred and twenty (120) days for good cause shown, after approval by the director of the final site investigation report prepared pursuant to stage 1 of the abatement plan. A stage 1 and 2 abatement plan proposal may be submitted together. The purpose of stage 2 of the abatement plan shall be to select and design, if necessary, an abatement option that, when implemented, will result in attainment of the abatement standards and requirements set forth in Section 19.15.1.19 NMAC, Subsection B including post-closure maintenance activities.

(b) Stage 2 of the abatement plan should include, at a minimum, the following information:

(i) brief description of the current situation at the site;

(ii) development and assessment of abatement options;

(iii) description, justification and design, if necessary, of preferred abatement option;

(iv) modification, if necessary, of the monitoring program approved pursuant to stage 1 of the abatement plan, including the designation of pre- and post-abatement-completion sampling stations and sampling frequencies to be used to demonstrate compliance with the standards and requirements set forth in Subsection B of Section 19.15.1.19 NMAC;

(v) site maintenance activities, if needed, proposed to be performed after termination of abatement activities;

(vi) a schedule for the duration of abatement activities, including the submission of summary quarterly progress reports;

(vii) a public notification proposal designed to satisfy the requirements of Section 19.15.1.19 NMAC, Subsection G, Paragraphs (2) and (3);

(viii) any additional information that may be reasonably required to select, describe, justify and design an effective abatement option.

F. Other requirements

(1) Any responsible person shall allow any authorized representative of the director, upon presentation of proper credentials and with reasonable prior notice, to:

(a) enter the facility at reasonable times;

(b) inspect and copy records required by an abatement plan;

(c) inspect any treatment works, monitoring and analytical equipment;

(d) sample any wastes, ground water, surface water, stream sediment, plants, animals, or vadose-zone material including vadose-zone vapor;

(e) use monitoring systems and wells under such responsible person's control in order to collect samples of any media listed in Subparagraph (d) above; and

(f) gain access to off-site property not owned or controlled by such responsible person, but accessible to such responsible person through a third-party access agreement, provided that it is allowed by the agreement.

(2) Any responsible person shall provide the director, or a representative of the director, with at least four (4) working days advance notice of any sampling to be performed pursuant to an abatement plan, or any well plugging, abandonment or destruction at any facility where an abatement plan has been required.

(3) Any responsible person wishing to plug, abandon or destroy a monitoring or water supply well within the perimeter of the 3-dimensional body where the standards set forth in Section 19.15.1.19 NMAC, Subsection B, Paragraph (2) of are exceeded, at any facility where an abatement plan has been required, shall propose such action by certified mail to the director for approval, unless such approval is required from the state engineer. The proposed action shall be designed to prevent water pollution that could result from water contaminants migrating through the well or borehole. The proposed action shall not take place without written approval from the director, unless written approval or disapproval is not received by the responsible person within thirty (30) days of the date of receipt of the proposal.

G. Public notice and participation

(1) Prior to public notice, the applicant shall give written notice, as approved by the division, of stage 1 and stage 2 abatement plans to the following persons:

(a) surface owners of record within one (1) mile of the perimeter of the geographic area where the standards and requirements set forth in Subsection B of Section 19.15.1.19 NMAC are exceeded;

(b) the county commission where the geographic area where the standards and requirements set forth in Subsection B of Section 19.15.1.19 NMAC are exceeded is located;

(c) the appropriate city official(s) if the geographic area where the standards and requirements set forth in Subsection B of Section 19.15.1.19 NMAC are exceeded is located or is partially located within city limits or within one (1) mile of the city limits;

(d) those persons, as identified by the director, who have requested notification, who shall be notified by mail;

(e) the New Mexico trustee for natural resources, and any other local, state or federal governmental agency affected, as identified by the director, which shall be notified by certified mail;

(f) the appropriate governor or president of any indian tribe, pueblo or nation if the geographic area where the standards and requirements set forth in Subsection B of Section 19.15.1.19 NMAC are exceeded is located or is partially located within tribal boundaries oar within one (1) mile of the tribal boundaries, who shall be notified by certified mail;

(g) the distance requirements for notice may be extended by the director is the director determines the proposed abatement plan has the potential to adversely impact public health or the environment at a distance greater than one (1) mile. The director may require additional notice as needed. A copy and proof of such notice will be furnished to the division.

(2) Within fifteen days after the division determines that a stage 1 abatement plan or a stage 2 abatement plan is administratively complete, the responsible person will issue public notice in a form approved by the division in a newspaper of general circulation in the county in which the release occurred, and in a newspaper of general circulation in the state. For the purposes of this paragraph, an administratively complete stage 1 abatement plan is a document that satisfies the requirements of Section 19.15.1.19 NMAC, Subsection E, Paragraph E (3) and an administratively complete stage 2 abatement plan is a document that satisfies the requirements of Section 19.15.1.19 NMAC, Subsection E, Paragraph (4), Subparagraph (b). The public notice shall include, as approved in advance by the director:

(a) name and address of the responsible person;

(b) location of the proposed abatement;

(c) brief description of the source extent, and estimated volume of release, whether the release occurred into the vadose zone, ground water or surface water; and a description of the proposed stage 1 or stage 2 abatement plan;

(d) brief description of the procedures followed by the director in making a final determination;

(e) statement that a copy of the abatement plan can be viewed by the public at the division's main office or at the division's district office for the area in which the release occurred, and a statement describing how the abatement plan can be accessed by the public electronically from a division-maintained site if such access is available;

(f) statement that the following comments and requests will be accepted for consideration if received by the director within thirty (30) days after the date of publication of the public notice:

(i) written comments on the abatement plan; and

(ii) for a stage 2 abatement plan, written requests for a public hearing that include reasons why a hearing should be held.

(g) address and phone number at which interested persons may obtain further information.

(3) Any person seeking to comment on a stage 1 abatement plan, or to comment or request a public hearing on a stage 2 abatement plan, must file written comments or hearing requests with the division within thirty (30) days of the date of public notice, or within thirty (30) days of receipt by the director of a proposed significant modification of a stage 2 abatement plan. Requests for a public hearing must set forth the reasons why a hearing should be held. A public hearing shall be held if the director determines that there is significant public interest or that the request has technical merit.

(4) The division will distribute notice of the filing of an abatement plan with the next division and commission hearing docket following receipt of the plan.

H. Director approval or notice of deficiency of submittals

(1) The director shall, within sixty (60) days of receiving an administratively complete stage 1 abatement plan a site investigation report, a technical infeasibility demonstration, or an abatement completion report, approve the document, or notify the responsible person of the document's deficiency, based upon the information available.

(2) If no public hearing is held pursuant to Section 19.15.1.19 NMAC, Subsection G, Paragraph (3) then the director shall, within ninety (90) days of receiving a stage 2 abatement plan proposal, approve the plan, or notify the responsible person of the plan's deficiency, based upon the information available.

(3) If a public hearing is held pursuant to Section 19.15.1.19 NMAC, Subsection G, Paragraph (3) then the director shall, within sixty (60) days of receipt of all required information, approve stage 2 of the abatement plan proposal, or notify the responsible person of the plan's deficiency, based upon the information contained in the plan and information submitted at the hearing.

(4) If the director notifies a responsible person of any deficiencies in a site investigation report, or in a stage 1 or stage 2 abatement plan proposal, the responsible person shall submit a modified document to cure the deficiencies specified by the director within thirty (30) days of receipt of the notice of deficiency. The responsible person shall be in violation of Section 19.15.1.19 NMAC if he fails to submit a modified document within the required time, or if the modified document does not make a good faith effort to cure the deficiencies specified by the director.

(5) Provided that the other requirements of Section 19.15.1.19 NMAC are met and provided further that stage 2 of the abatement plan, if implemented, will result in the standards and requirements set forth in Subsection B of Section 19.15.1.19 NMAC being met within a schedule that is reasonable given the particular circumstances of the site, the director shall approve the plan.

I. Investigation and abatement - Any responsible person who receives approval for stage 1 and/or stage 2 of an abatement plan shall conduct all investigation, abatement, monitoring and reporting activity in full compliance with Section 19.15.1.19 NMAC and according to the terms and schedules contained in the approved abatement plans.

J. Abatement plan modification

(1) Any approved abatement plan may be modified, at the written request of the responsible person, in accordance with Section 19.15.1.19 NMAC, and with written approval of the director.

(2) If data submitted pursuant to any monitoring requirements specified in the approved abatement plan or other information available to the director indicates that the abatement action is ineffective, or is creating unreasonable injury to or interference with health, welfare, environment or property, the director may require a responsible person to modify an abatement plan within the shortest reasonable time so as to effectively abate water pollution which exceeds the standards and requirements set forth in Subsection B of Section 19.15.1.19 NMAC, and to abate and prevent unreasonable injury to or interference with health, welfare, environment or property.

K. Completion and termination

(1) Abatement shall be considered complete when the standards and requirements set forth in Subsection B of Section 19.15.1.19 NMAC are met. At that time, the responsible person shall submit an abatement completion report, documenting compliance with the standards and requirements set forth in Subsection B of Section

19.15.1.19 NMAC, to the director for approval. The abatement completion report also shall propose any changes to long-term monitoring and site maintenance activities, if needed, to be performed after termination of the abatement plan.

(2) Provided that the other requirements of Section 19.15.1.19 NMAC are met and provided further that the standards and requirements set forth in Subsection B of Section 19.15.1.19 NMAC have been met, the director shall approve the abatement completion report. When the director approves the abatement completion report, he shall also notify the responsible person in writing that the abatement plan is terminated.

L. Dispute resolution - In the event of any technical dispute regarding the requirements of Section 19.15.3.116 NMAC, Subsections B, D, E, J, or K (above), including notices of deficiency, the responsible person may notify the director by certified mail that a dispute has arisen, and desires to invoke the dispute resolution provisions of this Paragraph, provided that such notification must be made within thirty (30) days after receipt by the responsible person of the decision of the director that causes the dispute. Upon such notification, all deadlines affected by the technical dispute shall be extended for a thirty (30) day negotiation period, or for a maximum of sixty (60) days if approved by the director for good cause shown. During this negotiation period, the director or his/her designee and the responsible person shall meet at least once. Such meeting(s) may be facilitated by a mutually agreed upon third party, but the third party shall assume no power or authority granted or delegated to the director by the Oil and Gas Act or by the division or commission. If the dispute remains unresolved after the negotiation period, the decision of director shall be final.

M. Appeals from director's and division's decisions

(1) If the director determines that (i) an abatement plan is required pursuant to Subsection D of 19.15.3.116 NMAC, (ii) approves or provides notice of deficiency of a proposed abatement plan, technical infeasibility demonstration or abatement completion report, or (iii) modifies or terminates an approved abatement plan, he shall provide written notice of such action by certified mail to the responsible person and any person who participated in the action.

(2) Any person who participated in the action before the director and who is adversely affected by the action listed in Paragraph (1) above may file a petition requesting a hearing before a division examiner.

(3) The petition shall be made in writing to the division and shall be filed with the division within thirty (30) days after receiving notice of the director's action. The petition shall specify the portions of the action to which the petitioner objects, certify that a copy of the petition has been mailed or hand-delivered to the director, and to the applicant or permittee if the petitioner is not the applicant or permittee, and attach a copy of the action for which review is sought. Unless a timely petition for hearing is made, the director's action is final.

(4) The hearing before the division shall be conducted in the same manner as other division hearings.

(5) The cost of the court reporter for the hearing shall be paid by the petitioner.

(6) Any party adversely affected by any order by the division pursuant to any hearing held by an Examiner, shall have a right to have such matter heard ***de novo*** before the commission.

(7) The appeal provisions do not relieve the owner, operator or responsible person of their obligations to comply with any federal or state laws or regulations.

[3-15-97; 6-30-97; 19.15.1.19 NMAC - Rn, 19 NMAC 15.A.19, 5-15-01; A, 3-15-02]

19.15.1.20 MEETINGS BY TELECONFERENCE:
Pursuant to Section 10-15-1 NMSA 1978, commission members may participate in commission meetings and hearings by means of a conference telephone or other similar communications equipment when it is otherwise difficult or impossible for members to attend the meeting or hearing in person. Each member participating by conference telephone or other similar communications equipment must be identified when speaking. All participants must be able to hear each other at the same time. Members of the public hearing attending the meetings or hearing must be able to hear commission members who speak during the meeting or hearing.
[12-31-96; 19.15.1.20 NMAC - Rn, 19 NMAC 15.A.20, 5-15-01]

19.15.1.21 SPECIAL PROVISIONS FOR SELECTED AREAS OF SIERRA AND OTERO COUNTIES:

A. The selected areas comprise:

(1) all of Sierra county except the area west of Range 8West NMPM and north of Township 18 South, NMPM; and

(2) all of Otero county except the area included in the following townships and ranges:

(a) township 11 south, range 9 1/2 east and range 10 east NMPM;

(b) township 12 south, range 10 east and ranges 13 east through 16 east, NMPM;

(c) township 13 south, ranges 11 east through 16 east, NMPM;

(d) township 14 south, ranges 11 east through 16 east, NMPM;

(e) township 15 south, ranges 11 east through 16 east, NMPM;

(f) township 16 south, ranges 11 east through 15 east, NMPM;

(g) township 17 south, range 11 east (surveyed) and ranges 12 east through 15 east, NMPM;

(h) township 18 south, ranges 11 east through 15 East, NMPM;

(i) township 20 1/2 south, range 20 east, NMPM;

(j) township 21 south, range 19 east and range 20 east, NMPM; and

(k) township 22 south, range 20 east, NMPM; and also excepting also the unsurveyed area bounded as follows:

(i) beginning at the most northerly northeast corner of Otero county, said point lying in the west line of range 13 east (surveyed);

(ii) thence west along the north boundary line of Otero county to the point of intersection of such line with the east line of range 10 east NMPM (surveyed);

(iii) thence south along the east line of range 10 east NMPM (surveyed) to the southeast corner of township 11 south, range 10 east NMPM (surveyed);

(iv) thence west along the south line of township 11 south, range 10 east NMPM (surveyed) to the more southerly northeast corner of township 12 south, range 10 east NMPM (surveyed);

(v) thence south along the east line of range 10 east NMPM (surveyed) to the inward corner of township 13 south, range 10 east NMPM (surveyed) (said inward corner formed by the east line running south from the more northerly northeast corner and the north line running west from the more southerly northeast corner of said township and range);

(vi) thence east along the north line of township 13 south NMPM (surveyed) to the southwest corner of township 12 south, range 13 east, NMPM (surveyed);

(vii) thence north along the west line of range 13 east, NMPM (surveyed) to the point of beginning.

B. The division shall not issue permits under 19.15.2.50 NMAC or 19.15.9.711 NMAC for pits located in the selected areas.

C. Produced water injection wells located in the selected areas are subject to the following requirements in addition to those set out in 19.15.9.701 NMAC through 19.15.9.710 NMAC.

(1) Permits shall be issued under 19.15.9.701 NMAC only after notice and hearing.

(2) The radius of the area of review shall be the greater of:

(a) one-half mile; or

(b) one and one-third times the radius of the zone of endangering influence, as calculated under environmental protection agency regulation 40 CFR Part 146.6(a) or by any other method acceptable to the division; but in no case shall the radius of the area of review exceed one and one-third miles.

(3) Operators shall demonstrate the vertical extent of any fresh water aquifer(s) prior to using a new or existing well for injection.

(4) All fresh water aquifers shall be isolated throughout their vertical extent with at least two cemented casing strings. In addition,

(a) existing wells converted to injection shall have continuous, adequate cement from casing shoe to surface on the smallest diameter casing, and

(b) wells drilled for the purpose of injection shall have cement circulated continuously to surface on all casing strings, except the smallest diameter casing shall have cement to at least 100 feet above the casing shoe of the next larger diameter casing.

(5) Operators shall run cement bond logs acceptable to the division after each casing string is cemented, and file the logs with the appropriate district office of the division. For existing wells the casing and cementing program shall comply with 19.15.9.702 NMAC.

(6) Produced water transportation lines shall be constructed of corrosion-resistant materials acceptable to the division, and shall be pressure tested to one and one-half times the maximum operating pressure prior to operation, and annually thereafter.

(7) All tanks shall be placed on impermeable pads and surrounded by lined berms or other impermeable secondary containment device having a capacity at least equal to one and one-third times the capacity of the largest tank, or, if the tanks are interconnected, of all interconnected tanks.

(8) Operators shall record injection pressures and volumes daily or in a manner acceptable to the division, and make the record available to the division upon request.

(9) Operators shall perform a mechanical integrity tests as described in Paragraph 2, Subsection A of 19.15.9.704 NMAC annually, shall advise the appropriate district office of the division of the date and time each such test is to be commenced in order that the test may be witnessed, and shall file the pressure chart with the appropriate district office of the division.

[19.15.1.21 NMAC - N, 08-13-04]

19.15.1.22-29 [RESERVED]

19.15.1.30 ENHANCED OIL RECOVERY PROJECT TAX INCENTIVE:

A. General - Applications for qualification of enhanced oil recovery projects or expansions of existing enhanced oil recovery projects for the recovered oil tax rate pursuant to the New Mexico "Enhanced Oil Recovery Act" (Sections 7-29A-1 through 7-29A-5 NMSA 1978) will be accepted by the division after March 6, 1992.

B. Applicability - These rules apply to:

(1) enhanced oil recovery (EOR) projects;

(2) expansions of existing EOR projects;

(3) the expanded use of enhanced oil recovery technology in existing EOR projects; and

(4) the change from a secondary recovery project to a tertiary recovery project.

C. Definitions

(1) Crude oil means oil and other liquid hydrocarbons removed from natural gas at or near the wellhead.

(2) Enhanced oil recovery (EOR) project means the use or the expanded use of any process for the displacement of crude oil from an oil well or division-designated pool other than a primary recovery process, including but not limited to the use of a pressure maintenance process, a waterflooding process, an immiscible, miscible, chemical, thermal or biological process or any other related process.

(3) Expansion or expanded use means a significant change or modification as determined by the Division in (a) the technology or process used for the displacement of crude oil from an oil well or division-designated pool; or (b) the expansion, extension or increase in size of the geologic area or adjacent geologic area that could reasonably be determined to represent a new or unique area of activity.

(4) Operator means the person responsible for the actual physical operation of an enhanced recovery project.

(5) Positive production response means that the rate of oil production from the wells or pools affected by an enhanced recovery project is greater than the rate that would have occurred without the project.

(6) Project area means a pool or a portion of a pool that is directly affected by EOR operations.

(7) Primary recovery means the displacement of crude oil from an oil well or division-designated pool into the well bore by means of the natural pressure of the oil well or pool, including but not limited to artificial lift.

(8) Recovered oil tax rate means the tax rate set forth in Section 7-29-4 NMSA 1978, on crude oil produced from an enhanced recovery project.

(9) Secondary recovery project means an enhanced oil recovery project that: (a) occurs subsequent to the completion of primary recovery and is not a tertiary recovery project; (b) involves the application, in accordance with sound engineering principles of carbon dioxide miscible fluid displacement, pressure maintenance, waterflooding or any other secondary recovery method accepted and approved by the division that can reasonably be expected to result in an increase, determined in light of all facts and circumstances, in the amount of crude oil that may ultimately be recovered; and (c) encompasses a pool or portion of a pool the boundaries of which can be adequately defined and controlled.

(10) Termination means the discontinuance of an enhanced recovery project by the operator.

(11) Tertiary recovery project means an enhanced recovery project that: (a) occurs subsequent to the completion of a secondary recovery project; (b) involves the application, in accordance with sound engineering principles, of carbon dioxide miscible fluid displacement, pressure maintenance, water flooding or any other tertiary recovery method accepted and approved by the division that can reasonably be expected to result in an increase, determined in light of all facts and circumstances, in the amount of crude oil that may ultimately be recovered; and (c) encompasses a pool or portion of a pool the boundaries of which can be adequately defined and controlled.

D. Procedure

(1) The division's general rules of procedure shall apply unless altered or amended by these rules.

(2) To be eligible for the tax rate the operator must apply for and receive division approval. No project or expansion approved by the division prior to March 6, 1992 shall qualify.

(3) All applications shall be filed in triplicate with the division's Santa Fe office. One copy of the application and all attachments shall also be filed with the appropriate division district office.

(4) All applications shall be executed and certified by the operator or its authorized representative having knowledge of the facts therein and shall contain:

(a) operator's name and address;

(b) description of the project area including:

(i) a plat outlining the project area;

(ii) description of the project area by section, township and range; total acres; and

(iii) name of the subject pool and formation;

(c) status of operations in the project area:

(i) if unitized, the name of the unit and the date and number of the division order approving the unit plan of operation;

(ii) if an application for approval of a unit plan has been made, the date the application was filed with the Division; and

(iii) if not unitized, identify each lease in the project area by lessor, lessee and legal description;

(d) method of recovery to be used:

(i) identify fluids to be injected;

(ii) if the division has approved the project, provide the date and number of the division order; and

(iii) if the project has not been approved by the division, provide the date the application for approval was filed with the division on form C-108;

(e) description of the project:

(i) a list of producing wells;

(ii) a list of injection wells;

(iii) capital costs of additional facilities;

(iv) total project cost;

(v) estimated total value of the additional production that will be recovered as a result of the project;

(vi) anticipated date for commencement of injection;

(vii) the type of fluid to be injected and the anticipated volumes; and if application is made for an expansion of an existing project, explain what changes in technology will be used or what additional geographic area will be added to the project area; and

(f) production data: provide graphs, charts and other supporting data to show the production history and production forecast of oil, gas, casinghead gas and water from the project area.

E. Approval and certification

(1) Project approval: An EOR project will be approved and the project area designated for the recovered oil tax rate when the operator proves that:

(a) the application of the proposed enhanced recovery techniques to the reservoir should result in an increase in the amount of crude oil that may be ultimately recovered;

(b) the project area has been so depleted that it is prudent to apply enhanced recovery techniques to maximize the ultimate recovery of crude oil; and

(c) the application is economically and technically reasonable and has not been prematurely filed.

(2) Positive production response certification:

(a) for the recovered oil tax rate to apply to oil produced from an approved qualified EOR project, the operator must demonstrate a positive production response to the division. Applications for certification of a positive production response shall be filed with the division's Santa Fe office and shall include:

(i) a copy of the division's approval of the enhanced recovery project or expansion;

(ii) a plat of the affected area showing all injection and producing wells with completion dates; and

(iii) production graphs and supporting data demonstrating a positive production response and showing the volumes of water or other substances that have been injected on the lease or unit since initiation of the enhanced recovery project;

(b) the division director shall have authority to administratively approve an application and certify a positive production response or, at the director's discretion or at the request of the applicant, may set the application for hearing; and

(c) the division shall certify that a positive production response occurred and notify the secretary of taxation and revenue. This certification and notice shall set forth the date the certification was made and the date the positive production response occurred provided however:

(i) for a secondary recovery project, the application for certification of a positive production response must occur not later than five (5) years from the date the division issued the certification of approval for the enhanced oil recovery project or expansion; and

(ii) for a tertiary recovery project, the application for certification of a positive production response must occur not later than seven (7) years from the date the division issues the certification of approval for the enhanced recovery project or expansion.

F. Reporting requirements

(1) The operator of an approved EOR project shall report annually on the status of the project and confirm that the project is still a viable EOR project as approved. The report will be for the year ending May 31 and shall be filed with the division's Santa Fe office. The report shall contain:

(a) the date and number of the division's certification order for the project;

(b) production graphs showing oil, gas and water production;

(c) a graph showing the volumes of fluid injected and the average injection pressures; and

(d) any additional data the director deems necessary for continued approval;

(2) the director may set for hearing the continued approval of any EOR project.

G. Termination - When active operation of an approved enhanced recovery project or expansion is terminated, the operator shall notify the division and the secretary of taxation and revenue in writing not later than the thirtieth (30) day after the termination of the enhanced recovery project or expansion.

[6-15-9; 19.15.1.30 NMAC - Rn, 19 NMAC 15.A.30, 5-15-01]

19.15.1.31 PRODUCTION RESTORATION PROJECT TAX INCENTIVE:

A. General - Applications for qualification of production restoration projects for the production restoration incentive tax exemption pursuant to the "Natural Gas and Crude Oil Production Incentive Act" (Sections 7-29B-1 through 7-29B-6 NMSA 1978) shall be accepted by the division after November 9, 1995.

B. Applicability - These rules apply to any natural gas or oil well division records show had thirty (30) days or less production in any period of twenty-four consecutive months beginning on or after January 1, 1993 upon which the operator commenced operations to restore production after June 16, 1995.

C. Definitions

(1) Operator means the person responsible for the actual physical operation of a natural gas or oil well;

(2) Production restoration incentive tax exemption means the severance tax exemption for natural gas and/or oil produced from an approved production restoration project found in Section 7-29-4 NMSA 1978.

(3) Production restoration project means returning to production any natural gas or oil well, including but not limited to any injection well which has previously produced, which had no more than (30) days of production in any period of twenty-four consecutive months beginning on or after January 1, 1993 as approved and certified by the division;

(4) Well means a wellbore with single or multiple completions, including all horizons and producing formations from the surface to total depth.

D. Procedure

(1) The division's general rules of procedure shall apply unless altered or amended by these rules.

(2) To be eligible for the exemption, the operator must apply for and receive division approval. No production restoration project commenced prior to June 16, 1995 shall qualify.

(3) An application must be filed with the division within twelve (12) months of the production restoration.

(4) Applications shall be filed by the operator on behalf of all interest owners in the project.

(5) Applications shall be filed in triplicate with the division at its appropriate district office on division form C-139 and shall contain:

(a) operator's name and address; and

(b) description of the production restoration project including:

(i) name and footage location of the well;

(ii) name of the pool from which the well previously produced;

(iii) a description of the process used, or to be used, by the operator for returning the well to production;

(iv) identification of the division records which show that the well had thirty (30) days or less production in any period of twenty-four consecutive months beginning on or after January 1, 1993;

(v) date the project was commenced and date the well was returned to production; and

(vi) a statement under oath by the operator or its authorized representative having knowledge of the facts contained in the application that: the application is complete and correct; production from the well has been reported to the division and division records establish the well had thirty (30) days or less production in any period of twenty-four consecutive months beginning on or after January 1, 1993.

E. Approval, certification, notification and hearing

(1) Project approval and certification

(a) A project shall be approved and a certification of approval issued to the operator designating the natural gas or oil well as a production restoration project when the operator proves that:

(i) after June 16, 1995, the operator has commenced any process to return the well to production; and

(ii) division records show the well had thirty (30) days or less of production in any period of twenty-four consecutive months beginning on or after January 1, 1993.

(b) The exemption will apply beginning the first day of the month following the date the well was returned to production as certified by the division.

(2) Notification to the secretary of taxation and revenue - The division shall notify the secretary of taxation and revenue of the approval. This notice shall identify the natural gas or oil well as a production restoration project and certify the date production was restored.

(3) Hearing - The division shall consider applications without a hearing. If the division district office denies an application, the division upon the applicant's request shall set the application for hearing. Any application not acted upon by the division district office within thirty (30) days from the date it is filed shall be deemed denied. [Rn, 19 NMAC 15.I.712.A through E, 6-15-99; A, 6-15-99; 19.15.1.31 NMAC - Rn, 19 NMAC 15.A.31, 5-15-01]

19.15.1.32 WELL WORKOVER PROJECT TAX INCENTIVE:

A. General - Applications for qualification of well workover projects for the well workover incentive tax rate pursuant to the "Natural Gas and Crude Oil Production Incentive Act" (Sections 7-29B-1 through 7-29B-6 NMSA 1978) shall be accepted by the division after November 9, 1995.

B. Applicability - These rules apply to any natural gas or oil well upon which the operator has commenced a workover after June 16, 1995 that is intended to increase production from the well.

C. Definitions

(1) Routine maintenance means repair or like-for-like replacement of downhole equipment or any other procedure performed by an operator to maintain the well's current production;

(2) Well means a wellbore with single or multiple completions, including all horizons and producing formations from the surface to total depth.

(3) Well workover incentive tax rate means the tax rate imposed by Section 7-29-4 NMSA 1978 on natural gas and/or oil produced from a well workover project;

(4) Well workover project means any procedure undertaken by the operator of a natural gas or oil well that is intended to increase production from the well and that has been approved and certified by the division;

(5) Workover means any procedure undertaken by the operator of the well intended to increase production but is not routine maintenance and includes, but is not limited to:

(a) re-entry into the well to drill deeper, to sidetrack to a different location, to recomplete for production or to restore production from a zone which has been temporarily abandoned;

(b) recompletion by re-perforation of a zone from which natural gas or oil has been produced or by perforation of a different zone;

(c) repair or replacement of faulty or damaged casing or related downhole equipment;

(d) fracturing, acidizing or installing compression equipment; and

(e) squeezing, cementing or installing equipment necessary for removal of excessive water, brine or condensate from the well bore in order to establish, continue or increase production from the well.

D. Procedure

(1) The division's general rules of procedure shall apply unless altered or amended by these rules.

(2) To be eligible for the incentive tax rate, the operator must apply for and receive division approval. No well workover project commenced by the operator prior to June 16, 1995 shall qualify.

(3) Applications must be filed with the division within twelve (12) months of completion of the workover.

(4) An application shall be filed by the operator on behalf of all interest owners in the project.

(5) The data utilized in the application shall be retained by the operator in its files during the period of time the well qualifies for and receives the well workover incentive tax rate and for such time thereafter as the department requires.

(6) Applications shall be filed in triplicate with the division at its appropriate district office on division form C-140 and shall contain:

(a) operator's name and address; and

(b) description of well workover project including:

(i) name and footage location of the well;

(ii) name of the pool from which the well previously produced;

(iii) the dates workover procedures commenced and were completed;

(iv) a description of the procedures undertaken by operator of the well intended to increase production;

(v) evidence of a positive production increase over the production rate of the well prior to the workover. The operator must submit a production curve or data tabulation made up of at least twelve months' production prior to the workover and at least three months' production following the workover that reflects a positive production increase;

(vi) other documentation the applicant determines may be applicable to this filing, such as division forms or division orders; and

(vii) a statement under oath by the operator or its authorized representative having knowledge of the facts contained in the application that he/she has made or caused to be made a diligent search of all production records which are reasonably available and contain information relevant to the production history of the well.

E. Approval, certification, notification and hearing

(1) Project approval and certification

(a) A workover shall be approved and a certification of approval issued to the operator designating the natural gas or oil well as a well workover project when the operator proves that:

(i) approved workover procedures have been undertaken on the well which are intended to increase production; and

(ii) the production curve or data tabulation from production data reflects a positive production increase from the workover.

(b) The incentive tax rate will apply beginning the first day of the month following the date the workover was completed as certified by the division.

(2) Notification to the secretary of taxation and revenue - The division shall notify the secretary of taxation and revenue of the approval by identifying the natural gas or oil well as a well workover project and certifying the date the project was completed.

(3) Hearings and requests for additional information

(a) The division shall consider applications without a hearing. If the division district office denies an application, the division upon the applicant's request shall set the application for hearing. Any application not acted upon by the division district office within thirty (30) days from the date it is filed is deemed denied.

(b) The division may request additional information from the operator to support an application. When additional information is requested, the 30-day approval period shall begin to run on the date the requested data is provided.

F. Certifications prior to July 1, 1999 - Well workover projects certified prior to July 1, 1999 shall be deemed to be approved and certified in accordance with the provisions of the 1999 act and natural gas or oil produced from those projects shall be eligible for the well workover incentive tax rate effective beginning July 1, 1999.

[6-15-99, Rn, 19. NMAC 15.I.713.A through E, 7-1-99; A, 7-1-99; 19.15.1.32 NMAC - Rn, 19 NMAC 15.A.32, 5-15-01]

19.15.1.33 STRIPPER WELL TAX INCENTIVE:

A. General - Qualification of stripper well properties for the stripper well incentive tax rates in Sections 7-29-4 and 7-31-4 NMSA 1978, requires certification by the division. The division shall certify stripper well properties for calendar year 1998 no later than June 30, 1999 and no later than June 1 of each succeeding year for the preceding calendar year.

B. Applicability - These rules apply to any property that the division certifies as a stripper well property after June 30, 1999.

C. Definitions

(1) Average daily production means the number derived by dividing the total volume of crude oil or natural gas production from the stripper well property reported to the division during a calendar year by the sum of the number of days each eligible well within the property produced or injected during that calendar year;

(2) Eligible well means a crude oil or natural gas well that produces, or an injection well that injects and is integral to production, for any period of time during the preceding calendar year.

(3) Stripper well property means a crude oil or natural gas producing property that is assigned a single production unit number (PUN) by the taxation and revenue department and:

(a) (if a crude oil producing property) produced a daily average of less than ten barrels of oil per eligible well per day for the preceding calendar year;

(b) (if a natural gas producing property) produced a daily average of less than sixty thousand cubic feet of natural gas per eligible well per day during the preceding calendar year; or

(c) (if a property with wells that produce both crude oil and natural gas) produced a daily average of less than ten barrels of oil per eligible well per day for the preceding calendar year, as determined by converting the volume of natural gas produced by the well to barrels of oil by using a ratio of six thousand cubic feet to one barrel of oil; and

(4) Stripper well incentive tax rates means the tax rates set for stripper well properties by Sections 7-29-4 and 7-31-4 NMSA 1978.

D. Certification, notification and hearing

(1) The division shall determine which wells qualify as stripper well properties.

(2) Upon certification of properties as stripper well properties, the division shall notify the operator and the secretary of taxation and revenue of that certification.

(3) The operator shall notify all the interest owners of the certification of the property as a stripper well property.

(4) An operator may make a written request that the division reevaluate a property for stripper well status.

(5) If the division denies stripper well certification to a property, the division upon the operator's request shall set the matter for hearing.

[6-15-99; 19.15.1.33 NMAC - Rn, 19 NMAC 15.A.33, 5-15-01]

19.15.1.34 NEW WELL TAX INCENTIVE:

A. Applicability - These rules apply to any new natural gas or oil well for which drilling commenced after January 1, 1999 and before July 1, 2000.

B. Definitions - New well means a crude oil or natural gas producing well for which drilling commenced after January 1, 1999 and before July 1, 2000, or a horizontal crude oil or natural gas well that was recompleted from a vertical well by drilling operations that commenced after January 1, 1999 and before July 1, 2000, that has been approved and certified as such by the division.

C. Procedure

(1) The division's general rules of procedure shall apply unless altered or amended by these rules.

(2) The operator must apply for and be granted division approval of the "new well". A new well shall qualify if the division certifies that:

(a) the operator applying for the tax credit commenced drilling the new well after January 1, 1999 and before July 1, 2000;

(b) the new well was completed as a producer; and

(c) the application is for one of the first six hundred new wells commenced after January 1, 1999 and before July 1, 2000.

(3) An application must be filed with the division: (a) within sixty (60) days of completion of the well as a producer, or (b) by Oct 1, 1999 for a well commenced after January 1, 1999 and before July 1, 1999.

(4) All applications shall be filed in triplicate with the division's Santa Fe office on form C-142 and shall contain:

(a) operator's name and address;

(b) description of the well:

(i) name and footage location;

(ii) date and time spudded; and

(iii) completion date and production test results;

(c) copies of division form C-103 or federal form 3160-5 showing spud date and time and form C-105 or federal form 3160-4 showing the well was completed as a producer;

(d) a list of all working interest owners in the well along with their percentage interests; and

(e) a statement under oath by the operator or its authorized representative having knowledge of the facts contained in the application that the application is complete and correct.

D. Certification, notification and hearing

(1) Upon approval of the application, the division shall certify that approval by sending a copy of the approved application to the operator and the secretary of taxation and revenue.

(2) The division shall consider applications without a hearing. The division may request additional information from an operator to support the application. If the division denies an application, the division upon the applicant's request shall set the application for hearing.

(3) The operator shall notify all working interest owners of the approval and certification of the well as a new well.

[6-15-99, A, 10-29-99; 19.15.1.34 NMAC - Rn, 19 NMAC 15.A.34, 5-15-01]

19.15.1.35 COMPULSORY POOLING. CHARGE FOR RISK

A. General rule - Compulsory pooling orders entered by the division pursuant to NMSA 1978 Section 70-2-17, as amended, may provide for the recovery, out of the share of production allocable to the working interest of any party that elects not to pay its proportionate share of well costs in advance, in addition to reasonable well costs and costs of supervision and management, of a charge for risk associated with the drilling, completion, or working over and recompletion of each unit well for which provision is made in the order. Unless otherwise ordered pursuant to Subsection B of 19.15.1.35 NMAC, the charge for risk shall be 200% of well costs.

(1) "Well costs" shall mean all reasonable costs of drilling, reworking, diverting, deepening, plugging back and testing the well; completing the well in any formation pooled by the order; and equipping the well for production. If, however, any well was previously completed in another formation or bottom-hole location, or was previously abandoned without completion, well costs as to such well shall mean only the reasonable costs of re-entering, reworking, diverting, deepening, plugging back or testing the well; completion in the pooled formation or formations and; if necessary, reequipping the well for production, unless the division determines that allowance of all or some portion of historical costs of drilling is just and reasonable due to particular circumstances. If a well is completed in two or more formations having diverse ownership or a different risk charge percentage, the order shall provide for allocation of well costs between the formations. As to any interest owner who elects not to pay its share of well costs associated with a specific well in advance, as provided in the applicable order, "well costs" shall include costs of any subsequent operation undertaken to secure or enhance production from any formation pooled by the order prior to the time that the entire amount of such non-consenting owner's share of well costs and applicable risk charge have been recovered from such non-consenting owner's share of production from such well. Such costs shall include expenses for reworking, diverting, deepening, plugging back, testing, completion or recompletion and equipping for production, but not ordinary operating expenses.

(2) Well costs shall also include reasonable costs of drilling, testing, completing, and equipping a substitute well if, in the drilling of a well pursuant to a compulsory pooling order, the operator loses the hole or encounters mechanical difficulties rendering it impracticable to drill to the objective depth, and the substitute well is located within 330 feet of the original well and drilling thereof is commenced within ten (10) days of the abandonment of the original well.

(3) An applicant for compulsory pooling shall not be required to present technical evidence justifying the risk charge provided in Subsection A of 19.15.1.35 NMAC.

B. Exceptions **-** Any person responding to a compulsory pooling application who seeks a different risk charge than that provided in Subsection A shall so state in a timely pre-hearing statement filed with the division and served on the applicant in accordance with Subsection B of 19.15.14.1208 NMAC, and shall have the burden to prove the justification for the risk charge sought by relevant geologic or technical evidence. The hearing officer shall have discretion to allow a responding party who has not filed a pre-hearing statement, but who appears in person or by attorney at the hearing, to offer evidence in support of a different risk charge than that provided in Subsection A of 19.15.1.35, but in such cases a continuance of the hearing shall be allowed, if requested, to enable the applicant to present rebuttal evidence.

[N, 8-15-03]

HISTORY of 19.15.5 NMAC:
Pre-NMAC History: Material in this part was derived from that previously filed with the commission of public records – state records center and archives as: Rule 0.1, Definitions, filed 1-8-82; Rule 0.1, Definitions, filed 11-6-86; Rule 0.1, Definitions, filed 10-11-89; Rule 0.1, Definitions, filed 7-10-90; Rule 0.1, Definitions, filed 2-5-91; Rule 1, Scope of Rules and Regulations, filed 1-8-82; Rule 1, Scope of Rules and Regulations, filed 9-16-85; Rule 1, Scope of Rules and Regulations, filed 2-5-91; Rule 2, Enforcement of Laws, Rules and Regulations Dealing with Conservation of Oil and Gas, filed 1-8-82; Rule 2, Enforcement of Laws, Rules and Regulations Dealing with Conservation of Oil and Gas; 9-16-85; Rule 2, Enforcement of Laws, Rules and Regulations Dealing with Conservation of Oil and Gas; 2-5-91; Rule 3, Waste Prohibited, filed 1-8-82; Rule 3, General Operations/Waste Prohibited, filed 9-16-85; Rule 3, General Operations/Waste Prohibited, filed 2-5-91; Rule 4, United States Government Leases, filed 1-8-82; Rule 4, United States Government Leases, filed 2-5-91; Rule 5, Classifying and Defining Pools, filed 1-8-82; Rule 5, Classifying and Defining Pools, filed 2-5-91; Rule 6, Forms Upon Request, filed 1-8-82; Rule 6, Forms upon Request, filed 2-5-91; Rule 7, Authority to Cooperate with Other Agencies, filed 9-16-85; Rule 7, Authority to Cooperate with Other Agencies, filed 9-16-85; Rule 7, Authority to Cooperate with Other Agencies, filed 2-5-91; Rule 8, Lined Pits/Below Grade Tanks, filed 9-12-85; Rule 8, Exposed Pits/Lined Pits/Below Grade Tanks, filed 8-17-89; Rule 8, Lined Pits/Below Grade Tanks, filed 2-5-91.

History of Repealed Material: [Reserved]

Other History: Rule 0.1, Definitions, filed 2-5-91; Rule 1, Scope of Rules and Regulations, filed 2-5-91; Rule 2, Enforcement of Laws, Rules and Regulations Dealing with Conservation of Oil and Gas; 2-5-91; Rule 3, General Operations/Waste Prohibited, filed 2-5-91; Rule 4, United States Government Leases, filed 2-5-91; Rule 5, Classifying and Defining Pools, filed 2-5-91; Rule 6, Forms upon Request, filed 2-5-91; Rule 7, Authority to Cooperate with Other Agencies, filed 2-5-91; and Rule 8, Lined Pits/Below Grade Tanks, filed 2-5-91 **renumbered, reformatted and amended to** 19 NMAC 15.A, General Provisions and Definitions, filed 01-18-96.
19 NMAC 15.A, General Provisions and Definitions, filed 01-18-96 **renumbered and reformatted to 19.15.1 NMAC**, General Provisions, effective 5-15-01.

TITLE 19 NATURAL RESOURCES and WILDLIFE
CHAPTER 15 OIL AND GAS
PART 2 GENERAL OPERATING PRACTICES, WASTES ARISING FROM EXPLORATION AND PRODUCTION

19.15.2.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department, Oil Conservation Division, 1220 S. St. Francis Drive, Santa Fe, New Mexico 87505, (505) 476-3440.
[19.15.2.1 NMAC - N, 2/13/04]

19.15.3.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico.
[19.15.2.2 NMAC - N, 02/13/04]

19.15.3.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the Oil and Gas Act which grants the oil conservation division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights, and the disposition of wastes resulting from oil and gas operations.
[19.15.2.3 NMAC - N, 02/13/04]

19.15.2.4 DURATION: Permanent.
[19.15.2.4 NMAC - N, 02/13/04]

19.15.2.5 EFFECTIVE DATE: February 13, 2004, unless a later date is cited at the end of a section.
[19.15.2.5 NMAC - N, 02/13/04]

19.15.2.6 OBJECTIVE: To regulate the drilling of oil and gas wells within the state of New Mexico to enable the oil conservation division to fulfill its statutory mandates under the Oil and Gas Act.
[19.15.2.6 NMAC - N, 02/13/04]

19.15.2.7 DEFINITIONS:

A. Alluvium shall mean detrital material that has been transported by water or other erosional forces and deposited at points along the flood plain of a watercourse. It typically is composed of sands, silts, and gravels, exhibits high porosity and permeability and generally carries fresh water.

B. Sump shall mean any impermeable single wall vessel with a capacity less than 500 gallons, where any portion of the sidewalls of the reservoir is below the surface of the ground and not visible which vessel remains predominantly empty, serves as a drain or receptacle for spilled or leaked liquids on an intermittent basis, and is not used to store, treat, dispose of, or evaporate products or wastes.
[19.15.2.7 NMAC - N, 02/13/04]

19.15.2.8 through 19.15.2.49 [RESERVED]

19.15.2.50 PITS AND BELOW-GRADE TANKS:

A. Permit required. Discharge into, or construction of, any pit or below-grade tank is prohibited absent possession of a permit issued by the division, unless otherwise herein provided or unless the division grants an exemption pursuant to Subsection G of 19.15.2.50 NMAC. Facilities permitted by the division pursuant to Section 711 of 19.15.9 NMAC or water quality control commission regulations are exempt from Section 50 of 19.15.2 NMAC.

B. Application.

(1) Where filed; application form.

(a) Downstream facilities. An operator shall apply to the division's environmental bureau for a permit to construct or use a pit or below-grade tank at a downstream facility such as a refinery, gas plant, compressor station, brine facility, service company, or surface waste management facility that is not permitted pursuant to Section 711 of 19.15.9 NMAC or water quality control commission regulations. The operator shall use a form C-144, application to discharge into a pit or below-grade tank. The operator may submit the form separately or as an attachment to an application for a discharge permit, best management practices permit, surface waste management facility permit, or other permit.

(b) Drilling or production. An operator shall apply to the appropriate district office for a permit for use of a pit or below-grade tank in drilling, production, or operations not otherwise identified in Subparagraph (a), Paragraph (1), Subsection B of 19.15.2.50 NMAC. The operator shall apply for the permit on the application for permit to drill or on the sundry notices and reports on wells, or electronically as otherwise provided in this chapter. Approval of such form constitutes a permit for all pits and below-grade tanks annotated on the form. A separate Corm C-144 is not required.

(2) General permit; individual permit. An operator may apply for a permit to use an individual pit or below-grade tank, or may apply for a general permit applicable to a class of like facilities.

(3) When filed.

(a) New pits or new below-grade tanks. After April 15, 2004, operators shall obtain a permit before constructing a pit or below-grade tank.

(b) Existing pits or new below-grade tanks. For each pit or below-grade tank in existence on April 15, 2004 that has not received an exemption after hearing as allowed by OCC Order R-3221 through R-3221D inclusive, the operator shall submit a notice not later than April 15, 2004 indicating either that use of the pit or below-grade tank will continue or that such pit or below grade tank will be closed. If use of a pit or below-grade tank is to be discontinued, discharge into the pit or use of the below-grade tank shall cease not later than June 30, 2005. If use of a pit or below-grade tank will continue, the operator shall file a permit application not later than September 30, 2004. If an operator files a timely, administratively complete application for continued use, use of the pit or below-grade tank may continue until the division acts upon the permit application.

C. Design, construction, and operational standards.

(1) In general. Pits, sumps and below-grade tanks shall be designed, constructed and operated so as to contain liquids and solids to prevent contamination of fresh water and protect public health and the environment.

(2) Special requirements for pits.

(a) Location. No pit shall be located in any watercourse, lakebed, sinkhole, or playa lake. Pits adjacent to any such watercourse or depression shall be located safely above the ordinary high-water mark of such watercourse or depression. No pit shall be located in any wetland. The division may require additional protective measures for pits located in groundwater sensitive areas or wellhead protection areas.

(b) Liners.

(i) Drilling pits, workover pits. Each drilling pit or workover pit shall contain, at a minimum, a single liner appropriate for conditions at the site. The liner shall be designed, constructed, and maintained so as to prevent the contamination of fresh water, and protect public health and the environment. Pits used to vent or flare gas during drilling or workover operations that are designed to allow liquids to drain to a separate pit do not require a liner.

(ii) Disposal or storage pits. Each disposal pit (including, but not limited to, any separator pit, tank drain pit, evaporation pit, blowdown pit used in production activities, pipeline drip pit, or production pit) and each storage pit (including any brine pit, salt water pit, fluid storage pit for an LPG system, or production pit) shall contain, at a minimum, a primary and a secondary liner appropriate to the conditions at the site. Liners shall be designed, constructed, and maintained so as to prevent the contamination of fresh water, and protect public health and the environment.

(iii) Alternative liner media. The division may approve liners that are not constructed in accordance with division guidelines only if the operator demonstrates to the division's satisfaction that the alternative liner protects fresh water, public health, and the environment as effectively as those prescribed in division guidelines.

(c) Leak detection. A leak detection system shall be installed between the primary and secondary liner in each disposal or storage pit. The leak detection system shall be designed, installed, and operated so as to prevent the contamination of fresh water, and protect public health and the environment. The operator shall notify the division at least twenty-four hours prior to installation of the primary liner so a division representative may inspect the leak detection system before it is covered.

(d) Drilling and workover pits. Each drilling or workover pit shall be of an adequate size to assure that a supply of fluid is available and sufficient to confine oil, natural gas, or water within its native strata. Hydrocarbon-based drilling fluids shall be contained in tanks made of steel or other division-approved material.

(e) Disposal or storage pits. No measurable or visible layer of oil may be allowed to accumulate or remain anywhere on the surface of any pit. Spray evaporation systems shall be operated such that all spray-borne suspended or dissolved solids remain within the perimeter of the pond's lined portion.

(f) Fencing and netting. All pits shall be fenced or enclosed to prevent access by livestock, and fences shall be maintained in good repair. Active drilling or workover pits may have a portion of the pit unfenced to facilitate operations. In issuing a permit, the division may impose additional fencing requirements for protection of wildlife in particular areas. All tanks exceeding 16 feet in diameter, exposed pits, and ponds shall be screened, netted, covered, or otherwise rendered non-hazardous to migratory birds. Drilling and workover pits are exempt from the netting requirement. Immediately after cessation of these operations such pits shall have any visible or measurable layer of oil removed from the surface. Upon written application, the division may grant an exception to screening, netting, or covering requirements upon a showing that an alternative method will adequately protect migratory birds or that the tank or pit is not hazardous to migratory birds.

(g) Unlined pits.

(i) General prohibition. After June 30, 2005 use of, or discharge into, any unlined pit that has not been previously permitted pursuant to Section 711of 19.15.9 NMAC or water quality control commission regulations is prohibited, except as otherwise provided in Section 50 of 19.15.2 NMAC. After April 15, 2004, construction of unlined pits is prohibited unless otherwise provided in Section 50 of 19.15.2 NMAC.

(ii) Unlined pits exempted by previous order. An operator of an unlined pit existing on April 15, 2004 for which a previous exemption was received after hearing as allowed pursuant to commission Orders No. R-3221 through R-3221D inclusive, shall not be required to reapply for an exemption pursuant to Subparagraph (g), Paragraph (2), Subsection C of 19.15.2.50 NMAC provided the operator notifies the division, no later than April 15, 2004, of the existence of each unlined pit it believes is exempted by order, the location of the pit, and the nature and amount of any discharge into the pit. Such order shall constitute a permit for the purpose of Subparagraph (g), Paragraph (2), Subsection C of 19.15.2.50 NMAC. The division may terminate any such permit in accordance with Paragraph (2), Subsection C of 19.15.2.50 NMAC. Any pit constructed after April 15,2004 shall comply with the permitting, lining and other requirements of Section 50 of 19.15.2 NMAC, notwithstanding any previous order to the contrary.

(iii) Unlined pits shall be allowed in the following areas provided that the operator has submitted, and the division has approved, an application for permit as provided in Section 50 of 19.15.2 NMAC, and provided that the pit site is not located in fresh water-bearing alluvium or in a wellhead protection area:

TOWNSHIP 19 SOUTH, RANGE 30 EAST, NMPM Sections 8 through 36;
TOWNSHIP 20 SOUTH, RANGE 30 EAST, NMPM Sections 1 through 36;
TOWNSHIP 20 SOUTH, RANGE 31 EAST, NMPM Sections 1 through 36;
TOWNSHIP 20 SOUTH, RANGE 32 EAST, NMPM Sections 4 through 9, Sections 16 through 21; and Sections 28 through 33;
TOWNSHIP 21 SOUTH, RANGE 29 EAST, NMPM Sections 1 through 36;
TOWNSHIP 21 SOUTH, RANGE 30 EAST, NMPM Sections 1 through 36;
TOWNSHIP 21 SOUTH, RANGE 31 EAST, NMPM Sections 1 through 36;
TOWNSHIP 22 SOUTH, RANGE 29 EAST, NMPM Sections 1 through 36;
TOWNSHIP 22 SOUTH, RANGE 30 EAST, NMPM Sections 1 through 36;
TOWNSHIP 23 SOUTH, RANGE 29 EAST, NMPM Sections 1 through 3, Sections 10 through 15, Sections 22 through 27, and Sections 34 through 36;
TOWNSHIP 23 SOUTH, RANGE 30 EAST, NMPM Sections 1 through 19; and that area within San Juan, Rio Arriba, Sandoval, and McKinley Counties that is outside the valleys of the San Juan, Animas, Rio Grande, and La Plata Rivers, which are bounded by the topographic lines on either side of the rivers that are 100 vertical feet above the river channels, measured perpendicularly to the river channels, andis outside those areas that lie within 50 vertical feet, measured perpendicularly to the drainage channel, of all perennial and ephemeral creeks, canyons, washes, arroyos, and draws, and is outside the areas between the above-named rivers and the Highland Park Ditch, Hillside Thomas Ditch, Cunningham Ditch, Farmers Ditch, Halford Independent Ditch, Citizens Ditch, or Hammond Ditch, provided that no protectable ground water is present or if present, will not be adversely affected; or any area where the discharge into the pit meets New Mexico Water Quality Control Commission ground water standards.

(3) Special requirements for below-grade tanks. All below-grade tanks constructed after April 15, 2004 shall be constructed with secondary containment and leak detection. The operator of any below-grade tank constructed prior to April 15, 2004 shall test its integrity annually and shall promptly repair or replace any below-grade tank that does not demonstrate integrity. Any such below-grade tank shall be equipped with leak detection at the time of any major repair.

(4) Sumps. Operators shall test the integrity of all sumps annually, and shall promptly repair or replace any sump that does not demonstrate integrity. Sumps that can be removed from their emplacements may be tested by visual inspection. Other sumps shall be tested by appropriate mechanical means.

D. Emergency actions.

(1) Permit not required. In an emergency an operator may construct a pit without a permit to contain fluids, solids, or wastes if an immediate danger to fresh water, public health, or the environment exists.

(2) Construction standards. A pit constructed in an emergency shall be constructed, to the extent possible given the emergency, in a manner that is consistent with the requirements of Section 50 of 19.15.2 NMAC and that prevents the contamination of fresh water, and protects public health and the environment.

(3) Notice. The operator shall notify the appropriate district office as soon as possible (if possible before construction begins) of the need for construction of such a pit.

(4) Use and duration. The pit may be used only for the duration of the emergency. If the emergency lasts more than forty-eight (48) hours, the operator must seek approval from the division for continued use of the pit. All fluids, solids or wastes must be removed within 24 hours after cessation of use unless the division extends that time period.

(5) "Emergency pits." Subsection D, of 19.15.2.50 NMAC shall not be construed to allow construction or use of so-called "emergency pits," which are pits constructed as a precautionary matter to contain a spill in the event of a release. Construction or use of any such pit shall require a permit issued pursuant to Section 50 of 19.15.2 NMAC unless the pit is described in a spill prevention, control and countermeasure (SPCC) plan required by the United States environmental protection agency, all fluids are removed from the pit within 24 hours, and the operator has filed a notice of the location of the pit with the division.

E. Drilling fluids and drill cuttings. Drilling fluids and drill cuttings shall either be recycled or be disposed of as approved by the division and in a manner to prevent the contamination of fresh water and protect public health and the environment. The operator shall describe the proposed disposal method in the application for permit to drill or the sundry notices and reports on wells.

F. Closure and restoration.

(1) Closure. Except as otherwise specified in Section 50 of 19.15.2 NMAC, a pit or below-grade tank shall be properly closed within six months after cessation of use. As a condition of a permit, the division may require the operator to file a detailed closure plan before closure may commence. The division for good cause shown may grant a six-month extension of time to accomplish closure. Upon completion of closure a closure report (form C- 144), or sundry notices and reports on wells shall be submitted to the division. Where the pit's contents will likely migrate and cause ground water or surface water to exceed water quality control commission standards, the pit's contents and the liner shall be removed and disposed of in a manner approved by the division.

(2) Surface restoration. Within one year of the completion of closure of a pit, the operator shall contour the surface where the pit was located to prevent erosion and ponding of rainwater.

G. Exemptions; additional conditions.

(1) The division may attach additional conditions to any permit upon a finding that such conditions are necessary to prevent the contamination of fresh water, or to protect public health or the environment.

(2) The division may grant an exemption from any requirement if the operator demonstrates that the granting of such exemption will not endanger fresh water, public health or the environment. The division may revoke any such exemption after notice to the operator of the pit and opportunity for a hearing if the division determines that such action is necessary to prevent the contamination of fresh water, or to protect public health or the environment.

(3) Exemptions may be granted administratively without hearing provided that the operator gives notice to the surface owner of record where the pit is to be located and to such other persons as the division may direct and (a) written waivers are obtained from all persons to whom notice is required, or (b) no objection is received by the division within 30 days of the time notice is given. If any objection is received and the director determines that the objection has technical merit or that there is significant public interest the director shall set the application for hearing. The director, however, may set any application for hearing.

[19.15.2.50 NMAC - N, 02/13/04]

HISTORY OF 19.15.2 NMAC:

Pre-NMAC History: The material in this part was derived from that previously filed with the state records center and archives:
OCC 67-10, Commission Order No. R-3221, Case No. 3551, filed 5/2/67.
OCC 67-10, Amendment No. 1, Commission Order No. R-3221-A, Case No. 3644, filed 8/31/67.
OCC 67-10, Amendment No. 2, Commission Order No. R-3221-B, Case No. 3806, filed 7/31/68.
OCC 67-10, Amendment No. 2, Commission Order No. R-3221-B-1, Case No. 3806, filed 8/20/68.
Order No. R-7940-C, Special Rules and Regulations for the Disposal of Oil and Natural Gas Wastes in the Vulnerable Area in San Juan, McKinley, Rio Arriba and Sandoval Counties, New Mexico, filed 2/10/93.

History of Repealed Material:
OCC 67-10, Commission Order No. R-3221, Case No. 3551 (filed 5/2/67), repealed 02/13/04.
Order No. R-7940-C, Special Rules and Regulations for the Disposal of Oil and Natural Gas Wastes in the Vulnerable Area in San Juan, McKinley, Rio Arriba and Sandoval Counties, New Mexico (filed 2/10/93), repealed 02/13/04.

Other History:
OCC 67-10, Commission Order No. R-3221, Case No. 3551 (filed 5/2/67) and Order No. R-7940-C, Special Rules and Regulations for the Disposal of Oil and Natural Gas Wastes in the Vulnerable Area in San Juan, McKinley, Rio Arriba and Sandoval Counties, New Mexico, (filed 2/10/93) replaced by 19.15.2 NMAC, General Operating Practices, Wastes Arising from Exploration and Production, effective 02/13/04.

TITLE 19 NATURAL RESOURCES & WILDLIFE
CHAPTER 15 OIL AND GAS
PART 3 DRILLING

19.15.3.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department, Oil Conservation Division, 2040 S. Pacheco, Santa Fe, New Mexico 87505, (505) 827-7131.
[2-1-96; 19.15.3.1 NMAC - Rn, 19 NMAC 15.C.1, 11-15-01]

19.15.3.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico.
[2-1-96; 19.15.3.2 NMAC - Rn, 19 NMAC 15.C.2, 11-15-01]

19.15.3.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the Oil and Gas Act which grants the Oil Conservation Division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights, and the disposition of wastes resulting from oil and gas operations.
[2-1-96; 19.15.3.3 NMAC - Rn, 19 NMAC 15.C.3, 11-15-01]

19.15.3.4 DURATION: Permanent.
[2-1-96; 19.15.3.4 NMAC - Rn, 19 NMAC 15.C.4, 11-15-01]

19.15.3.5 EFFECTIVE DATE: February 1, 1996.
[2-1-96; 19.15.3.5 NMAC - Rn, 19 NMAC 15.C.5, 11-15-01]

19.15.3.6 OBJECTIVE: To regulate the drilling of oil and gas wells within the State of New Mexico to enable the Oil Conservation Division to fulfill its statutory mandates under the Oil & Gas Act.
[2-1-96; 19.15.3.6 NMAC - Rn, 19 NMAC 15.C.6, 11-15-01]

19.15.3.7 DEFINITIONS: [Reserved].

19.15.3.8-100 [RESERVED].

19.15.3.101 PLUGGING BOND:

A. Any person, firm, corporation, or association who has drilled or acquired, is drilling, or proposes to drill or acquire any oil, gas, or service well on privately owned or state owned lands within this state shall furnish to the division, and obtain approval thereof, a surety bond running to the State of New Mexico, in a form prescribed by the division, and conditioned that the well be plugged and abandoned in compliance with the rules and regulations of the division. Such bond may be a one-well plugging bond or a blanket plugging bond. All bonds shall be executed by a responsible surety company authorized to do business in the State of New Mexico.

B. Blanket plugging bonds shall be in the amount of fifty thousand dollars ($50,000) conditioned as above provided, covering all oil, gas, or service wells drilled, acquired or operated in this state by the principal on the bond.

C. One-well plugging bonds shall be in the amounts stated below in accordance with the depth and location of the well:

(1) Chaves, Eddy, Lea, McKinley, Rio Arriba, Roosevelt, Sandoval, and San Juan Counties, New Mexico:

Projected Depth of Proposed Well or Actual Depth of Existing Well	Amount of Bond
Less than 5,000 feet	$ 5,000
5,000 feet to 10,000 feet	$ 7,500

More than 10,000 feet	$ 10,000

(2) All other Counties in the State:

Projected Depth of Proposed Well or Actual Depth of Existing Well	Amount of Bond
Less than 5,000 feet	$ 7,500
5,000 feet to 10,000 feet	$ 10,000
More than 10,000 feet	$ 12,500

D. Revised plans for an actively drilling well may be approved by the appropriate District Office of the division for drilling as much as 500 feet deeper than the normal maximum depth allowed on the well's bond. Any well to be drilled more than 500 feet deeper than the normal depth bracket must be covered by a new bond in the amount prescribed for the deeper depth bracket.

E. The bond requirement for any intentionally deviated well shall be determined by the well's measured depth, and not its true vertical depth.

F. A cash bond may be accepted by the division pursuant to the conditions set forth hereinafter. Cash representing the full amount of the bond shall be deposited by the operator in an account in a federally-insured financial institution located within the State of New Mexico, such account to be held in trust for the division. Both one well and blanket cash bonds shall be in the amount specified for surety bonds. A document, approved by the division, evidencing the terms and conditions of the cash bond shall be executed by an authorized representative of the operator and the depository institution and filed with the division prior to the effective date of the bond. No cash bond will be authorized by the Director and no wells may be drilled or acquired under a blanket cash bond unless the operator/applicant is in good standing with the division. If the financial status or reliability of the applicant is unknown to the Director he may require the filing of a financial statement or such other information as may be necessary to evaluate the ability of the applicant/operator to fulfill the conditions of the bond.

G. From time to time any accrued interest over and above the face amount of the bond may be paid to the operator. Upon satisfactory plugging by the operator of any well(s) covered by a cash bond, the Director shall issue an order authorizing the release of said bond.

H. Any bond required by Section 101 of 19.15.3 NMAC is a plugging bond, not a drilling bond, and shall endure until any well drilled or acquired under such bond has been plugged and abandoned and such plugging and abandonment has been approved by the division, or has been covered by another bond approved by the division.

I. Transfer of a property does not of itself release a bond. In the event of transfer of ownership of a well, the appropriate form, C-103 or C-104, properly executed, shall be filed with the District Office of the division in accordance with Rule 1103 or Rule 1104 by the new owner of the well. The District Office may approve the transfer providing that a new one-well bond covering the well or a blanket bond in the name of the new owner has been approved by the Santa Fe office of the division.

J. Upon approval of the bond and the Form C-103 or C-104, the transferror is released of plugging responsibility for the well, and upon request, the original bond will be released. No blanket bond will be released, however, until all wells covered by the bond have been plugged and abandoned or transferred in accordance with the provisions of Section 101 of 19.15.3 NMAC.

K. All bonds shall be filed with the Santa Fe office of the division, and approval of such bonds, as well as releases thereof, obtained from said office.

L. All bonds required by these rules shall be conditioned for well plugging and location cleanup only, and not to secure payment for damages to livestock, range, water, crops, tangible improvements, nor any other purpose.

M. Upon failure of the operator to properly plug and abandon the well(s) covered by a bond, the division shall give notice to the operator and surety, if applicable, and hold a hearing as to whether the well(s) should be plugged in accordance with a division-approved plugging program. If, at the hearing, it is determined that the operator has failed to plug the well as provided for in the bond conditions and division rules, the Division director shall issue an order directing the well(s) to be plugged in a time certain. Such an order may also direct the forfeiture of the bond upon the failure or refusal of the operator, surety, or other responsible party to properly plug the well(s). If the proceeds of the bond(s) are not sufficient to cover all of the costs incurred by the division in plugging the

well(s) covered by the bond, the division shall take such legal action as is necessary to recover such additional costs. Any monies recovered through bond forfeiture or legal actions shall be placed in the Oil & Gas Reclamation Fund.
[1-1-50, 6-17-77, 6-5-86, 2-1-96; 19.15.3.101 NMAC - Rn, 19 NMAC 15.C.101, 11-15-01]

19.15.3.102 NOTICE OF INTENTION TO DRILL:

A. Prior to the commencement of operations, notice shall be delivered to the division of intention to drill any well for oil or gas or for injection purposes and approval obtained on Form C-101. A copy of the approved Form C-101 must be kept at the well site during drilling operations.

B. No permit shall be approved for the drilling of any well within the corporate limits of any city, town, or village of this state unless notice of intention to drill such well has been given to the duly constituted governing body of such city, town or village or its duly authorized agent. Evidence of such notification shall accompany the application for a permit to drill (Form C-101).

C. When filing a permit to drill in any quarter-quarter section containing an existing well or wells, the applicant shall concurrently file a plat or other acceptable document locating and identifying such well(s) and a statement that the operator(s) of such well(s) have been furnished a copy of the permit.
[1-1-50, 5-22-73…2-1-96; 19.15.3.102 NMAC - Rn, 19 NMAC 15.C.102, 11-15-01]

19.15.3.103 SIGN ON WELLS:

A. All wells and related facilities regulated by the division shall be identified by a sign, which sign shall remain in place until the well is plugged and abandoned and the related facilities are closed.

B. For drilling wells, the sign shall be posted on the derrick or not more than 20 feet from the well. C. The sign shall be of durable construction and the lettering shall be legible and large enough to be read under normal conditions at a distance of 50 feet.

D. The wells on each lease or property shall be numbered in non-repetitive, logical and distinctive sequence.

E. An operator will have 90 days from the effective date of an operator name change to change the operator name on the well sign unless an extension of time, for good cause shown along with a schedule for making the changes, is granted.

F. Each sign shall show the:

(1) number of well;

(2) name of property;

(3) name of operator;

(4) location by footage, quarter-quarter section, township and range (or Unit Letter can be substituted for the quarter-quarter section); and

(5) API number.

[1-1-50, 2-1-96, 6-30-97, 3-31-00; 19.15.3.103 NMAC - Rn, 19 NMAC 15.C.103, 11-15-01; A, 01-31-03]

19.15.3.104 WELL SPACING AND LOCATION:

A. Classification Of Wells: Wildcat And Development Wells

(1) Wildcat Well

(a) In San Juan, Rio Arriba, Sandoval, and McKinley Counties a wildcat well is any well to be drilled the spacing unit of which is a distance of two miles or more from:

(i) the outer boundary of any defined pool that has produced oil or gas from the formation to which the well is projected to be drilled; and

(ii) any well that has produced oil or gas from the formation to which the proposed well is projected to be drilled.

(b) In all counties except San Juan, Rio Arriba, Sandoval, and McKinley, a wildcat well is any well to be drilled the spacing unit of which is a distance of one mile or more from:

(i) the outer boundary of any defined pool that has produced oil or gas from the formation to which the well is projected to be drilled; and

(ii) any well that has produced oil or gas from the formation to which the proposed well is projected.

(2) Development Well

(a) Any well that is not a wildcat well shall be classified as a development well for the nearest pool that has produced oil or gas from the formation to which the well is projected to be drilled. Such development well shall be spaced, drilled, operated, and produced in accordance with the rules in effect for that pool, provided the well is completed in that pool.

(b) Any well classified as a development well for a pool but completed in a producing formation not included in the vertical limits of that pool shall be operated and produced in accordance with the rules in effect for the nearest pool that is producing from that formation within the two miles in San Juan, Rio Arriba, Sandoval, and McKinley Counties or within one mile everywhere else. If there is no designated pool for that producing formation within the two miles in San Juan, Rio Arriba, Sandoval, and McKinley Counties or within one mile everywhere else, the well shall be re-classified as a wildcat well.

B. Oil Well Acreage And Well Location Requirements

(1) Any wildcat well that is projected to be drilled as an oil well to a formation and in an area that in the opinion of the division may reasonably be presumed to be productive of oil rather than gas and each development well for a defined oil pool, unless otherwise provided in special pool orders, shall be located on a spacing unit consisting of approximately 40 contiguous surface acres substantially in the form of a square which is a legal subdivision of the U.S. Public Land Surveys, which is a governmental quarter-quarter section or lot, and shall be located no closer than 330 feet to any boundary of such unit. Only those 40-acre spacing units committed to active secondary recovery projects shall be permitted more than four wells.

(2) If a well drilled as an oil well is completed as a gas well but does not conform to the applicable gas well location rules, the operator must apply for administrative approval for a non-standard location before the well can produce. The Director may set any such application for hearing.

C. Gas Wells Acreage And Well Location Requirements. Any wildcat well that is projected to be drilled as a gas well to a formation and in an area that in the opinion of the division may reasonably be presumed to be productive of gas rather than oil and each development well for a defined gas pool, unless otherwise provided in special pool orders, shall be spaced and located as follows:

(1) 640-Acre Spacing applies to any deep gas well in Rio Arriba, San Juan, Sandoval or McKinley County that is projected to be drilled to a gas producing formation older than the Dakota formation or is a development well within a gas pool created and defined by the division after June 1, 1997 in a formation older than the Dakota formation, which formation or pool is located within the surface outcrop of the Pictured Cliffs formation (i.e., the San Juan Basin). Such well shall be located on a spacing unit consisting of 640 contiguous surface acres, more or less, substantially in the form of a square which is a section and legal subdivision of the U.S. Public Land Surveys and shall be located no closer than: 1200 feet to any outer boundary of the spacing unit, 130 feet to any quarter section line, and 10 feet to any quarter-quarter section line or subdivision inner boundary.

(2) 320-Acre Spacing applies to any deep gas well in Lea, Chaves, Eddy or Roosevelt County, defined as a well that is projected to be drilled to a gas producing formation or is within a defined gas pool in the Wolfcamp or an older formation. Such well shall be located on a spacing unit consisting of 320 surface contiguous acres, more or less, comprising any two contiguous quarter sections of a single section that is a legal subdivision of the U.S. Public Land Surveys provided that:

(a) the initial well on a 320-acre unit is located no closer than 660 feet to the outer boundary of the quarter section on which the well is located and no closer than 10 feet to any quarter-quarter section line or subdivision inner boundary;

(b) only one infill well on a 320-acre unit shall be allowed provided that the well is located in the quarter section of the 320-acre unit not containing the initial well and is no closer than 660 feet to the outer boundary of the quarter section and no closer than 10 feet to any quarter-quarter section line or subdivision inner boundary; and

(c) the division-designated operator for the infill well is the same operator currently designated by the division for the initial well.

(3) 160-Acre Spacing applies to any other gas well not covered above. Such well shall be located in a spacing unit consisting of 160 surface contiguous acres, more or less, substantially in the form of a square which is a quarter section and a legal subdivision of the U.S. Public Land Surveys and shall be located no closer than 660 feet to any outer boundary of such unit and no closer than 10 feet to any quarter-quarter section or subdivision inner boundary.

D. Acreage Assignment

(1) Well Tests and Classification. It is the responsibility of the operator of any wildcat or development gas well to which more than 40 acres has been dedicated to conduct a potential test within 30 days following completion of the well and to file the test with the division within 10 days following completion of the test. (See Rule 401)

(a) The date of completion for a gas well is the date of the conclusion of active completion work on the well.

(b) If the division determines that a well should not be classified as a gas well, the division will reduce the acreage dedicated to the well to the standard acreage for an oil well.

Failure of the operator to file the test within the specified time will also subject the well to such acreage reduction.

(2) Non-Standard Spacing Units. Any well that does not have the required amount of acreage dedicated to it for the pool or formation in which it is completed may not be produced until a standard spacing unit for the well has been formed and dedicated or until a non-standard spacing unit has been approved.

(a) Division District Offices have the authority to approve non-standard spacing units without notice when the unorthodox size or shape is necessitated by a variation in the legal subdivision of the U. S. Public Land Surveys and/or consists of an entire governmental section and the non-standard spacing unit is not less than 70% or more than 130% of a standard spacing unit. The operator must obtain division approval of division Form C-102 showing the proposed non-standard spacing unit and the acreage contained therein.

(b) The Director may grant administrative approval to non-standard spacing units after notice and opportunity for hearing when an application has been filed and the unorthodox size or shape is necessitated by a variation in the legal subdivision of the U.S. Public Land Surveys or the following facts exist:

(i) the non-standard spacing unit consists of: (A) a single quarter-quarter section or lot or (B) quarter-quarter sections or lots joined by a common side; and

(ii) the non-standard spacing unit lies wholly within: a single quarter section if the well is completed in a pool or formation for which 40, 80, or 160 acres is the standard spacing unit size; a single half section if the well is completed in a pool or formation for which 320 acres is the standard spacing unit size; or a single section if the well is completed in a pool or formation for which 640 acres is the standard spacing unit size.

(c) Applications for administrative approval of non-standard spacing units pursuant to Subsection D, Paragraph (2), Subparagraph (b) of 19.15.3.104 NMAC shall be submitted to the division's Santa Fe Office and accompanied by: (i) a plat showing the spacing unit and an applicable standard spacing unit for that pool or formation, the proposed well dedications and all adjoining spacing units; (ii) a list of affected persons as defined in Rule 1207.A(2); and (iii) a statement discussing the reasons for the formation of the non-standard spacing unit.

(d) The applicant shall submit a statement attesting that the applicant, on or before the date the application was submitted to the division, sent notification to the affected persons by submitting a copy of the application, including a copy of the plat described in Subparagraph (c) above, by certified mail, return receipt requested, advising them that if they have an objection it must be filed in writing within 20 days from the date the division receives the application. The Director may approve the application upon receipt of waivers from all the notified persons or if no person has filed an objection within the 20-day period.

(e) The Director may set for hearing any application for administrative approval.

(3) Number of Wells Per Spacing Unit. Exceptions to the provisions of statewide rules or special pool orders concerning the number of wells allowed per spacing unit may be permitted by the Director only after notice and opportunity for hearing. Notice shall be given to those affected persons defined in Rule 1207.A.(2).

E. Forms - Form C-102 "Well Location and Acreage Dedication Plat" for any well shall designate the exact legal subdivision dedicated to the well. Form C-101 "Application for Permit to Drill, Deepen, or Plug Back" will not be approved without an acreage designation on Form C-102.

F. Unorthodox Locations

(1) Well locations for producing wells and/or injection wells that are unorthodox based on the requirements of Subsection B above and are necessary for an efficient production and injection pattern within a secondary recovery, tertiary recovery, or pressure maintenance project are hereby authorized, provided that the unorthodox location within the project is no closer than the required minimum distance to the outer boundary of the lease or unitized area, and no closer than 10 feet to any quarter-quarter section line or subdivision inner boundary. These locations shall only require such prior approvals as are necessary for an unorthodox location.

(2) The Director may grant an exception to the well location requirements of Subsections B and C above or special pool orders after notice and opportunity for hearing when the exception is necessary to prevent waste or protect correlative rights.

(3) Applications for administrative approval pursuant to Subsection F, Paragraph (2) above shall be submitted to the division's Santa Fe Office accompanied by (a) a plat showing the spacing unit, the proposed unorthodox well location and the adjoining spacing units and wells; (b) a list of affected persons as defined in Rule 1207.A(2); and (c) information evidencing the need for the exception. Notice shall be given as required in Rule 1207.A(2).

(4) The applicant shall submit a statement attesting that applicant, on or before the date that the application was submitted to the division, sent notification to the affected persons by submitting a copy of the application, including a copy of the plat described in Subsection F, Paragraph (3) above, by certified mail, return receipt requested, advising them that if they have an objection it must be filed in writing within 20 days from the date the division receives the application. The Director may approve the unorthodox location upon receipt of waivers from all the affected persons or if no affected person has filed an objection within the 20-day period.

(5) The Director may set for hearing any application for administrative approval of an unorthodox location.

(6) Whenever an unorthodox location is approved, the division may order any action necessary to offset any advantage of the unorthodox location.

G. Effect On Allowables

(1) If the drilling tract is within a prorated/allocated oil pool or is subsequently placed within such pool and the drilling tract consists of less than 39½ acres or more than 40½ acres, the top unit allowable for the well shall be increased or decreased in the proportion that the number of acres in the drilling tract bears to 40.

(2) If the drilling tract is within a prorated/allocated gas pool or is subsequently placed within such pool and the drilling tract consists of less than 158 acres or more than 162 acres in 160-acre pools, or less than 316 acres or more than 324 acres in 320-acre pools, or less than 632 acres or more than 648 acres in 640-acre pools, the top allowable for the well shall be decreased or increased in the proportion that the number of acres in the drilling tract bears to a standard spacing unit for the pool.

(3) In computing acreage under Paragraphs (1) and (2) above, less than ½ acre shall not be counted but ½ acre or more shall count as one acre.

(4) The provisions of Paragraphs (1) and (2) above shall apply only to wells completed after January 1, 1950.

H. Division-Initiated Exceptions - In order to prevent waste, the division may, after hearing, set different spacing requirements and require different acreage for drilling tracts in any defined oil or gas pool.

I. Pooling Or Communitization Of Small Oil Lots

(1) The division may approve the pooling or communitization of fractional oil lots of 20.49 acres or less with a contiguous oil spacing unit when the ownership is common and the tracts are part of the same lease with the same royalty interests if the following requirements are satisfied:

(a) Applications for administrative approval shall be submitted to the division's Santa Fe Office and accompanied by: (i) a plat showing the dimensions and acreage involved, the ownership of such acreage, the location of all existing and proposed wells and all adjoining spacing units; (ii) a list of affected persons as defined in Rule 1207.A(2); and (iii) a statement discussing the reasons for the pooling or communitization.

(b) The applicant shall submit a statement attesting that the applicant, on or before the date the application was submitted to the division, sent notification to the affected persons by submitting a copy of the application, including a copy of the plat described in (a) above, by certified mail, return receipt requested, advising them that if they have an objection it must be filed in writing within 20 days from the date the division receives the application. The Director may approve the application upon receipt of waivers from all the notified persons or if no person has filed an objection within the 20-day period.

(c) The Director may set for hearing any application for administrative approval.

(2) The division may consider the common ownership and common lease requirements met if the applicant furnishes with the application a copy of an executed pooling agreement communitizing the tracts involved.
[1-1-50…2-1-96; A, 6-30-97; A, 8-31-99; 19.15.3.104 NMAC - Rn, 19 NMAC 15.C.104, 11-15-01]

19.15.3.105 [RESERVED].
[1-1-50, 9-1-89…2-1-96; 19.15.3.105 NMAC - Rn, 19 NMAC 15.C.105, 11-15-01; Repealed, 5-28-04]

19.15.3.106 SEALING OFF STRATA:

A. During the drilling of any oil well, injection well or any other service well, all oil, gas, and water strata above the producing and/or injection horizon shall be sealed or separated in order to prevent their contents from passing into other strata.

B. All fresh waters and waters of present or probable value for domestic, commercial, or stock purposes shall be confined to their respective strata and shall be adequately protected by methods approved by the division. Special precautions by methods satisfactory to the division shall be taken in drilling and abandoning wells to guard against any loss of artesian water from the strata in which it occurs, and the contamination of artesian water by objectionable water, oil, or gas.

C. All water shall be shut off and excluded from the various oil- and gas-bearing strata which are penetrated. Water shut-offs shall ordinarily be made by cementing casing.
[1-1-50, 3-1-91…2-1-96; 19.15.3.106 NMAC - Rn, 19 NMAC 15.C.106, 11-15-01]

19.15.3.107 CASING AND TUBING REQUIREMENTS:

A. Any well drilled for oil or natural gas shall be equipped with such surface and intermediate casing strings and cement as may be necessary to effectively seal off and isolate all water-, oil-, and gas-bearing strata and other strata encountered in the well down to the casing point. In addition thereto, any well completed for the production of oil or natural gas shall be equipped with a string of properly cemented production casing at sufficient depth to ensure protection of oil- and gas-bearing strata encountered in the well, including the one(s) to be produced.

B. Sufficient cement shall be used on surface casing to fill the annular space behind the casing to the top of the hole, provided however, that authorized field personnel of the division may, at their discretion, allow exceptions to the foregoing requirement when known conditions in a given area render compliance impracticable.

C. All cementing shall be by pump and plug method unless some other method is expressly authorized by the division.

D. All cementing shall be with conventional-type hard-setting cements to which such additives (lighteners, densifiers, extenders, accelerators, retarders, etc.) have been added to suit conditions in the well.

E. Authorized field personnel of the division may, when conditions warrant, allow exceptions to the above paragraph and permit the use of oil-base casing packing material in lieu of hard-setting cements on intermediate and production casing strings; provided however, that when such materials are used on the intermediate casing string, conventional-type hard-setting cements shall be placed throughout all oil- and gas-bearing zones and throughout at least the lowermost 300 feet of the intermediate casing string. When such materials are used on the production casing string, conventional-type hard-setting cements shall be placed throughout all oil- and gas-bearing zones and shall extend upward a minimum of 500 feet above the uppermost perforation or, in the case of an open-hole completion, 500 feet above the production casing shoe.

F. All casing strings shall be tested and proved satisfactory as provided in Subsection I. below.

G. After cementing, but before commencing tests required in Subsection I. below, all casing strings shall stand cemented in accordance with Option 1 or 2 below. Regardless of which option is taken, the casing shall remain stationary and under pressure for at least eight hours after the cement has been placed. Casing shall be "under pressure" if some acceptable means of holding pressure is used or if one or more float valves are employed to hold the cement in place.

(1) Option 1 Allow all casing strings to stand cemented a minimum of eighteen (18) hours prior to commencing tests. Operators using this option shall report on Form C-103 the actual time the cement was in place before initiating tests.

(2) Option 2 (May be used in the counties of San Juan, Rio Arriba, McKinley, Sandoval, Lea, Eddy, Chaves, and Roosevelt only.) Allow all casing strings to stand cemented until the cement has reached a compressive strength of at least 500 pounds per square inch in the "zone of interest" before commencing tests, provided however, that no tests shall be commenced until the cement has been in place for at least eight (8) hours.

(a) The "zone of interest" for surface and intermediate casing strings shall be the bottom 20 percent of the casing string, but shall be no more than 1000 feet nor less than 300 feet of the bottom-part of the casing unless the casing is set at less than 300 feet. The "zone of interest" for production casing strings shall include the interval or intervals where immediate completion is contemplated.

(b) To determine that a minimum compressive strength of 500 pounds per square inch has been attained, operators shall use the typical performance data for the particular cement mix used in the well, at the minimum temperature indicated for the zone of interest by Figure 107-A, Temperature Gradient Curves. Typical performance data used shall be that data furnished by the cement manufacturer or by a competent materials testing agency, as determined in accordance with the latest edition of API Code RP 10 B "Recommended Practice for Testing Oil-Well Cements."

(See Temperature Gradient - Page 17A)

H. Operators using the compressive strength criterion (Option 2) shall report the following information on Form C-103:

(1) Volume of cement slurry (cubic feet) and brand name of cement and additives, percent additives used, and sequence of placement if more than one type cement slurry is used.

(2) Approximate temperature of cement slurry when mixed.

(3) Estimated minimum formation temperature in zone of interest.

(4) Estimate of cement strength at time of casing test.

(5) Actual time cement in place prior to starting test.

I. All casing strings except conductor pipe shall be tested after cementing and before commencing any other operations on the well. Form C-103 shall be filed for each casing string reporting the grade and weight of pipe used. In the case of combination strings utilizing pipe of varied grades or weights, the footage of each grade and weight used shall be reported. The results of the casing test, including actual pressure held on pipe and the pressure drop observed shall also be reported on the same Form C-103.

(1) Casing strings in wells drilled with rotary tools shall be pressure tested. Minimum casing test pressure shall be approximately one-third of the manufacturer's rated internal yield pressure except that the test pressure shall not be less than 600 pounds per square inch and need not be greater than 1500 pounds per square inch. In cases where combination strings are involved, the above test pressure shall apply to the lowest pressure rated casing used. Test pressures shall be applied for a period of 30 minutes. If a drop of more than 10 percent of the test pressure should occur, the casing shall be considered defective and corrective measures shall be applied.

(2) Casing strings in wells drilled with cable tools may be tested as outlined in Subsection I, Paragraph (1) above, or by bailing the well dry in which case the hole must remain satisfactorily dry for a period of at least one (1) hour before commencing any further operations on the well.

J. Well Tubing Requirements

(1) All flowing oil wells equipped with casing larger in size than 2 7/8-inch OD shall be tubed.

(2) All gas wells equipped with casing larger in size than 3 ½-inch OD shall be tubed.

(3) Tubing shall be set as near the bottom as practical and tubing perforations shall not be more than 250 feet above top of pay zone.

(4) The supervisor of the appropriate division district office, upon application, may grant exceptions to these requirements, provided waste will not be caused.

(5) The supervisor may request that an application be reviewed by the Director. The operator shall

submit information and give notice as requested by the Director. Unprotested applications may be approved after 20 days of receipt of the application and supporting information. If the application is protested, or the Director so decides, the application shall be set for hearing.

K. Repealed.

[1-1-50, 5-5-58, 6-26-59, 2-29-64, 2-1-96, 2-26-99; 19.15.3.107 NMAC - Rn, 19 NMAC 15.C.107, 11-15-01]

19.15.3.108 DEFECTIVE CASING OR CEMENTING:

If any well appears to have a defective casing program or faultily cemented or corroded casing which will permit or may create underground waste or contamination of fresh waters, the operator shall give written notice to the division within five (5) working days and proceed with diligence to use the appropriate method and means to eliminate such hazard. If such hazard of waste or contamination of fresh water cannot be eliminated, the well shall be properly plugged and abandoned.

[1-1-50...2-1-96; 19.15.3.108 NMAC - Rn, 19 NMAC 15.C.108, 11-15-01]

19.15.3.109 BLOWOUT PREVENTION: (See Section 114, Subsection B of 19.15.3 NMAC also)

A. Blowout preventers shall be installed and maintained in good working order on all drilling rigs operating in areas of known high pressures at or above the projected depth of the well and in all areas where pressures which will be encountered are unknown, and on all workover rigs working on wells in which high pressures are known to exist.

B. Blowout preventers shall be installed and maintained in good working order on all drilling rigs and workover rigs operating within the corporate limits of any city, town, or village, or within 1320 feet of habitation, school, or church, wherever located.

C. All operators, when filing Form C-101, Application for Permit to Drill, Deepen, or Plug Back, or Form C-103, Sundry Notices, for any operation requiring blowout prevention equipment in accordance with Subsections A and B above, shall submit a proposed blowout prevention program for the well. The program as submitted may be modified by the district supervisor if, in his judgement, such modification is necessary.

[10-22-74...2-1-96; 19.15.3.109 NMAC - Rn, 19 NMAC 15.C.109, 11-15-01]

19.15.3.110 PULLING OUTSIDE STRINGS OF CASING:

In pulling outside strings of casing from any oil or gas well, the space outside the casing left in the hole shall be kept and left full of mud-laden fluid or cement of adequate specific gravity to seal off all fresh and salt water strata and any strata bearing oil or gas not producing.

[1-1-50...2-1-96; 19.15.3.110 NMAC - Rn, 19 NMAC 15.C.110, 11-15-01]

19.15.3.111 DEVIATION TESTS AND DIRECTIONAL WELLS:

A. Definitions - the following definitions shall apply to Section 111 of 19.15.3 NMAC only:

(1) Azimuth - the deviation in the horizontal plane of a wellbore expressed in terms of compass degrees.

(2) Deviated Well - any wellbore which is intentionally deviated from vertical but not with an intentional azimuth. Any deviated well is subject to Section 111, Subsection B of 19.15.3 NMAC.

(3) Directional Well - a wellbore which is intentionally deviated from vertical with an intentional azimuth. Any directional well is subject to Section 111, Subsection C of 19.15.3 NMAC.

(4) Kick-off Point - the point at which the wellbore is intentionally deviated from vertical.

(5) Lateral - any portion of a wellbore past the point where the wellbore has been intentionally departed from the vertical.

(6) Penetration Point - the point where the wellbore penetrates the top of the pool from which it is intended to produce.

(7) Producing Area - the area that lies within a window formed by plotting the measured distance from the North, South, East and West boundaries of a project area, inside of which a vertical wellbore can be drilled and produced in conformity with the setback requirements from the outer boundary of a standard spacing unit for the

applicable pool(s).

(8) Producing Interval - that portion of the wellbore drilled inside the vertical limits of a pool, between its penetration point and its terminus.

(9) Project Area - an area designated on Form C-102 that is enclosed by the outer boundaries of a spacing unit, a combination of complete spacing units, or an approved secondary, secondary, tertiary or pressure maintenance project.

(10) Project Well - any well drilled, completed, produced or injected into as either a vertical well, deviated well or directional well.

(11) Spacing Unit - the acreage that is dedicated or a well in accordance with Rule 104. Included in this definition is a “unit of proration for oil or gas” as defined by the division and all non-standard such units previously approved by the division.

(12) Terminus - the farthest point attained along the wellbore.

(13) Unorthodox - any part of the producing interval which is located outside of the producing area.

(14) Vertical Well - a well that does not have an intentional departure or course deviation from the vertical.

(15) Wellbore - the interior surface of a cased or open hole through which drilling, production, or injection operations are conducted.

B. Deviated Wellbores

(1) Deviation Tests Required. Any vertical or deviated well which is drilled or deepened shall be tested at reasonably frequent intervals to determine the deviation from the vertical. Such tests shall be made at least once each 500 feet or at the first bit change succeeding 500 feet. A tabulation of all deviation tests run, sworn to and notarized, shall be filed with Form C-104, Request for Allowable and Authorization to Transport Oil and Natural Gas.

(2) Excessive Deviation. When the deviation averages more than five degrees in any 500-foot interval, the operator shall include the calculations of the maximum possible horizontal displacement of the hole. When the maximum possible horizontal displacement exceeds the distance to the nearest outer boundary line of the appropriate unit, the operator shall run a directional survey to establish the location of the producing interval(s).

(3) Unorthodox Locations. If the results of the directional survey indicate that the producing interval is more than 50 feet from the approved surface location and closer than the minimum setback requirements to the outer boundaries of the applicable unit, then the well shall be considered unorthodox. To obtain authority to produce such well, the operator shall file an application with the Division director, copy to the appropriate division district office, and shall otherwise follow the normal process outlined in Section 104, Subsection F, Paragraph (3) of 19.15.3 NMAC to obtain approval of the unorthodox location.

(4) Directional Survey Requirements. Upon request from the Division director, any vertical or deviated well shall be directionally surveyed. The appropriate division district office shall be notified of the approximate time any directional surveys are to be conducted. All directional surveys run on any well in any manner for any reason must be filed with the division upon completion of the well. The division shall not assign an allowable to the well until all such directional surveys have been filed.

C. Directional Wellbores

(1) Directional Drilling Within a Project Area. A permit to directionally drill a wellbore may be granted by the appropriate division district office if the producing interval is entirely within the producing area or at an unorthodox location previously approved by the division. Additionally, if the project area consists of a combination of drilling units and includes any State or Federal acreage, a copy of the OCD Form C-102 shall be sent to the State Land Office or the Bureau of Land Management.

(2) Unorthodox Wellbores. If all or part of the producing interval of any directional wellbore is projected to be outside of the producing area, the wellbore shall be considered unorthodox. To obtain approval for such wellbore, the applicant shall file a written application in duplicate with the Division director, copy to the appropriate division district office, and shall otherwise follow the normal process outlined in Section 104, Subsection F, Paragraph (3) of 19.15.3 NMAC.

(3) Allowables for Project Areas With Multiple Proration Units. The maximum allowable assigned to

the project area within a prorated pool shall be based upon the number of standard spacing units (or approved non-standard spacing units) that are developed or traversed by the producing interval of the directional wellbore or wellbores. Such maximum allowable shall be applicable to all production from the project area, including any vertical wellbores on standard spacing units inside the project area.

(4) Directional Surveys Required. A directional survey shall be required on each well drilled under the provisions of this section. The appropriate division district office shall be notified of the approximate time all directional surveys are to be conducted. All directional surveys run on any well in any manner for any reason must be filed with the division upon completion of the well. The division shall not assign an allowable to the well until all such directional surveys have been filed. If the directional survey indicates that any part of the producing interval is outside of the producing area, or, in the case of an approved unorthodox location, less than the approved setback requirements from the outer boundary of the applicable unit, then the operator shall file an application with the Division director, copy to the appropriate division district office, and shall otherwise follow the normal process outlined in Section 104, Subsection F, Paragraph (3) of 19.15.3 NMAC to obtain approval of the unorthodox location.

(5) Re-entry of Vertical or Deviated Wellbores for Directional Drilling Projects. These wellbores shall be considered orthodox provided the surface location is orthodox and the location of producing interval is within the tolerance allowed for deviated wellbores under Section 111, Subsection B, Paragraph (3) of 19.15.3 NMAC.

D. Additional Matters

(1) Directional surveys required under the provisions of Section 111 of 19.15.3 NMAC shall have shot points no more than 200 feet apart and shall be run by competent surveying companies that are approved by the Division director. Exceptions to the minimum shot point spacing will be allowed provided the accuracy of the survey is still within acceptable limits.

(2) The Division director, may, at his discretion, set any application for administrative approval whereby the operator shall submit appropriate information and give notice as requested by the Division director. Unprotested applications may be approved administratively within 20 days of receipt of the application and supporting information. If the application is protested, or the Division director decides that a public hearing is appropriate, the application may be set for public hearing.

(3) Permission to deviate or directionally drill any wellbore for any reason or in any manner not provided for in Section 111 of 19.15.3 NMAC shall be granted only after notice and opportunity for hearing.

E. Reserved.

(1) Reserved.

(2) Reserved.

F. Reserved.

(1) Reserved.

(2) Reserved.

(3) Reserved.

[1-1-50; 8-28-62; 3-2-84; 7-26-95; 2-1-96; A, 7-31-97; 19.15.3.111 NMAC - Rn, 19 NMAC 15.C.111, 11-15-01]

19.15.3.112 [MULTIPLE COMPLETIONS; BRADENHEAD GAS WELLS]

A. Multiple Completions

(1) Filing. Operators intending to multiple complete must file Form C-101 and/or C-103 for approval before completing and C-104 after completing along with any information required by the form instructions.

(2) Operation and Testing

(a) Wells shall be completed and produced so that no commingling of hydrocarbons from separate pools occurs.

(b) The operator shall commence a segregation and/or packer leakage test within 20 days after the multiple completion. Segregation tests and/or packer leakage tests shall also be made any time the packer is disturbed. The operator shall also conduct any other tests and determinations required by the division. The appropriate district office shall be notified 48 hours in advance of tests so the district office may schedule personnel to witness the tests. Offset operators may witness such tests and shall advise the operator in writing if they desire to be notified of the tests. Test results shall be filed with the division within 20 days of test completion. In the event a segregation and/or packer leakage test indicates communication between separate pools, the operator shall immediately notify the division and commence corrective action on the well.

(c) Wells shall be equipped so that (i) reservoir pressure may be determined for each of the separate pools, and (ii) meters may be installed so that the gas and/or oil produced from each of the separate pools may be accurately measured.

(d) No multiple completion shall produce in a manner unnecessarily wasting reservoir energy.

(e) The division may require the proper plugging of any zone of a multiple-completed well if the plugging appears necessary to prevent waste, protect correlative rights or protect groundwater, public health or the environment.

B. Bradenhead Gas Wells

(1) The production of gas from a bradenhead gas well may be permitted only by order of the division upon hearing, except as noted by the provisions of Subsection C of 19.15.3.112 NMAC.

(2) The application for such hearings shall be submitted in triplicate and shall include an exhibit showing the location of all wells on applicant's lease and all offset wells on offset leases, together with a diagrammatic sketch showing the casing program, formation tops, estimated top of cement on each casing string run and any other pertinent data, including drill stem tests.

(3) The Division director shall have authority to grant an exception to the requirements of paragraph A. above without notice and hearing where application has been filed in due form, and when the lowermost producing zone involved in the completion is an oil or gas producing zone within the defined limits of an oil or gas pool and the producing zone to be produced through the bradenhead connection is a gas producing zone within the defined limits of a gas pool.

(4) Applicants shall furnish all operators who offset the lease upon which the subject well is located a copy of the application to the division, and applicant shall include with his application a written stipulation that all offset operators have been properly notified. The Division director shall wait at least 10 days before approving the production of gas from the bradenhead gas well, and shall approve such production only in the absence of objection from any offset operator. In the event an operator objects to the completion the Division director shall consider the matter only after proper notice and hearing.

(5) The division may waive the 10-day waiting period requirement if the applicant furnishes the division with the written consent to the production of gas from the bradenhead connection by all offset operators involved.

(6) Section 112-2 of 19.15.3 NMAC shall apply only to wells hereinafter completed as bradenhead gas wells.

(7) (1), (2), (3), (4) Repealed.

(8) (1); (1).(a); (1).(b); (2) Repealed.

(9) (1), (2) Repealed.

(10) (1).(a), (b), (c), (d), (e), (f), (g) Reserved.

[4-3-53; 7-3-58…2-1-82; 2-1-96; 19.15.3.112 NMAC - Rn, 19 NMAC 15.C.112-A and 112-B, 11-15-01]

19.15.3.113 SHOOTING AND CHEMICAL TREATMENT OF WELLS:
If injury results to the producing formation, injection interval, casing or casing seat from shooting, fracturing, or treating a well and which injury may create underground waste or contamination of fresh water, the operator shall give written notice to the division within five (5) working days and proceed with diligence to use the appropriate method and means for rectifying such damage. If shooting, fracturing, or chemical treating results in irreparable injury to the well the division may require the operator to properly plug and abandon the well.
[1-1-50...2-1-96; 19.15.3.113 NMAC - Rn, 19 NMAC 15.C.113, 11-15-01]

19.15.3.114 SAFETY REGULATIONS:

A. All oil wells shall be cleaned into a pit or tank, not less than 40 feet from the derrick floor and 150 feet from any fire hazard. All flowing oil wells must be produced through an oil and gas separator of ample capacity and in good working order. No boiler or portable electric lighting generator shall be placed or remain nearer than 150 feet to any producing well or oil tank. Any rubbish or debris that might constitute a fire hazard shall be removed to a distance of at least 150 feet from the vicinity of wells and tanks. All waste shall be burned or disposed of in such manner as to avoid creating a fire hazard.

B. When coming out of the hole with drill pipe, drilling fluid shall be circulated until equalized and subsequently drilling fluid level shall be maintained at a height sufficient to control subsurface pressures. During course of drilling blowout preventers shall be tested at least once each 24-hour period.

[1-1-50...2-1-96; 19.15.3.114 NMAC - Rn, 19 NMAC 15.C.114, 11-15-01]

19.15.3.115 WELL AND LEASE EQUIPMENT:

A. Christmas tree fittings or wellhead connections shall be installed and maintained in first class condition so that all necessary pressure tests may easily be made on flowing wells. On oil wells the Christmas tree fittings shall have a test pressure rating at least equivalent to the calculated or known pressure in the reservoir from which production is expected. On gas wells the Christmas tree fittings shall have a test pressure equivalent to at least 150 percent of the calculated or known pressure in the reservoir from which production is expected.

B. Valves shall be installed and maintained in good working order to permit pressures to be obtained on both casing and tubing. Each flowing well shall be equipped to control properly the flowing of each well, and in case of an oil well, shall be produced into an oil and gas separator of a type generally used in the industry.

[1-1-50...2-1-96; 19.15.3.115 NMAC - Rn, 19 NMAC 15.C.115, 11-15-01]

19.15.3.116 RELEASE NOTIFICATION AND CORRECTIVE ACTION:

A. Notification

(1) The division shall be notified of any unauthorized release occurring during the drilling, producing, storing, disposing, injecting, transporting, servicing or processing of crude oil, natural gases, produced water, condensate or oil field waste including Regulated NORM, or other oil field related chemicals, contaminants or mixture thereof, in the State of New Mexico in accordance with the requirements of Section 116 of 19.15.3 NMAC.

(2) The division shall be notified in accordance with Section 116 of 19.15.3 NMAC with respect to any release from any facility of oil or other water contaminant, in such quantity as may with reasonable probability be detrimental to water or cause an exceedance of the standards in Section 19, Subsection B, Paragraphs (1) and (2) or (3) of 19.15.1 NMAC.

B. Reporting Requirements. Notification of the above releases shall be made by the person operating or controlling either the release or the location of the release in accordance with the following requirements:

(1) A Major Release shall be reported by giving both immediate verbal notice and timely written notice pursuant to Subsection C, Paragraphs (1) and (2) of 19.15.3.116 NMAC. A Major Release is:

(a) an unauthorized release of a volume, excluding natural gases, in excess of 25 barrels;

(b) an unauthorized release of any volume which:

(i) results in a fire;

(ii) will reach a water course;

(iii) may with reasonable probability endanger public health; or

(iv) results in substantial damage to property or the environment;

(c) an unauthorized release of natural gases in excess of 500 mcf; or

(d) a release of any volume which may with reasonable probability be detrimental to water or cause an exceedance of the standards in Section 19, Subsection B, Paragraphs (1) and (2) or (3) of 19.15.1 NMAC.

(2) A Minor Release shall be reported by giving timely written notice pursuant to Subsection C, Paragraph (2) of 19.15.3.116 NMAC. A Minor Release is an unauthorized release of a volume, greater than 5 barrels but not more than 25 barrels; or greater than 50 mcf but less than 500 mcf of natural gases.

C. Contents Of Notification

(1) Immediate verbal notification required pursuant to Subsection B of 19.15.3.116 NMAC shall be reported within twenty-four (24) hours of discovery to the division district office for the area within which the

release takes place. In addition, immediate verbal notification pursuant to Subsection B, Paragraph (1), Subparagraph (d) of 19.15.3.116 NMAC shall be reported to the division's Environmental Bureau Chief. This notification shall provide the information required on division Form C-141.

(2) Timely written notification is required to be reported pursuant to Subsection B of 19.15.3.116 NMAC within fifteen (15) days to the division district office for the area within which the release takes place by completing and filing division Form C-141. In addition, timely written notification required pursuant to Subsection B, Paragraph (1), Subparagraph (d) of 19.15.3.116 NMAC shall also be reported to the division's Environmental Bureau Chief within fifteen (15) days after the release is discovered. The written notification shall verify the prior verbal notification and provide any appropriate additions or corrections to the information contained in the prior verbal notification.

D. Corrective Action. The responsible person must complete division approved corrective action for releases which endanger public health or the environment. Releases will be addressed in accordance with a remediation plan submitted to and approved by the division or with an abatement plan submitted in accordance with Section 19 of 19.15.1 NMAC.

[1-1-50…5-22-73…2-1-96; A, 3-15-97; 19.15.3.116 NMAC - Rn, 19 NMAC 15.C.116, 11-15-01]

19.15.3.117 WELL LOG, COMPLETION AND WORKOVER REPORTS:
Within 20 days after the completion of a well drilled for oil or gas, or the recompletion of a well into a different common source of supply, a completion report shall be filed with the division on Form C-105. For the purpose of Section 117 of 19.15.3 NMAC, any hole drilled or cored below fresh water or which penetrates oil- or gas-bearing formations or which is drilled by an "owner" as defined herein shall be presumed to be a well drilled for oil or gas.
[1-1-50...2-1-96; 19.15.3.117 NMAC - Rn, 19 NMAC 15.C.117, 11-15-01]

19.15.3.118 HYDROGEN SULFIDE GAS (HYDROGEN SULFIDE):

A. Applicability. This section applies to any person, operator or facility subject to the jurisdiction of the division, including, but not limited to, any person, operator or facility engaged in drilling, stimulating, injecting into, completing, working over or producing any oil, natural gas or carbon dioxide well or any person, operator or facility engaged in gathering, transporting, storing, processing or refining of crude oil, natural gas or carbon dioxide (referred to herein as "person, operator or facility" or "well, facility or operation"). This section shall not act to exempt or otherwise excuse surface waste management facilities permitted by the division pursuant to 19.15.9.711 NMAC from more stringent conditions on the handling of hydrogen sulfide required of such facilities by 19.15.9.711 NMAC or more stringent conditions in permits issued thereunder, nor shall such facilities be exempt or otherwise excused from the requirements set forth in this section by virtue of permitting under 19.15.9.711 NMAC.

B. Definitions (specific to this section).

(1) ANSI. The acronym "ANSI" means the American national standards institute.

(2) API. The acronym "API" means the American petroleum institute.

(3) Area of Exposure. The phrase "area of exposure" means the area within a circle constructed with a point of escape at its center and the radius of exposure as its radius.

(4) ASTM. The acronym "ASTM" means the American society for testing and materials.

(5) Dispersion Technique. A "dispersion technique" is a mathematical representation of the physical and chemical transportation characteristics, dilution characteristics and transformation characteristics of hydrogen sulfide gas in the atmosphere.

(6) Escape Rate. The "escape rate" is the maximum volume (Q) that is used to designate the possible rate of escape of a gaseous mixture containing hydrogen sulfide, as set forth herein.

(a) For existing gas facilities or operations, the escape rate shall be calculated using the maximum daily rate of the gaseous mixture produced or handled or the best estimate thereof. For an existing gas well, the escape rate shall be calculated using the current daily absolute open flow rate against atmospheric pressure or the best estimate of that rate.

(b) For new gas operations or facilities, the escape rate shall be calculated as the maximum anticipated flow rate through the system. For a new gas well, the escape rate shall be calculated using the maximum open-flow rate of offset wells in the pool or reservoir, or the pool or reservoir average of maximum open-flow rates.

(c) For existing oil wells, the escape rate shall be calculated by multiplying the producing gas/oil ratio by the maximum daily production rate or the best estimate thereof.

(d) For new oil wells, the escape rate shall be calculated by multiplying the producing gas/oil ratio by the maximum daily production rate of offset wells in the pool or reservoir, or the pool or reservoir average of the producing gas/oil ratio multiplied by the maximum daily production rate.

(e) For facilities or operations not mentioned, the escape rate shall be calculated using the actual flow of the gaseous mixture through the system or the best estimate thereof.

(7) GPA. The acronym "GPA" means the gas processors association.

(8) LEPC. The acronym "LEPC" means the local emergency planning committee established pursuant to the emergency planning and community right-to-know act, 42 U.S.C. Section 11001.

(9) NACE. The acronym "NACE" refers to the national association of corrosion engineers.

(10) PPM. The acronym "ppm" means "parts per million" by volume.

(11) Potentially Hazardous Volume means the volume of hydrogen sulfide gas of such concentration that:

(a) the 100-ppm radius of exposure includes any public area;

(b) the 500-ppm radius of exposure includes any public road; or

(c) the 100-ppm radius of exposure exceeds 3,000 feet.

(12) Public Area. A "public area" is any building or structure that is not associated with the well, facility or operation for which the radius of exposure is being calculated and that is used as a dwelling, office, place of business, church, school, hospital, or government building, or any portion of a park, city, town, village or designated school bus stop or other similar area where members of the public may reasonably be expected to be present.

(13) Public Road. A "public road" is any federal, state, municipal or county road or highway.

(14) Radius of Exposure. The radius of exposure is that radius constructed with the point of escape as its starting point and its length calculated using the following Pasquill-Gifford derived equation, or by such other method as may be approved by the division:

(a) For determining the 100-ppm radius of exposure: $X= [(1.589)(\text{hydrogen sulfide concentration})(Q)]^{(0.6258)}$, where "X" is the radius of exposure in feet, the "hydrogen sulfide concentration" is the decimal equivalent of the mole or volume fraction of hydrogen sulfide in the gaseous mixture, and "Q" is the escape rate expressed in cubic feet per day (corrected for standard conditions of 14.73 psia and 60 degrees F).

(b) For determining the 500-ppm radius of exposure: $X=[(0.4546)(\text{hydrogen sulfide concentration})(Q)]^{(0.6258)}$, where "X" is the radius of exposure in feet, the "hydrogen sulfide concentration" is the decimal equivalent of the mole or volume fraction of hydrogen sulfide in the gaseous mixture, and "Q" is the escape rate expressed in cubic feet per day (corrected for standard conditions of 14.73 psia and 60 degrees F).

(c) For a well being drilled, completed, recompleted, worked over or serviced in an area where insufficient data exists to calculate a radius of exposure but where hydrogen sulfide could reasonably be expected to be present in concentrations in excess of 100 ppm in the gaseous mixture, a 100-ppm radius of exposure equal to 3,000 feet shall be assumed.

C. Regulatory Threshold.

(1) Determination of Hydrogen Sulfide Concentration.

(a) Each person, operator or facility shall determine the hydrogen sulfide concentration in the gaseous mixture within each of its wells, facilities or operations either by testing (using a sample from each well, facility or operation), testing a representative sample, or using process knowledge in lieu of testing. If a representative sample or process knowledge is used, the concentration derived from the representative sample or process knowledge must be reasonably representative of the hydrogen sulfide concentration within the well, facility or operation.

(b) The tests used to make the determination referred to in the previous subparagraph shall be conducted in accordance with applicable ASTM or GPA standards or by another method approved by the division.

(c) If a test was conducted prior to the effective date of this section that otherwise meets the requirements of the previous subparagraphs, new testing shall not be required.

(d) If any change or alteration may materially increase the concentration of hydrogen sulfide in a well, facility or operation, a new determination shall be required in accordance with this section.

(2) Concentrations Determined to be Below 100 ppm. If the concentration of hydrogen sulfide in a given well, facility or operation is less than 100 ppm, no further actions shall be required pursuant to this section.

(3) Concentrations Determined to be Above 100 ppm.

(a) If the concentration of hydrogen sulfide in a given well, facility or operation is determined to be 100 ppm or greater, then the person, operator or facility must calculate the radius of exposure and comply with applicable requirements of this section.

(b) If calculation of the radius of exposure reveals that a potentially hazardous volume is present, the results of the determination of the hydrogen sulfide concentration and the calculation of the radius of exposure shall be provided to the division. For a well, facility or operation existing on the effective date of this section, the determination, calculation and submission required herein shall be accomplished within 180 days of the effective date of this section; for any well, facility or operation that commences operations after the effective date of this section, the determination, calculation and submission required herein shall be accomplished before operations begin.

(4) Recalculation. The person, operator or facility shall calculate the radius of exposure if the hydrogen sulfide concentration in a well, facility or operation increases to 100 ppm or greater. The person, operator or facility shall also recalculate the radius of exposure if the actual volume fraction of hydrogen sulfide increases by a factor of twenty-five percent in a well, facility or operation that previously had a hydrogen sulfide concentration of 100 ppm or greater. If calculation or recalculation of the radius of exposure reveals that a potentially hazardous volume is present, the results shall be provided to the division within sixty (60) days.

D. Hydrogen Sulfide Contingency Plan.

(1) When Required. If a well, facility or operation involves a potentially hazardous volume of hydrogen sulfide, a hydrogen sulfide contingency plan that will be used to alert and protect the public must be developed in accordance with the following paragraphs.

(2) Plan Contents.

(a) API Guidelines. The hydrogen sulfide contingency plan shall be developed with due consideration of paragraph 7.6 of the guidelines published by the API in its publication entitled “Recommended Practices for Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide," RP-55, most recent edition, or with due consideration to another standard approved by the division.

(b) Required Contents. The hydrogen sulfide contingency plan shall contain, but shall not be limited to, information on the following subjects, as appropriate to the well, facility or operation to which it applies:

(i) Emergency procedures. The hydrogen sulfide contingency plan shall contain information on emergency procedures to be followed in the event of a release and shall include, at a minimum, information concerning the responsibilities and duties of personnel during the emergency, an immediate action plan as described in the API document referenced in the previous subsubparagraph, and telephone numbers of emergency responders, public agencies, local government and other appropriate public authorities. The plan shall also include the locations of potentially affected public areas and public roads and shall describe proposed evacuation routes, locations of any road blocks and procedures for notifying the public, either through direct telephone notification using telephone number lists or by means of mass notification and reaction plans. The plan shall include information on the availability and location of necessary safety equipment and supplies.

(ii) Characteristics of hydrogen sulfide and sulfur dioxide. The hydrogen sulfide contingency plan shall include a discussion of the characteristics of hydrogen sulfide and sulfur dioxide.

(iii) Maps and drawings. The hydrogen sulfide contingency plan shall include maps and drawings that depict the area of exposure and public areas and public roads within the area of exposure.

(iv) Training and Drills. The hydrogen sulfide contingency plan shall provide for training and drills, including training in the responsibilities and duties of essential personnel and periodic on-site or classroom drills or exercises that simulate a release, and shall describe how the training, drills and attendance will be documented. The hydrogen sulfide contingency plan shall also provide for training of residents as appropriate on the proper protective measures to be taken in the event of a release, and shall provide for briefing of public officials on issues such as evacuation or shelter-in-place plans.

(v) Coordination with State Emergency Plans. The hydrogen sulfide contingency plan shall describe how emergency response actions under the plan will be coordinated with the division and with the New Mexico state police consistent with the New Mexico hazardous materials emergency response plan (HMER).

(vi) Activation Levels. The hydrogen sulfide contingency plan shall include the activation level and a description of events that could lead to a release of hydrogen sulfide sufficient to create a concentration in excess of the activation level.

(3) Plan Activation. The hydrogen sulfide contingency plan shall be activated when a release creates a concentration of hydrogen sulfide greater than the activation level set forth in the hydrogen sulfide contingency plan. At a minimum, the plan must be activated whenever a release may create a concentration of hydrogen sulfide of more than 100 ppm in any public area, 500 ppm at any public road or 100 ppm 3,000 feet from the site of release.

(4) Submission.

(a) Where Submitted. The hydrogen sulfide contingency plan shall be submitted to the division.

(b) When Submitted. A hydrogen sulfide contingency plan for a well, facility or operation existing on the effective date of this section shall be submitted within one year of the effective date of this section. A hydrogen sulfide contingency plan for a new well, facility or operation shall be submitted before operations commence. The hydrogen sulfide contingency plan for a drilling, completion, workover or well servicing operation must be on file with the division before operations commence and may be submitted separately or along with the application for permit to drill (APD) or may be on file from a previous submission. A hydrogen sulfide contingency plan shall also be submitted within 180 days after the person, operator or facility becomes aware or should have become aware that a public area or public road is established that creates a potentially hazardous volume where none previously existed.

(c) Electronic Submission. Any filer who operates more than one hundred wells or who operates a crude oil pump station, compressor station, refinery or gas plant must submit each hydrogen sulfide contingency plan in electronic format. The hydrogen sulfide contingency plan may be submitted through electronic mail, through an Internet filing or by delivering electronic media to the division, so long as the electronic submission is compatible with the division's systems.

(5) Failure to Submit Plan. Failure to submit a hydrogen sulfide contingency plan when required may result in denial of an application for permit to drill, cancellation of an allowable for the subject well or other enforcement action appropriate to the well, facility or operation.

(6) Review, Amendment. The person, operator or facility shall review the hydrogen sulfide contingency plan any time a subject addressed in the plan materially changes and make appropriate amendments. If the division determines that a hydrogen sulfide contingency plan is inadequate to protect public safety, the division may require the person, operator or facility to add provisions to the plan or amend the plan as necessary to protect public safety.

(7) Retention and Inspection. The hydrogen sulfide contingency plan shall be reasonably accessible in the event of a release, maintained on file at all times, and available for inspection by the division.

(8) Annual Inventory of Contingency Plans. On an annual basis, each person, operator or facility required to prepare one or more hydrogen sulfide contingency plans pursuant to this section shall file with the appropriate local emergency planning committee and the state emergency response commission an inventory of the wells, facilities and operations for which plans are on file with the division and the name, address and telephone number of a point of contact.

(9) Plans Required by Other Jurisdictions. A hydrogen sulfide contingency plan required by the Bureau of Land Management or other jurisdiction that meets the requirements of this subsection may be submitted to the division in satisfaction of this subsection.

E. Signage, Markers. For each well, facility or operation involving a concentration of hydrogen sulfide of 100 ppm or greater, signs and/or markers shall be installed and maintained. Each sign or marker shall conform with the current ANSI standard Z535.1-2002 (“Safety Color Code”), or some other standard approved by the division, shall be readily readable, and shall contain the words "poison gas" and other information sufficient to warn the public that a potential danger exists. Signs or markers shall be prominently posted at locations, including but not limited to entrance points and road crossings, sufficient to alert the public that a potential danger exists. Signs and/or markers that conform with this subsection shall be installed no later than one year from the effective date of this section.

F. Protection from Hydrogen Sulfide During Drilling, Completion, Workover, and Well Servicing Operations.

(1) API Standards. All drilling, completion, workover and well servicing operations involving a hydrogen sulfide concentration of 100 ppm or greater shall be conducted with due consideration to the guidelines published by the API entitled “Recommended Practice for Oil and Gas Well Servicing and Workover Operations Involving Hydrogen Sulfide," RP-68, and “Recommended Practices for Drilling and Well Servicing Operations Involving Wells Containing Hydrogen Sulfide,” RP-49, most recent editions, or some other standard approved by the division.

(2) Detection and Monitoring Equipment. Drilling, completion, workover and well servicing operations involving a hydrogen sulfide concentration of 100 ppm or greater shall include hydrogen sulfide detection and monitoring equipment as follows:

(a) Each drilling and completion site shall have an accurate and precise hydrogen sulfide detection and monitoring system that will automatically activate visible and audible alarms when the ambient air concentration of hydrogen sulfide reaches a predetermined value set by the operator, not to exceed 20 ppm. There shall be a sensing point located at the shale shaker, rig floor and bell nipple for a drilling site and the cellar, rig floor and circulating tanks or shale shaker for a completion site.

(b) For workover and well servicing operations, one operational sensing point shall be located as close to the well bore as practical. Additional sensing points may be necessary for large or long-term operations.

(c) Hydrogen sulfide detection and monitoring equipment must be provided and must be made operational during drilling when drilling is within 500 feet of a zone anticipated to contain hydrogen sulfide and continuously thereafter through all subsequent drilling.

(3) Wind Indicators. All drilling, completion, workover and well servicing operations involving a hydrogen sulfide concentration of 100 ppm or greater shall include wind indicators. Equipment to indicate wind direction shall be present and visible at all times. At least two devices to indicate wind direction shall be installed at separate elevations and visible from all principal working areas at all times. When a sustained concentration of hydrogen sulfide is detected in excess of 20 ppm at any detection point, red flags shall be displayed.

(4) Flare System. For drilling and completion operations in an area where it is reasonably expected that a potentially hazardous volume of hydrogen sulfide will be encountered, the person, operator or facility shall install a flare system to safely gather and burn hydrogen-sulfide-bearing gas. Flare outlets shall be located at least 150 feet from the well bore. Flare lines shall be as straight as practical. The flare system shall be equipped with a suitable and safe means of ignition. Where noncombustible gas is to be flared, the system shall provide supplemental fuel to maintain ignition.

(5) Well Control Equipment. When the 100 ppm radius of exposure includes a public area, the following well control equipment shall be required:

(a) Drilling. A remote-controlled well control system shall be installed and operational at all times beginning when drilling is within 500 feet of the formation believed to contain hydrogen sulfide and continuously thereafter during drilling. The well control system must include, at a minimum, a pressure and hydrogen-sulfide-rated well control choke and kill system including manifold and blowout preventer that meets or exceeds the specifications API-16C and API-RP 53 or other specifications approved by the division. Mud-gas separators shall be used. These systems shall be tested and maintained pursuant to the specifications referenced, according to the requirements of this part, or otherwise as approved by the division.

(b) Completion, Workover and Well Servicing. A remote controlled pressure and hydrogen-sulfide-rated well control system that meets or exceeds API specifications or other specifications approved by the division shall be installed and shall be operational at all times during completion, workover and servicing of a well.

(6) Mud Program. All drilling, completion, workover and well servicing operations involving a

hydrogen sulfide concentration of 100 ppm or greater shall use a hydrogen sulfide mud program capable of handling hydrogen sulfide conditions and well control, including de-gassing.

(7) Well Testing. Except with prior approval of the division, drill-stem testing of a zone that contains hydrogen sulfide in a concentration of 100 ppm or greater shall be conducted only during daylight hours and formation fluids shall not be permitted to flow to the surface.

(8) If Hydrogen Sulfide Encountered During Operations. If hydrogen sulfide was not anticipated at the time the division issued a permit to drill but is encountered during drilling in a concentration of 100 ppm or greater, the operator must satisfy the requirements of this section before continuing drilling operations. The operator shall notify the division of the event and the mitigating steps that have been or are being taken as soon as possible, but no later than 24 hours following discovery. The division may grant verbal approval to continue drilling operations pending preparation of any required hydrogen sulfide contingency plan.

G. Protection from Hydrogen Sulfide at Crude Oil Pump Stations, Producing Wells, Tank Batteries and Associated Production Facilities, Pipelines, Refineries, Gas Plants and Compressor Stations.

(1) API Standards. Operations at crude oil pump stations and producing wells, tank batteries and associated production facilities, refineries, gas plants and compressor stations involving a concentration of hydrogen sulfide of 100 ppm or greater shall be conducted with due consideration to the guidelines published by the API in its publication entitled “Recommended Practices for Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide," RP-55, latest edition or some other standard approved by the division.

(2) Security. Well sites and other unattended, fixed surface facilities involving a concentration of hydrogen sulfide of 100 ppm or greater shall be protected from public access by fencing with locking gates when the location is within 1/4 mile of a public area. A surface pipeline shall not be considered a fixed surface facility for purposes of this paragraph.

(3) Wind Direction Indicators. All crude oil pump stations, producing wells, tank batteries and associated production facilities, pipelines, refineries, gas plants and compressor stations involving a concentration of hydrogen sulfide of 100 ppm or greater shall have equipment to indicate wind direction. The wind direction equipment shall be installed and visible from all principal working areas at all times.

(4) Control Equipment. When the 100 ppm radius of exposure includes a public area, the following additional measures are required:

(a) Safety devices, such as automatic shut-down devices, shall be installed and maintained in good operating condition to prevent the escape of hydrogen sulfide. Alternatively, safety procedures shall be established to achieve the same purpose.

(b) Any well shall possess a secondary means of immediate well control through the use of an appropriate christmas tree or downhole completion equipment. Such equipment shall allow downhole accessibility (reentry) under pressure for permanent well control.

(5) Tanks or vessels. Each stair or ladder leading to the top of any tank or vessel containing 300 ppm or more of hydrogen sulfide in the gaseous mixture shall be chained or marked to restrict entry.

(6) Compliance Schedule. Each existing crude oil pump station, producing well, tank battery and associated production facility, pipeline, refinery, gas plant and compressor station not currently meeting the requirements of this subsection shall be brought into compliance within one year of the effective date of this section.

H. Personnel Protection and Training. All persons responsible for the implementation of any hydrogen sulfide contingency plan shall be provided training in hydrogen sulfide hazards, detection, personal protection and contingency procedures.

I. Standards for Equipment That May Be Exposed to Hydrogen Sulfide. Whenever a well, facility or operation involves a potentially hazardous volume of hydrogen sulfide, equipment shall be selected with consideration for both the hydrogen sulfide working environment and anticipated stresses and NACE Standard MR0175 (latest edition) or some other standard approved by the division shall be used for selection of metallic equipment or, if applicable, adequate protection by chemical inhibition or other methods that control or limit the corrosive effects of hydrogen sulfide shall be used.

J. Exemptions. Any person, operator or facility may petition the director or the director's designee for an exemption to any requirement of this section. Any such petition shall provide specific information as to the circumstances that warrant approval of the exemption requested and how the public safety will be protected. The director or the director's designee, after considering all relevant factors, may approve an exemption if the circumstances warrant and so long as the public safety will be protected.

K. Notification of the Division. The person, operator or facility shall notify the division upon a release of hydrogen sulfide requiring activation of the hydrogen sulfide contingency plan as soon as possible, but no more than four hours after plan activation, recognizing that a prompt response should supercede notification. The person, operator or facility shall submit a full report of the incident to the division on Form C-141 no later than fifteen (15) days following the release.

[5-22-73…1-1-87...2-1-96; A 3-15-97; 19.15.3.118 NMAC - Rn, 19 NMAC 15.C.118, 11-15-2001; A, 01-31-03]

History of 19.15.3 NMAC:

Pre-NMAC History:

Material in this part was derived from that previously filed with the commission of public records - state records center and archives as:

Rule 101, Plugging Bond, filed 06-04-86;
Rule 101, Plugging Bond, filed 01-06-88;
Rule 101, Plugging Bond, filed 02-05-91;
Rule 102, Notice of Intention to Drill, filed 01-08-82;
Rule 102, Notice of Intention to Drill, filed 11-25-85;
Rule 102, Notice of Intention to Drill, filed 02-05-91;
Rule 103, Sign on Wells, filed 01-08-82;
Rule 103, Sign on Wells, filed 02-05-91;
Rule 104, Well Spacing: Acreage Requirements for Drilling Tracts, filed 01-08-82;
Rule 104, Well Spacing: Acreage Requirements for Drilling Tracts, filed 02-05-91;
Rule 105, Pit for Clay, Shale, and Drill Cutting, filed 01-08-82;
Rule 105, Pit for Clay, Shale, and Drill Cutting, filed 08-17-89;
Rule 105, Pit for Clay, Shale, and Drill Cutting, filed 02-05-91;
Rule 106, Sealing Off Strata, filed 01-08-82;
Rule 106, Sealing Off Strata, filed 10-11-89;
Rule 106, Sealing Off Strata, filed 02-05-91;
Rule 107, Casing and Tubing Requirements, filed 01-08-82;
Rule 107, Casing and Tubing Requirements, filed 02-05-91;
Rule 108, Defective Casing or Cementing, filed 01-08-82;
Rule 108, Defective Casing or Cementing, filed 09-16-85;
Rule 108, Defective Casing or Cementing, filed 02-05-91;
Rule 109, Blowout Prevention, filed 01-27-82;
Rule 109, Blowout Prevention, filed 02-05-91;
Rule 110, Pulling Outside Strings of Casing, filed 01-27-82;
Rule 110, Pulling Outside Strings of Casing, filed 02-05-91;
Rule 111, Deviation Tests and Directional Drilling, filed 01-08-82;
Rule 111, Deviation Tests and Directional Drilling, filed 09-16-85;
Rule 111, Deviation Tests and Directional Drilling, filed 10-11-89;
Rule 111, Deviation Tests and Directional Drilling, filed 02-05-91;
Rule 111, Deviation Tests/Deviated Wells and Directional Drilling, filed 07-27-95;
Rule 112-A, Multiple Completions, filed 01-08-82;
Rule 112-A, Multiple Completions, filed 02-05-91;
Rule 112-B, Brandenhead Gas Wells, filed 01-08-82;
Rule 112-B, Brandenhead Gas Wells, filed 02-05-91;
Rule 113, Shooting and Chemical Treatment of Wells, filed 01-08-82;
Rule 113, Shooting and Chemical Treatment of Wells, filed 09-16-85.

Rule 113, Shooting and Chemical Treatment of Wells, filed 02-05-91.
Rule 114, Safety Regulations, filed 01-08-82;
Rule 114, Safety Regulations, filed 02-05-91.
Rule 115, Well and Lease Equipment, filed 01-08-82;
Rule 115, Well and Lease Equipment, filed 02-05-91.
Rule 116, Notification of Fire, Breaks, Leaks, Spills, and Blowouts, filed 01-08-82;
Rule 116, Notification of Fire, Breaks, Leaks, Spills, and Blowouts, filed 02-05-91;
Rule 117, Well Log, Completion and Workover Reports, filed 01-08-82;
Rule 117, Well Log, Completion and Workover Reports, filed 10-11-89;
Rule 117, Well Log, Completion and Workover Reports, filed 02-05-91;
Rule 118, Hydrogen Sulfide Gas - Public Safety, filed 12-30-86;
Rule 118, Hydrogen Sulfide Gas - Public Safety, filed 10-11-89;
Rule 118, Hydrogen Sulfide Gas - Public Safety, filed 02-05-91.

History of Repealed Material: [Reserved]

Other History:
Rule 101, filed 02-05-91; Rule 102, filed 02-05-91; Rule 103, filed 02-05-91; Rule 104, filed 02-05-91; Rule 105, filed 02-05-91; Rule 106, filed 02-05-91; Rule 107, filed 02-05-91; Rule 108, filed 02-05-91; Rule 109, filed 02-05-91; Rule 110, filed 02-05-91; Rule 111, filed 07-27-95; Rule 112-A, filed 02-05-91; Rule 112-B, filed 02-05-91; Rule 113, filed 02-05-91; Rule 114, filed 02-05-91; Rule 115, filed 02-05-91; Rule 116, filed 02-05-91; Rule 117, filed 02-05-91; Rule 118, filed 02-05-91; all renumbered, reformatted **to and replaced by** 19 NMAC 15.C, Drilling, filed 01-18-96.
19 NMAC 15.C, Drilling, filed 01-18-96; **renumbered, reformatted and replaced by** 19.15.3 NMAC, effective 11-15-01.

TITLE 19 NATURAL RESOURCES & WILDLIFE
CHAPTER 15 OIL AND GAS
PART 4 PLUGGING AND ABANDONMENT OF WELLS

19.15.4.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department, Oil Conservation Division, 2040 S. Pacheco, Santa Fe, New Mexico 87505 (505) 827-7131.
[2-1-96; 19.15.4.1 NMAC - Rn, 19 NMAC 15.D.1, 12-14-01]

19.15.4.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico.
[2-1-96; 19.15.4.2 NMAC - Rn, 19 NMAC 15.D.2, 12-14-01]

19.15.4.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the Oil and Gas Act which grants the Oil Conservation Division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights, and the disposition of wastes resulting from oil and gas operations.
[2-1-96; 19.15.4.3 NMAC - Rn, 19 NMAC 15.D.3, 12-14-01]

19.15.4.4 DURATION: Permanent.
[2-1-96; 19.15.4.4 NMAC - Rn, 19 NMAC 15.D.4, 12-14-01]

19.15.4.5 EFFECTIVE DATE: February 1, 1996.
[2-1-96; 19.15.4.5 NMAC - Rn, 19 NMAC 15.D.5, 12-14-01]

19.15.4.6 OBJECTIVE: To provide for the proper plugging and abandonment of wells to protect fresh water and public health and environment pursuant to the Oil and Gas Act.
[2-1-96; 19.15.4.6 NMAC - Rn, 19 NMAC 15.D.6, 12-14-01]

19.15.4.7 DEFINITIONS: [Reserved].

19.15.4.8-200 [RESERVED].

19.15.4.201 WELLS TO BE PROPERLY ABANDONED

A. The operator of any well drilled for oil, gas or injection; for seismic, core or other exploration, or for a service well, whether cased or uncased, shall be responsible for the plugging thereof.

B. A well shall be either properly plugged and abandoned or temporarily abandoned in accordance with these rules within ninety (90) days after:

(1) a sixty (60) day period following suspension of drilling operations, or
(2) a determination that a well is no longer usable for beneficial purposes, or
(3) a period of one (1) year in which a well has been continuously inactive.

[7-12-90…2-1-96; 19.15.4.201 NMAC - Rn, 19 NMAC 15.D.201, 12-14-01]

19.15.4.202 PLUGGING AND PERMANENT ABANDONMENT

A. Notice of Plugging

(1) Notice of intention to plug must be filed with the Division on Form C-103, Sundry Notices and Reports on Wells, by the operator prior to the commencement of plugging operations, which notice must provide all of the information required by Rule 1103 including operator and well identification and proposed procedures for plugging said well, and in addition the operator shall provide a well-bore diagram showing the proposed plugging procedure. Twenty-four hours notice shall be given prior to commencing any plugging operations. In the case of a newly drilled dry hole, the operator may obtain verbal approval from the appropriate District Supervisor or his representative of the method of plugging and time operations are to begin. Written notice in accordance with this rule shall be filed with the Division ten (10) days after such verbal approval has been given.

B. Plugging

(1) Before any well is abandoned, it shall be plugged in a manner which will permanently confine all oil, gas and water in the separate strata in which they are originally found. This may be accomplished by using mud-laden fluid, cement and plugs singly or in combination as approved by the Division on the notice of intention to plug.

(2) The operator shall mark the exact location of plugged and abandoned wells with a steel marker not less than four inches (4") in diameter set in cement and extending at least four feet (4') above mean ground level. The operator name, lease name and well number and location, including unit letter, section, township and range, shall be welded, stamped or otherwise permanently engraved into the metal of the marker. No permanent structures preventing access to the wellhead shall be built over a plugged and abandoned well without written approval of the OCD. No plugged and abandonment marker shall be removed without the written permission of the OCD.

(3) As soon as practical but no later than one year after the completion of plugging operations, the operator shall:

(a) fill all pits;

(b) level the location;

(c) remove deadmen and all other junk; and

(d) take such other measures as are necessary or required by the Division to restore the location to a safe and clean condition.

(4) Upon completion of plugging and clean up restoration operations as required, the operator shall contact the appropriate district office to arrange for an inspection of the well and location.

(5) Below-ground plugged and abandonment markers can be used only with written permission of the OCD when an above-ground marker would interfere with agricultural endeavors. The below-ground marker shall have a steel plate welded onto the surface or conductor pipe of the abandoned well and shall be at least 3 feet below the ground surface and of sufficient size so that all the information required by Section 103 of 19.15.3 NMAC can be stenciled into the steel or welded onto the surface of the steel plate. The OCD may require a re-survey of the well location.

C. Reports

(1) The operator shall file Form C-105, Well Completion or Recompletion Report and Log as provided in Rule 1105.

(2) Within thirty (30) days after completing all required restoration work, the operator shall file with the Division, in triplicate, a record of the work done on Form C-103 as provided in Rule 1103.

(3) The Division shall not approve the record of plugging or release any bonds until all necessary reports have been file and the location has been inspected and approved by the Division.

[1-1-50, 7-12-90…2-1-96; A, 3-31-00; 19.15.4.202 NMAC - Rn, 19 NMAC 15.D.202, 12-14-01]

19.15.4.203 TEMPORARY ABANDONMENT

A. Wells Which May Be Temporarily Abandoned

(1) The Division may permit any well which is required to be properly abandoned under these rules but which has potential for future beneficial use for enhanced recovery or injection, and any other well for which an operator requests temporary abandonment, to be temporarily abandoned for a period of up to five (5) years. Prior to the expiration of any approved temporary abandonment the operator shall return the well to beneficial use under a plan approved by the Division, permanently plug and abandon said well or apply for a new approval to temporarily abandon the well.

B. Request For Approval And Permit

(1) Any operator seeking approval for temporary abandonment shall submit on Form C-103, Sundry Notices and Reports on Wells, a notice of intent to temporarily abandon the well describing the proposed temporary abandonment procedure to be used. No work shall be commenced until approved by the Division and the operator shall give 24 hours notice to the appropriate District office of the Division before work actually begins.

(2) No temporary abandonment shall be approved unless evidence is furnished to show that the casing of such well is mechanically sound and in such condition as to prevent:

(a) damage to the producing zone;

(b) migration of hydrocarbons or water;

(c) the contamination of fresh water or other natural resources; and

(d) the leakage of any substance at the surface.

(3) If the well fails the mechanical integrity test required herein, the well shall be plugged and abandoned in accordance with these rules or the casing problem corrected and the casing retested within ninety (90) days.

(4) Upon successful completion of the work on the temporarily abandoned well, the operator will submit a request for Temporary Abandonment to the appropriate district office on Form C-103 together with such other information as is required by Rule 1103 E.(1).

(5) The Division may require the operator to post with the Division a one-well plugging bond for the well in an amount to be determined by the Division to be satisfactory to meet the particular requirements of the well.

(6) The Division shall specify the expiration date of the permit, which shall be not more than five (5) years from the date of approval.

C. Tests Required

(1) The following methods of demonstrating casing integrity may be approved for temporarily abandoning a well:

(a) a cast iron bridge plug will be set within one hundred (100) feet of uppermost perforations or production casing shoe and the casing loaded with inert fluid and pressure tested to 500 pounds per square inch with a pressure drop of not more than 10% for thirty (30) minutes; or

(b) a retrievable bridge plug or packer will be run to within one hundred (100) feet of uppermost perforations or production casing shoe and the well tested to 500 pounds per square inch for thirty minutes with a pressure drop of not greater than 10% for thirty (30) minutes; or

(c) for a gas well in southeast New Mexico completed above the San Andres formation, if the operator can demonstrate that the fluid level is below the base of the salt and that a Bradenhead test shows no casing leaks, the Division may exempt the well from the requirement for a bridge plug or packer; or

(d) a casing inspection log confirming the mechanical integrity of the production casing may be submitted.

(2) Any such test which is submitted must have been conducted within the previous twelve (12) months.

(3) The Division may approve other casing tests submitted on Form C-103 on an individual basis.

[7-12-90...7-12-90, 2-1-96; 19.15.4.203 NMAC - Rn, 19 NMAC 15.D.203, 12-14-01]

19.15.4.204 WELLS TO BE USED FOR FRESH WATER

A. When a well to be plugged may safely be used as a fresh water well and the landowner agrees to take over said well for such purpose, the well need not be plugged above the sealing plug set below the fresh water formation.

B. The operator must comply with all other requirements contained in Section 202 of 19.15.3 NMAC regarding plugging, including surface restoration and reporting requirements.

C. Upon completion of plugging operations, the operator must file with the Division a written agreement signed by the landowner whereby the landowner agrees to assume responsibility for such well. Upon the filing of this agreement and approval by the Division of well abandonment operations, the operator shall no longer be responsible for such well, and any bonds thereon may be released.

[1-1-50…7-12-1-96; 19.15.4.204 NMAC - Rn, 19 NMAC 15.D.204, 12-14-01]

HISTORY of 19.15.4 NMAC:

Pre-NMAC History:

Material in this part was derived from that previously filed with the commission of public records - state records center and archives as:

Rule 201, Notice, file 1-8-82;
Rule 201, Wells to be Properly Abandoned, filed 7-10-90;
Rule 201, Wells to be Properly Abandoned, filed 2-5-91;
Rule 202, Plugging and Abandonment, 1-8-82;
Rule 202, Plugging and Permanent Abandonment, filed 7-10-90;
Rule 202, Plugging and Permanent Abandonment, filed 2-5-91;
Rule 203, Wells to be used for Fresh Water, filed 1-8-82;
Rule 203, Temporary Abandonment, filed 7-10-90;
Rule 203. Temporary Abandonment, filed 2-5-91;
Rule 204, Liability, filed 1-8-82;
Rule 204, Wells to be Used for Fresh Water, filed 7-10-90;
Rule 204, Wells to be Used for Fresh Water, filed 2-5-91.

History of the Repealed Material: [RESERVED].

Other History:

Rule 201, Wells to be Properly Abandoned, filed 2-5-91; Rule 202, Plugging and Permanent Abandonment, filed 2-5-91; Rule 203, Temporary Abandonment, filed 2-5-91; Rule 204, Wells to be Used For Fresh Water, filed 2-5-91; all renumbered, reformatted **to and replaced by** 19 NMAC 15.D, Plugging and Abandonment of Wells, filed 01-18-96.
19 NMAC 15.D, Plugging and Abandonment of Wells, filed 01-18-96; **renumbered, reformatted and replaced by** 19.15.4 NMAC, effective 12-14-01.

TITLE 19 NATURAL RESOURCES & WILDLIFE
CHAPTER 15 OIL AND GAS
PART 5 OIL PRODUCTION OPERATING PRACTICES

19.15.5.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department.
[2-1-96; 19.15.5.1 NMAC - Rn, 19 NMAC 15.E.1, 5-15-00]

19.15.5.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico.
[2-1-96; 19.15.5.2 NMAC - Rn, 19 NMAC 15.E.2, 5-15-00]

19.15.5.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the Oil and Gas Act which grants the Oil Conservation Division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights, and the disposition of wastes resulting from oil and gas operations.
[2-1-96; 19.15.5.3 NMAC - Rn, 19 NMAC 15.E.3, 5-15-00]

19.15.5.4 DURATION: Permanent
[2-1-96; 19.15.5.4 NMAC - Rn, 19 NMAC 15.E.4, 5-15-00]

19.15.5.5 EFFECTIVE DATE: February 1, 1996, unless a later date is cited at the of a section.
[2-1-96; 19.15.5.5 NMAC - Rn, 19 NMAC 15.E.5, 5-15-00]

19.15.5.6 OBJECTIVE: To regulate the production of oil to enable the oil conservation division to fulfill its statutory mandates under the Oil and Gas Act.
[2-1-96; 19.15.5.6 NMAC - Rn, 19 NMAC 15.E.6, 5-15-00]

19.15.5.7 DEFINITIONS: [RESERVED]. See 19.15.1.7 NMAC.

19.15.5.8-300 [RESERVED]

19.15.5.301 GAS-OIL RATIO AND PRODUCTION TESTS:

A. Each operator shall take a gas-oil ratio test no sooner than 20 days nor later than 30 days following the completion or recompletion of each oil well, if:

(1) the well is a wildcat, or

(2) the well is located in a pool which is not exempt from the requirements of this rule. Wells completed within one mile of the outer boundary of a defined oil pool producing from the same formation shall be governed by the provisions of this rule which are applicable to the pool. The results of the test shall be reported to the division on form C-116 within 10 days following completion of the test. The gas-oil ratio thus reported shall become effective for proration purposes on the first day of the calendar month following the date they are reported.

(3) Each operator shall also take an annual gas-oil ratio test of each producing oil well, located within a pool not exempted from the requirements of this rule, during a period prescribed by the division. A gas-oil ratio survey schedule shall be established by the division setting forth the period in which gas-oil ratio tests are to be taken for each pool wherein a test is required. The gas-oil ratio test shall be such test designated by the division, made by such method and means, and in such manner as the division in its discretion may prescribe from time to time.

B. The results of gas-oil ratio tests taken during survey periods shall be filed with the division on form C-116 not later than the 10^{th} of the month following the close of the survey period for the pool in which the well is located. The gas-oil ratios thus reported shall become effective for proration purposes on the first day of the second month following the close of the survey period. Unless form C-116 is filed within the required time limit, no further allowable will be assigned the affected well until form C-116 is filed.

C. In the case of special tests taken between regular gas-oil ratio surveys, the gas-oil ratio shall become effective for proration purposes upon the date form C-116, reporting the results of such test, is received by the division. A special test does not exempt any well from the regular survey.

D. During gas-oil ratio test, no well shall be produced at a rate exceeding top unit allowable for the pool in which it is located by more than 25 percent.

E. The director shall have the authority to exempt such pools as he may deem proper from the gas-oil ratio test requirements of this rule. Such exemption shall be by executive order directed to all operators in the pool being exempted.

F. The director shall have the authority to require annual productivity tests of all oil wells in pools exempt from gas-oil ratio tests, during a period prescribed by the division. An oil well productivity survey schedule shall be established by the division setting forth the period in which productivity tests are to be taken for each pool wherein such tests are required.

G. The results of productivity tests taken during survey periods shall be filed with the division on form C-116 (with the word "Exempt" inserted in the column normally used for reporting gas production) not later than the 10^{th} of the month following the close of the survey period for the pool in which the well is located. Unless form C-116 is filed within the required time limit, no further allowable will be assigned the affected well until form C-116 is filed.

H. In the case of special productivity tests taken between regular test survey periods, which result in a change of allowable assigned to the well, the allowable change shall become effective upon the date the form C-116 is received by the proration department. A special test does not exempt any well from the regular survey.

I. During the productivity test, no well shall be produced at a rate exceeding top unit allowable for the pool in which it is located by more than 25 percent.

[1-1-50…2-1-96; 19.15.5.301 NMAC - Rn, 19 NMAC 15.E.301, 5-15-00]

19.15.5.302 SUBSURFACE PRESSURE TESTS:

The operator shall make a subsurface pressure test on the discovery well of any new pool hereafter discovered, and shall report the results thereof to the division within 30 days after the completion of such discovery well. On or before December 1 of each calendar year the division shall designate the months in which subsurface pressure tests shall be taken in designated pools. Included in the designated list shall be listed the required shut-in pressure time and datum of tests to be taken in each pool. In the event a newly discovered pool is not included in the division's list, the division shall issue a supplementary bottom hole pressure schedule. Tests as designated by the division shall only apply to flowing wells in each pool. This test shall be made by a person qualified by both training and experience to make such test, and with an approved subsurface pressure instrument which shall be calibrated against an approved dead-weight tester at intervals frequent enough to ensure its accuracy within one percent. Unless otherwise designated by the division all wells shall remain completely shut in for at least 24 hours prior to the test. In the event a definite datum is not established by the division the subsurface determination shall be obtained as close as possible to the mid-point of the productive sand of the reservoir. The report shall be on form C-124 and shall state the name of the pool, the pool datum (if established), the name of the operator and lease, the well number, the wellhead elevation above sea level, the date of the test, the total time the well was shut in prior to the test, the subsurface temperature in degrees fahrenheit at the test depth, the depth in feet at which the subsurface pressure test was made, the observed pressure in pounds per square inch gauge (corrected for calibration and temperature), the corrected pressure computed from applying to the observed pressure the appropriate correction for difference in test depth and reservoir datum plane and any other information as required by form C-124.

[1-1-50...2-1-96; 19.15.5.302 NMAC - Rn, 19 NMAC 15.E.302, 5-15-00]

19.15.5.303 SEGREGATION OF PRODUCTION FROM DIFFERENT POOLS OR LEASES:

A. In general

(1) Pool segregation required - Each pool shall be produced as a single common source of supply and wells therein shall be completed, cased, maintained, and operated so as to prevent communication within the wellbore with any other pool. Oil, gas, or oil or gas produced from each pool shall at all times be segregated, and the combination commingling of production, before marketing, with production from any other pool without division approval is prohibited.

(2) Lease segregation required - Oil, gas, or oil and gas shall not be transported from a lease until it has been accurately measured or determined by other methods acceptable to the division. The production from each lease shall at all times be segregated, and the combination or commingling of production, before marketing, with production from any other lease without division approval is prohibited.

(3) Exceptions. Exceptions to Paragraphs (1) and (2) of Subsection A of 19.15.5.303 NMAC may be permitted for surface commingling, downhole commingling and off-lease storage and/or measurement pursuant to Subsections B, C and D of 19.15.5.303 NMAC, respectively. Exceptions granted by previous orders of the division remain in effect in accordance with their terms and conditions.

B. Surface commingling - oil gas or oil and gas

(1) Introduction - To prevent waste, to promote conservation and to protect correlative rights, the division shall have the authority to grant exceptions to permit the surface commingling of oil, gas or oil and gas in common facilities from two or more pools, two or more leases or combinations of pools and leases provided that:

(a) the method used to allocate the production to the various leases or pools to be commingled is approved by the division;

(b) if federal, Indian or state lands are involved, the United States bureau of land management or the commissioner of public lands for the state of New Mexico (as applicable) has been notified of the proposed commingling; and

(c) all other applicable requirements set out in Subsection B of 19.15.5.303 NMAC are met.

(2) Definitions - For purposes of Section 303 of 19.15.5 NMAC only, the following definitions shall apply:

(a) Lease. "Lease" means a contiguous geographical area of identical ownership overlying a pool or portion of a pool. An area pooled, unitized or communitized, either by agreement or by division order, or a participating area shall constitute a lease. If there is any diversity of ownership between different pools, or between different zones or strata, then each such pool, zone or stratum having such diverse ownership shall be considered a separate lease.

(b) Diverse ownership. "Diverse Ownership" exists if leases or pools have any different working, royalty or overriding royalty interest owners or any different ownership percentages of the same working, royalty or overriding royalty interest owners.

(c) Identical ownership. "Identical Ownership" exists if leases or pools have all the same working, royalty and overriding royalty owners in exactly the same percentages.

(3) Specific requirements and provisions for commingling of leases, pools or leases and pools with identical ownership.

(a) Measurement and allocation methods.

(i) Well test method - If all wells or units to be commingled are marginal and are physically incapable of producing the top unit allowable for their respective pools, or if all affected pools are unprorated, commingling shall be permitted without separately measuring the production from each pool or lease. Instead, the production from each well and from each pool or lease may be determined from well tests conducted periodically, but no less than annually. The well test method shall not apply to wells or units that can produce an amount of oil equal to the top unit allowable for the pool but are restricted because of high gas-oil ratios. The operator of any such marginal commingling installation shall notify the division at any time any well or unit so commingled under this subsection becomes capable of producing the top unit allowable for its pool, at which time the division shall require separate measurement.

(ii) Metering method - Production from each pool or lease may be determined by separately metering before commingling.

(iii) Subtraction method - If production from all except one of the pools or leases to be commingled is separately measured, the production from the remaining pool or lease may be determined by the subtraction method as follows: For oil, the net production from the unmetered pool or lease shall be the difference between the net pipeline runs with the beginning and ending stock adjustments and the sum of the net production of all metered pools or leases. For gas, the net production from the unmetered pool or lease shall be the difference between the volume recorded at the sales meter and the sum of the volumes recorded at the individual pool or lease meters.

(iv) Top allowable producers - If any well or unit in a prorated pool to be commingled can physically be produced at top unit allowable rates (even if restricted because of high gas-oil ratios), commingling may be permitted only if the production from such unit is metered prior to commingling, or determined by the subtraction method.

(v) Alternative methods - Production from each pool or lease to be commingled may also be determined by any other method specifically approved by the division prior to commingling. The division shall determine what evidence is necessary to support any request to use an alternative method.

(b) Approval process. Prior to commingling, the applicant shall notify the division by filing form C-103 (sundry notices and reports on wells) in the Santa Fe office with the following information set forth therein or attached thereto:

(i) Identification of each of the leases, pools or leases and pools to be commingled;

(ii) The method of allocation to be used. If the well test method is proposed for production from a prorated pool, the notification to the division shall be accompanied by a tabulation of production showing that the average daily production of any affected proration unit over a 60-day period has been below the top unit allowable for the subject pool (or for any newly drilled well without a 60-day production history, a tabulation of the available production) or other evidence acceptable to the division to establish that the well or wells on such unit are not capable of producing the top unit allowable. If the proposed method of allocation is other than an approved method provided in this section, the operator shall submit evidence of the reliability of such method;

(iii) A certification by a licensed attorney or qualified petroleum landman that the ownership in all pools and leases to be commingled is identical as defined in this section; and

(iv) Evidence of notice to the state land office and/or the United States bureau of land management, if required. Commingling may be authorized without any notice or hearing and may be commenced upon approval of form C-103 by the division, subject to compliance with any conditions of such approval noted by the division; provided however that commingling involving any state, federal or tribal leases shall not be commenced unless or until approved by the state land office or the United States bureau of land management, as applicable.

(4) Specific requirements and provisions for commingling of leases, pools or leases and pools with diverse ownership.

(a) Measurement and allocation methods. Where there is diversity of ownership between two or more leases, two or more pools, or between different pools and leases, the surface commingling of production therefrom shall be permitted only if production from each of such pools or leases is accurately metered, or determined by other methods specifically approved by the division, prior to such commingling.

(b) Meter proving and calibration frequencies.

(i) Oil. Each meter used in oil production accounting shall be tested for accuracy as follows: monthly, if more than 100,000 barrels of oil per month are measured through the meter; quarterly, if between 10,000 and 100,000 barrels of oil per month are measured through the meter; and semi-annually, if less than 10,000 barrels of oil per month are measured through the meter.

(ii) Gas. For each gas sales and allocation meter, the accuracy of the metering equipment at the point of delivery or allocation shall be tested following the initial installation and following repair and retested: quarterly, if 100 thousand cubic feet of gas per day ("Mcfgpd") or more are measured through the meter; and semi-annually, if less than 100 Mcfgpd are measured through the meter.

(iii) Correction and adjustment. If a meter proving and calibration test reveals inaccuracy in the metering equipment of more than two percent (2%), the volume measured shall be corrected and the meter adjusted to zero error. The operator shall submit a corrected report adjusting the volume of oil or gas measured and showing all calculations made in correcting the volumes. The volumes shall be corrected back to the time the inaccuracy occurred, if known. If the time is unknown, the volumes shall be corrected for the last half of the period elapsed since the date of the last calibration. If a test reveals an inaccuracy of less than 2%, the meter shall be adjusted, but correction of prior production shall not be required.

(c) Low production gas wells. For gas wells producing less than 15 Mcfgpd, estimation of production is an acceptable alternative to individual well measurement provided that commingling of production from different pools or leases does not take place unless otherwise authorized pursuant to Section 303 of 19.15.5 NMAC.

(d) Approval process.

(i) In general. Where there is diversity of ownership, the division may grant an exception to the requirements of Subsection A of 19.15.5.303 NMAC to permit surface commingling of production from different leases, pools or leases and pools only after notice and an opportunity for hearing as provided in Subparagraph (d) of Paragraph (4) of Subsection B of 19.15.5.303 NMAC.

(ii) Application. An application for administrative approval shall be submitted to the division's Santa Fe office on form C-107-B and shall contain a list of all parties (hereinafter called "interest owners") owning any interest in any of the production to be commingled (including owners of royalty and overriding royalty interests whether or not they have a right or option to take their interests in kind) and a method of allocating production to ensure the protection of correlative rights.

(iii) Notice. Notice shall be given to all interest owners in accordance with Subsection A of 19.15.14.1207 NMAC. The applicant shall submit a statement attesting that applicant, on or before the date the application was submitted to the division, sent notification to each of the interest owners by submitting a copy of the application and all attachments thereto, by certified mail, return receipt requested, and advising them that any objection must be filed in writing with the Santa Fe office of the division within 20 days from the date the division received the application. The division may approve the application administratively, without hearing, upon receipt of written waivers from all interest owners, or if no such owner has filed an objection within the 20-day period. If any objection is received, the application shall be set for hearing. Notice of the hearing shall be given to the applicant, to any party who has filed an objection, and to such other parties as the division shall direct.

(iv) Hearing ordered by the division. The division may set for hearing any application for administrative approval of surface commingling, and, in such case, notice of such hearing shall be given in such manner as the division shall direct.

(v) Notice by publication. When an applicant has been unable to locate all interest owners after exercising reasonable diligence, notice shall be provided by publication, and proof of publication shall be submitted with the application. Such proof shall consist of a copy of the legal advertisement that was published in a newspaper of general circulation in the county or counties in which the commingled production is located. The contents of such advertisement shall include (a) the name, address, telephone number, and contact party for the applicant, (b) the location by section, township and range of the leases from which production will be commingled and the location of the commingling facility; (c) the source of all commingled production by pool name, and (d) a notation that interested parties must file objections or requests for hearing in writing with the oil conservation division's Santa Fe office, within 20 days after publication, or the division may approve the application.

(vi) Effect of protest. All protests and requests for hearing received by the division shall be included in the case file; provided however, the protest will not be considered by the division as evidence. If the protesting party does not appear at the hearing, the application may be granted without the division receiving additional evidence in support thereof.

(vii) Additions. A surface commingling order may authorize, prospectively, the inclusion therein of additional pools and/or leases within defined parameters set forth in the order, provided that (a) the notice to the interest owners has included a statement that authorization for subsequent additions is being sought and of the parameters for such additions proposed by the applicant, and (b) the division finds that subsequent additions within defined parameters will not, in reasonable probability, reduce the value of the commingled production or otherwise adversely affect the interest owners. A subsequent application to amend an order to add to the commingled production other leases, pools or leases and pools that are within the defined parameters shall require notice only to the owners of interests in the production to be added, unless the division otherwise directs.

(viii) State, federal or tribal lands. Notwithstanding the issuance of an exception under Subsection B of 19.15.5.303 NMAC, no commingling involving any state, federal or tribal leases shall be commenced unless or until approved by the state land office or the United States bureau of land management, as applicable.

C. Downhole commingling

(1) The director may grant an exception to Subsection A of 19.15.303 NMAC to permit the commingling of multiple producing pools in existing or proposed wellbores when the following conditions are met:

(a) the fluids from each pool are compatible and combining the fluids will not result in damage to any of the pools;

(b) the commingling will not jeopardize the efficiency of present or future secondary recovery operations in any of the pools to be commingled;

(c) the bottom perforation of the lower zone is within 150% of the depth of the top perforation in the upper zone and the lower zone is at or below normal pressure with normal pressure assumed to be 0.433 psi per foot of depth. If the pools to be commingled are not within this vertical interval, then evidence will be required to demonstrate that commingling will not result in shut-in or flowing wellbore pressures in excess of the fracture parting pressure of any commingled pool. The fracture parting pressure shall be assumed to be 0.65 psi per foot of depth unless the applicant submits other measured or calculated pressure data acceptable to the division;

(d) the commingling will not result in the permanent loss of reserves due to cross-flow in the wellbore;

(e) fluid-sensitive formations that may be subject to damage from water or other produced liquids shall be protected from contact with such liquids produced from other pools in the well;

(f) if any of the pools being commingled is prorated, or the well's production has been restricted by division order in any manner, the allocated production from each producing pool in the commingled wellbore shall not exceed the top oil or gas allowable rate for a well in that pool or rate restriction applicable to such well;

(g) the commingling will not reduce the value of the total remaining production; and

(h) correlative rights will not be violated.

(2) The director may rescind authority to commingle production in a wellbore and require the pools to be produced separately if, in the director's opinion, waste or reservoir damage is resulting, correlative rights are being impaired or the efficiency of any secondary recovery project is being impaired, or any changes or conditions render the installation no longer eligible for downhole commingling.

(3) When the conditions set forth in Paragraph (1) of Subsection C of 19.15.5.303 NMAC are satisfied, the director may approve a request to downhole commingle production in one of the following ways:

(a) **Individual exceptions:** Applications to downhole commingle in wellbores located outside of an area subject to a downhole commingling order issued in a "reference case" and not within a pre-approved pool or area shall be filed on division form C-107-A with the division.

(i) The director may administratively approve a form C-107-A application in the absence of a valid objection filed within 20-days after receipt of the application by the division if, in the director's opinion, waste will not occur and correlative rights will not be impaired.

(ii) In those instances where the ownership or percentages between the pools to be commingled is not identical, applicant shall send a copy of form C-107-A to all interest owners in the spacing unit by certified mail (return receipt).

(iii) Applicant shall send copies of form C-107-A to the commissioner of public lands for the state of New Mexico for wells in spacing units containing state lands or the bureau of land management for wells in spacing units containing federal lands.

(iv) The director may set any administratively filed form C-107-A application for hearing.

(b) **Exceptions for wells located in pre-approved pools or areas**: Applications to downhole commingle in wellbores within pools or areas that have been established by the division as "pre-approved pools or areas" pursuant to Subparagraph (b) of Paragraph (4) of Subsection C of 19.15.5.303 NMAC shall be filed on form C-103 (sundry notice of intent) at the appropriate division district office. The supervisor of the appropriate division district office may approve the proposed downhole commingling following receipt of form C-103. In addition to the information required by form C-103, the applicant shall include:

(i) number of division order that established pre-approved pool or area;

(ii) names of pools to be commingled;

(iii) perforated intervals;

(iv) allocation method and supporting data;

(v) a statement that the commingling will not reduce the value of the total remaining production;

(vi) in those instances where the ownership or percentages between the pools to be commingled is not identical, a statement attesting that applicant sent notice to all interest owners in the spacing unit by certified mail (return receipt) of its intent to apply for downhole commingling and no objection was received within 20 days of sending this notice; and

(vii) a statement attesting that applicant sent a copy of the division form C-103 to the commissioner of public lands for the state of New Mexico for wells in spacing units containing state lands or the bureau of land management for wells in spacing units containing federal lands using sundry notice form 3160-5.

(c) **Exceptions for wells located in areas subject to a downhole commingling order issued in a "reference case"**: Applications to downhole commingle in wellbores within an area subject to a division order that excepted any of the criteria required by Subsection C of 19.15.5.303 NMAC or division form C-107-A shall be filed with the supervisor of the appropriate division district office and, except for the place of filing, shall meet the requirements of the applicable order issued in that "reference case".

(4) Applications for establishing a "reference case" or for pre-approval of downhole commingling on an area-wide or pool-wide basis:

(a) **Reference cases:** If sufficient data exists for a lease, pool, formation, or geographical area to render it unnecessary to repeatedly provide such data on form C-107-A, an operator may except any of the various criteria required under Subsection C of 19.15.5.303 NMAC or set forth in form C-107-A by establishing a "reference case." The division, upon its own motion or application from an operator, may establish "reference cases" either administratively or by hearing. Upon division approval of such "reference cases" for specific criteria, subsequent form C-107-A applications to downhole commingle will be required only to cite the division order number that established such exceptions and shall not be required to submit data for those criteria. Cases involving exceptions to the specific criteria required by Subsection C of 19.15.5.303 NMAC or by division form C-107-A may be approved by the division after notice sent to all interest owners in the affected spacing units by certified mail (return receipt) and based on evidence that such approval would adequately satisfy the conditions of Paragraph (1) of Subsection C of 19.15.5.303 NMAC.

(b) **Pre-approval of downhole commingling on a pool-wide or area-wide basis:** If sufficient data exists for multiple formations or pools that have previously been commingled or are proposed to be commingled, the division, upon its own motion or application from an operator, may establish downhole commingling on a pool-wide or area-wide basis either administratively or by hearing:

(i) Applications for pre-approval shall include all of the data required by division form C-107-A, a list of the names and address of all operators in the pools, all previous orders authorizing downhole commingling for the pools or area, and a map showing the location of all wells in the pools or area and indicating those wells approved for downhole commingling.

(ii) Applications for pre-approval of downhole commingling on a pool-wide or area-wide basis may be approved by the director after notice sent to operators in the affected pools or area by certified mail (return receipt) and based on evidence that such approval would adequately satisfy the conditions of Subsection C of 19.15.5.303 NMAC.

(iii) Upon approval of certain pools or areas for downhole commingling, subsequent applications for approval to downhole commingle wells within those pools or areas may be obtained by filing a division sundry notice (form C-103) in accordance with the procedure set forth in Subparagraph (b) of Paragraph (3) of Subsection C of 19.15.5.303 NMAC.

(c) The division will maintain and continually update a list of pre-approved pools or areas as set forth in Paragraph (5) of Subsection C of 19.15.5.303 NMAC.

(5) Pre-approved pools and areas: Downhole commingling is hereby approved within the described pool combinations or geographical areas set forth in Exhibit "A," provided, however, that the operator shall file form C-103 (sundry notice of intent) with the appropriate division district office in accordance with the procedure set forth in Subparagraph (b) of Paragraph (3) of Subsection C of 19.15.5.303 NMAC.

Pre-approved pools or geographic areas for downhole commingling, permian basin

All Blinebry, Tubb, Drinkard, Blinebry-Tubb, Blinebry-Drinkard & Tubb-Drinkard pool combinations within the following described geographic area in Lea County:

Township 18 South, Ranges 37, 38 and 39 East;
Township 19 South, Ranges 36, 37, 38 and 39 East;
Township 20 South, Ranges 36, 37, 38 and 39 East;
Township 21 South, Ranges 36, 37 and 38 East;
Township 22 South, Ranges 36, 37 and 38 East;
Township 23 South, Ranges 36, 37 and 38 East;
Township 24 South, Ranges 36, 37 and 38 East;
Township 25 South, Ranges 36, 37 and 38 East;
Township 26 South, Ranges 36, 37 and 38 East;

Blinebry Pools

6660	Blinebry Oil & Gas Pool (Oil)	34200	Justis-Blinebry Pool
72480	Blinebry Oil & Gas Pool (Pro Gas)	46990	Monument-Blinebry Pool
6670	West Blinebry Pool	47395	Nadine-Blinebry Pool
12411	Cline Lower Paddock-Blinebry Pool	47400	West Nadine Paddock-Blinebry Pool
29710	Hardy-Blinebry Pool	47960	Oil Center-Blinebry Pool
31700	East Hobbs-Blinebry Pool	96314	North Teague Lower Paddock-Blinebry Assoc.
31680	Hobbs Upper-Blinebry Pool	58300	Teague Paddock-Blinebry Pool
31650	Hobbs Lower-Blinebry Pool	59310	East Terry-Blinebry Pool
33230	House-Blinebry Pool	63780	Weir-Blinebry Pool
33225	South House-Blinebry Pool	63800	East Weir-Blinebry Pool

Tubb Pools

12440	Cline-Tubb Pool	47530	West Nadine-Tubb Pool
77120	Fowler-Tubb Pool	58910	Teague-Tubb Pool
26635	South Fowler-Tubb Pool	96315	North Teague-Tubb Associated Pool
78760	House-Tubb Pool	60240	Tubb Oil & Gas Pool (Oil)
33460	East House-Tubb Pool	86440	Tubb Oil & Gas Pool (Pro Gas)
33470	North House-Tubb Pool	87080	Warren-Tubb Pool
47090	Monument-Tubb Pool	87085	East Warren-Tubb Pool
47525	Nadine-Tubb Pool		

Drinkard Pools

7900	South Brunson Drinkard-Abo Pool	47505	West Nadine-Drinkard Pool
12430	Cline Drinkard-Abo Pool	47510	Nadine Drinkard-Abo Pool
15390	D-K Drinkard Pool	57000	Skaggs-Drinkard Pool
19190	Drinkard Pool	96768	Northwest Skaggs-Drinkard Pool
19380	South Drinkard Pool	58380	Teague-Drinkard Pool
26220	Fowler-Drinkard Pool	96313	North Teague Drinkard-Abo Pool
28390	Goodwin-Drinkard Pool	63080	Warren-Drinkard Pool
31730	Hobbs-Drinkard Pool	63120	East Warren-Drinkard Pool
33250	House-Drinkard Pool	63840	Weir-Drinkard Pool
47503	East Nadine-Drinkard Pool		

Blinebry-Tubb Pools

62965 Warren Blinebry-Tubb Oil & Gas Pool

Tubb-Drinkard Pools

18830	Dollarhide Tubb-Drinkard Pool	33600	Imperial Tubb-Drinkard Pool
29760	Hardy Tubb-Drinkard Pool	35280	Justis Tubb-Drinkard Pool
96356	North Hardy Tubb-Drinkard Pool		

Pool-Combinations, Lea County

Airstrip-Bone Spring (960) & Airstrip-Wolfcamp (970) Pools
Baish-Wolfcamp (4480) & Maljamar-Abo (43250) Pools
Blinebry Oil & Gas & Wantz-Abo (62700) Pools

Blinebry Oil & Gas & South Brunson-Ellenburger (8000) Pools
Blinebry Oil & Gas & Paddock (49210) Pools
Cerca Lower-Wolfcamp (11800) & Cerca Upper-Pennsylvanian (11810) Pools
Drinkard (19190) & Paddock (49210) Pools
Drinkard (19190) & Wantz-Abo (62700) Pools
Drinkard (19190) & Wantz-Granite Wash (62730) Pools
Lazy J Penn (37430) & South Baum-Wolfcamp (4967) Pools
Mesa Verde-Delaware (96191) & Mesa Verde-Bone Spring (96229) Pools
West Red Tank-Delaware (51689) & Red Tank-Bone Spring (51683) Pools
South Shoe Bar-Wolfcamp (56300) & South Shoe Bar Upper-Penn (56285) Pools
Skaggs-Glorieta (57190) & Skaggs-Drinkard (57000) Pools
West Triste Draw-Delaware (59945) & South Sand Dunes Bone Spring (53805) Pools
Triste Draw-Delaware (59930) & Triste Draw-Bone Spring (96603) Pools
Tubb Oil & Gas & Paddock (49210) Pools
North Vacuum-Abo (61760) & Vacuum-Wolfcamp (62340) Pools
Vacuum-Blinebry (61850) & Vacuum-Glorieta (62160) Pools
Vacuum-Blinebry (61850) & Vacuum-Drinkard (62110) Pools
Vacuum Upper-Penn (62320) & Vacuum-Wolfcamp (62340) Pools
Wantz-Abo (62700) & Wantz-Granite Wash (62730) Pools
Pool Combinations, Eddy County
Red Lake Queen-Grayburg-San Andres (51300) & Northeast Red Lake-Glorieta Yeso (96836) Pools
Pool Combination, San Juan Basin
Basin-Dakota (71599) & Angels Peak-Gallup Associated (2170) Pools
Basin-Dakota (71599) & Armenta-Gallup (2290) Pools
Basin-Dakota (71599) & Baca-Gallup (3745) Pools
Basin-Dakota (71599) & Bisti Lower-Gallup (5890) Pools
Basin-Dakota (71599) & BS Mesa-Gallup (72920) Pools
Basin-Dakota (71599) & Calloway-Gallup (73700) Pools
Basin-Dakota (71599) & Devils Fork-Gallup Associated (17610) Pools
Basin-Dakota (71599) & Ensenada-Gallup (96321) Pools
Basin-Dakota (71599) & Flora Vista-Gallup (76640) Pools
Basin-Dakota (71599) & Gallegos-Gallup Associated (26980) Pools
Basin-Dakota (71599) & Ice Canyon-Gallup (93235) Pools
Basin-Dakota (71599) & Kutz-Gallup (36550) Pools
Basin-Dakota (71599) & Largo-Gallup (80000) Pools
Basin-Dakota (71599) & Otero-Gallup (48450) Pools
Basin-Dakota (71599) & Tapacito-Gallup Associated (58090) Pools
Basin-Dakota (71599) & Wild Horse-Gallup (87360) Pools
Basin-Dakota (71599) & Aztec-Pictured Cliffs (71280) Pools
Basin-Dakota (71599) & Ballard-Pictured Cliffs (71439) Pools
Basin-Dakota (71599) & Blanco-Pictured Cliffs (72359) Pools
Basin-Dakota (71599) & South Blanco-Pictured Cliffs (72439) Pools
Basin-Dakota (71599) & Fulcher Kutz-Pictured Cliffs (77200) Pools
Basin-Dakota (71599) & West Kutz-Pictured Cliffs (79680) Pools
Basin-Dakota (71599) & Tapacito-Pictured Cliffs (85920) Pools
Basin-Fruitland Coal (71629) & Aztec-Pictured Cliffs (71280) Pools
Basin-Fruitland Coal (71629) & Ballard-Pictured Cliffs (71439) Pools
Basin-Fruitland Coal (71629) & Blanco-Pictured Cliffs (72359) Pools
Basin-Fruitland Coal (71629) & East Blanco-Pictured Cliffs (72400) Pools
Basin-Fruitland Coal (71629) & South Blanco-Pictured Cliffs (72439) Pools

Basin-Fruitland Coal (71629) & Carracas-Pictured Cliffs (96154) Pools
Basin-Fruitland Coal (71629) & Choza Mesa-Pictured Cliffs (74960) Pools
Basin-Fruitland Coal (71629) & Fulcher Kutz-Pictured Cliffs (77200) Pools
Basin-Fruitland Coal (71629) & West Kutz-Pictured Cliffs (79680) Pools
Basin-Fruitland Coal (71629) & Gavilan-Pictured Cliffs (77360) Pools
Basin-Fruitland Coal (71629) & Gobernador-Pictured Cliffs (77440) Pools
Basin-Fruitland Coal (71629) & Huerfano-Pictured Cliffs (78840) Pools
Basin-Fruitland Coal (71629) & Potwin-Pictured Cliffs (83000) Pools
Basin-Fruitland Coal (71629) & Tapacito-Pictured Cliffs (85920) Pools
Basin-Fruitland Coal (71629) & Twin Mounds Fruitland Sand-Pictured Cliffs (86620) Pools
Basin-Fruitland Coal (71629) & W. A. W. Fruitland Sand-Pictured Cliffs (87190)
Blanco-Mesaverde (72319) & Basin-Dakota (71599) Pools
Blanco-Mesaverde (72319) & Blanco-Pictured Cliffs (72359) Pools
Blanco-Mesaverde (72319) & South Blanco-Pictured Cliffs (72439) Pools
Blanco-Mesaverde (72319) & Gobernador-Pictured Cliffs (77440) Pools
Blanco-Mesaverde (72319) & West Lindrith Gallup-Dakota (39189) Pools
Blanco-Mesaverde (72319) & Tapacito-Pictured Cliffs (85920) Pools
Blanco-Mesaverde (72319) & Armenta-Gallup (2290) Pools
Blanco-Mesaverde (72319) & BS Mesa-Gallup (72920) Pools
Blanco-Mesaverde (72319) & Calloway-Gallup (73700) Pools
Blanco-Mesaverde (72319) & Ensenada-Gallup (96321) Pools
Blanco-Mesaverde (72319) & Flora Vista-Gallup (76640) Pools
Blanco-Mesaverde (72319) & Largo-Gallup (80000) Pools
Blanco-Mesaverde (72319) & West Lindrith Gallup-Dakota (39189) Pools
Blanco-Mesaverde (72319) & McDermott Gallup (81050) Pools
Blanco-Mesaverde (72319) & Potter-Gallup (50387) Pools
Blanco-Mesaverde (72319) & Tapacito-Gallup Associated (58090) Pools
Blanco-Mesaverde (72319) & Wild Horse-Gallup (87360) Pools
Otero-Chacra (82329) & Aztec-Pictured Cliffs (71280) Pools
Otero-Chacra (82329) & Basin-Dakota (71599) Pools
Otero-Chacra (82329) & Blanco-Mesaverde (72319) Pools
Otero-Chacra (82329) & South Blanco-Pictured Cliffs (72439) Pools
Otero-Chacra (82329) & Fulcher Kutz-Pictured Cliffs (77200) Pools

D. Off-lease transportation or storage prior to measurement**.** The division may grant exceptions to the requirements of Subsection A of 19.15.5.303 NMAC, administratively, without hearing, to permit production from one lease to be transported prior to measurement to another lease for storage thereon when:

(1) an application for off-lease transportation or storage prior to measurement has been filed on division form C-107-B with the Santa Fe office of the division with one copy to the appropriate district office of the division;

(2) all such production is from the same common source of supply;

(3) commingling of production from different leases will not result;

(4) there will be no intercommunication of the handling, separating, treating or storage facilities designated to each lease;

(5) all parties owning working interests in any of the production to be transported off lease prior to measurement have been notified of the application in accordance with the provisions of 19.15.N.1207.A NMAC and have consented in writing ;

(6) in lieu of Paragraph (5), Subsection D of 19.15.5.303 NMAC, the applicant furnishes proof that said parties were notified by registered or certified mail of its intent to transport the production from one lease to another lease for storage prior to measurement, and after a period of twenty (20) days following receipt of the application, no party has filed objection to the application; and

(7) if state, federal or Indian lands are involved, the commissioner of public lands for the state of New Mexico or the United States bureau of land management (as applicable) has been notified. The division may set for hearing any application for approval of off-lease transportation or storage prior to measurement, in which event notice of hearing shall be given, pursuant to 19.15.N.1207.A NMAC, to all owners of working interests in any of the production to be transported off lease prior to measurement, and to such other owners as the division may direct.
[1-1-50…2-1-96; 19.15.5.303 NMAC - Rn, 19 NMAC 15.E.303 & A, 5-15-00; A, 3-31-03]

19.15.5.304 CONTROL OF MULTIPLE COMPLETED WELLS:
Multiple completed wells which have been authorized by the division shall at all times be operated, produced, and maintained in a manner to ensure the complete segregation of the various common sources of supply. The division may require such tests as it deems necessary to determine the effectiveness of segregation of the different common sources of supply.
[1-1-50...2-1-96; 19.15.5.304 NMAC - Rn, 19 NMAC 15.E.304, 5-15-00]

19.15.5.305 METERED CASINGHEAD GAS:
The owner of a lease shall not be required to measure the exact amount of casinghead gas produced and used by him for fuel purposes in the development and normal operation of the lease. All casinghead gas produced and sold or transported away from a lease, except small amounts of flare gas, shall be metered and reported in standard cubic feet monthly to the division. The amount of casinghead gas sold in small quantities for use in the field may be calculated upon a basis generally acceptable in the industry, or upon a basis approved by the division in lieu of meter measurements.
[1-1-50...2-1-96; 19.15.5.305 NMAC - Rn, 19 NMAC 15.E.305, 5-15-00]

19.15.5.306 CASINGHEAD GAS:

A. No casinghead gas produced from any well in this state shall be flared or vented after 60 days following completion of the well.

B. Any operator seeking an exception to the foregoing shall file an application therefor on division form C-129, application for exception to no-flare rule 306. Form C-129 shall be filed in triplicate with the appropriate district office of the division. The district supervisor may grant an exception when the same appears reasonably necessary to protect correlative rights, prevent waste, or prevent undue hardships on the applicant. The district supervisor shall either grant the exception within ten days after receipt of the application or refer it to the division director who will advertise the matter for public hearing if a hearing is desired by the applicant.

C. The flaring or venting by an operator of gas from any well in violation of this rule will result in suspension of the allowable assigned to the well.

D. No extraction plant processing gas in the state of New Mexico shall flare or vent such gas unless such flaring or venting is made necessary by mechanical difficulty of a very limited temporary nature or unless the gas flared or vented is of no commercial value.

E. In the event of a more prolonged mechanical difficulty or in the event of plant shut-downs or curtailment because of scheduled or non-scheduled maintenance or testing operations or other reasons, or in the event a plant is unable to accept, process, and market all of the casinghead gas produced by wells connected to its system, the plant operator shall notify the division as soon as possible of the full details of such shut-down or curtailment, following which the division shall take such action as is necessary to reduce the total flow of gas to such plant.

F. Pending connection of a well to a gas-gathering facility, or when a well has been excepted from the provisions of Paragraph A. of this rule, all gas produced and not utilized shall be burned, and the estimated volume reported on the monthly production report, form C-115.

G. The provisions of Paragraph A. of this rule shall not be applicable to wells completed prior to January 1, 1971, in pools which had no gas-gathering facilities on that date, provided however, said provisions shall be applicable to all wells in such a pool 60 days after the date of first casinghead gas connection in the pool.
[9-1-72...2-1-96; 19.15.5.306 NMAC - Rn, 19 NMAC 15.E.306, 5-15-00]

19.15.5.307 OPERATION AT BELOW ATMOSPHERIC PRESSURE:

A. A well operator may use vacuum pumps, gathering system compressors or other devices to operate a well or gathering system at below atmospheric pressure only if that operator has:

(1) executed a written agreement with the operator of the downstream gathering system or pipeline to which the well or gathering system so operated is immediately connected allowing operation of the well or gathering system at below atmospheric pressure; and

(**2**) filed a sundry notice in the appropriate district office of the division for each well operated at below atmospheric pressure or served by a gathering system operated at below atmospheric pressure, within ninety (90) days before beginning operation at below atmospheric pressure, notifying the division that the well or gathering system serving the well is being operated at below atmospheric pressure.

B. A gathering system operator may use vacuum pumps, gathering system compressors or other devices to operate a gathering system at below atmospheric pressure, or may accept gas originating from a well operated at below atmospheric pressure or that has been carried by any upstream gathering system operated at below atmospheric pressure, only if that operator has executed a written agreement with the operator of the downstream gathering system or pipeline to which the gathering system is immediately connected allowing delivery of gas from a well or gathering system that has been operated at below atmospheric pressure into the downstream gathering system or pipeline.

[1-1-50...2-1-96; 19.15.5.307 NMAC - Rn, 19 NMAC 15.E.307, 5-15-00; Repealed, 08/31/04; N, 08/31/04]

19.15.5.308 SALT OR SULPHUR WATER:

Operators shall report monthly on form C-115 the amount of water produced with the oil and gas from each well.

[1-1-50...2-1-96; 19.15.5.308 NMAC - Rn, 19 NMAC 15.E.308, 5-15-00]

19.15.5.309 AUTOMATIC CUSTODY TRANSFER EQUIPMENT:

A. Oil shall be received and measured in a facility of an approved design. Such facilities shall permit the testing of each well at reasonable intervals and may be comprised of manually gauged, closed stock tanks for which proper strapping tables have been prepared, or of automatic custody transfer (ACT) equipment. The use of such automatic custody transfer equipment shall be permitted only after compliance with the following: The operator shall file with the division form C-106, notice of intention to utilize automatic custody transfer equipment, and shall receive approval thereof prior to transferring oil through the ACT system. The carrier shall not accept delivery of oil through the ACT system until form C-106 has been approved.

B. Form C-106 shall be submitted in quadruplicate to the appropriate district office of the division and shall be accompanied (in quadruplicate) by the following:

(1) Plat of the lease showing thereon all wells which will be produced into the ACT system.

(2) Schematic diagram of the ACT equipment, showing thereon all major components such as surge tanks and their capacity, extra storage tanks and their capacity, transfer pumps, monitors, reroute valves, treaters, samplers, strainers, air and gas eliminators, back pressure valves, metering devices, (indicating type and capacity, i.e. whether automatic measuring tank, positive volume metering chamber, weir-type measuring vessel, or positive displacement meter). Schematic diagram shall also show means employed to prove accuracy of measuring device.

(3) Letter from transporter agreeing to utilization of ACT system as shown on schematic diagram.

C. Form C-106 will not be approved by the division unless the ACT system is to be installed and operated in compliance with the following:

(1) Provision must be made for accurate determination and recording of uncorrected volume and applicable temperature, or of temperature corrected volume. The overall accuracy of the system shall equal or surpass manual methods.

(2) Provision must be made for representative sampling of the oil transferred for determination of API gravity and BS&W content.

(3) Provision must be made if required by either the producer or the transporter of the oil to give adequate assurance that only merchantable oil is run by the ACT system.

(4) Provision must be made for set-stop counters to stop the flow of oil through the ACT system at or prior to the time the allowable has been run. All counters shall provide non-reset totalizers which shall be visible for inspection at all times.

(5) All necessary controls and equipment must be enclosed and sealed, or otherwise be so arranged as to provide assurance against, or evidence of, accidental or purposeful mismeasurement resulting from tampering.

(6) All components of the ACT system shall be properly sized to ensure operation within the range of their established ratings. All components of the system which require periodic calibration and/or inspection for proof of continued accuracy must be readily accessible. The frequency and methods of such calibration and/or inspection shall be set forth in Paragraph (12) of Subsection C of 19.15.5 NMAC.

(7) The control and recording system must include adequate fail-safe features which will provide assurance against mismeasurement in the event of power failure, or the failure of the ACT system's component parts.

(8) The ACT system and allied facilities shall include such fail-safe equipment as may be necessary, including high level switches in the surge tank or overflow storage tank which, in the event of power failure or malfunction of the ACT or other equipment, will shut down all artificially lifted wells connected to the ACT system and will shut in all flowing wells at the well-head or at the header manifold, in which latter case all flowlines shall be pressure-tested to at least 1 ½ times the maximum well-head shut-in pressure prior to initial use of the ACT system and each two years thereafter.

(9) As an alternative to the requirements of, Paragraph (8) of Subsection C of 19.15.5 NMAC the producer shall provide and shall at all times maintain a minimum of available storage capacity above the normal high working level of the surge tank to receive and hold the amount of oil which may be produced during maximum unattended time of lease operation.

(10) In all ACT systems employing automatic measuring tanks, weir-type measuring vessels, positive volume metering chambers, or any other volume measuring container, the container and allied components shall be properly calibrated prior to initial use and shall be operated, maintained, and inspected as necessary to ensure against incrustation, changes in clingage factors, valve leakage or other leakage, and improper action of floats, level detectors, etc.

(11) In all ACT systems employing positive displacement meters, the meter(s) and allied components shall be properly calibrated prior to initial use and shall be operated, maintained, and inspected as necessary to ensure against mismeasurement of oil.

(12) The measuring and recording devices of all ACT systems shall be checked for accuracy at least once each month unless exception to such determination has been obtained from the division director. API standard 1101, "measurement of petroleum liquid hydrocarbons by positive displacement meter," shall be used where applicable. Meters may be proved against master meters, portable prover tanks, or prover tanks permanently installed on the lease. If permanently installed prover tanks are used, the distance between the opening and closing levels and the provision for determining the opening and closing readings shall be sufficient to detect variations of 5/100 of one percent. Reports of determination shall be filed on the division form entitled "meter test report," or on another acceptable form and shall be submitted in duplicate to the appropriate district office of the division.

(13) To obtain exception to the requirement of Paragraph (12) of Subsection C of 19.15.5 NMAC that all measuring and recording devices be checked for accuracy once each month, either the producer or transporter may file such a request with the division director setting forth all facts pertinent to such exception. The application shall include a history of the average factors previously obtained, both tabulated and plotted on a graph of factors versus time, showing that the particular installation has experienced no erratic drift. The applicant shall also furnish evidence that the other interested party has agreed to such exception. The division director may then set the frequency for determination of the system's accuracy at the interval which he deems prudent.

D. Failure to operate an automatic custody transfer system in compliance with this rule shall subject the approval thereof to revocation by the division.

[5-1-61…2-1-96; 19.15.5.309 NMAC - Rn, 19 NMAC 15.E.309, 5-15-00, A, 3-31-03]

19.15.5.310 TANKS, OIL TANKS, FIRE WALLS, AND TANK IDENTIFICATION:

A. Oil shall not be stored or retained in earthen reservoirs, or in open receptacles. Dikes or fire walls shall not be required except such fire walls must be erected and kept around all permanent oil tanks, or battery of tanks that are within the corporate limits of any city, town or village, or where such tanks are closer than 150 feet to any producing oil or gas well or 500 feet to any highway or inhabited dwelling or closer than 1000 feet to any school or church, or where such tanks are so located as to be deemed an objectional hazard within the discretion of the division. Where fire walls are required, fire walls shall form a reservoir having a capacity one-third larger than the capacity of the enclosed tank or tanks.

B. After August 1, 1982, all oil tanks, tank batteries, automatic custody transfer systems, tanks used for salt water collection or disposal, and tanks used for sediment oil treatment or storage shall be identified by a sign posted on or not more than 50 feet from the tank, tank battery, or system. Such signs shall be of durable construction and the lettering thereon shall be kept in a legible condition and shall be large enough to be legible under normal conditions at a distance of 50 feet and shall identify the name of the operator, the name of the lease(s) being served by the tank(s) or system, if any, and the location of such tank(s) or system by unit letter, section, township, and range.

[1-1-50...2-1-96; 19.15.5.310 NMAC - Rn, 19 NMAC 15.E.310, 5-15-00]

19.15.5.311 SEDIMENT OIL, TANK CLEANING, AND TRANSPORTATION OF MISCELLANEOUS HYDROCARBONS:

A. "Sediment oil" is defined as tank bottoms and any other accumulations of liquid hydrocarbons on an oil and gas lease, which hydrocarbons are not merchantable through normal channels.

B. No tank shall be cleaned of sediment oil nor shall sediment oil be removed from any lease without prior approval of the appropriate division district office. Authorization for tank cleaning may be received by the operator of the lease or by the company contracted or otherwise authorized to perform the tank cleaning by obtaining approval on form C-117-A (tank cleaning, sediment oil removal, transportation of miscellaneous hydrocarbons and disposal permit). No operator, contractor, or other party shall engage in the cleaning of any tank of sediment oil or the removal of sediment oil from any lease without an approved copy of form C-117-A at the site.

C. No sediment oil shall be destroyed unless and until the appropriate division district office has approved an application to destroy the same on form C-117-A (tank cleaning, sediment oil removal, transportation of miscellaneous hydrocarbons and disposal permit). Unless the authorization to destroy sediment oil is utilized within ten (10) days after approval of the form C-117-A such authorization is automatically revoked. However, the district supervisor may approve one ten (10) day extension for good cause shown.

D. Any operator, contractor, or party, other than a treating plant operator, who cleans any tank of sediment oil and removes sediment oil from any lease shall file form C-117-B (monthly sediment oil disposal statement) setting out all information required thereon.

E. A representative sample of sediment oil from any source shall be tested in a manner designed to accurately estimate the percentage of good oil expected to be recovered therefrom. Such test shall be performed prior to transport and prior to commingling with sediment oil from other leases or sources and the results recorded on the appropriate form C-117-A. The division recommends the standard centrifugal tests prescribed by API Manual of Petroleum Measurement Standards, Chapter 10, Section 4. Other test procedures may be used if such procedures reliably predict the percentage of good oil to be recovered from sediment oil.

F. All sediment oil removed from storage shall be reported on form C-115 (operator's monthly report) together with the form C-117-A (tank cleaning, sediment oil removal, transportation of miscellaneous hydrocarbons and disposal permit) permit number.

G. "Miscellaneous hydrocarbons" are defined as tank bottoms occurring at pipeline stations, crude oil storage terminals, or refineries, pipeline break oil, catchings collected in traps, drips, or scrubbers by operators of gasoline plants in such plants or in the gathering lines serving such plants, the catchings collected in private, community, or commercial salt water disposal systems, or any other liquid hydrocarbon which is not lease crude or condensate.

H. Except in case of emergency, no miscellaneous hydrocarbons shall be delivered to a treating plant or other facility until division approval is obtained on form C-117-A (tank cleaning, sediment oil removal, transportation of miscellaneous hydrocarbons and disposal permit).

I. Whenever an emergency exists which requires delivery of miscellaneous hydrocarbons to a treating plant or other facilities prior to approval of form C-117-A, the transporter of such hydrocarbons shall notify the supervisor of the appropriate division district office of the nature and extent of such emergency on the first working day following the emergency and shall file form C-117-A within two working days following the emergency. For prolonged emergencies, the district supervisor may authorize the extended movement of miscellaneous hydrocarbons to a treating plant or other facilities during the period of the emergency and shall approve a form C-117-A filed subsequent to the conclusion of such emergency covering the entire volume of miscellaneous hydrocarbons transported.
[1-1-50…2-1-96; 19.15.5.311 NMAC - Rn, 19 NMAC 15.E.311, 5-15-00]

19.15.5.312 RESERVED: [Formerly "Treating Plants". Repealed 7-26-95]

19.15.5.313 EMULSION, BASIC SEDIMENTS, AND TANK BOTTOMS:
Wells producing oil shall be operated in such a manner as will reduce as much as practicable the formation of emulsion and basic sediments. These substances and tank bottoms shall not be allowed to pollute fresh waters or cause surface damage.
[1-1-50...2-1-96; 19.15.5.313 NMAC - Rn, 19 NMAC 15.E.313, 5-15-00; A, 03/31/04]

19.15.5.314 GATHERING, TRANSPORTING AND SALE OF DRIP:

A. "Drip" is defined as any liquid hydrocarbon incidentally accumulating in a gas gathering or transportation system.

B. The waste of drip is hereby prohibited when it is economically feasible to salvage the same.

C. The movement and sale of drip is hereby authorized, provided the provisions of this Rule are complied with.

D. No drip shall be transported nor sold until the gas transporter has filed division form C-104 designating the drip transporter authorized to remove the drip from its gas gathering or transportation system.

E. Every person transporting drip within the state of New Mexico shall file division form C-112 each month, showing the amount, source, and disposition of all drip handled during the reporting period, and such other reports as may hereafter be required by the division.

F. Prior to commencement of operations, every person transporting drip directly from a gas gathering or transportation system shall file with the division plats drawn to scale, locating and identifying each drip trap which he is authorized to service.

G. Every person transporting drip directly from a gas gathering or transportation system shall keep a record of daily acquisitions from each drip trap which he is authorized to service, which records shall be made available at all reasonable times for inspection by the division or its authorized representatives.

H. Every gas transporter in the state of New Mexico shall, on or before the first day of November of each year, file with the division maps of its entire gas gathering and transportation systems within the state of New Mexico, locating and identifying thereon each drip trap in said systems, said maps to be accompanied by a report, on a form prescribed by the division, showing the disposition being made of the drip from each of said drip traps.
[8-26-57…2-1-96; 19.15.5.314 NMAC - Rn, 19 NMAC 15.E.314, 5-15-00]

History of 19.15.5 NMAC:
Pre-NMAC History:
Rule 301, Gas-Oil Ratio and Production Tests, filed 1-8-82;
Rule 301, Gas-Oil Ratio and Production Tests, filed 10-11-89;
Rule 301, Gas-Oil Ratio and Production Tests, filed 2-5-91;
Rule 302, Subsurface Pressure Tests, filed 1-8-82;
Rule 302, Subsurface Pressure Tests, filed 2-5-91;
Rule 303, Segregation of Production from Pools, filed 1-8-82;
Rule 303, Amendment No. 1, Segregation of Production from Pools, filed 1-27-82;

Rule 303, Segregation of Production from Pools, filed 10-11-89;
Rule 303, Segregation of Production from Pools, filed 2-5-91;
Rule 304, Control of Multiple Completed Wells, filed 1-8-82;
Rule 304, Control of Multiple Completed Wells, filed 2-5-91;
Rule 305, Metered Casinghead Gas, filed 1-8-82;
Rule 305, Metered Casinghead Gas, filed 2-5-91;
Rule 306, Casinghead Gas, filed 1-8-82;
Rule 306, Amendment No. 1, Casinghead Gas, filed 2-23-84;
Rule 306, Casinghead Gas, filed 2-5-91;
Rule 307, Use of Vacuum Pumps, filed 1-8-82;
Rule 307, Use of Vacuum Pumps, filed 2-5-91;
Rule 308, Salt or Sulfur Water, filed 1-8-82;
Rule 308, Produced Water, filed 9-16-85;
Rule 308, Salt or Sulfur Water, filed 2-5-91;
Rule 309-A, Central Tank Batteries - Automatic Custody Transfer Equipment, filed 1-8-82;
Rule 309-A, Central Tank Batteries - Automatic Custody Transfer Equipment, filed 2-5-91;
Rule 309-B, Administrative Approval, Lease Commingling, filed 1-8-82;
Rule 309-B, Administrative Approval, Lease Commingling, filed 2-5-91;
Rule 309-C, Administrative Approval, Off-Lease Storage, filed 1-8-82;
Rule 309-C, Administrative Approval, Off-Lease Storage, filed 10-11-89;
Rule 309-C, Administrative Approval, Off-Lease Storage, filed 2-5-91;
Rule 310, Tanks, Oil Tanks, Fire Walls, and Tank Identification, filed 1-8-82;
Rule 310, Amendment No. 1, Tanks, Oil Tanks, Fire Walls, and Tank Identification, filed 1-27-82;
Rule 310, Tanks, Oil Tanks, Fire Walls, and Tank Identification, filed 2-5-91;
Rule 311, Sediment Oil, Tank Cleaning, and Transportation of Miscellaneous Hydrocarbons, filed 1-8-82;
Rule 311, Amendment No. 1, Sediment Oil, Tank Cleaning, and Transportation of Miscellaneous Hydrocarbons, filed 1-27-82;
Rule 311, Sediment Oil, Tank Cleaning, and Transportation of Miscellaneous Hydrocarbons, filed 2-5-91;
Rule 312, Treating Plants, filed 1-8-82
Rule 312, Amendment No. 1, Treating Plants, filed 1-27-82
Rule 312, Treating Plants, filed 8-20-86
Rule 312, Treating Plants, filed 8-17-89
Rule 312, Treating Plants, filed 10-11-89
Rule 312, Treating Plants, filed 7-26-95
Rule 312, Treating Plants, filed 2-5-91
Rule 313, Emulsion, Basic Sediments, and Tank Bottoms, filed 1-8-82;
Rule 313, Emulsion, Basic Sediments, and Tank Bottoms, filed 10-18-85;
Rule 313, Emulsion, Basic Sediments, and Tank Bottoms, filed 8-17-89;
Rule 313, Emulsion, Basic Sediments, and Tank Bottoms, filed 2-5-91;
Rule 314, Gathering, Transportation and Sale of Drip, filed 1-8-82;
Rule 314, Gathering, Transportation and Sale of Drip, filed 2-5-91.

History of Repealed Material: Rule 312, Treating Plants, filed 7-26-95.

Other History:
Rule 301, Gas-Oil Ratio and Production Tests, filed 2-5-91; Rule 302, Subsurface Pressure Tests, filed 2-5-91; Rule 303, Segregation of Production from Pools, filed 2-5-91; Rule 304, Control of Multiple Completed Wells, filed 2-5-91; Rule 305, Metered Casinghead Gas, filed 2-5-91; Rule 306, Casinghead Gas, filed 2-5-91; Rule 307, Use of Vacuum Pumps, filed 2-5-91; Rule 308, Salt or Sulfur Water, filed 2-5-91; Rule 309-A, Central Tank Batteries - Automatic Custody Transfer Equipment, filed 2-5-91; Rule 309-B, Administrative Approval, Lease Commingling,

filed 2-5-91; Rule 309-C, Administrative Approval, Off-Lease Storage, filed 2-5-91; Rule 310, Tanks, Oil Tanks, Fire Walls, and Tank Identification, filed 2-5-91; Rule 311, Sediment Oil, Tank Cleaning, and Transportation of Miscellaneous Hydrocarbons, filed 2-5-91; Rule 313, Emulsion, Basic Sediments, and Tank Bottoms, filed 2-5-91; Rule 314, Gathering, Transportation and Sale of Drip, filed 2-5-91; all renumbered, reformatted **to and replaced by** 19 NMAC 15.E, Oil Production Operating Practices, filed 01-18-96.
19 NMAC 15.E, Oil Production Operating Practices, filed 01-18-96 renumbered, reformatted **to and replaced by** 19.15.5 NMAC, effective 5-15-00.

TITLE 19 NATURAL RESOURCES & WILDLIFE
CHAPTER 15 OIL AND GAS
PART 6 NATURAL GAS PRODUCTION OPERATING PRACTICE

19.15.6.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department, Oil Conservation Division, 2040 South Pacheco, Santa Fe, New Mexico 87505, (505) 827-7131.
[2-1-96; 19.15.6.1 NMAC - Rn, 19 NMAC 15.F.1, 12-14-01]

19.15.6.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico.
[2-1-96; 19.15.6.1 NMAC - Rn, 19 NMAC 15.F.2, 12-14-01]

19.15.6.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the Oil and Gas Act which grants the Oil Conservation Division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights, and the disposition of wastes resulting from oil and gas operations.
[2-1-96; 19.15.6.3 NMAC - Rn, 19 NMAC 15.F.3, 12-14-01]

19.15.6.4 DURATION: Permanent.
[2-1-96; 19.15.6.4 NMAC - Rn, 19 NMAC 15.F.4, 12-14-01]

19.15.6.5 EFFECTIVE DATE: February 1, 1996.
[2-1-96; 19.15.6.5 NMAC - Rn, 19 NMAC 15.F.5, 12-14-01]

19.15.6.6 OBJECTIVE: To regulate the production of natural gas to enable the Oil Conservation Division to fulfill its statutory mandates under the Oil and Gas Act.
[2-1-96; 19.15.6.6 NMAC - Rn, 19 NMAC 15.F.6, 12-14-01]

19.15.6.7 DEFINITIONS: [RESERVED].

19.15.6.8-400 [RESERVED].

19.15.6.401 METHOD OF DETERMINING NATURAL GAS WELL POTENTIAL:

A. All operators shall conduct tests to determine the daily open flow potential volumes of all natural gas wells from which gas is being used or marketed. Such tests shall be reported on forms prescribed by the division within 60 days after:

(1) the date of initial connection of the well to a gas transportation facility; and

(2) the date of reconnection following workover.

B. To establish comparable open flow capacity, wells shall be tested in accordance with the Oil Conservation Division "Manual for Back-Pressure Testing of Natural Gas Wells." In the event the division approves the alternate method for testing, all wells producing from a common source of supply shall be tested in a uniform and comparable manner.

C. All gas wells which are not connected to a gas gathering facility shall be tested within 30 days following the installation of a christmas tree. Tests shall be taken in accordance with the Rules of Procedure for Testing Unconnected Gas Well contained in the Oil Conservation Division "Manual for Back-Pressure Testing of Natural Gas Wells." Tests shall be reported on Form C-122 in compliance with Rule 1122 and shall be filed within 10 days following completion of the test.
[5-25-64...2-1-96; 19.15.6.401 NMAC - Rn, 19 NMAC 15.F.401, 12-14-01]

19.15.6.402 [RESERVED].

[7-15-63...2-1-96; 19.15.6.402 NMAC - Rn, 19 NMAC 15.F.402, 12-14-01; 19.15.6.402 NMAC - Repealed, 02-17-03]

19.15.6.403 NATURAL GAS FROM GAS WELLS TO BE MEASURED:

A. All natural gas produced shall be accounted for by metering or other method approved by the division and reported to the division by the transporter of the gas. Gas produced from a gas well and delivered to a gas transportation facility shall be reported by the owner or operator of the gas transportation facility. Gas produced from a gas well and required to be reported under this rule, which is not delivered to and reported by a gas transportation facility shall be reported by the operator of the well.

B. An operator may apply to the OCD District Supervisor, using Form C-136, for approval of one of the following procedures for measuring gas:

(1) In the event a well is not capable of producing more than 15 MCFD, a measurement method agreed upon by the operator and transporter whereby the parties establish by annual test the producing rate of said well under normal operating conditions and apply that rate to the period of time the well is in a producing status. If such well is capable of producing greater than 5 MCFD, a device shall be attached to the line which will determine the actual time period that the well is flowing.

(2) Any well which has a producing capacity of 100 MCFD or less and which is on a multi-well lease may be produced without being separately metered when the gas is measured using a lease meter at a Central Point Delivery (CPD). The ownership of the lease must be common throughout including working interest, royalty and overriding royalty ownership.

(3) If normal operating conditions change, either party may request a new well test, the cost of which will be borne by the party so requesting unless otherwise agreed upon.

C. Operators and transporters shall report the well volumes on Forms C-115 and C-111 based upon the approved method of measurement and, in the case of a CPD, upon the method of allocation of production to individual wells approved by the district supervisor.

[1-1-50, 12-23-91...2-1-96; 19.15.6.403 NMAC - Rn, 19 NMAC 15.F.403, 12-14-01]

19.15.6.404 NATURAL GAS UTILIZATION:

A. After the completion of a natural gas well, no gas from such well shall be:

(1) permitted to escape to the air;

(2) used expansively in engines or pumps and then vented, or

(3) used to gas-lift wells unless all gas produced is processed in a gasoline plant, used in the manufacture of carbon black, or beneficially used thereafter without waste.

B. Carbon black plants may utilize natural gas only in those instances in which all casinghead gas and residue gas produced in the vicinity of or which may reasonably be reached from the carbon black plant, is being used beneficially.

C. Any carbon black plant constructed after June 10, 1954, or any then existing carbon black plant which enlarges or expands its facilities for the manufacture of carbon black, may utilize natural gas in the manufacture of carbon black only after permission of the division is obtained upon due notice and hearing.

[1-1-50, 6-10-54...2-1-96; 19.15.6.404 NMAC - Rn, 19 NMAC 15.F.404, 12-14-01]

19.15.6.405 STORAGE GAS:

With the exception of the requirement to meter and report monthly the amount of gas injected and the amount of gas withdrawn from storage, in the absence of waste these rules and regulations shall not apply to gas being injected into or removed from storage. (See Rule 1131.)

[1-1-50...2-1-96; 19.15.6.405 NMAC - Rn, 19 NMAC 15.F.405, 12-14-01]

19.15.6.406 CARBON DIOXIDE:

The statewide regulations relating to gas and natural gas, gas wells, and gas reservoirs including, but not limited to, those provisions relating to well locations, acreage dedication requirements, casing and cementing requirements, and measuring and reporting of production shall also apply to carbon dioxide gas, carbon dioxide wells, and carbon dioxide reservoirs.

[1-1-50...2-1-96; 19.15.6.406 NMAC - Rn, 19 NMAC 15.F.406, 12-14-01]

19.15.6.407 DISCONNECTION OF GAS WELLS:

All gas wells which are disconnected from intrastate gas transportation facilities shall be reported to the division by the operator of the well or wells within 30 days of the date of disconnection. Such notice must be filed on Form C-130 in compliance with Rule 1130.

[8-23-77...2-1-96; 19.15.6.407 NMAC - Rn, 19 NMAC 15.F.407, 12-14-01]

19.15.6.408 HARDSHIP GAS WELL:

A. Hardship gas well is defined as a gas well wherein "underground waste" will occur if the well should be shut-in or curtailed below its minimum sustainable flow rate.

B. No well shall be classified as a hardship gas well except after notice and hearing or upon appropriate administrative action of the division.

C. Wells approved as hardship gas wells under Sections 409 and/or 410 of 19.15.6 NMAC shall be given priority access (over other gas wells) to the current available gas market to the extent that they might otherwise be restricted below the approved minimum flow rate.

[3-2-84...2-1-96; 19.15.6.408 NMAC - Rn, 19 NMAC 15.F.408, 12-14-01]

19.15.6.409 APPLICATION FOR HARDSHIP GAS WELL CLASSIFICATION:

A. Application for hardship gas well classification shall be made in the form prescribed by the division and shall include the following:

(1) a narrative description of the problem(s) which leads the applicant to believe that underground waste will occur if the well is shut-in or curtailed below its ability to produce;

(2) documentation that the applicant has made all reasonable and economic attempts to eliminate or correct the problem(s) or an explanation and justification as to why such attempts were not made;

(3) a wellbore sketch;

(4) historical data such as permanent loss of productivity after shut-in, frequency and actual costs of swabbing after shut-in or curtailment including length of swab time required, actual cost figures showing the inability to continue operations without special relief, or any other data which would show that shut-in or curtailment would cause underground waste;

(5) if failure to obtain a hardship gas well classification would result in premature abandonment of the well, a calculation of the reserves which would be lost thereby;

(6) the minimum sustainable producing rate as determined by a minimum flow or "log-off" test or documentation of well production history;

(7) a plat and/or map showing the proration unit dedicated to the well and the ownership of the offsetting acreage;

(8) the name of the authorized transporter (and purchaser if different) of gas; and

(9) any other data the applicant considers relevant.

B. Applications for hardship gas well classification shall be made in duplicate with the original copy being filed at Santa Fe and a copy being filed with the appropriate division district office.

C. In addition, the applicant will notify the transporter and purchaser of gas from the well and all offset operators of the application and the requested minimum producing rate and shall so certify to the division in his application.

[3-2-84...2-1-96; 19.15.6.409 NMAC - Rn, 19 NMAC 15.F.409, 12-14-01]

19.15.6.410 PROCESSING OF APPLICATIONS FOR HARDSHIP GAS WELLS:

A. The director of the division may administratively approve any application for hardship gas well classification or he may set such matter for notice and hearing.

B. Applications which are to be approved administratively shall be listed in the dockets of division or commission hearings which are issued from time to time.

(1) If no affected party has filed written objection to any such proposed administrative action within 20 days following the date of the hearing for which the docket is issued, the application may be approved. If any such party shall file an objection before or within such 20 day period, the application will be set for hearing unless withdrawn by the applicant.

(2) The director of the division, on his own or upon the request of an affected party, may require a minimum flow (log-off) test on the well for which the hardship classification is being sought. The applicant shall give notice to the division, the gas transporter and purchaser and the requesting affected party of any minimum flow test conducted following such a request, in order that such test may, at the option of the division or said parties, be witnessed. Notice of any minimum flow test conducted prior to submitting a hardship gas well application shall be given to the appropriate division district office, the gas transporter and purchaser, and offset operators in order that such test may, at the option of said parties, be witnessed.

[3-2-84...2-1-96; 19.15.6.410 NMAC - Rn, 19 NMAC 15.F.410, 12-14-01]

19.15.6.411 EMERGENCY HARDSHIP GAS WELL CLASSIFICATION:

A. The supervisor of the appropriate division district office may grant emergency approval of a hardship gas well classification upon receipt of a copy of the application form and attachments and a request by the applicant.

B. Approval of such emergency classification shall be made in writing to the director of the division, the applicant, and the purchaser. Emergency approval shall be given for 90 days and on a one time only basis.

[3-2-84...2-1-96; 19.15.6.411 NMAC - Rn, 19 NMAC 15.F.411, 12-14-01]

19.15.6.412 LIMITS ON HARDSHIP GAS WELL CLASSIFICATION:

A. No hardship gas well classification shall be retained for a period in excess of one year unless the applicant shall annually request an extension thereof and certify that the condition of the well has not substantially changed.

B. The division on its own motion may require that the applicant show cause why approval of the hardship gas well classification should not be rescinded in cases of suspected abuse, changed market conditions, or for any other reason.

C. Any well classified as a hardship gas well located in a prorated gas pool shall accumulate over or under production. No well which is classified as a hardship gas well shall be shut in for reason of over production.

D. Affected parties may petition the division for hearing for the purpose of offsetting any ratable take advantage which might be gained by the operator of a hardship gas well.

[3-2-84...2-1-96; 19.15.6.412 NMAC - Rn, 19 NMAC 15.F.412, 12-14-01]

19.15.6.413 [RESERVED].

19.15.6.414 GAS SALES BY LESS THAN ONE HUNDRED PERCENT OF THE OWNERS IN A WELL: When there are separate owners in a well and where any such owner's gas is not being sold with current production from such well, such owner may, if necessary to protect his correlative rights, petition the division for a hearing seeking appropriate relief.

[1-1-84...2-1-96; 19.15.6.414 NMAC - Rn, 19 NMAC 15.F.414, 12-14-01]

History of 19.15.6 NMAC:

Pre-NMAC History:

Material in this part was derived from that previously filed with the commission of public records - state records center and archives as:

Rule 401, Method of Determining Natural Gas Well Potential, filed 1-8-82;
Rule 401, Method of Determining Natural Gas Well Potential, filed 2-5-91;
Rule 402, Method and Time of Shut-in Pressure Tests, filed 1-8-82;
Rule 402, Method and Time of Shut-in Pressure Tests, filed 11-6-86;
Rule 402, Method and Time of Shut-in Pressure Tests, filed 2-5-91;
Rule 403, Natural Gas from Gas Well to be Measured, filed 1-8-82;
Rule 403, Natural Gas from Gas Well to be Measured, filed 3-17-86;
Rule 403, Natural Gas from Gas Well to be Measured, filed 2-5-91;
Rule 404, Natural Gas Utilization, filed 1-8-82;
Rule 404, Natural Gas Utilization, filed 2-5-91;
Rule 405, Storage Gas, filed 1-8-82;
Rule 405, Storage Gas, filed 2-5-91;
Rule 406, Carbon Dioxide, filed 1-8-82;
Rule 406, Carbon Dioxide, filed 2-5-91;
Rule 407, Disconnection of Gas Wells, filed 1-8-82;
Rule 407, Disconnection of Gas Wells, filed 2-5-91;
Rule 408, Hardship Gas Well, filed 2-23-84;
Rule 408, Hardship Gas Well, filed 2-5-91;
Rule 409, Application for Hardship Gas Well Classification, filed 2-23-84;
Rule 409, Application for Hardship Gas Well Classification, filed 2-5-91;
Rule 410, Processing of Applications for Hardship Gas Wells, filed 2-23-84;
Rule 410, Processing of Applications for Hardship Gas Wells, filed 2-5-91;
Rule 411, Emergency Hardship Gas Well Classification, filed 2-23-84;
Rule 411, Emergency Hardship Gas Well Classification, filed 2-5-91;
Rule 412, Limits On Hardship Gas Well Classification, filed 2-23-84;
Rule 412, Limits On Hardship Gas Well Classification, filed 2-5-91;
Rule 414, Gas Sales By Less than One Hundred Percent of the Owners in a Well, filed 12-30-86;
Rule 414, Gas Sales By Less than One Hundred Percent of the Owners in a Well, filed 2-5-91;

History of Repealed Material: [RESERVED].

Other History:

Rule 401, Method of Determining Natural Gas Well Potential, filed -5-91; Rule 402, Method and Time of Shut-In Pressure Tests, filed 2-5-91; Rule 403, Natural Gas From Gas Wells to be Measured, filed 2-5-91; Rule 404, Natural Gas Utilization, filed2-5-91; Rule 405, Storage Gas, filed 2-5-91; Rule 406, Carbon Dioxide, filed 2-5-91; Rule 407, Disconnection of Gas Wells, filed 2-5-91; Rule 408, Hardship Gas Well, filed 2-5-91; Rule 409, Application for Hardship Gas Well Classification, filed 2-5-91; Rule 410, Processing of Applications for Hardship Gas Wells, filed 2-5-91; Rule 411, Emergency Hardship Gas Well Classification, filed 2-5-91; Rule 412, Limits on Hardship Gas Well Classification, filed, 2-5-91; Rule 414, Gas Sales By Less Than One Hundred Percent of the owners in a Well, filed 2-5-91; all renumbered, reformatted **to and replaced by** 19 NMAC 15.F, Natural

Gas Production Operating Practice**,** filed 01-18-96.
19 NMAC 15.F, Natural Gas Production Operating Practice, filed 01-18-96; **renumbered, reformatted and replaced by** 19.15.6 NMAC, effective 12-14-01.

TITLE 19 NATURAL RESOURCES & WILDLIFE
CHAPTER 15 OIL AND GAS
PART 7 OIL PRORATION AND ALLOCATION

19.15.7.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department, Oil Conservation Division, 2040 S. Pacheco, Santa Fe, New Mexico 87505, (505) 827-7131.
[2-1-96; 19.15.7.1 NMAC – Rn, 19 NMAC 15.G.1, 6-14-02]

19.15.7.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico.
[2-1-96; 19.15.7.2 NMAC – Rn, 19 NMAC 15.G.2, 6-14-02]

19.15.7.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the Oil and Gas Act which grants the Oil Conservation Division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights, and the disposition of wastes resulting from oil and gas operations.
[2-1-96; 19.15.7.3 NMAC – Rn, 19 NMAC 15.G.3, 6-14-02]

19.15.7.4 DURATION: Permanent.
[2-1-96; 19.15.7.3 NMAC – Rn, 19 NMAC 15.G.4, 6-14-02]

19.15.7.5 EFFECTIVE DATE: February 1, 1996.
[2-1-96; 19.15.7.5 NMAC – Rn, 19 NMAC 15.G.5, 6-14-02]

19.15.7.6 OBJECTIVE: To regulate oil proration and allocation to prevent waste and protect correlative rights pursuant to the Oil and Gas Act.
[2-1-96; 19.15.7.6 NMAC – Rn, 19 NMAC 15.G.6, 6-14-02]

19.15.7.7 DEFINITIONS: [RESERVED].

19.15.7.8-500 [RESERVED].

19.15.7.501 REGULATION OF OIL POOLS:

A. To prevent waste, the division shall prorate and distribute the allowable production among the producers in a pool upon a reasonable basis and recognizing correlative rights.

B. After notice and hearing, the division, in order to prevent waste and protect correlative rights, may promulgate special rules, regulations, or orders pertaining to any pool.
[1-1-50...2-1-96; 19.15.7.501 NMAC – Rn, 19 NMAC 15.G.501, 6-14-02]

19.15.7.502 RATE OF PRODUCING WELLS:

A. Daily Tolerance

(1) It is recognized that oil wells located on units capable of producing their allowables may overproduce one day and underproduce another. No unit capable of producing its allowable, except for the purpose of testing, in the process of completing or recompleting a well or for tests made for the purpose of obtaining scientific data, shall produce any day more than 125% of the daily top unit allowable for the pool in which the same is located. (Subject to the foregoing, any underproduction may be made up by production from the same unit within the same month, and in like manner any overproduction shall be adjusted or balanced by underproduction from the same unit, within the same proration period).

(2) It is also recognized that certain wells must, as a matter of practicality, be produced at daily rates in excess of 125% of the daily top unit allowable for the pool in which such wells are located. The division director is hereby given authority to grant exceptions to the provisions of Paragraph (1) of Subsection A of 19.15.7.502 NMAC, without formal hearing, where application is filed in due form setting out the reasons for such requested exception; applicants for such exceptions shall, at the time of filing, also furnish each operator in the pool in which the subject well is located, a copy of such application. Included in any application for exception or attached thereto, filed under authority hereof, shall be a formal written statement by the applicant that every operator in the pool in which the subject well is located has been served with a copy of such application. The division director shall wait at least ten (10) days after receipt before approving any such application, and shall approve the same only in absence of objection from any operator or interested party, or in his discretion. In the event the Director for any reason fails to

approve such application, the division after notice will hear and determine the matter.

B. Monthly Tolerance - No unit shall produce during any one proration period more than the allowable production of such unit for the proration period plus a tolerance of not to exceed five (5) days allowable production. This permissive tolerance of overproduction from a unit shall be subject to all other provisions of 19.15.7.502 NMAC and particularly to the provisions of Subsection D of 19.15.7.502 NMAC. This permissive tolerance of overproduction from a unit shall be adjusted or balanced by subsequent corresponding underproduction from the same unit. Overproduction within the permitted tolerance shall be considered as oil produced against the allowable production assigned to the unit for the proration period during which such overproduction is adjusted or balanced by underproduction.

C. Production in Excess of Monthly Allowable, Plus Tolerance

(1) Oil produced from any unit in excess of the assigned monthly allowable plus the permissive proration period tolerance shall be "illegal oil" as defined in the Oil and Gas Act, unless:

(a) such excess oil be produced as a result of mistake or error;

(b) mechanical failure beyond the immediate control of the operator; or,

(c) resulting from essential tests of the unit within the purview of Oil Conservation Rules.

(2) Whenever production from any unit for a proration period is in excess of the assigned allowable, plus the permitted tolerance authorized herein and the cause of such excess reasonably falls within Subparagraphs (a), (b), or (c) of Paragraph (1) of Subsection C of 19.15.7.502 NMAC, the producer or operator shall briefly set forth the cause of such excess production together with a proposed plan of adjustment thereof, upon all copies of the operator's monthly report (Form C-115) for the month in which such excess production occurs. Such excess production shall be considered as oil produced against the allowable assigned to the unit for the following proration period, and it may be transported from the lease tanks only as and when the unit accrues daily allowable to offset such excess production.

D. General

(1) The tolerance permitted on a daily or monthly basis as provided hereinabove shall not be construed to increase the allowable of a producing unit or to grant authority to any operator to market or to any transporter to transport any quantity of oil in excess of the unit's allowable.

(2) The possession of a quantity of oil in lease storage at the end of any proration period in excess of five days allowable plus any rerun allowable oil shall be construed as violation of this Rule, unless reported in the manner and within the time provided for filing Form C-115 provided by Subsection C of 19.15.7.502 NMAC above.

E. Storage Records - All producers and all transporters of oil are required to maintain adequate records showing unrun allowable oil in storage at the end of each proration period. Such storage oil shall be the amount of oil in tanks from which oil is measured and delivered to the transporter.

[8-28-53...2-1-96; 19.15.7.502 NMAC – Rn, 19 NMAC 15.G.502, 6-14-02]

19.15.7.503 AUTHORIZATION FOR PRODUCTION OF OIL:

A. Except as provided below, the daily top unit allowable for any oil pool shall be 100 percent of the depth bracket allowable for the pool determined pursuant to the provisions of 19.15.7.505 NMAC.

B. The division shall have the option, within five days prior to the end of the month, to make a determination as to the likelihood of the total producing capacity of all oil wells in the state being in excess of anticipated reasonable market demand for crude petroleum oil from this state. If the division determines that such capacity may be in excess of the anticipated reasonable market demand, and that a market demand factor of less than 100 percent may be necessary to prevent waste, it shall immediately institute proper proceedings for a hearing to be held before the 20th day of the following month to determine actual reasonable market demand up to a maximum of 6 months.

C. At said hearing the division shall consider all evidence of market demand for crude petroleum oil from this state, and if it is determined that the market demand percentage factor should be less than 100 percent, an order shall be issued establishing the market demand factor and setting a date for the next market demand hearing.

D. The market demand factor thus established shall be multiplied by the applicable depth bracket allowable for each well and each pool to determine its unit allowable. Any fraction of a barrel shall be regarded as a full barrel in determining top unit allowable. Upon initial establishment of a market demand factor, and from time to time thereafter, the division shall issue a proration schedule authorizing the production of oil from the various proration units in the various pools in the state. Any well completed or recompleted after the issuance of said schedule and for which Form C-104 has been approved, shall, by supplement to the schedule, be authorized a daily allowable equal to the top unit allowable in effect. The allowable for such well shall become effective at 7:00 a.m. on the date of the completion, provided Form C-104 is submitted and approved within ten days following date of completion; otherwise the allowable shall be effective on the date the C-104 is approved. (As provided in Rule 1104, "date of completion" is the date when new oil is delivered into the stock tanks.)

E. A non-marginal unit is defined as being a proration unit which is capable of producing top unit allowable for the pool in which it is located and to which has been assigned a top unit allowable. Any such non-marginal unit shall be permitted to produce said top unit allowable without waste and subject to the provisions of 19.15.5.301 NMAC, 19.15.7.502 NMAC and 19.15.7.506 NMAC and all other applicable rules.

F. A marginal unit is defined as being a proration unit which is incapable of producing top unit allowable for the pool in which it is located as evidenced by well test, production history, or other report or form filed by the operator with the division. Any such marginal unit shall be permitted to produce any amount of oil which it is capable of producing without waste up to top unit allowable for the pool, subject to the provisions of 19.15.5.301 NMAC, 19.15.7.502 NMAC and 19.15.7.506 NMAC, and all other applicable rules, provided that an allowable has been assigned to the unit to authorize such production.

G. A penalized non-marginal unit is defined as being a proration unit to which, because of an excessive gas-oil ratio, an allowable has been assigned which shall be determined in accordance with the procedure set forth in 19.15.7.506 NMAC. In calculating a penalized allowable, any fraction of a barrel shall be regarded as a full barrel.

H. A periodic tabulation of all supplements to the current proration schedule shall be made and distributed by the division.

I. The provisions of Subsection H of 19.15.3.104 NMAC shall be adhered to in fixing top unit allowables.

J. In the event it becomes necessary for any transporter of crude petroleum to resort to pipeline proration in New Mexico, such transporter shall, as soon as possible and not later than 24 hours after the effective date thereof, notify the division of its decision to so prorate; upon receipt of such notice from such transporter, the division may take such emergency action, as may be deemed proper, and/or upon its own motion, after notice, hold a hearing for the purpose of considering any action within its authority, to preserve and protect correlative rights.

K. In case of pipeline proration any operator affected thereby has the right to make application to the division for authorization to have any shortage or underproduction resulting therefrom included in subsequent proration schedules. Such applications shall be made upon a form hereby authorized to be prescribed by the division and filed therewith within thirty days after the close of the first proration period in which such pipeline proration shortage occurred, and such authorization shall be limited in any event to wells capable of producing the daily top unit allowable for such period.

L. In approving any such application the division shall determine the period of time during which such shortage shall be made up without injury to the well or pool, and shall include the same in the regularly approved proration schedules following the conclusion of pipeline proration.

[9-1-72...2-1-96; 19.15.7.503 NMAC – Rn, 19 NMAC 15.G.503, 6-14-02]

19.15.7.504 AUTHORIZATION FOR PRODUCTION OF OIL WHILE COMPLETING, RECOMPLETING, OR TESTING AN OIL WELL:

A. In the event an operator does not have sufficient lease storage to hold oil produced from a well during the process of its drilling, completing, recompleting, or testing, the operator of said well shall be permitted to produce and sell from said well an amount of oil as may be necessary to drill, complete, recomplete or test said well; provided however, that the operator of said well shall file with the division a written application stating the circumstances at said well and setting forth therein the estimated amount of oil to be produced during the aforementioned process of operations, and provided further that said application is approved by the division. Oil produced during the process of drilling, completion or recompletion, or testing a well shall be charged against the allowable production of said well.

B. No well shall be placed on the proration schedule until Form C-104 has been filed with and approved by the division.

[7-1-52...2-1-96; 19.15.7.504 NMAC – Rn, 19 NMAC 15.G.504, 6-14-02]

19.15.7.505 DEPTH BRACKET ALLOWABLES:

A. Subject to the market demand percentage factor determined pursuant to the provisions of 19.15.7.503 NMAC, the daily oil allowable for each oil pool in the state shall be equal to the appropriate depth bracket allowable below. The depth of the casing shoe or the top perforation in the casing, whichever is higher, in the first well completed in the pool shall determine the depth classification for the pool. Daily oil allowables for each of the several ranges of depth and spacing patterns shall be as follows:

POOL DEPTH RANGE	DEPTH BRACKET ALLOWABLE		
	40 Acres	80 Acres	160 Acres
0 to 4,999 feet	80 bbls.	160 bbls.	
5,000 to 5,999 "	107 "	187 "	347 bbls.
6,000 to 6,999 "	142 "	222 "	382 "
7,000 to 7,999 "	187 "	267 "	427 "
8,000 to 8,999 "	230 "	310 "	470 "

9,000 to 9,999 "	275 "	355 "	515 "
10,000 to 10,999 "	320 "	400 "	560 "
11,000 to 11,999 "	365 "	445 "	605 "
12,000 to 12,999 "	410 "	490 "	650 "
13,000 to 13,999 "	455 "	535 "	695 "
14,000 to 14,999 "	500 "	580 "	740 "
15,000 to 15,999 "	545 "	625 "	785 "
16,000 to 16,999 "	590 "	670 "	830 "
17,000 to	635 "	715 "	875 "

B. The 40-acre depth bracket allowables shall apply to all undesignated wells not governed by special pool rules and to all pools developed on the normal 40-acre statewide spacing unit.

C. The 80-acre and 160-acre depth bracket allowables shall apply to wells governed by applicable special pool rules promulgated by the division as an exception to the normal 40-acre statewide spacing unit.

D. The division may, where the same is deemed appropriate, assign to a given pool a special depth bracket allowable at variance to the depth bracket allowable normally assigned to a pool of similar depth and spacing. Such special allowable may be more or less than the regular depth bracket allowable and shall be assigned only after notice and hearing.

E. In assigning a lesser than regular depth bracket allowable, the division may consider, among other pertinent factors, reservoir damage, casinghead gas production and disposition, water production and disposition, transportation facilities, the prevention of surface or underground waste, and the protection of correlative rights.

F. Assignment of a greater than regular depth bracket allowable shall be made only after sufficient reservoir information is available to ensure that said allowable can be produced without damage to the reservoir and without causing surface or underground waste. The division shall also consider the availability of crude oil transportation and marketing facilities, casinghead gas transportation, processing, and marketing facilities, water disposal facilities, the protection of correlative rights, and other pertinent factors.

[9-1-72...2-1-96; 19.15.7.505 NMAC – Rn, 19 NMAC 15.G.505, 6-14-02]

19.15.7.506 GAS-OIL RATIO LIMITATION:

A. In allocated pools containing a well or wells producing from a reservoir which contains both oil and gas, each proration unit shall be permitted to produce only that volume of gas equivalent to the applicable limiting gas-oil ratio multiplied by the top unit oil allowable for the pool. In the event the division has not set a gas-oil ratio limit for a particular oil pool, the limiting gas-oil ratio shall be 2,000 cubic feet of gas for each barrel of oil produced. In allocated oil pools all producing wells, whether oil or casinghead gas, shall be placed on the oil proration schedule.

B. Unless heretofore or hereafter specifically exempted by order of the division issued after hearing, a gas-oil ratio limitation shall be placed on all allocated oil pools, and all proration units having a gas-oil ratio exceeding the limit for the pool shall be penalized in accordance with the following procedure:

(1) Any proration unit which, on the basis of the latest official gas-oil ratio test, has a gas-oil ratio in excess of the limiting gas-oil ratio and has the capacity to produce above the top casinghead gas volume calculated by Subsection A of 19.15.7.506 NMAC for the pool in which it is located shall be permitted to produce daily that number of barrels of oil which shall be determined by multiplying the current top unit allowable by a fraction, the numerator of which shall be the limiting gas-oil ratio for the pool and the denominator of which shall be the official test gas-oil ratio of the well, and the proration unit will be designated non-marginal.

(2) Any unit containing a well or wells producing from a reservoir which contains both oil and gas shall be permitted to produce only that volume of gas equivalent to the applicable limiting gas-oil ratio multiplied by the top unit allowable currently assigned to the pool.

(3) A marginal unit shall be permitted to produce the same volume of gas which it would be permitted to produce if it were a non-marginal unit.

C. All non-marginal proration units to which gas-oil ratio adjustments are applied shall be so indicated in the proration schedule with adjusted allowables stated.

D. In cases of new pools, the limit shall be 2,000 cubic feet per barrel until such time as changed by order of the division issued after a hearing. Upon petition and after notice and hearing according to law, the division will determine or redetermine the specific gas-oil ratio limit which is applicable to a particular allocated oil pool.

[1-1-50...2-1-96; 19.15.7.506 NMAC – Rn, 19 NMAC 15.G.506, 6-14-02]

19.15.7.507 UNITIZED AREAS:

After petition and notice and hearing, the division may grant approval for the combining of contiguous developed proration units

into a unitized area.
[1-1-50...2-1-96; 19.15.7.507 NMAC – Rn, 19 NMAC 15.G.507, 6-14-02]

19.15.7.508 RECOVERED LOAD OIL:

A. Recovered load oil may be run from the lease on which it is recovered, provided division approval is obtained by means of Form C-126. Form C-126 must be filed in QUADRUPLICATE with the appropriate district office of the division. Upon approval, one copy will be returned to the operator and one copy will be sent to the designated transporter as authority to transport the oil.

B. 19.15.7.508 NMAC applies only to oil which has been obtained from a source other than the lease on which it is used.

C. Recovered load oil as used herein is any oil or liquid hydrocarbon which has been used in any operation in an oil or gas well, and which has been recovered as a merchantable product.
[4-15-54...2-1-96; 19.15.7.508 NMAC – Rn, 19 NMAC 15.G.508, 6-14-02]

19.15.7.509 OIL DISCOVERY ALLOWABLE:

A. In addition to the normally assigned allowable, an oil discovery allowable may be assigned to a well completed as a bona fide discovery well in a new common source of supply. Said oil discovery allowable shall be in the amount of 5 barrels for each foot of depth of said well from the surface of the ground to the top of the perforations in the new pool or the depth of the casing shoe, whichever is higher. In counties where there is no other current oil production, and in any county when the discovery is the deepest oil production in the county, the oil discovery allowable shall be 10 barrels per foot of depth.

B. Date of discovery to determine the well which should properly receive the oil discovery allowable for any new pool shall be the date the well is completed and new oil is run into stock tanks, provided however, any operator drilling through and discovering a new oil pool in the course of drilling to a lower horizon may file an affidavit of such discovery within seven days after drill stem tests were made of said pool, accompanying said affidavit with all available pool data. If, prior to completion of said well, another operator claims discovery of a similar pool and there are reasonable grounds to believe the pools are one and the same, no discovery allowable will be assigned to either well until after the initial well for which the affidavit was filed has been completed. If at that time the operator of the initial well makes formal application for the discovery allowable in said pool, it will be determined after hearing which well shall receive the discovery allowable.

C. To obtain an oil discovery allowable, the owner of a discovery well shall file two copies of division Form C-109, Application for Discovery Allowable and Creation of a New Pool, with the appropriate district office of the division and one with the Santa Fe office. Each copy of said form shall be accompanied by the following:

(1) A map depicting all wells within a two-mile radius of the discovery well. All producing oil and gas wells and the formations from which they are producing or have produced are to be clearly shown as well as all dry holes and the depths to which they were drilled. Maps shall be on a scale one inch equals 1,000 feet and shall also indicate the names of all lessees of record in the depicted area.

(2) A complete electrical log of the subject well with the tops and bottoms of producing formations in the subject well and in nearby wells identified thereon.

(3) If application is based on horizontal separation, a sub-surface structural map of the producing formation(s) for which the discovery allowable is sought, showing seismic or geological interpretation of the subject structure and any troughs, faults, pinch-outs, etc., which separate the subject well from nearby wells producing from the same formation(s).

(4) A geological cross-section prepared from electrical logs of the subject well and nearby wells establishing horizontal as well as vertical separation from other wells depicted on the plat which are producing or have produced from the discovery formation(s).

(5) A summary of all available reservoir data including bottom hole pressure data, fluid levels, core analyses, reservoir liquid characteristics and any other pertinent data on the subject reservoir as well as other nearby reservoirs which may help establish whether the subject well is in fact a discovery.

D. If, in the opinion of the division staff, good cause exists to bring the pool on for hearing as a discovery, and no objection has been received from any other operator, the pool will be placed on the first available hearing docket for inclusion by the staff in its regular pool nomenclature case. If the staff is not in agreement with the applicant's contention that a new pool has been discovered, or if, within ten days after receiving a copy of the application another operator files with the division an objection to the creation of a new pool and the assignment of a discovery allowable, the applicant will be so notified, and he will be expected to present the evidence supporting his case. Or, if the applicant so desires, the application may be set for separate hearing on other than the nomenclature docket for presentation of evidence by the applicant.

E. Effective date of a well's discovery allowable will be 7:00 a.m. on the first day of the month next succeeding the month in which the division approves the discovery.

F. The total discovery allowable attributable to each zone in the well shall be produced over a two-year period commencing with the time of authorization. The well's daily allowable for each pool receiving the discovery allowable shall not exceed the daily top unit allowable for the pool plus the total pool discovery allowable divided by 730 days (731 days if a leap year is included).

G. A discovery well shall be permitted to produce only that volume of gas equivalent to the applicable limiting gas-oil ratio for the pool multiplied by the top unit allowable for the pool plus the daily oil discovery allowable. In addition to all other statewide rules not specifically excepted herein, the provisions of 19.15.7.502 NMAC relating to daily tolerance, monthly tolerance, and underproduction and overproduction, shall apply to oil discovery allowables as well as to regular allowables for discovery wells.

H. Nothing herein contained shall be construed as prohibiting the division from curtailing the discovery allowables of wells during times of depressed market demand, provided however, such discovery allowables shall be reinstated for production at the earliest possible date. Further, when it appears reservoir damage or waste might result from production of the oil discovery allowable within the normal two-year period, the division may, after notice and hearing, extend said period.

[9-1-66...2-1-96; 19.15.7.509 NMAC – Rn, 19 NMAC 15.G.509, 6-14-02]

History of 19.15.7 NMAC:

Pre-NMAC History:

Rule 501, Regulation of Oil Pools, filed 1-8-82;
Rule 501, Regulations of Oil Pools, filed 2-5-91;
Rule 502, Rate of Producing Wells, filed 1-8-82;
Rule 502, Rate of Producing Wells, filed 2-5-91;
Rule 503, Authorization for Production of Oil, filed 1-8-82;
Rule 503, Authorization for Production of Oil, filed 10-11-89;
Rule 503, Authorization for Production of Oil, filed 2-5-91;
Rule 504, Authorization for Production of Oil While Completing, Recompleting, or Testing an Oil Well, filed 1-8-82;
Rule 504, Authorization for Production of Oil While Completing, Recompleting, or Testing an Oil Well, filed 2-5-91;
Rule 505, Depth Bracket Allowable, filed 1-8-82;
Rule 505, Depth Bracket Allowable, filed 10-11-89;
Rule 505, Depth Bracket Allowable, filed 2-5-91;
Rule 506, Gas-Oil Ratio Limitation, filed 1-8-82;
Rule 506, Gas-Oil Ratio Limitation, filed 10-11-89;
Rule 506, Gas-Oil Ratio Limitation, filed 2-5-91;
Rule 507, Unitized Areas, filed 1-8-82;
Rule 507, Unitized Areas, filed 2-5-91;
Rule 508, Recovered Load Oil, filed 1-8-82;
Rule 508, Recovered Load Oil, filed 2-5-91;
Rule 509, Oil Discovery Allowable, filed 1-8-82;
Rule 509, Oil Discovery Allowable, filed 10-11-89;
Rule 509, Oil Discovery Allowable, filed 2-5-91.

History of Repealed Material: [Reserved]

Other History:

Rule 501, Regulation of Oil Pools, filed 2-5-91; Rule 502, Rate of Producing Wells, filed 2-5-91; Rule 503, Authorization for Production of Oil, filed 2-5-91; Rule 504, Authorization for Production of Oil While Completing, Recompleting, or Testing an Oil Well, filed 2-5-91; Rule 505, Depth Bracket Allowables, filed 2-5-91; Rule 506, Gas-Oil Ratio Limitation, filed 2-5-91; Rule 507, Unitized Areas, filed 2-5-91; Rule 508, Recovered Load Oil, filed 2-5-91; Rule 509, Oil Discovery Allowable, filed 2-5-91 all renumbered, reformatted **to and replaced by** 19 NMAC 15.G, Oil Proration and Allocation, filed 01-18-96.
19 NMAC 15.G, Oil Proration and Allocation, filed 01-18-96 renumbered, reformatted **to and replaced by** 19.15.7 NMAC, effective 6-14-02.

TITLE 19 **NATURAL RESOURCES AND WILDLIFE**
CHAPTER 15 **OIL AND GAS**
PART 8 **GAS PRORATION AND ALLOCATION**

19.15.8.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department, Oil Conservation Division, 2040 S. Pacheco, Santa Fe, New Mexico 87505, (505) 827-7131.
[2-1-96; 19.15.8.1 NMAC – Rn, 19 NMAC 15.H.1, 04-30-03]

19.15.8.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico.
[2-1-96; 19.15.8.2 NMAC - Rn, 19 NMAC 15.H.2, 04-30-03]

19.15.8.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the Oil and Gas Act which grants the oil conservation division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights, and the disposition of wastes resulting from oil and gas operations.
[2-1-96; 19.15.8.3 NMAC - Rn, 19 NMAC 15.H.3, 04-30-03]

19.15.8.4 DURATION: Permanent.
[2-1-96; 19.15.8.4 NMAC - Rn, 19 NMAC 15.H.4, 04-30-03]

19.15.8.5 EFFECTIVE DATE: February 1, 1996.
[2-1-96; 19.15.8.5 NMAC - Rn, 19 NMAC 15.H.5, 04-30-03]

19.15.8.6 OBJECTIVE: To regulate gas proration and allocation to prevent waste and protect correlative rights pursuant to the Oil and Gas Act.
[2-1-96; 19.15.6. NMAC - Rn, 19 NMAC 15.H.6, 04-30-03]

19.15.8.7 DEFINITIONS:

A. Acreage factor: A GPU's acreage factor shall be determined to the nearest hundredth of a unit by dividing the acreage assigned to the GPU by a number equal to the number of acres in a standard GPU for such pool. However, the acreage tolerance provided in Subparagraph (b), of Paragraph (2) of Subsection A, of 19.15.8.605 NMAC, shall apply.

B. Ad factor: An acreage times deliverability factor is calculated in pools in which acreage and deliverability are proration factors. The product obtained by multiplying the acreage factor by the calculated deliverability (expressed as MCF per day) for that GPU shall be known as the AD factor for that GPU. The AD Factor shall be computed to the nearest whole unit.

C. Allocation hearing: A hearing held by the division twice each year to determine pool allocations for the ensuing allocation period.

D. Allocation period: A six-month period beginning at 7:00 A.M. April 1 and October 1 of each year.

E. Balancing date: The date 7:00 A.M. April 1 of each year shall be known as the balancing date, and the twelve months following this date shall be known as the gas proration period.

F. Broker: A third party who negotiates contracts for purchase and resale.

G. Classification period: A three month period beginning at 7:00 A.M. April 1, July 1, October 1, and January 1 of each year.

H. Gas pool: Any pool which has been designated as a gas pool by the division after notice and hearing.

I. Gas proration unit (GPU): The acreage allocated to a well, or in the case of an infill well or wells to a group of wells, for purposes of spacing and proration. GPU's may be either of a standard or nonstandard size as provided in these rules. (GPU's means plural GPU).

J. Gas transporter: Any taker of gas, the party servicing the well meter, or the party responsible for measurement of gas sold from the well or beneficially used off-lease. This could be at the wellhead, at any other point on the lease, or at any other point authorized by the division where connection is made for gas transportation or utilization (other than is necessary for maintaining the producing ability of the well). The gas transporter can be the gatherer, transporter, producer, or a delegate of one of those parties. The gas transporter shall be identified on form C-104 and will be responsible for filing form C-111 as required under the provisions of 19.15.13.1111 NMAC.

K. Gas purchaser: The purchaser (where ownership of the gas is first exchanged by the producer to the purchaser for an agreed value) of the gas from a gas well or GPU.

L. Hardship gas well: A gas well wherein underground waste will occur if the well is shut-in or curtailed below its minimum sustainable flow rate. No well shall be classified as a hardship gas well except after notice and hearing or upon appropriate administrative action of the division.

M. Infill well: An additional producing well on a GPU which serves as a companion well to an existing well on the GPU.

N. Marginal GPU: A proration unit which is incapable of producing or has not produced the non-marginal allowable based on pool allocation factors. Marginal GPU's do not accrue over or underproduction.

O. Non-marginal GPU: A proration unit receiving an allowable based upon pool allocation factors. Non-marginal proration units accrue over or underproduction.

P. Overproduction: The volume of gas produced on a GPU in any month greater than the assigned non-marginal allowable (does not include gas used in maintaining the producing ability of the well(s) of the GPU). Overproduction accumulates month to month during the proration period.

Q. Prorated gas pool: A prorated gas pool is a gas pool in which, after notice and hearing, the production is allocated by the division according to these rules and any applicable special pool rules.

R. Proration period: The twelve-month period beginning April 1 of each year shall be the gas proration period.

S. Shadow allowable: The gas volume calculated for a marginal GPU that is equal to the allowable assigned to a non-marginal GPU in the same pool of the same A (acreage) or A and AD (acreage deliverability) factors as the marginal GPU.

T. Underproduction: The volume of assigned non-marginal allowable not produced on a GPU. Underproduction accumulates month to month during the proration period.

[5-30-98; 19.15.8.7 NMAC - Rn, 19 NMAC 15.H.7, 04-30-03]

19.15.8.8-600 [RESERVED]

19.15.8.601 ALLOCATION OF GAS PRODUCTION:

When the division determines that allocation of gas production in a designated gas pool is necessary to prevent waste, the division, after notice and hearing, shall consider the nominations of purchasers from that gas pool and other relevant data, and shall fix the allowable production of that pool, and shall allocate production among the gas wells in the pool delivering to a gas transportation facility upon a reasonable basis and recognizing correlative rights. The division shall include in the proration schedule of such pool any gas well which it finds is being unreasonably discriminated against through denial of access to a gas transportation facility which is reasonably capable of handling the type of gas produced by such well.

[1-1-50...2-1-96; 19.15.8.601 NMAC - Rn, 19 NMAC 15.H.601, 04-30-03]

19.15.8.602 PRORATION PERIOD:

The proration period shall be at least six months and the pool allowable and allocations thereof shall be made at least 30 days prior to each proration period.

[1-1-50...2-1-96; 19.15.8.602 NMAC - Rn, 19 NMAC 15.H.602, 04-30-03]

19.15.8.603 ADJUSTMENT OF ALLOWABLES:

When the actual market demand from any allocated gas pool during a proration period is more than or less than the allowable set by the division for the pool for the period, the division shall adjust the gas proration unit allowables for the pool for the next proration period so that each gas proration unit shall have a reasonable opportunity to produce its fair share of the gas production from the pool and so that correlative rights shall be protected.

[1-1-50...2-1-96; 19.15.8.603 NMAC - Rn, 19 NMAC 15.H.603, 04-30-03]

19.15.8.604 GAS PRORATION UNITS:

Before issuing a proration schedule for an allocated gas pool, the division after notice and hearing, shall fix the gas proration unit for that pool.

[1-1-50...2-1-96; 19.15.8.604 NMAC - Rn, 19 NMAC 15.H.604, 04-30-03]

19.15.8.605 GAS PRORATION RULES:

A. Well Acreage and Location Requirements

(1) Standard Gas Proration Unit Size and Well Spacing:

(a) Unless otherwise provided for in applicable special pool rules, gas wells in prorated gas pools shall be drilled according to the well spacing and acreage requirements contained in these rules provided that when wells are drilled in pools with 640 acre spacing, a government section shall comprise the proration unit.

(b) Any GPU drilled according to Subparagraph (a), of Paragraph (1) of Subsection A of 19.15.8.605 which contains acreage within the tolerances below shall be considered a standard GPU for calculating allowables:

Standard Proration Unit	Acreage Tolerance
160 acres	158-162 acres
320 acres	316-324 acres
640 acres	632-648 acres

(2) Non-Standard Gas Proration Units:

(a) The district supervisor of the appropriate district office of the division has the authority to approve a nonstandard GPU without notice and hearing when the unorthodox size and shape of the GPU is necessitated by a variation in the legal subdivision of the U.S. public land surveys and the nonstandard GPU is not less that 75% nor more than 125% of a standard GPU by accepting a form C-102 land plat showing the proposed nonstandard GPU with the number of acres contained therein, and shall assign an allowable to the nonstandard GPU based upon the acreage factor for that acreage.

(b) Non-standard proration units and unorthodox locations may be approved by the division according to applicable special pool rules or division rules.

B. Nominations

(1) Gas Purchasers Or Gas Transporters Shall Nominate: Each gas purchaser or each gas transporter as herein provided shall file with the division its nomination for the amount of gas which it in good faith desires to purchase and/or expects to transport during the ensuing allocation period from each gas pool regulated by this order. The purchaser may delegate the nomination responsibility to the transporter, operator, or broker by notifying the division's Santa Fe office. One copy of such nomination for each pool shall be submitted to the division's Santa Fe office on form C-121-A by the first day of the month during which the division will consider at its allocation hearing the nominations for the succeeding allocation period. The division shall consider at its allocation hearing the nominations received, actual production, and such other factors as may be deemed applicable in determining the amount of gas that may be produced without waste during the ensuing allocation period.

The division director may, at his discretion, suspend this rule whenever it appears that the nominations are of little or no value.

(2) Schedule: The division shall issue a gas proration schedule for each allocation period showing the monthly allowable for each GPU that may be produced during each month of the ensuing allocation period, the current classification of each GPU, and such other information as is necessary to show the allowable production status of each GPU on the schedule. The division may issue supplemental proration schedules during an allocation period as necessary to show changes in GPU classification, adjustments to allowables due to changes in market conditions, or to reflect any other changes as the division deems necessary.

(3) Proration of all Gas Wells Within a Pool: The division shall include in the proration schedule the gas wells in the gas pools regulated by this order delivering to a gas transporter, and shall include in the proration schedule any well which it finds is being unreasonably discriminated against through denial of access to a gas transportation facility, which is reasonably capable of handling the type of gas produced by such a well.

C. Allocation and Granting of Allowables

(1) Filing of Form C-102 and Form C-104 Required: No GPU shall be assigned an allowable before receipt of form C-102 (well location and acreage dedication plat) and the approval date of form C-104 (request for allowable and authorization to transport oil and natural gas).

(2) How Allowables are Calculated: The total allowable to be allocated to each gas pool regulated by this order for each allocation period shall be equal to the estimated market demand as determined by the division, plus any adjustments the director deems necessary to equate the total pool allowable to the estimated market demand. The director may make such adjustments as he deems necessary to compensate for overproduction, underproduction, and other circumstances which may necessitate such adjustment to equate pool allowable to the anticipated market demand. The estimated market demand for each pool shall be established from any information the director requires and can consist of nominations from purchasers, transporters or other parties having knowledge of market demand for gas from such pools, actual past production figures, seasonal trends, or any other factors deemed necessary to establish estimated market demand. The director shall not be bound to use all the information requested and can establish market demand by any method so approved. A monthly allowable shall be assigned to each GPU entitled to an allowable for the ensuing allocation period by allocating the pool allowable among all such GPU's in that pool according to the procedure set forth in the following paragraphs of this order. Should market conditions indicate a change is necessary, the director may adjust allowables up or down during the 6-month allocation period using a maximum of 10% as a guideline.

(3) Marginal GPU Allowable: The monthly allowable to be assigned to each marginal GPU shall be equal to its average monthly production from its latest classification period.

(4) Non-Marginal GPU Allowable: Non-marginal GPU allowables shall be determined in conformance with the applicable special pool rules.

(a) In pools where acreage is the only proration factor, the total non-marginal allowable shall be allocated to each GPU in the proportion that each GPU acreage factor bears to the total acreage factor for all non-marginal GPU's.

(b) In pools where acreage and deliverability are proration factors:

(i) A percentage as set forth in special pool rules, of the non-marginal allowable shall be allocated to each GPU in the proportion that each GPU's AD factor bears to the total AD factor for all non-marginal GPU's in the pool; and

(ii) The remaining non-marginal allowable shall be allocated to non-marginal GPU's among each GPU in the proportion that each GPU's acreage factor bears to the total acreage factor for all non-marginal GPU's in the pool.

(5) New Connects Assignment of Allowables: Allowables to newly completed gas wells shall commence, in pools where acreage is the only proration factor, on the date of first delivery of gas to a gas transporter as demonstrated by an affidavit furnished by the transporter to the appropriate division district office or the approval date of form C-102 and form C-104, whichever is later.

(6) Gas Charged Against GPU's Allowable: Except as provided in the Special Pool rules, the volume of produced gas sold or beneficially used other than lease fuel from each GPU shall be charged against the GPU's allowable; however, the gas used in maintaining the producing ability of the well shall not be charged against the allowable.

(7) Change in Acreage: If the acreage assigned to a GPU is changed, the operator shall notify the appropriate division district office in writing of such change by filing a revised plat (form C-102). The revised allowable, as determined by the division, assigned to the GPU shall be effective on the first day of the month following receipt of the notification.

(8) Minimum Allowables: After notice and hearing, the division may assign minimum allowables for prorated gas pools to avoid waste, encourage efficient operations, and to prevent the premature abandonment of wells. (see Special Pool Rules for minimum allowable amount.) In determining the volume of minimum allowable for a well with a standard proration unit, the division shall take into account economic and engineering factors such as drilling and operating costs, anticipated revenues, taxes, and any similar data that will establish that the ultimate recovery of hydrocarbons will be increased from the pool because of the adoption of a minimum allowable for the pool. Once adopted, the minimum allowable for wells with nonstandard proration units shall be proportionally adjusted.

(9) Deliverability Tests: In pools where acreage and deliverability are proration factors, wells on non-marginal GPUs will be tested in accordance with division rules and the test results shall be used in calculating deliverabilities for the succeeding proration period. Wells on GPUs reclassified to non-marginal shall be tested within 90 days of the order and thereafter in accordance with the appropriate testing schedule for the pool. Wells on marginal GPUs are exempt from deliverability testing.

D. Balancing of Production

(1) Underproduction: Any non-marginal GPU which has an underproduced status as of the end of a gas proration period shall be allowed to carry such underproduction forward in the next gas proration period and may produce such underproduction in addition to the allowable assigned during such succeeding period. Any underproduction carried forward into a gas proration period and remaining unproduced at the end of such gas proration period shall be canceled.

(2) Balancing Underproduction: Production during any one month of a gas proration period greater than the allowable assigned to a GPU for such a month shall be applied against the underproduction carried into such a period in determining the amount of allowable, if any, to be canceled.

(3) Overproduction: Any GPU which has an overproduced status as of the end of a gas proration period shall carry such overproduction forward into the next gas proration period. Said overproduction shall be made up by underproduction during the succeeding gas proration period. Any GPU which has not made up the overproduction carried into a gas proration period by the end of said period shall be shut in until such overproduction is made up.

(a) Twelve-Times Overproduced, Northwest: For the prorated gas pools of northwest New Mexico, if it is determined that GPU is overproduced in an amount exceeding twelve times its current year January allowable (or, in the case of a newly connected well, a marginal well, or a well recently reclassified as non-marginal, twelve times the January allowable assigned to a non-marginal GPU of similar acreage and deliverability factors), it shall be shut in until its overproduction is less than twelve times its January allowable, as determined hereinabove.

(b) Six-Times Overproduced, Southeast: For the prorated gas pools of southeast New Mexico, if it is determined that a GPU is overproduced in an amount exceeding six times its current year January allowable (or, in the case of a newly connected well, a marginal well, or a well recently reclassified as non-marginal, six times the January allowable assigned to a non-marginal GPU of a similar acreage factor), it shall be shut in until its overproduction is less than six times its January allowable, as determined hereinabove.

(4) Exception to Shut in for Overproduction: The director shall have authority to permit a GPU which is subject to shut-in, pursuant to Subparagraphs (a) or (b) of Paragraph (3) of Subsection D of 19.15.8.605 NMAC above to produce up to 250 MCF of gas per month upon proper showing to the director that complete shut-in would cause undue hardship, provided however, such permission may be rescinded for any GPU produced greater than the monthly rate authorized by the director.

(5) Balancing Overproduction: Allowable assigned to a GPU during any one month of a gas proration period greater than the production for the same month shall be applied against the overproduction chargeable to such GPU in determining the overproduction which must be made up pursuant to the provisions of Subparagraphs (a) or (b) of Paragraph (3) of Subsection D of 19.15.8.605 NMAC above.

(6) Exception to Balancing Overproduction: The director may allow overproduction to be made up at a lesser rate than permitted under Subparagraphs (a) or (b) of Paragraph (3) of Subsection D of 19.15.8.605 NMAC above upon a showing at public hearing that the same is necessary to avoid material damage to the well.

(7) Hardship Gas Wells: If a GPU containing a hardship gas well is overproduced, the operator must take the necessary steps to reduce production in order to reduce the overproduction. Any overproduction existing at the time of designation of a well as a hardship gas well or accruing to the GPU thereafter shall be carried forward until it is made up by underproduction. No GPU containing a hardship gas well, which GPU is overproduced, shall be permitted to produce at a rate higher than the minimum producing rate authorized by the division.

(8) Moratorium on Shut-ins: The director shall have authority to grant a pool-wide moratorium of up to three months as to the shutting in of gas wells in a pool during periods of high demand emergency upon proper showing that such emergency exists, and that a significant number of the wells in the pool are subject to shut-in pursuant to the provisions of Subparagraphs (a) or (b) of Paragraph (3) of Subsection D of 19.15.8.605 NMAC above. No moratorium beyond the aforementioned three months shall be granted except after notice and hearing.

(9) The director may reinstate allowable to wells which suffered cancellation of allowable under Paragraph (1) of Subsection D of 19.15.8.605 NMAC above or Paragraph (3) of Subsection E of 19.15.8.605 NMAC below or loss of allowable due to reclassification of a well under Paragraph (2) of Subsection E of 19.15.8.605 NMAC below. If such cancellation or loss of allowable was caused by non-access or limited access to the average market demand in the pool rather than inability of the well to produce. Upon petition, with a showing of circumstances which prevented production of the non-marginal allowable, and evidence that the well was capable of producing at allowable rates during the period for which reinstatement is requested, the allowable may be reinstated in such amounts needed to avoid curtailment or shut-in of the well for excessive overproduction. Such petition shall be approved administratively or docketed for hearing within 30 days after receipt in the division's Santa Fe office.

E. Classification of GPU's

(1) Reclassification by the Director: The director may reclassify a marginal or non-marginal GPU anytime the GPU's producing ability justifies such reclassification. The director may suspend the reclassification of GPU's on his own initiative, or upon proper showing by an affected interest owner, should it appear that such suspension is necessary to permit underproduced GPU's, which would otherwise be reclassified, a proper opportunity to make up such underproduction.

(2) Reclassification to Marginal: A non-marginal well may be reclassified as marginal in either of the following ways:

(a) After the production data is available for the last month of each classification period, any GPU which had an underproduced status at the beginning of the allocation period shall be reclassified to marginal if its highest single month's production during the classification period is less than its average monthly allowable during such period; however, the operator of any GPU so classified, or other affected interest owner, shall have 30 days after receipt of notification of marginal classification in which to submit satisfactory evidence to the division that the GPU is not of marginal character and should not be so classified; or

(b) A GPU which is underproduced more than the overproduction limit as described in -Subparagraphs (a) or (b) of Paragraph (3) of Subsection D of 19.15.8.605 NMAC above, whichever is applicable, shall be reclassified as marginal.

(3) Cancellation of Underproduction for Marginal GPU: A GPU which is classified as marginal shall not be permitted to accumulate underproduction, and any underproduction accrued to a GPU before its classification as marginal shall be canceled.

(4) Reclassification to Non-Marginal: If, at the end of any classification period, a marginal GPU has produced more gas during the proration period to that time than its shadow allowable for that same period, the GPU shall be reclassified as a non-marginal GPU.

(5) Reinstatement of Status: A GPU reclassified to non-marginal under the provisions of Paragraph (4) of Subsection E of 19.15.8.605 NMAC above shall have reinstated to it all underproduction which accrued or would have accrued as a non-marginal GPU from the current proration period, underproduction from the prior proration period may be reinstated after notice and hearing. All uncompensated-for overproduction accruing to the GPU while marginal shall be chargeable upon reclassification to non-marginal.

F. Reporting of Production - Filing C-111 and C-115 Reports: Transporters and operators shall file gas transportation and production reports pursuant to 19.15.13.1111 NMAC and 19.15.13.1115 NMAC of the division rules provided that upon approval by the director as to the specific program to be used, any producer or transporter of gas may be permitted to report metered production of gas on a chart-period basis; provided the following provisions shall be applicable to each gas well:

(1) Reports for a month shall include not less that 24 nor more than 32 reported days.

(2) Reported days may include as many as the last seven days of the previous month but no days of the succeeding month.

(3) The total of the monthly reports for a year shall include not less than 360 nor more than 368 reported days.

(4) For purposes of these rules, the term "month" shall mean "calendar month" for those reporting on a calendar month basis, and shall mean "reporting month" for those reporting on a chart-period basis according to the exception provided in this rule.

[5-30-98; 19.15.8.605 NMAC - Rn, 19 NMAC 15.H.605, 04-30-03]

19.15.8.606 TESTS AND TEST PROCEDURES FOR PRORATED POOLS IN NORTHWEST NEW MEXICO:

A. Type of Tests Required for Wells Completed in Prorated Gas Pools

(1) Reclassified GPUs: An operator of a well on a gas proration unit (GPU) that has been reclassified as non-marginal will conduct deliverability tests on that well within 90 days of the order reclassifying it, unless there are current tests on file with the division or that order requires a new test. A current test is a test which was conducted during the last test period for that pool or later.

(2) Non-marginal GPUs: Operators will conduct deliverability tests on wells on non-marginal GPUs every five years. If the division determines that a well's test data and production data warrant more frequent testing of a well, the division may set up special testing schedules for that well.

(3) Scheduling of Tests

(a) Notification of Pools to be Tested: By September 1 of each year the Aztec district office of the division will notify operators of non-marginal GPUs if their wells will be tested during the following test period.

(b) The results of all deliverability tests required must be filed with the Aztec district office within 90 days following the completion of each test. Provided however, that any test completed between December 31 of the test year and March 10 of the following year are due no later than March 31. No extension of time for filing tests beyond March 31 will be granted except after notice and hearing.

(c) Failure to file any test within the above-prescribed times will subject the GPU to the loss of one day's allowable for each day the test is late.

(d) Any well scheduled for testing during its test year may have the conditioning period, test flow period, and part of the seven-day shut-in period conducted in December of the previous year provided that, if the seven-day shut-in period immediately follows the test flow period, the seven-day shut-in pressure is to be measured in January of the test year. The earliest date that a well can be scheduled for a deliverability test would be such that the test flow period would end on December 25 of the previous year.

(e) Downhole commingled wells are to be scheduled for tests on dates for the pool of the lowermost prorated completion of the well.

(f) In the event a well is shut-in by the division for overproduction, the operator may produce the well for a period of time to secure a test after written notification to the division. All gas produced during this testing period will be used in determining the over/under produced status of the well.

(g) An operator may schedule a well for a deliverability retest upon notification to the Aztec district office at least ten days before the test is to be commenced. Such retest will be for substantial reason and will be subject to the approval of the division. A retest will be conducted in conformance with the deliverability test procedures of these rules. The division, at its discretion, may require the retesting of any well by notification to the operator to schedule such retest. These tests, as filed on form C-122A, should be identified as "RETEST" in the remarks column.

(4) Witnessing of Tests: Any deliverability test may be witnessed by any or all of the following: a representative of the division, an offset operator, a representative of the gas transportation facility connected to the well under test, or a representative of the gas transportation facility taking gas from an offset operator.

B. Procedure for Testing

(1) The test shall begin by producing a well in the normal operating manner into the pipeline through either the casing or tubing, but not both, for a period of fourteen consecutive days. This shall be known as the conditioning period. The production valve and choke settings shall not be changed during either the conditioning or flow periods, except during the first ten days of the conditioning period when maximum production would over-range the meter chart or location production equipment. The first ten days of the conditioning period shall not have more than 48 hours of cumulative interruptions of flow. The eleventh to fourteenth days, inclusive of the conditioning period, shall have no interruptions of flow whatsoever. Any interruption of flow that occurs as normal operation of the well as stop-cock flow, intermittent flow, or well blow down will not

be counted as shut-in time in either the conditioning or flow period.

(2) The daily flowing rate shall be determined from an average of seven or eight consecutive producing days, following a minimum conditioning period of 14 consecutive days of production. This shall be known as the flow period.

(3) Instantaneous pressure shall be measured by a deadweight gauge or other method approved by the division during the seven-day or eight-day flow period at the casinghead, tubinghead, and orifice meter, and shall be recorded along with instantaneous meter-chart static pressure reading.

(4) If a well is producing through a compressor that is located between the wellhead and the meter run, the meter run pressure and the wellhead casing pressure and the wellhead tubing pressure are to be reported on form C-122A. (Neither the suction pressure nor the discharge pressure of the compressor is considered **wellhead** pressure.) A note shall be entered in the remarks portion on form C-122A stating: "This well produced through a compressor."

(5) When it is necessary to restrict the flow of gas between the wellhead and the orifice meter, the ratio of the downstream pressure, psia, to the upstream pressure, psia, shall be determined. When this ratio is 0.57 or less, critical flow conditions shall be considered to exist across the restriction.

(6) When more than one restriction between the wellhead and the orifice meter causes the pressures to reflect critical flow between the wellhead and the orifice meter, the pressures across each of these restrictions shall be measured to determine whether critical flow exists at any restriction. When critical flow does not exist at any restriction, the pressures taken to disprove the critical flow shall be reported to the division on form C-122A in item (n) of the form. When critical flow conditions exist, the instantaneous flowing pressures required above shall be measured during the last 48 hours of the seven-day or eight-day flow period.

(7) When critical flow exists between the wellhead and the orifice meter, the measured wellhead flowing pressure of the string through which the well flowed during the test shall be used as P_t when calculating the static wellhead working pressure (P_w) using the method established below.

(8) When critical flow does not exist at any restriction, P_t shall be the corrected average static pressure from the meter chart plus friction loss from the wellhead to the orifice meter.

(9) The static wellhead working pressure (P_w) of any well under test shall be the calculated seven-day or eight-day average static tubing pressure if the well is flowing through the casing; it shall be the calculated seven-day or eight-day average static casing pressure if the well is flowing through the tubing. The static wellhead working pressure (P_w) shall be calculated by applying the tables and procedures set out in the "Gas Well Testing Manual for Northwest New Mexico" ("the Manual") available from the division.

(10) To obtain the shut-in pressure of a well under test, the well shall be shut-in some time during the current testing season for a period of seven to fourteen consecutive days, which have been preceded by a minimum of seven days of uninterrupted production. Such shut-in pressure shall be measured on the seventh to fourteenth day of shut-in of the well with a deadweight gauge or other method approved by the division. The seven-day shut-in pressure shall be measured on both the tubing and the casing when communication exists between the two strings. The higher of such pressures shall be used as P_c in the deliverability calculation. When any such shut-in pressure is determined by the division to be abnormally low or the well can not be shut-in due to "HARDSHIP" classification, the shut-in pressure to be used as P_c shall be determined by one of the following methods:

(a) A division-designated value.

(b) An average shut-in pressure of all offset wells completed in the same zone. Offset wells include the four side and four corner wells, if available.

(c) A calculated surface pressure based on a calculated bottom-hole pressure. Such calculations shall be made in accordance with the examples in the manual.

(11) All wellhead pressures, as well as the flowing meter pressure tests which are to be taken during the seven-day or eight-day deliverability test period as required above, shall be taken with a deadweight gauge or other method approved by the division. The pressure readings and the date and time according to the chart shall be recorded and maintained in the operator's records with the test information.

(12) Orifice meter charts shall be changed and arranged so as to reflect upon a single chart the flow data for the gas from each well for the full seven-day or eight-day deliverability test period; however, no tests shall be voided if satisfactory explanation is made as to the necessity for using test volumes through two chart periods. Corrections shall be made for pressure base, measured flowing temperature, specific gravity, and supercompressibility; provided however, if the specific gravity of the gas from any well under test is not available, an estimated specific gravity may be assumed therefore, based upon that of gas from near-by wells, the specific gravity of which has been actually determined by measurement.

(13) The average flowing meter pressure for the seven-day or eight-day flow period and the corrected integrated volume shall be determined by the purchasing company that integrates the flow charts and furnished to the operator or testing agency.

(14) The seven-day or eight-day flow period volume shall be calculated from the integrated readings as determined from the flow period orifice meter chart. The volume so calculated shall be divided by the number of testing days on the chart to determine the average daily rate of flow during said flow period. The flow period shall have a minimum of seven and a maximum of eight legibly recorded flowing days to be acceptable for test purposes. The volume used in this calculation shall be corrected to the division's standard conditions of 15.025 psia pressure base, 60 degrees F. temperature base and 0.60 specific gravity base.

(15) The daily volume of flow, as determined from the flow period chart readings, shall be calculated by applying the basic orifice meter formula or other acceptable industry standard practices.

$Q = C' (h_w P_f)^{.5}$

Where:

Q = Metered volume of flow Mcf/d @ 15.025 psia, 60 degrees F., and 0.60 specific gravity.

C' = The 24-hour basic orifice meter flow factor corrected for flowing temperature, gravity, and supercompressibility.

h_w = Daily average differential meter pressure from flow period chart.

P_f = Daily average flowing meter pressure from flow period chart.

(16) The basic orifice meter flow factors, flowing temperature factor, and specific gravity factor shall be determined from the tables in the manual.

(17) The daily flow period average corrected flowing meter pressure, psig, shall be used to determine the supercompressibility factor. Supercompressibility tables may be obtained from the division.

(18) When supercompressibility correction is made for a gas containing either nitrogen or carbon dioxide in excess of two percent, the supercompressibility factors of such gas shall be determined by the use of Table V of the C.N.G.A. Bulletin TS-402 for pressures 100-500 psig, or Table II, TS-461 for pressures in excess of 500 psig.

(19) The use of tables for calculating rates of flow from integrator readings which do not specifically conform to the division's "Back Pressure Test Manual", or the Manual, may be approved for determining the daily flow period rates of flow upon a showing that such tables are appropriate and necessary.

(20) The daily average integrated rate of flow for the seven-day or eight-day flow period shall be corrected for meter error by multiplication by a correction factor. Said correction factor shall be determined by dividing the square root of the deadweight flowing meter pressure, psia, by the square root of the chart flowing meter pressure, psia.

(21) "Deliverability pressure" is a defined pressure applied to each well and used in the process of comparing the abilities of wells in a pool to produce at static wellhead working pressures equal to a percentage of the seven-day shut-in pressure of the respective individual wells. Such percentage shall be determined and announced periodically by the division based on the relationship of the average static wellhead working pressures (P_w) divided by the average seven-day shut-in pressure (Pc) of the pool.

(22) The deliverability of gas at the deliverability pressure of any well under test shall be calculated from the test data derived from the tests above required by use of the following deliverability formula:

$$D = Q \left[\frac{(P_c^2 - P_d^2)}{(P_c^2 - P_w^2)} \right]^n$$

Where:

D = Deliverability Mcf/d at the deliverability pressure, (P_d), (at Standard Conditions of 15.025 psia, 60 degrees F. and 0.60 sp. gr.).

Q = Daily flow rate in Mcf/d, at wellhead pressure (P_w).

P_c = Seven-day shut-in wellhead pressure, psia.

P_d = Deliverability pressure, psia, as defined above.

P_w = Average static wellhead working pressure, as determined from seven-day or eight-day flow period, psia, and calculated from tables in the manual entitled "Pressure Loss Due to Friction Tables for Northwest New Mexico".

n = Average pool slope of back pressure curves as follows:

For pictured cliffs and shallower formations, 0.85

For formations deeper than pictured cliffs, 0.75

(Note: Special rules for any specific pool or formation may supersede the above values. Check special rules if in doubt.)

(23) The value of the multiplier in the above formula (ratio factor after the application of the pool slope) by which Q is multiplied shall not exceed a limiting value to be determined and announced periodically by the division. Such determination shall be made after a study of the test data of the pool obtained during the previous testing season.

(24) Downhole commingled wells are to be tested in the test year for the pool of the lowermost prorated completion of the well and shall use pool slope (n), and deliverability pressure of the lowermost pool. The total flow rate from the downhole commingled well will be used to calculate a value of deliverability. For each prorated gas zone of a downhole

commingled well, a form C-122A is required to be filed. Also, in the summary portion of that form all zones will indicate the same data for line h, P_c, Q, P_w, and P_d. The value shown for deliverability (D) will be that percentage of the total deliverability of the well that is applicable to this zone. A note shall be placed in the remarks column that indicates the percentage of deliverability to be allocated to this zone of the well.

(25) Any test prescribed herein will be considered acceptable if the average flow rate for the final seven-day or eight-day deliverability test is not more than ten percent in excess of any consecutive seven-day or eight-day average of the preceding two weeks. A deliverability test not meeting this requirement may be declared invalid, requiring the well to be re-tested.

(26) All charts relative to deliverability tests or copies thereof shall be made available to the division upon its request.

(27) Operators shall use only testing agencies, whether individuals, companies, pipeline companies, or operators, that maintain a log of all tests accomplished by them including all field test data. The operator shall maintain the above data for a period of not less than two years plus the current test year.

(28) All forms heretofore mentioned are hereby adopted for use in the northwest New Mexico area in open form subject to such modification as experience may indicate desirable or necessary.

(29) Deliverability tests for gas wells in all formations shall be conducted and reported in accordance with these rules. Provided, however, these rules shall be subject to any specific modification or change contained in Special Pool Rules adopted for any pool after notice and hearing.

C. Informational Tests

(1) One-Point Back Pressure Test: A one-point back pressure test may be taken on newly completed wells before their connection or reconnection to a gas transportation facility. This test shall not be a required official test, but may be taken for informational purposes at the option of the operator. When taken, this test must be taken and reported as prescribed below.

(2) Test Procedure

(a) This test shall be accomplished after a minimum shut-in of seven days. The shut-in pressure shall be measured with a deadweight gauge or other method approved by the division.

(b) The flow rate shall be that rate in Mcf/d measured at the end of a three hour test flow period. The flow from the well shall be for three hours through a positive choke, which has a 3/4 inch orifice.

(c) A 2-inch nipple which provides a mechanical means of accurately measuring the pressure and temperature of the flowing gas shall be installed immediately upstream from the positive choke.

(d) The absolute open flow shall be calculated using the conventional back pressure formula as shown in the manual or the division's "Back Pressure Test Manual."

(e) The observed data and flow calculations shall be reported in duplicate on form C-122, "Multi-Point Back Pressure Test for Gas Wells."

(f) Non-critical flow shall be considered to exist when the choke pressure is 13 psig or less. When this condition exists the flow rate shall be measured with a pitot tube and nipple as specified in the manual or in the division's manual of "Tables and Procedure for Pitot Tests." The pitot test nipple shall be installed immediately downstream from the 3/4-inch positive choke.

(g) Any well completed with 2-inch nominal size tubing (1.995-inch ID) or larger shall be tested through the tubing.

(3) Other tests for informational purposes may be conducted prior to obtaining a pipeline connection for a newly completed well upon receiving specific approval therefore from the Aztec district office. Approval of these tests shall be based primarily upon the volume of gas to be vented.

[5-30-98; 19.15.8.606 NMAC - Rn, 19 NMAC 15.H.606, 04-30-03]

History of 19.15.8 NMAC:

Pre-NMAC History:

Rule 601, Allocation of Gas Production, filed 1-8-82;
Rule 601, Allocation of Gas Production, filed 2-5-91;
Rule 602, Proration Period, filed 1-8-82;
Rule 602, Proration Period, filed 2-5-91;
Rule 603, Adjustment of Allowables, filed 1-8-82;
Rule 603, Adjustment of Allowables, filed 2-5-91;
Rule 604, Gas Proration Units, filed 1-8-82;
Rule 604, Gas Proration Units, filed 2-5-91.

History of Repealed Material: [Reserved]

Other History:
Rule 601, Allocation of Gas Production, filed 2-5-91; Rule 602, Proration Period, filed 2-5-91; Rule 603, Adjustment of Allowables, filed 2-5-91; Rule 604, Gas Proration Units, filed 2-5-91 all renumbered, reformatted **to and replaced by** 19 NMAC 15.H, Gas Proration and Allocation, filed 01-18-96.
19 NMAC 15.H, Gas Proration and Allocation, filed 01-18-96 renumbered, reformatted **to and replaced by** 19.15.8 NMAC, effective 4-30-03.

TITLE 19 NATURAL RESOURCES & WILDLIFE
CHAPTER 15 OIL AND GAS
PART 9 SECONDARY OR OTHER ENHANCED RECOVERY, PRESSURE MAINTENANCE, SALT WATER DISPOSAL, AND UNDERGROUND STORAGE

19.15.9.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department.
[2-1-96; 19.15.9.1 NMAC - Rn, 19 NMAC 15.I.1, 11-30-00; A, 11-30-00]

19.15.9.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico. [2-1-96; 19.15.9.2 NMAC - Rn, 19 NMAC 15.I.2, 11-30-00]

19.15.9.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the Oil and Gas Act which grants the Oil Conservation Division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights, and the disposition of wastes resulting from oil and gas operations. [2-1-96; 19.15.9.3 NMAC - Rn, 19 NMAC 15.I.3, 11-30-00]

19.15.9.4 DURATION: Permanent. [2-1-96; 19.15.9.4 NMAC - Rn, 19 NMAC 15.I.4, 11-30-00]

19.15.9.5 EFFECTIVE DATE: February 1, 1996, unless a later date is cited at the end of a section.
[2-1-96; 19.15.9.5 NMAC - Rn, 19 NMAC 15.I.5, 11-30-00; A, 11-30-00]

19.15.9.6 OBJECTIVE: To regulate secondary or other enhanced recovery, pressure maintenance, salt water disposal, and underground storage to prevent waste, protect correlative rights and protect public health and the environment pursuant to the Oil and Gas Act. [2-1-96; 19.15.9.6 NMAC - Rn, 19 NMAC 15.I.6, 11-30-00]

19.15.9.7 DEFINITONS: Reserved. [2-1-96; 19.15.9.7 NMAC - Rn, 19 NMAC 15.I.7, 11-30-00]

19.15.9.8-700 RESERVED [2-1-96; 19.15.9.8-700 NMAC - Rn, 19 NMAC 15.I.7-700, 11-30-00]

19.15.9.701 INJECTION OF FLUIDS INTO RESERVOIRS

A. Permit for Injection Required - The injection of gas, liquefied petroleum gas, air, water, or any other medium into any reservoir for the purpose of maintaining reservoir pressure or for the purpose of secondary or other enhanced recovery or for storage or the injection of water into any formation for the purpose of water disposal shall be permitted only by order of the Division after notice and hearing, unless otherwise provided herein.

B. Method of Making Application

(1) Application for authority for the injection of gas, liquefied petroleum gas, air, water or any other medium into any formation for any reason, including but not necessarily limited to the establishment of or the expansion of water flood projects, enhanced recovery projects, pressure maintenance projects, and salt water disposal, shall be by submittal of Division Form C-108 complete with all attachments.

(2) The Applicant shall furnish, by certified or registered mail, a copy of the application to the owner of the surface of the land on which each injection or disposal well is to be located and to each leasehold operator within one-half mile of the well.

C. Administrative Approval

(1) If the application is for administrative approval rather than for a hearing, it must also be accompanied by a copy of a legal publication published by the applicant in a newspaper of general circulation in the county in which the proposed injection well is located. (The details required in such legal notice are listed on Side 2 of Form C-108).

(2) No application for administrative approval may be approved until 15 days following receipt by the Division of Form C-108 complete with all attachments including evidence of mailing as required under Subsection B, Paragraph (2) above of 19.15.9.701 NMAC and proof of publication as required by Subsection C, Paragraph (1) above of 19.15.9.701 NMAC.

(3 f no objection is received within said 15-day period, and a hearing is not otherwise required, the application may be approved administratively.

D. Hearings - If a written objection to any application for administrative approval of an injection well is filed within 15 days after receipt of a complete application, or if a hearing is required by these rules or deemed advisable by the Division Director, the application shall be set for hearing and notice thereof given by the Division.

E. Salt Water Disposal Wells

(1) The Division Director shall have authority to grant an exception to the requirements of Subsection A of 19.15.9.701 NMAC for water disposal wells only, without hearing, when the waters to be disposed of are mineralized to such a degree as to be unfit for domestic, stock, irrigation, or other general use, and when said waters are to be disposed of into a formation older than Triassic (Lea County only) and provided no objections are received pursuant to Subsection C of 19.15.9.701 NMAC.

(2) Disposal will not be permitted into zones containing waters having total dissolved solids concentrations of 10,000 mg/1 or less except after notice and hearing, provided however, that the Division may establish exempted aquifers for such zones wherein such injection may be approved administratively.

(3) Notwithstanding the provisions of Subsection E, Paragraph (2) above of 19.15.9.701 NMAC, the Division Director may authorize disposal into such zones if the waters to be disposed of are of higher quality than the native water in the disposal zone.

F. Pressure Maintenance Projects

(1) Pressure maintenance projects are defined as those projects in which fluids are injected into the producing horizon in an effort to build up and/or maintain the reservoir pressure in an area which has not reached the advanced or "stripper" state of depletion.

(2) All applications for establishment of pressure maintenance projects shall be set for hearing. The project area and the allowable formula for any pressure maintenance project shall be fixed by the Division on an individual basis after notice and hearing.

(3) Pressure maintenance projects may be expanded and additional wells placed on injection only upon authority from the Division after notice and hearing or by administrative approval.

(4) The Division Director shall have authority to grant an exception to the hearing requirements of

Subsection A of 19.15.9.701 NMAC for the conversion to injection of additional wells within a project area provided that any such well is necessary to develop or maintain efficient pressure maintenance within such project and provided that no objections are received pursuant to Subsection C of 19.15.9.701 NMAC.

G. Water Flood Projects

(1) Water flood projects are defined as those projects in which water is injected into a producing horizon in sufficient quantities and under sufficient pressure to stimulate the production of oil from other wells in the area, and shall be limited to those areas in which the wells have reached an advanced state of depletion and are regarded as what is commonly referred to as "stripper" wells.

(2) All applications for establishment of water flood projects shall be set for hearing.

(3) The project area of a water flood project shall comprise the proration units owned or operated by a given operator upon which injection wells are located plus all proration units owned or operated by the same operator which directly or diagonally offset the injection tracts and have producing wells completed on them in the same formation; provided however, that additional proration units not directly nor diagonally offsetting an injection tract may be included in the project area if, after notice and hearing, it has been established that such additional units have wells completed thereon which have experienced a substantial response to water injection.

(4) The allowable assigned to wells in a water flood project area shall be equal to the ability of the wells to produce and shall not be subject to the depth bracket allowable for the pool nor to the market demand percentage factor.

(5) Nothing herein contained shall be construed as prohibiting the assignment of special allowables to wells in buffer zones after notice and hearing. Special allowables may also be assigned in the limited instances where it is established at a hearing that it is imperative for the protection of correlative rights to do so.

(6) Water flood projects may be expanded and additional wells placed on injection only upon authority from the Division after notice and hearing or by administrative approval.

(7) The Division Director shall have authority to grant an exception to the hearing requirements of Subsection A of 19.15.9.701 NMAC for conversion to injection of additional wells provided that any such well is necessary to develop or maintain thorough and efficient water flood injection for any authorized project and provided that no objections are received pursuant to Subsection C of 19.15.9.701 NMAC.

H. Storage Wells

(1) The Division Director shall have authority to grant an exception to the hearing requirements of Subsection A of 19.15.9.701 NMAC for the underground storage of liquefied petroleum gas or liquid hydrocarbons in secure caverns within massive salt beds, and provided no objections are received pursuant to Subsection C of 19.15.9.701 NMAC.

(2) In addition to the filing requirements of Subsection B of 19.15.9.701 NMAC, the applicant for approval of a storage well under this rule shall file the following:

(a) With the Division Director, a plugging bond in accordance with the provisions of Rule 101;

(b) With the appropriate district office of the Division in TRIPLICATE:

(i) Form C-101, Application for Permit to Drill, Deepen, or Plug Back;
(ii) Form C-102, Well Location and Acreage Dedication Plat; and
(iii) Form C-105, Well Completion or Recompletion Report and Log.

[1-1-50…2-1-96; 19.15.9.701 NMAC - Rn, 19 NMAC 15.I.701, 11-30-00]

19.15.9.702 CASING AND CEMENTING OF INJECTION WELLS:

Wells used for injection of gas, air, water, or any other medium into any formation shall be cased with safe and adequate casing or tubing so as to prevent leakage, and such casing or tubing shall be so set and cemented as to prevent the movement of formation or injected fluid from the injection zone into any other zone or to the surface around the outside of any casing string. [1-1-50…2-1-96; 19.15.9.702 NMAC - Rn, 19 NMAC 15.I.702, 11-30-00]

19.15.9.703 OPERATION AND MAINTENANCE

A. Injection wells shall be equipped, operated, monitored, and maintained to facilitate periodic testing and to assure continued mechanical integrity which will result in no significant leak in the tubular goods and packing materials used and no significant fluid movement through vertical channels adjacent to the well bore.

B. Injection project, including injection wells and producing wells and all related surface facilities shall be operated and maintained at all times in such a manner as will confine the injected fluids to the interval or intervals approved and prevent surface damage or pollution resulting from leaks, breaks, or spills.

C. Failure of any injection well, producing well, or surface facility, which failure may endanger underground sources of drinking water, shall be reported under the "Immediate Notification" procedure of Rule 116.

D. Injection well or producing well failures requiring casing repair or cementing are to be reported to the Division prior to commencement of workover operations.

E. Injection wells or projects which have exhibited failure to confine injected fluids to the authorized injection zone or zones may be subject to restriction of injection volume and pressure, or shut-in, until the failure has been identified and corrected.

[7-1-81…2-1-96; 19.15.9.703 NMAC - Rn, 19 NMAC 15.I.703, 11-30-00]

19.15.9.704 TESTING, MONITORING, STEP-RATE TESTS, NOTICE TO THE DIVISION, REQUESTS FOR PRESSURE INCREASES

A. Testing

(1) Prior to commencement of injection and any time tubing is pulled or the packer is reseated, wells shall be tested to assure the integrity of the casing and the tubing and packer, if used, including pressure testing of the casing-tubing annulus to a minimum of 300 psi for 30 minutes or such other pressure and/or time as may be approved by the appropriate district supervisor. A pressure recorder shall be used and copies of the chart shall be submitted to the appropriate Division district office within 30 days following the test date.

(2) At least once every five years thereafter, injection wells shall be tested to assure their continued mechanical integrity. Tests demonstrating continued mechanical integrity shall include the following:

(a) measurement of annular pressures in wells injecting at positive pressure under a packer or a balanced fluid seal; or,

(b) pressure testing of the casing-tubing annulus for wells injecting under vacuum conditions; or,

(c) such other tests which are demonstrably effective and which may be approved for use by the Division.

(3) Notwithstanding the test procedures outlined above, the Division may require more comprehensive testing of the injection wells when deemed advisable, including the use of tracer surveys, noise logs, temperature logs, or other test procedures or devices.

(4) In addition, the Division may order special tests to be conducted prior to the expiration of five years if conditions are believed to so warrant. Any such special test which demonstrates continued mechanical integrity of a well shall be considered the equivalent of an initial test for test scheduling purposes, and the regular five-year testing schedule shall be applicable thereafter.

(5) The injection well operator shall advise the Division of the date and time any initial, five-year, or special tests are to be commenced in order that such tests may be witnessed.

B. Monitoring - Injection wells shall be so equipped that the injection pressure and annular pressure may be determined at the wellhead and the injected volume may be determined at least monthly.

C. Step-Rate Tests, Notice to the Division, Requests for Injection Pressure Limit Increases

(1) Whenever an operator shall conduct a step-rate test for the purpose of increasing an authorized injection or disposal well pressure limit, notice of the date and time of such test shall be given in advance to the appropriate Division district office.

(2) Copies of all injection or disposal well pressure-limit increase applications and supporting documentation shall be submitted to the Division Director and to the appropriate district office.

[7-1-81…2-1-96; 19.15.9.704 NMAC - Rn, 19 NMAC 15.I.704, 11-30-00]

19.15.9.705 COMMENCEMENT, DISCONTINUANCE, AND ABANDONMENT OF INJECTION OPERATIONS:

A. The following provisions apply to all injection projects, storage projects, salt water disposal wells and special purpose injection wells:

B. Notice of Commencement and Discontinuance

(1) Immediately upon the commencement of injection operations in any well, the operator shall notify the Division of the date such operations began.

(2) Within 30 days after permanent cessation of gas or liquefied petroleum gas storage operations or within 30 days after discontinuance of injection operations into any other well, the operator shall notify the Division of the date of such discontinuance and the reasons therefor.

(3) Before any injection well is temporarily abandoned or plugged, the operator shall obtain approval from the appropriate District Office of the Division in the same manner as when temporarily abandoning or plugging

oil and gas wells or dry holes.

C. Abandonment of Injection Operations

(1) Whenever there is a continuous one year period of non-injection into any injection project, storage project, salt water disposal well, or special purpose injection well, such project or well shall be considered abandoned, and the authority for injection shall automatically terminate *ipso facto*.

(2) For good cause shown, the Division Director may grant an administrative extension or extensions of injection authority as an exception to Subsection C, Paragraph (1) above of 19.15.9.705 NMAC.

[1-1-50…2-1-96; 19.15.9.705 NMAC - Rn, 19 NMAC 15.I.705, 11-30-00; A, 11-30-00; A, 07-15-03]

19.15.9.706 RECORDS AND REPORTS

A. The operator of an injection well or project for secondary or other enhanced recovery, pressure maintenance, natural gas storage, salt water disposal, or injection of any other fluids shall keep accurate records and shall report monthly to the Division gas or fluid volumes injected, stored, and/or produced as required on the appropriate form listed below:

(1) Secondary or Other Enhanced Recovery on Form C-115;

(2) Pressure Maintenance on Form C-115 and as otherwise prescribed by the Division;

(3) Salt Water Disposal on Form C-120-A;

(4) Natural Gas Storage on Form C-131-A; and

(5) Injection of other fluids on a form prescribed by the Division.

B. The operator of a liquefied petroleum gas storage project shall report annually on Form C-131-B, Annual LPG Storage Report.

[1-1-50…2-1-96; 19.15.9.706 NMAC - Rn, 19 NMAC 15.I.706, 11-30-00]

19.15.9.707 RECLASSIFICATION OF WELLS:

The Division Director shall have authority to reclassify an injection well from any category defined in Subsection B of 19.15.9.701 NMAC to any other category without notice and hearing upon request and proper showing by the operator thereof.

[7-1-81…2-1-96; 19.15.9.707 NMAC - Rn, 19 NMAC 15.I.707, 11-30-00]

19.15.9.708 TRANSFER OF AUTHORITY TO INJECT

A. Authority to inject granted under any order of the Division is not transferable except upon approval of the Division. Approval of transfer of authority to inject may be obtained by filing Form C-104 in accordance with Rule 1104 E.

B. The Division may require a demonstration of mechanical integrity prior to approving transfer of authority to inject.

[1-1-50…2-1-96; 19.15.9.708 NMAC - Rn, 19 NMAC 15.I.708, 11-30-00]

19.15.9.709 REMOVAL OF PRODUCED WATER FROM LEASES AND FIELD FACILITIES

A. Transportation of any produced water by motor vehicle from any lease, central tank battery, or other facility, without an approved Form C-133 (Authorization to Move Produced Water) is prohibited.

B. Authorization to transport produced water may be obtained by filing three copies of Form C-133 with the Director of the Division in Santa Fe.

C. No owner or operator shall permit produced water to be removed from its leases or field facilities by motor vehicle except by a person possessing an approved Form C-133.

[1-1-50…2-1-96; 19.15.9.709 NMAC - Rn, 19 NMAC 15.I.709, 11-30-00]

19.15.9.710 DISPOSITION OF TRANSPORTED PRODUCED WATER

A. No person, including any transporter, may dispose of produced water on the surface of the ground, or in any pit, pond, lake, depression, draw, streambed, or arroyo, or in any watercourse, or in any other place or in any manner which will constitute a hazard to any fresh water supplies.

B. Delivery of produced water to approved salt water disposal facilities, secondary recovery or pressure maintenance injection facilities, or to a drill site for use in drilling fluid will not be construed as constituting a hazard to fresh water supplies provided the produced waters are placed in tanks or other impermeable storage at such facilities.

C. The supervisor of the appropriate district office of the Division may grant temporary exceptions to Paragraph A. above for emergency situations, for use of produced water in road construction or maintenance, or for use of produced waters for other construction purposes upon request and a proper showing by a holder of an approved Form C-133 (Authorization to Move Produced Water).

D. Vehicular movement or disposition of produced water in any manner contrary to these rules shall be considered cause, after notice and hearing, for cancellation of Form C-133.

[2-1-82…2-1-96; 19.15.9.710 NMAC - Rn, 19 NMAC 15.I.710, 11-30-00]

19.15.9.711 APPLICABLE TO SURFACE WASTE MANAGEMENT FACILITIES ONLY:

A. A surface waste management facility is defined as any facility that receives for collection, disposal, evaporation, remediation, reclamation, treatment or storage any produced water, drilling fluids, drill cuttings, completion fluids, contaminated soils, bottom sediment and water (BS&W), tank bottoms, waste oil or, upon written approval by the Division, other oilfield related waste. Provided, however, if (a) a facility performing these functions utilizes underground injection wells subject to regulation by the Division pursuant to the federal Safe Drinking Water Act, and does not manage oilfield wastes on the ground in pits, ponds, below grade tanks or land application units, (b) if a facility, such as a tank only facility, does not manage oilfield wastes on the ground in pits, ponds below grade tanks or land application units or (c) if a facility performing these functions is subject to Water Quality Control Commission Regulations, then the facility shall not be subject to this rule.

(1) A commercial facility is defined as any surface waste management facility that does not meet the definition of centralized facility.

(2) A centralized facility is defined as a surface waste management facility that accepts only waste generated in New Mexico and that:

(a) does not receive compensation for waste management;

(b) is used exclusively by one generator subject to New Mexico's "Oil and Gas Conservation Tax Act" Section 7-30-1 NMSA-1978 as amended; or

(c) is used by more than one generator subject to New Mexico's "Oil and Gas Conservation Tax Act" Section 7-30-1 NMSA-1978 as amended under an operating agreement and which receives wastes that are generated from two or more production units or areas or from a set of jointly owned or operated leases.

(3) Centralized facilities exempt from permitting requirements are:

(a) facilities that receive wastes from a single well;

(b) facilities that receive less than 50 barrels of RCRA exempt liquid waste per day and have a capacity to hold 500 barrels of liquids or less or 1400 cubic yards of solids or less and when a showing can be made to the satisfaction of the Division that the facility will not harm fresh water, public health or the environment;

(c) emergency pits that are designed to capture fluids during an emergency upset period only and provided such fluids will be removed from the pit within twenty-four (24) hours from introduction;

(d) facilities that do not meet the requirements of the foregoing exemptions in Subsection A, Paragraph (3) of 19.15.9.711 NMAC, but that are shown by the facility operator to the satisfaction of the Division to not present a risk to public health and the environment.

B. Unless exempt from Section 19.15.9.711 NMAC, all commercial and centralized facilities including facilities in operation on the effective date of Section 19.15.9.711 NMAC, new facilities prior to construction and all existing facilities prior to major modification or major expansion shall be permitted by the Division in accordance with the following requirements:

(1) Application Requirements - An application, Form C-137, for a permit for a new facility or to modify an existing facility shall be filed in DUPLICATE with the Santa Fe Office of the Division and ONE COPY with the appropriate Division district office. The application shall comply with Division guidelines and shall include:

(a) The names and addresses of the applicant and all principal officers of the business if different from the applicant;

(b) A plat and topographic map showing the location of the facility in relation to governmental surveys (1/4 1/4 section, township, and range), highways or roads giving access to the facility site, watercourses, water sources, and dwellings within one (1) mile of the site;

(c) The names and addresses of the surface owners of the real property on which the management facility is sited and surface owners of the real property of record within one (1) mile of the site;

(d) A description of the facility with a diagram indicating location of fences and cattle guards, and detailed construction/installation diagrams of any pits, liners, dikes, piping, sprayers, and tanks on the facility;

(e) A plan for management of approved wastes.

(f) A contingency plan for reporting and cleanup of spills or releases;

(g) A routine inspection and maintenance plan to ensure permit compliance;

(h) A Hydrogen Sulfide Prevention and Contingency Plan to protect public health;

(i) A closure plan including a cost estimate sufficient to close the facility to protect public health and the environment; said estimate to be based upon the use of equipment normally available to a third party contractor;

(j) Geological/hydrological evidence, including depth to and quality of groundwater beneath the site, demonstrating that disposal of oilfield wastes will not adversely impact fresh water;

(k) Proof that the notice requirements of Section 19.15.9.711 NMAC have been met;

(l) Certification by an authorized representative of the applicant that information submitted in the application is true, accurate, and complete to the best of the applicant's knowledge.

(m) Such other information as is necessary to demonstrate that the operation of the facility will not adversely impact public health or the environment and that the facility will be in compliance with OCD rules and orders.

(2) Notice Requirements:

(a) Prior to public notice, the applicant shall give written notice of application to the surface owners of record within one (1) mile of the facility, the county commission where the facility is located or is proposed to be located, and the appropriate city official(s) if the facility is located or proposed to be located within city limits or within one (1) mile of the city limits. The distance requirements for notice may be extended by the Director if the Director determines the proposed facility has the potential to adversely impact public health or the environment at a distance greater than one (1) mile. The Director may require additional notice as needed. A copy and proof of such notice will be furnished to the Division.

(b) The applicant will issue public notice in a form approved by the Division in a newspaper of general circulation in the county in which the facility is to be located. For permit modifications, the Division may require the applicant to issue public notice and give written notice as above.

(c) Any person seeking to comment or request a public hearing on such application must file comments or hearing requests with the Division within 30 days of the date of public notice. Requests for a public hearing must be in writing to the Director and shall set forth the reasons why a hearing should be held. A public hearing shall be held if the Director determines there is significant public interest.

(d) The Division will distribute notice of the filing of an application for a new facility or major modifications with the next OCD and OCC hearing docket following receipt of the application.

(3) Financial Assurance Requirements:

(a) Centralized Facilities: Upon determination by the Director that the permit can be approved, any applicant of a centralized facility shall submit acceptable financial assurance in the amount of $25,000 per facility or a statewide "blanket" financial assurance in the amount of $50,000 to cover all of that applicant's facilities in a form approved by the Director.

(b) New Commercial Facilities or major expansions or major modification of Existing Facilities: Upon determination by the Director that a permit for a commercial facility to commence operation after the effective date of this rule can be approved, or upon determination by the Director that a major modification or major expansion of an existing facility can be approved, any applicant of such a commercial facility shall submit acceptable financial assurance in the amount of the closure cost estimated in Subsection B, Paragraph (1), Subparagraph (i) above of 19.15.9.711 NMAC in a form approved by the Director according to the following schedule:

(i) within one (1) year of commencing operations or when the facility is filled to 25% of the permitted capacity, whichever comes first, the financial assurance must be increased to 25% of the estimated closure cost;

(ii) within two (2) years of commencing operations or when the facility is filled to 50% of the permitted capacity, whichever comes first, the financial assurance must be increased to 50% of the estimated closure cost;

(iii) within three (3) years of commencing operations or when the facility is filled to 75% of the permitted capacity, whichever comes first, the financial assurance must be increased to 75% of the estimated closure cost;

(iv) within four (4) years of commencing operations or when the facility is filled to 100% of the permitted capacity, whichever comes first, the financial assurance must be increased to the estimated closure cost.

(c) Existing Commercial Facilities: All permittees of commercial facilities approved for operation at the time this rule becomes effective shall have submitted financial assurance in the amount of the closure cost estimated pursuant to Subsection B, Paragraph (1), Subparagraph (i) above of 19.15.9.711 NMAC but not less than $25,000 nor more than $250,000 per facility in a form approved by the Director.

(i) within one (1) year of the effective date of Section 19.15.9.711 NMAC the financial assurance amount must be increased to 25% of the estimated closure costs or $62,500.00, whichever is less;

(ii) within two (2) years of the effective date of Section 19.15.9.711 NMAC the financial assurance amounts must be increased to 50% of the estimated closure costs or $125,000.00, whichever is less;

(iii) within three (3) years of the effective date of Section 19.15.9.711 NMAC the financial assurance amounts must be increased to 75% of the estimated closure costs or $187,000.00, whichever is less;

(iv) within four (4) years of the effective date of Section 19.15.9.711 NMAC the financial assurance amounts must be increased to the estimated closure cost or $250,000.00, whichever is less.

(d) The financial assurance required in subparagraphs (a), (b), or (c), above shall be payable to the State of New Mexico and conditioned upon compliance with statutes of the State of New Mexico and rules of the Division, and acceptable closure of the site upon cessation of operation, in accordance with Subsection B, Paragraph (1), Subparagraph (i) of 19.15.9.711 NMAC. If adequate financial assurance is posted by the applicant with a federal or state agency and the financial assurance otherwise fulfills the requirements of this rule, the Division may consider the financial assurance as satisfying the requirement of Section 19.15.9.711 NMAC. The applicant must notify the Division of any material change affecting the financial assurance within 30 days of discovery of such change.

(4) The Director may accept the following forms of financial assurance:

(a) Surety Bonds

(i) A surety bond shall be executed by the permittee and a corporate surety licensed to do business in the State.

(ii) Surety bonds shall be noncancellable during their terms.

(b) Letter of Credit - Letter of credit shall be subject to the following conditions:

(i) The letter may be issued only by a bank organized or authorized to do business in the United States;

(ii) Letters of credit shall be irrevocable for a term of not less than five (5) years. A letter of credit used as security in areas requiring continuous financial assurance coverage shall be forfeited and shall be collected by the State of New Mexico if not replaced by other suitable financial assurance or letter of credit at least 90 days before its expiration date;

(iii) The letter of credit shall be payable to the State of New Mexico upon demand, in part or in full, upon receipt from the Director of a notice of forfeiture.

(c) Cash Accounts - Cash accounts shall be subject to the following conditions:

(i) The Director may authorize the permittee to supplement the financial assurance through the establishment of a cash account in one or more federally insured or equivalently protected accounts made payable upon demand to, or deposited directly with, the State of New Mexico.

(ii) Any interest paid on a cash account shall not be retained in the account and applied to the account unless the Director has required such action as a permit requirement.

(iii) Certificates of deposit may be substituted for a cash account with the approval of the Director.

(d) Replacement of Financial Assurances

(i) The Director may allow a permittee to replace existing financial assurances with other financial assurances that provide equivalent coverage.

(ii) The Director shall not release existing financial assurances until the permittee has submitted, and the Director has approved, acceptable replacements.

(5) A permit may be denied, revoked or additional requirements imposed by a written finding by the Director that a permittee has a history of failure to comply with Division rules and orders and state or federal environmental laws.

(6) The Director may, for protection of public health and the environment, impose additional requirements such as setbacks from an existing occupied structure.

(7) The Director may issue a permit upon a finding that an acceptable application has been filed and that the conditions of paragraphs 2 and 3 above have been met. All permits are revocable upon showing of good cause after notice and, if requested, hearing. Permits shall be reviewed a minimum of once every five (5) years for compliance with state statutes, Division rules and permit requirements and conditions.

C. Operational Requirements

(1) All surface waste management facility permittees shall file forms C-117-A, C-118, and C-120-A as required by OCD rules.

(2) Facilities permitted as treating plants will not accept sediment oil, tank bottoms and other miscellaneous hydrocarbons for processing unless accompanied by an approved Form C-117A or C-138.

(3) Facilities will only accept oilfield related wastes except as provided in Subsection C, Paragraph (4), Subparagraph (c) of 19.15.9.711 NMAC below. Wastes which are determined to be RCRA Subtitle C hazardous wastes by either listing or characteristic testing will not be accepted at a permitted facility.

(4) The permittee shall require the following documentation for accepting wastes, other than wastes returned from the wellbore in the normal course of well operations such as produced water and spent treating fluids, at commercial waste management facilities:

(a) Exempt Oilfield Wastes: As a condition to acceptance of the materials shipped, a generator, or his authorized agent, shall sign a certificate which represents and warrants that the wastes are: generated from oil and gas exploration and production operations; exempt from Resource Conservation and Recovery Act (RCRA) Subtitle C regulations; and not mixed with non-exempt wastes. The permittee shall have the option to accept on a monthly, weekly, or per load basis a load certificate in a form of its choice. While the acceptance of such exempt oilfield waste materials does not require the prior approval of the Division, both the generator and permittee shall maintain and shall make said certificates available for inspection by the Division for compliance and enforcement purposes.

(b) Non-exempt, Non-hazardous Oilfield Wastes: Prior to acceptance, a "Request For Approval To Accept Solid Waste", OCD Form C-138, accompanied by acceptable documentation to determine that the waste is non-hazardous shall be submitted to the appropriate District office. Acceptance will be on a case-by-case basis after approval from the Division's Santa Fe office.

(c) Non-oilfield Wastes: Non-hazardous, non-oilfield wastes may be accepted in an emergency if ordered by the Department of Public Safety. Prior to acceptance, a "Request To Accept Solid Waste", OCD Form C-138 accompanied by the Department of Public Safety order will be submitted to the appropriate District office and the Division's Santa Fe office. With prior approval from the Division, other non-hazardous, non-oilfield waste may be accepted into a permitted surface waste management facility if the waste is similar in physical and chemical composition to the oilfield wastes authorized for disposal at that facility and is either: (1) exempt from the “hazardous waste” provisions of Subtitle C of the federal Resource Conservation and Recovery Act; or (2) has tested non-hazardous and is not listed as hazardous. Prior to acceptance, a "Request For Approval to Accept Solid Waste," OCD Form C-138, accompanied by acceptable documentation to characterize the waste, shall be submitted to and approved by the Division’s Santa Fe office.

(5) The permittee of a commercial facility shall maintain for inspection the records for each calendar month on the generator, location, volume and type of waste, date of disposal, and hauling company that disposes of fluids or material in the facility. Records shall be maintained in appropriate books and records for a period of not less than five years, covering their operations in New Mexico.

(6) Disposal at a facility shall occur only when an attendant is on duty unless loads can be monitored or otherwise isolated for inspection before disposal . The facility shall be secured to prevent unauthorized disposal when no attendant is present.

(7) No produced water shall be received at the facility from motor vehicles unless the transporter has a valid Form

C-133, Authorization to Move Produced Water, on file with the Division.

(8) To protect migratory birds, all tanks exceeding 16 feet in diameter, and exposed pits and ponds shall be screened, netted or covered. Upon written application by the permittee, an exception to screening, netting or covering of a facility may be granted by the district supervisor upon a showing that an alternative method will protect migratory birds or that the facility is not hazardous to migratory birds.

(9) All facilities will be fenced in a manner approved by the Director.

(10) A permit may not be transferred without the prior written approval of the Director. Until such transfer is approved by the Director and the required financial assurance is in place, the transferor's financial assurance will not be released.

D. Facility Closure

(1) The permittee shall notify the Division thirty (30) days prior to its intent to cease accepting wastes and close the facility. The permittee shall then begin closure operations unless an extension of time is granted by the Director. If disposal operations have ceased and there has been no significant activity at the facility for six (6) months and the permittee has not responded to written notice as defined in Subsection D, Paragraph (2), Subparagraph (a) of 19.15.9.711 NMAC, then the facility shall be considered abandoned and shall be closed utilizing the financial assurance pledged to the facility. Closure shall be in accordance with the approved closure plan and any modifications or additional requirements imposed by the Director to protect public health and the environment. At all times the permittee must maintain the facility to protect public health and the environment. Prior to release of the financial assurance covering the facility, the Division will inspect the site to determine that closure is complete.

(2) If a permittee refuses or is unable to conduct operations at the facility in a manner that protects public health or the environment or refuses or is unable to conduct or complete the closure plan, the terms of the permit are not met, or the permittee defaults on the conditions under which the financial assurance was accepted, the Director shall take the following actions to forfeit all or part of the financial assurance:

(a) Send written notice by certified mail, return receipt requested, to the permittee and the surety informing them of the decision to close the facility and to forfeit all or part of the financial assurance, including the reasons for the forfeiture and the amount to be forfeited and notifying the permittee and surety that a hearing request must be made within ten (10) days of receipt of the notice.

(b) Advise the permittee and surety of the conditions under which the forfeiture may be avoided. Such conditions may include but are not limited to:

(i) An agreement by the permittee or another party to perform closure operations in accordance with the conditions of the permit, the closure plan and these Rules, and that such party has the ability to satisfy the conditions.

(ii) The Director may allow a surety to complete closure if the surety can demonstrate an ability to complete the closure in accordance with the approved plan. No surety liability shall be released until successful completion of closure.

(c) In the event forfeiture of the financial assurance is required by this rule, the Director shall proceed to collect the forfeited amount and use the funds collected from the forfeiture to complete the closure. In the event the amount forfeited is insufficient for closure, the permittee shall be liable for the deficiency. The Director may complete or authorize completion of closure and may recover from the permittee all reasonably incurred costs of closure and forfeiture in excess of the amount forfeited. In the event the amount forfeited was more than the amount necessary to complete closure and all costs of forfeiture, the excess shall be returned to the party from whom it was collected.

(d) Upon showing of good cause, the Director may order immediate cessation of operations of the facility when it appears that such cessation is necessary to protect public health or the environment, or to assure compliance with Division rules and orders.

(e) In the event the permittee cannot fulfill the conditions and obligations of the permit, the State of New Mexico, its agencies, officers, employees, agents, contractors and other entities designated by the State shall have all rights of entry into, over and upon the facility property, including all necessary and convenient rights of ingress and egress with all materials and equipment to conduct operation, termination and closure of the facility, including but not limited to the temporary storage of equipment and materials, the right to borrow or dispose of materials, and all other rights necessary for operation, termination and closure of the facility in accordance with the permit.

E. Waste management facilities in operation at the time Section 19.15.9.711 NMAC becomes effective shall:

(1) within one (1) year after the effective date permitted facilities submit the information required in Subsection B, Paragraph (1), Subparagraphs (a, h, i and l) of 19.15.9.711 NMAC not already on file with the Division;

(2) within one (1) year after the effective date unpermitted facilities submit the information required in Subsection B, Paragraph (1), Subparagraphs (a) through (j) and Subsection B, Paragraph (1), Subparagraph (l) of 19.15.9.711 NMAC;

(3) comply with Subsections C and D of 19.15.9.711 NMAC unless the Director grants an exemption from a requirement in these sections based upon a demonstration by the operator that such requirement is not necessary to protect public

health and the environment.
[6-6-88…2-1-96; 19.15.9.711 NMAC - Rn, 19 NMAC 15.I.711, 11-30-00; A, 4-15-03]

19.15.9.712. DISPOSAL OF CERTAIN NON-DOMESTIC WASTE AT SOLID WASTE FACILITIES.

A. General - Certain non-domestic waste arising from the exploration, development, production or storage of crude oil or natural gas, certain nondomestic waste arising from the oil field service industry, and certain non-domestic waste arising from the transportation, treatment or refinement of crude oil or natural gas, may be disposed of at a solid waste facility.

B. Definitions - The following words and phrases have particular meanings for purposes of this section:

(1) "BTEX." The acronym "BTEX" in this section refers to benzene, toluene, ethelbenzene and xylene.

(2) "Discharge Plan." A "discharge plan" is a plan submitted and approved by the Division pursuant to NMSA 1978, Section 70-2-12(B)(22) (2000 Cum.Supp.) and rules and regulations of the Water Quality Control Commission.

(3) "EPA." The acronym "EPA" refers to the United States Environmental Protection Agency.

(4) "EPA Clean." The phrase "EPA Clean" refers to cleanliness standards established by the EPA in 40 C.F.R. Part 261, Section 261.7(b).

(5) "NESHAP." The acronym "NESHAP" refers to the National Emission Standards for Hazardous Air Pollutants of the EPA, 40 C.F.R. Part 61.

(6) "NORM." The acronym "NORM" refers to naturally occurring radioactive materials regulated by 20 NMAC 3.1, Subpart 14.

(7) "Section." "Section" or "this section" refers to Section 19.15.9.712.

(8) "Solid Waste Facility." A "solid waste facility" is a facility permitted or authorized as a solid waste facility by the New Mexico Environment Department pursuant to the Solid Waste Act, NMSA 1978, Sections 74-9-1 et seq. and rules and regulations of the Environmental Improvement Board, to accept industrial solid waste or other special waste.

(9) "TCLP" The acronym "TCLP" in this section refers to the testing protocol established by the EPA in 40 C.F.R. Part 261, entitled "Toxicity Characteristic Leaching Procedure" or an alternative hazardous constituent analysis approved by the Division.

(10) "TPH." The acronym "TPH" in this section refers to the phrase "total petroleum hydrocarbons."

(11) "Waste." The word "waste" refers to nondomestic waste resulting from the exploration, development, production or storage of crude oil or natural gas pursuant to NMSA 1978, Section 70-2-12(B)(21) and nondomestic waste arising from the oil field service industry, and certain non-domestic waste arising from the transportation, treatment or refinement of crude oil or natural gas pursuant to NMSA 1978, Section 70-2-12(B)(22).

C. Procedure

(1) Waste Listed in Subsection D, Paragraph (1) of Section 19.15.9.712. Waste listed in Subsection D,

Paragraph (1) of Section 19.15.9.712 may be disposed of at a solid waste facility without prior written authorization of the Division.

(2) Waste Listed in Subsection D, Paragraph (2) of Section 19.15.9.712. Waste listed in Subsection D, Paragraph (2) of Section 19.15.9.712 may be disposed of at a solid waste facility after testing and prior written authorization of the Division. Before authorization is granted, copies of test results must be provided to the Division and to the solid waste facility where the waste is to be disposed. Disposal may commence only after written authorization of the Division. In appropriate cases and so long as a representative sample is tested, the Division may authorize disposal of a waste stream listed in Subsection D, Paragraph (2) of Section 19.15.9.712 without individual testing of each delivery.

(3) Waste Listed in Subsection D, Paragraph (3) of Section 19.15.9.712. Waste listed in Subsection D, Paragraph (3) of Section 19.15.9.712 may be disposed of at a solid waste facility on a case-by-case basis after testing required at the discretion of the Division and after prior written authorization of the Division. Before authorization is granted, copies of test results must be provided to the Division and to the solid waste facility where the waste is to be disposed. Disposal may commence only after written authorization of the Division.

(4) Simplified Procedure for Holders of Discharge Plans. Holders of an approved discharge plan may amend the discharge plan to provide for disposal of waste listed in Waste Listed in Subsection D, Paragraph (2) of Section 19.15.9.712 and, as applicable, Subsection D, Paragraph (3) of Section 19.15.9.712. If the amendment to the Discharge Plan is approved, wastes listed in Subsection D, Paragraph (2) of Section 19.15.9.712 and Subsection D, Paragraph (3) of Section 19.15.9.712 may be disposed of at a solid waste facility without the necessity of prior written authorization of the Division.

D. Waste Governed By This Section

(1) Waste That Does Not Require Testing Before Disposal:

(a) Barrels, drums, 5-gallon buckets, 1-gallon containers so long as empty and EPA-clean.

(b) Uncontaminated brush and vegetation arising from clearing operations.

(c) Uncontaminated concrete.

(d) Uncontaminated construction debris.

(e) Non-friable asbestos and asbestos contaminated waste material, so long as the disposal complies with all applicable federal and state regulations for nonfriable asbestos materials and so long as asbestos is removed from steel pipes and boilers and, if applicable, the steel recycled.

(f) Detergent buckets, so long as completely empty.

(g) Fiberglass tanks so long as the tank is empty, cut up or shredded, and EPA clean.

(h) Grease buckets, so long as empty and EPA clean.

(i) Uncontaminated ferrous sulfate or elemental sulfur so long as recovery and sale as a raw material is not possible.

(j) Metal plate and metal cable.

(k) Office trash.

(l) Paper and paper bags, so long as empty (paper bags).

(m) Plastic pit liners, so long as cleaned well.

(n) Soiled rags or gloves. If wet, must pass Paint Filter Test prior to disposal.

(o) Uncontaminated wood pallets.

(2) Waste That Must Be Tested:

(a) Activated alumina must be tested for TPH and BTEX.

(b) Activated carbon must be tested for TPH and BTEX.

(c) Amine filters must be tested for BTEX (and air-dried for at least 48 hours before testing).

(d) Friable asbestos and asbestos-contaminated waste material must be tested pursuant to NESHAP (and so long as the disposal otherwise complies with all applicable federal and state regulations for friable asbestos materials, and so long as asbestos is removed from steel pipes and boilers and, if applicable, the steel should be recycled before disposal).

(e) Cooling tower filters must be tested for TCLP/chromium (and drained and then air-dried for at least 48 hours before testing).

(f) Dehydration filter media must be tested for TPH and BTEX (and drained and then air-dried for at least 48 hours before testing).

(g) Gas condensate filters must be tested for BTEX (and drained and then air-dried for at least 48 hours before testing).

(h) Glycol filters must be tested for BTEX (and drained and then air-dried for at least 48 hours before testing).

(i) Iron sponge must be oxidized completely and then undergo Ignitability Testing.

(j) Junked pipes, valves, and metal pipe must be tested for NORM.

(k) Molecular sieve must be tested for TPH and BTEX (and must be cooled in a non-hydrocarbon inert atmosphere and hydrated in ambient air for at least 24 hours before testing).

(l) Pipe scale and other deposits removed from pipeline and equipment must be tested for TPH, TCLP/metals and NORM.

(m) Produced water filters must be tested for Corrosivity (and drained and then air-dried for at least 48 hours before testing).

(n) Sandblasting sand must be tested for TCLP/metals or, at the discretion of the Division, TCLP/total metals.

(o) Waste oil filters must be tested for TCLP/metals (and must be drained thoroughly of oil for at least 24 hours before testing and oil and metal parts must be recycled).

(3) Waste That May Be Disposed Of On A Case-By-Case Basis:

(a) Sulfur contaminated soil.

(b) Catalysts.

(c) Contaminated soil other than petroleum contaminated soil.

(d) Petroleum contaminated soil in the event of an emergency declared by the director.

(e) Contaminated concrete.

(f) Demolition debris not otherwise specified herein.

(g) Unused dry chemicals (in addition to any testing required by the Division, a copy of the Material Safety Data Sheet shall be forwarded to the Division and the solid waste facility on each chemical proposed for disposal).

(h) Contaminated ferrous sulfate or elemental sulfur.

(i) Unused pipe dope.

(j) Support balls.

(k) Tower packing materials.

(l) Contaminated wood pallets.

(m) Partial sacks of unused drilling mud (in addition to any testing required by the Division, a copy of the Material Safety Data Sheet shall be forwarded to Division and the solid waste facility at which the partial sacks will be disposed).

(n) Other wastes as applicable.

E. Testing

(1) General - Testing required herein shall be conducted according to the Test Methods for Evaluating Solid Waste, EPA No. SW-846. Any questions concerning the standards or a particular testing facility should be directed to the Division.

(2) Methodology - Testing must be conducted according to the test method listed:

(a) TPH: EPA method 418.1 or 8015 (D-R-O and G-R-O only) or an alternative hydrocarbon analysis approved by the Division.

(b) TCLP: EPA Method 1311 or an alternative hazardous constituent analysis approved by the Division.

(c) Paint Filter Testing: EPA Method 9095A.

(d) Ignitability Test: EPA Method 1030.

(e) Corrosivity: EPA Method 1110.

(f) Reactivity: Test procedures and standards established on a case-by-case basis by the Division.

(g) NORM. 20 NMAC 3.1, Subpart 14.

(3) Limits - To be eligible for disposal pursuant to this section, substances found during testing shall not exceed the following limits:

(a) Benzene: Less than 10 mg/Kg.

(b) BTEX: Less than 500 mg/Kg (sum of all).

(c) TPH: Shall not exceed 1000 mg/Kg.

(d) Hazardous Air Pollutants: Shall not exceed the standards set forth in NESHAP.

(e) TCLP: Shall not exceed the following:

(i) Arsenic: 5.0 mg/l
(ii) Barium: 100.0 mg/l
(iii) Cadmium: 1.0 mg/l
(iv) Chromium: 5.0 mg/l
(v) Lead: 5.0 mg/l
(vi) Mercury: 0.2 mg/l
(vii) Selenium: 1.0 mg/l
(viii) Silver: 5.0 mg/l

19.15.9.713 This entire section moved and renumbered to 19 NMAC 15.A.32.
[12-30-95, 2-1-96; A, 6-15-99; 19.15.9.713 NMAC - Rn, 19 NMAC 15.I.713; 11-30-00]

19.15.9.714 DISPOSAL OF REGULATED NATURALLY OCCURRING RADIOACTIVE MATERIAL (REGULATED NORM)

A. Purpose - This rule establishes procedures for the disposal of regulated naturally occurring radioactive material (Regulated NORM) associated with the oil and gas industry. Any person disposing of Regulated NORM, as defined at 19 NMAC 15.A.7, is subject to this rule and to the New Mexico Environmental Improvement Board regulations at 20 NMAC 3.1, Subpart 14.

B. Nonretrieved Flowlines and Pipelines

(1) The Division will consider a proposal for leaving flowlines and pipelines (hereinafter "pipeline") that contain Regulated NORM in the ground provided such abandonment procedures are performed in a manner to protect the environment, public health, and fresh waters. Division approval is contingent on the applicant meeting the following requirements as a minimum:

(2) An application submitted to the Division must contain the following as a minimum:

(a) The pipeline layout over its entire length on an OCD Form C-102 (Well Location and Acreage Dedication Plat) including the legal description of the location of both ends and all surface ownership along the pipeline.

(b) Results of a radiation survey conducted at all accessible points and a surface radiation survey along the complete pipeline route in a form approved by the Division. All surveys are to be conducted consistent with procedures approved by the Division.

(c) The type of material for which the pipeline had been used.

(d) The procedure to be used for flushing hydrocarbons and/or produced water from the pipeline.

(e) An explanation as to why it is more beneficial to leave the pipeline in the ground than to retrieve it.

(f) Proof of notice of the proposed abandonment to all surface owners where the pipeline is located. Additional notification may be required as described in Subsection F of 19.15.9.714 NMAC.

(3) Procedure

(a) Upon approval of the application by the Division, the operator must notify the OCD District office at least 24 hours prior to beginning any work on the pipeline abandonment.

(b) As a condition of completion of the pipeline abandonment, all accessible points must be permanently capped.

(4) General

(a) No additional Regulated NORM may be placed in any pipeline to be abandoned under this section other than that which accumulated in the pipeline under normal operation of the pipeline.

(b) Any pipeline that does not exhibit Regulated NORM pursuant to required surveys may be abandoned without application under this section in accordance with the operator's applicable lease agreements.

(c) If an appurtenance of a pipeline contains Regulated NORM, but upon removal of the appurtenance, no accessible point or surface above the pipeline exhibits the presence of

Regulated NORM, then the applicant must submit to the Division the information regarding the Regulated NORM in the appurtenance and a statement concerning management of that Regulated NORM. With respect to the pipeline left in the ground, the applicant will be subject to the requirements under Subsection B of 19.15.9.714 NMAC with the exception of Subsection B, Paragraph (2), Subparagraph (f) of 19.15.9.714 NMAC.

C. Commercial or Centralized Surface Waste Management Facilities

(1) The Division will consider proposals for the disposal of Regulated NORM in commercial or centralized surface waste management facilities, provided such disposal is performed in a manner to protect the environment, public health, and fresh waters. Division approval is contingent on the applicant obtaining a permit in accordance with Section 19.15.9.711 NMAC for the facility and complying with additional requirements specifically related to Regulated NORM disposal as described below.

(2) Application - All requests for authority to receive and dispose of Regulated NORM in commercial or centralized surface waste management facilities must be set for hearing by the Division in order for the operator of the facility to obtain or modify a permit in accordance with Section 19.15.9.711 NMAC. A request to dispose of Regulated NORM at a facility previously permitted under Section 19.15.9.711 NMAC will be considered a major modification to that facility. The hearing request must be submitted to the Division and must contain the following at a minimum:

(a) Complete plans for the facility, including the sources of Regulated NORM, radiation survey readings, quantities of Regulated NORM to be disposed, and monitoring proposals;

(b) A copy of this permit for the facility, if one has been issued by the Division;

(c) Proof of public notice of the application as required by Section 19.15.9.711 NMAC; and

(d) Evidence of issuance of a specific license pursuant to 20 NMAC 3.1, Subpart 14, a license pursuant to 20 NMAC 3.1, Subpart 13, and any other authorizations required by law.

(3) Procedures

(a) Operating procedures that are protective of the environment, public health, and fresh waters will be established in the Division's order.

(b) Any person desiring to dispose of Regulated NORM in an approved commercial or centralized surface waste management facility must furnish Regulated NORM information to the facility operator sufficient for the operator to submit Form C-138 (Request for Approval to Accept Solid Waste) for approval to the Division. The facility operator must receive Division approval prior to receiving the Regulated NORM at the disposal facility.

D. Downhole Disposal in Wells to be Plugged and Abandoned

(1) The Division will consider proposals for downhole disposal of Regulated NORM in wells that are to be plugged and abandoned, provided such plugging and abandonment procedures are performed in a manner to protect the environment, public health and fresh waters and in accordance with Division Rules pertaining to well plugging and abandonment.

(2) Application

(a) A plugging and abandonment (P&A) Form C-103 must be completed by the applicant and submitted to the Division for approval.

(b) In addition to all other information required for P&A submittal, the form must specifically state that Regulated NORM will be placed in the wellbore. The abandonment procedure contained in the application must identify depths at which the Regulated NORM will be placed, radiation survey results conducted on the Regulated NORM to be disposed, the procedure to be used to place the Regulated NORM in the wellbore, and the specific form of Regulated NORM being placed in the wellbore (e.g. scale, pipe, dirt, etc).

(c) Notice of the submittal of an application to dispose of Regulated NORM in a P&A well must be sent to the surface owner and the mineral lessor. Additional notification may be required as described in Subsection F of 19.15.9.714 NMAC.

(3) Procedures

(a) All P&A procedures routinely required by the Division must be followed unless specifically superseded at the instruction of the Division to facilitate the Regulated NORM disposal.

(b) No work will be commenced until the application for Regulated NORM disposal in a P&A well has been approved by the Division.

(c) The cement plug located directly above the Regulated NORM and the surface plug must be color-dyed with red iron oxide.

(4) General

(a) Regulated NORM must be disposed at a depth of at least 100 feet below the lower most known Underground Source of Drinking Water (USDW) zone. There must be evidence that there is cement across the known USDW zones.

(b) Abnormally pressured zone(s) in the wellbore that might result in migration of the Regulated NORM after it has been placed in the P&A well must be addressed in the application.

E. Injection

(1) The Division will consider proposals for injecting Regulated NORM into injection wells provided such injection is performed in a manner to protect the environment, public health, and fresh waters and such injection is in compliance with Division Rules pertaining to injection. Division approval is contingent on the applicant meeting the following requirements at a minimum:

(2) Disposal wells

(a) An application submitted to the Division must contain the following information at a minimum:

(i) For both existing and newly permitted disposal wells, a completed Form C-108 (Application for Authorization to Inject) with proof of required notification and a statement that Regulated NORM will be injected;

(ii) Description of Regulated NORM to be disposed including its source, radiation levels, and quantity; and

(iii) Description of any process used on the material to improve injectivity;

(b) Procedures

(i) Regulated NORM to be injected may only be from the applicant’s operations.

(ii) Each time Regulated NORM is injected, a Form C-103 (Subsequent Report Form) must be submitted to the Division and District offices. This form must be submitted within five (5) working days following the injection and must contain the following information: source of Regulated NORM; NORM radiation level; quantity of material injected; description of any process used on the material to improve injectivity; the injection pressure while injecting; and date(s) of injection.

(iii) Failures and repairs **-** All mechanical failures must be reported to the appropriate District office within 24 hours of the occurrence. A description of the failure and immediate measures taken in response to the failure must be submitted no later than 15 days following the occurrence. The operator must notify the District office of proposed repair plans. Approval of repair plans must be received prior to any work commencing, and notice of commencement must be given to the District office such that the repairs may be witnessed and/or inspected. All well repairs must be monitored by the operator to ensure Regulated NORM does not escape the wellbore or is completely contained in the repair operations.

(iv) At the time of abandonment of the disposal well, the injection interval that was used for Regulated NORM injection must be squeezed with cement or a cement plug must be located directly above the injection interval. Cement in either case must contain red iron oxide.

(v) The injection zone must be at a depth of at least 100 feet below the lower most known USDW zone.

(3) Injection in Enhanced Oil Recovery (EOR) Injection Wells **-** The Division will consider issuing a permit for the disposal of Regulated NORM into injection wells within an approved Enhanced Oil Recovery (EOR) Project only after notice and hearing and upon a minimum demonstration that:

(a) such injection will not reduce the efficiency of the project or otherwise cause a reduction in the ultimate recovery of hydrocarbons from the project;

(b) such injection will not cause an increase in the radiation level of Regulated NORM produced from the EOR interval in any producing well located either within or offsetting the project area; and

(c) the operations will be in conformance with provisions of Subsection E, Paragraph (2) of 19.15.9.714 NMAC above.

(4) Injection Above Fracture Pressure

(a) The Division will consider issuing a permit for the disposal of Regulated NORM in a disposal well above fracture pressure only after notice and hearing and upon receiving the following minimum information from the applicant:

(i) A completed Form C-108 clearly stating that disposal of Regulated NORM at or above fracture pressure is proposed.

(ii) Information required under Subsection E, Paragraph (2) of 19.15.9.714 NMAC above.

(iii) Model results predicting the fracture propagation including the expected height, extension, direction, and any other evidence sufficient to demonstrate that the fracture will not extend beyond the injection interval or into the confining zones. The application must include the procedure, the anticipated pressures and the type and pressure rating of equipment that will be used. The current or potential utilization of zones immediately above and below the zone of interest may be considered by the Division in the acceptance or rejection of model predictions.

(iv) A contingency plan of the procedures, including containment plans, that will be employed if a mechanical failure occurs.

(b) Procedures

(i) 24 hour notice that injection will commence must be given to the District office.

(ii) Upon completion of the injection, the disposal interval must be squeezed with cement or a cement plug must be located directly above the injection interval (cement in either case must contain red iron oxide), and a Form C-103 (Subsequent Report Form) must be submitted to the Division and the District office within five working days of the injection. If the operator desires to return the well to injection below fracture pressure, such plans must be contained in the application.

(5) Injection in Commercial Disposal Facilities - The Division will consider issuing a permit for the commercial disposal of Regulated NORM by injection only after notice and hearing, and provided a specific license has been obtained pursuant to 20 NMAC 3.1, Subpart 14 and a license has been obtained pursuant to 20 NMAC 3.1, Subpart 13. In addition to obtaining these licenses the operator must also comply with Subsection E, Paragraph (2), Subparagraph (b), Sub-subparagraph (i) above of 19.15.9.714 NMAC.

F. Additional Notification

(1) The Director may, at his discretion, require additional notice for any application under this rule.

(2) Any notified party seeking to comment or request a public hearing on such an application must file comments or a hearing request with the Division within 20 days of notice. A request for a hearing must be in writing and must set forth the reasons why a hearing should be held.

(3) A public hearing will be held as required in 19.15.9.714 NMAC or if the Director determines there is sufficient cause.

[7-15-96; 19.15.9.714 NMAC - Rn, 19 NMAC 15.I.714, 11-30-00]

HISTORY of 19.15.9 NMAC:

Pre-NMAC History:

Material in the part was derived from that previously filed with the commission of public records - state records center and archives:

Rule 701, Injection of Fluids into Reservoirs, 1-08-82

Rule 701, Injection of Fluids into Reservoirs, 1-28-87

Rule 701, Injection of Fluids into Reservoirs, 2-05-91

Rule 702, Casing and Cementing of Injection Wells, 1-08-82
Rule 702, Casing and Cementing of Injection Wells, 2-05-91
Rule 703, Operation and Maintenance, 1-08-82
Rule 703, Operation and Maintenance, 2-05-91
Rule 704, Testing and Monitoring, 1-08-82
Rule 704, Testing, Monitoring, Step-Rate Tests, Notice to the Division, Requests for Pressure Increases, 11-07-86
Rule 704, Testing, Monitoring, Step-Rate Tests, Notice to the Division, Requests for Pressure Increases, 2-05-91
Rule 705, Commencement, Discontinuance, And Abandonment of Injection Operations, 1-08-82
Rule 705, Commencement, Discontinuance, And Abandonment of Injection Operations, 2-05-91
Rule 706, Records and Reports, 1-08-82
Rule 706, Records and Reports, 2-05-91
Rule 707, Reclassification of Wells, 1-08-82
Rule 707, Reclassification of Wells, 2-05-91
Rule 708, Transfer of Authority To Inject, 1-08-82
Rule 708, Transfer of Authority To Inject, 2-05-91
Rule 709, Removal of Produced Water from Leases and Field Facilities, 1-27-82
Rule 709, Removal of Produced Water from Leases and Field Facilities, 9-16-85
Rule 709, Removal of Produced Water from Leases and Field Facilities, 2-05-91
Rule 710, Disposition of Transported Produced Water, 1-27-82
Rule 710, Disposition of Produced Water, 9-16-85
Rule 710, Disposition of Transported Produced Water, 2-05-91
Rule 711, Commercial Surface Waste Disposal Facilities, 6-6-88
Rule 711, Commercial Surface Waste Disposal Facilities, 10-11-89
Rule 711, Commercial Surface Waste Disposal Facilities, 2-5-91
Rule 711, Applicable to Surface Waste Management Facilities Only, 7-27-95
Rule 711, Applicable to Surface Waste Management Facilities Only, 12-18-95
Rule 712, Qualification of Production Restoration Projects and Certification for the Production Restoration Incentive Tax Exemption, 12-07-95
Rule 713, Qualification of Well Workover Projects and Certification for the Well Workover Incentive Tax Rate, 12-07-95

Other History:
Rule 701, Injection of Fluids into Reservoirs, 2-05-91; Rule 702, Casing and Cementing of Injection Wells, 2-05-91; Rule 703, Operation and Maintenance, 2-05-91; Rule 704, Testing, Monitoring, Step-Rate Tests, Notice to the Division, Requests for Pressure Increases, 2-05-91; Rule 705, Commencement, Discontinuance, And Abandonment of Injection Operations, 2-05-91; Rule 706, Records and Reports, 2-05-91; Rule 707, Reclassification of Wells, 2-05-91; Rule 708, Transfer of Authority To Inject, 2-05-91; Rule 709, Removal of Produced Water from Leases and Field Facilities, 2-05-91; Rule 710, Disposition of Transported Produced Water, 2-05-91; Rule 711, Applicable to Surface Waste Management Facilities Only, 12-18-95; Rule 712, Qualification of Production Restoration Projects and Certification for the Production Restoration Incentive Tax Exemption, 12-07-95; and Rule 713, Qualification of Well Workover Projects and Certification for the Well Workover Incentive Tax Rate, 12-07-95 **all renumbered and reformatted to 19 NMAC 15.I,** filed 01-18-96.
Renumbered and amended **from** 19 NMAC 15.I, filed 01-18-96 **to** 19.15.9 NMAC, effective 11-30-2000.

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 10 OIL PURCHASING AND TRANSPORTING

19.15.10.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Dept., Oil Conservation Division, 2040 S. Pacheco, Santa Fe, New Mexico 87505, (505) 827-7131.
[2/1/96; 19.15.10.1 NMAC - Rn, 19 NMAC 15.J.1, 04-15-03]

19.15.10.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico.
[2/1/96; 19.15.10.2 NMAC - Rn, 19 NMAC 15.J.2, 04-15-03]

19.15.10.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the Oil and Gas Act which grants the Oil Conservation Division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights and the disposition of wastes resulting from oil and gas operations.
[2/1/96; 19.15.10.3 NMAC - Rn, 19 NMAC 15.J.3, 04-15-03]

19.15.10.4 DURATION: Permanent.
[2/1/96; 19.15.10.4 NMAC - Rn, 19 NMAC 15.J.4, 04-15-03]

19.15.10.5 EFFECTIVE DATE: February 1, 1996 [unless a later date is cited at the end of a section]
[2/1/96; 19.15.10.5 NMAC - Rn, 19 NMAC 15.J.5, 04-15-03]

19.15.10.6 OBJECTIVE: To regulate oil purchasing and transporting under the Oil and Gas Act.
[2/1/96; 19.15.10.6 NMAC - Rn, 19 NMAC 15.J.6, 04-15-03]

19.15.10.7 DEFINITIONS: [RESERVED]

19.15.10.8 - 800 [RESERVED]

19.15.10.801 ILLEGAL SALE PROHIBITED:

The sale or purchase or acquisition, or the transporting, refining, processing or handling in any other way, of crude petroleum oil or of any crude petroleum produced in excess of the amount allowed by any statute of this state, or by any rule, regulation or order of the division made thereunder, is prohibited.
[1/1/50...2/1/96; 19.15.10.801 NMAC - Rn, 19 NMAC 15.J.801, 04-15-03]

19.15.10.802 RATABLE TAKE; COMMON PURCHASER:

A. Every person now engaged or hereafter engaging in the business of purchasing oil to be transported through pipelines shall be a common purchaser thereof, and shall without discrimination in favor of one producer as against another in the same field, purchase any oil tendered to it which has been lawfully produced in the vicinity of, or which may be reasonably reached by pipelines through which it is transporting oil, or the gathering branches thereof, or which may be delivered to the pipeline or gathering branches thereof by truck or otherwise and shall fully perform all the duties of a common purchaser. If any common purchaser shall not have need for all such oil lawfully produced within a field, or if for any reason it shall be unable to purchase all such oil, then it shall purchase from each producer in a field ratably, taking and purchasing the same quantity of oil from each well to the extent that each well is capable of producing its ratable portions; provided, however, nothing herein contained shall be construed to require more than one pipeline connection for each producing well. In the event any such common purchaser of oil is likewise a producer or is affiliated with a producer, directly or indirectly, it is hereby expressly prohibited from discriminating in favor of its own production or in favor of the production of an affiliated producer as against that of others and the oil produced by such common purchaser, or by the affiliate of such common purchaser shall be treated as that of any other producer for the purposes of ratable taking.

B. It shall be unlawful for any common purchaser, to unjustly or unreasonably discriminate as to the relative quantities of oil purchased by it in various fields of the state; the question of the justice or reasonableness to be determined by the division, taking into consideration the production and age of wells in the respective fields and all other factors. It is the intent of this rule that all fields shall be allowed to produce and market a just and equitable share of the oil produced and marketed in the state, insofar as the same can be effected economically and without waste.

C. In order to preclude premature abandonment, the common purchaser within its purchasing area is authorized and directed to make 100 percent purchases from units of settled production producing ten (10) barrels or less daily of crude petroleum in lieu of ratable purchases or takings. Provided, however, where such purchaser's takings are curtailed below ten (10) barrels per unit of crude petroleum daily, then such purchaser is authorized and directed to purchase equally from all such units within its purchasing area, regardless of their producing ability insofar as they are capable of producing.
[7/1/52…2/1/96; 19.15.10.802 NMAC - Rn, 19 NMAC 15.J.802, 04-15-03]

19.15.10.803 PRODUCTION OF LIQUID HYDROCARBONS FROM GAS WELLS:
A. All liquid hydrocarbons produced incidental to the authorized production of gas from a well classified by the division as a gas well shall, for all purposes, be legal production.
B. For purposes of this rule, all gas produced from a gas well shall be considered to be authorized production with the following exceptions:
(1) When the well is being produced without an approved form C-104, designating the gas transporter and the oil or condensate transporter for said well.
(2) When the well has been directed to be shut in by the division.
C. In the event a gas well is directed to be shut in by the division, both the gas transporter and oil transporter named on the well's form C-104 shall be immediately notified of such fact.
[12/1/57...2/1/96; 19.15.10.803 NMAC - Rn, 19 NMAC 15.J.803, 04-15-03]

19.15.10.804 DOCUMENTATION REQUIRED:
A. All off-lease transportation of crude oil or lease condensate by motor vehicle shall be pursuant to an approved form C-104 and shall be accompanied by a run ticket or equivalent document. The documentation shall identify the name and address of the transporter, the name of the operator and of the lease or facility from which the oil was taken, the date of removal, the API gravity of the oil, the observed percentage of BS and W, the volume of oil or opening and closing tank gauges or meter readings and the signature of the driver. The document shall provide space for recording of the lease number and for signature of the operator or his representative.
B. After August 1, 1982, all such transportation must be accompanied by documentation sufficient to verify the location of the tanks or facility from which the liquid was removed. The location may be shown on the run ticket or equivalent document or may be carried separately.
C. All off-lease transportation of liquids which may contain crude oil, lease condensate, sediment oil or miscellaneous hydrocarbons shall be accompanied by a run ticket, work order or equivalent document, i.e., form C-117-A. The documentation shall identify the name and address of the transporter, the name of the operator and of the lease or facility from which the liquid was removed, the nature of the liquid removed including the observed percentage of liquid hydrocarbons, the volume or estimated volume of liquids and the destination.
D. After August 1, 1982, all such transportation must be accompanied by documentation sufficient to verify the location of the tanks or facility from which the liquid was removed. The location may be shown on the run ticket or equivalent document or may be carried separately.
E. The documentation required under Subsections A and B of 19.15.10.804 NMAC above shall be carried in the vehicle during transportation and shall be produced for examination and inspection by any employee of the division, any state police officer or any other law enforcement officer upon identification and request.
F. Except where the owner and the transporter are the same, one copy of such documentation shall be left at the facility from which the oil or other liquids were removed.
[2/1/82...2/1/96; 19.15.10.804 NMAC - Rn, 19 NMAC 15.J.804, 04-15-03]

HISTORY OF 19.15.10 NMAC:
Pre-NMAC History: The material in this Part was derived from that previously filed with the State Records Center and Archives:
Rule 801, Illegal Sale Prohibited, 1/8/82.
Rule 801, Illegal Sale Prohibited, 2/5/91.
Rule 802, Ratable Take; Common Purchaser, 1/8/82.
Rule 802, Ratable Take; Common Purchaser, 2/5/91.
Rule 803, Production of Liquid Hydrocarbons From Gas Wells, 1/8/82.
Rule 803, Production of Liquid Hydrocarbons From Gas Wells, 2/5/91.
Rule 804, Documentation Required, 1/27/82.
Rule 804, Documentation Required, 2/5/91.

History of Repealed Material: [RESERVED]

Other History:
Rule 801, Illegal Sale Prohibited, 2/5/91; Rule 802, Ratable Take; Common Purchaser, 2/5/91; Rule 803, Production of Liquid Hydrocarbons From Gas Wells, 2/5/91; Rule 804, Documentation Required, 2/5/91, **all renumbered and reformatted to 19 NMAC 15.J,** filed 01/18/96.
Renumbered and reformatted **from** 19 NMAC 15.J, filed 01-18-96 **to** 19.15.10 NMAC, effective 04/15/2003.

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 11 GAS PURCHASING AND TRANSPORTING

19.15.11.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Dept., Oil Conservation Division, 2040 S. Pacheco, Santa Fe, New Mexico 87505, (505) 827-7131.
[2/1/96; 19.15.11.1 NMAC - Rn, 19 NMAC 15.K.1, 09-30-03]

19.15.11.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico.
[2/1/96; 19.15.11.2 NMAC - Rn, 19 NMAC 15.K.2, 09-30-03]

19.15.11.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the Oil and Gas Act which grants the oil conservation division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights and the disposition of wastes resulting from oil and gas operations.
[2/1/96; 19.15.11.3 NMAC - Rn, 19 NMAC 15.K.3, 09-30-03]

19.15.11.4 DURATION: Permanent.
[2/1/96; 19.15.11.4 NMAC - Rn, 19 NMAC 15.K.4, 09-30-03]

19.15.11.5 EFFECTIVE DATE: February 1, 1996 [unless a later date is cited at the end of a section].
[2/1/96; 19.15.11.5 NMAC - Rn, 19 NMAC 15.K.5, 09-30-03]

19.15.11.6 OBJECTIVE: To regulate gas purchasing and transporting and enable the oil conservation division to fulfill its statutory mandate pursuant to the Oil and Gas Act.
[2/1/96; 19.15.11.6 NMAC - Rn, 19 NMAC 15.K.6, 09-30-03]

19.15.11.7 DEFINITIONS: [RESERVED]

19.15.11.8 - 900 [RESERVED]

19.15.11.901 ILLEGAL SALE PROHIBITED:
The sale, purchase or acquisition or the transporting, refining, processing or handling in any other way, of natural gas in whole or in part (or of any product of natural gas so produced) produced in excess of the amount allowed by any statute of this state, or by any rule, regulation or order of the division made thereunder, is prohibited.
[1/1/50...2/1/96; 19.15.11.901 NMAC - Rn, 19 NMAC 15.K.901, 09-30-03]

19.15.11.902 RATABLE TAKE:
A. Any person now or hereafter engaged in purchasing from one or more producers, gas produced from gas wells or casinghead gas produced from oil wells shall be a common purchaser thereof within each common source of supply from which it purchases, and as such it shall purchase gas lawfully produced from gas wells or casinghead gas produced from oil wells with which its gas transportation facilities are connected in the pool and other gas lawfully produced within the pool and tendered to a point on its gas transportation facilities. Such purchases shall be made without unreasonable discrimination in favor of one producer against another in the price paid, the quantities purchased, the bases of measurement or the gas transportation facilities afforded for gas of like quantity, quality and pressure available from such wells. In the event any such person is likewise a producer, he is prohibited to the same extent from discriminating in favor of himself on production from gas wells or casinghead gas produced from oil wells in which he has an interest, direct or indirect, as against other production from gas wells or casinghead gas produced from oil wells in the same pool. For the purposes of Section 902 of 19.15.11 NMAC, reasonable differences in prices paid or facilities afforded, or both, shall not constitute unreasonable discrimination if such differences bear a fair relationship to differences in quality, quantity or pressure of the gas available or to the relative lengths of time during which such gas will be available to the purchaser. The provisions of this Subsection shall not apply to:
(1) any wells or pools used for storage and withdrawal from storage of natural gas originally produced not in violation of the rules, regulations or orders of the division; or
(2) persons purchasing gas principally for use in the recovery or production of oil or gas, or
(3) any well which has been designated a "hardship well" by the division.

B. Any common purchaser taking gas produced from gas wells or casinghead gas produced from oil wells from a common source of supply shall take ratably under such rules, regulations and orders, concerning quantity, as may be promulgated by the division consistent with Section 902 of 19.15.11 NMAC. The division, in promulgating such rules, regulations and orders may consider the quality and the deliverability of the gas, the pressure of the gas at the point of delivery, acreage attributable to the well, market requirements in the case of unprorated pools and other pertinent factors.

C. Nothing in Section 902 of 19.15.11 NMAC shall be construed or applied to require, directly or indirectly, any person to purchase gas of a quality or under a pressure or under any other condition by reason of which such gas cannot be economically and satisfactorily used by such purchaser by means of his gas transportation facilities then in service.
[1/1/50...2/1/96; 19.15.11.902 NMAC - Rn, 19 NMAC 15.K.902, 09-30-03]

HISTORY OF 19.15.11 NMAC:
Pre-NMAC History: The material in this Part was derived from that previously filed with the State Records Center and Archives:
Rule 901, Illegal Sale Prohibited, filed 1/8/82;
Rule 901, Illegal Sale Prohibited, filed 2/5/91;
Rule 902, Ratable Take, filed 1/8/82;
Rule 902, Ratable Take, filed 2/5/91.

History of Repealed Material: [RESERVED]

Other History:
Rule 901, Illegal Sale Prohibited and Rule 902, Ratable Take, (both filed 2/5/91) were both renumbered and reformatted and replaced by 19 NMAC 15.K, Gas Purchasing and Transporting, effective 2/1/96.
19 NMAC 15.K, Gas Purchasing and Transporting (filed 01-18-96)**,** renumbered **from** 19 NMAC 15.K **to** 19.15.11 NMAC, effective 09-30-03.

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 12 REFINING

19.15.12.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Dept., Oil Conservation Division, 2040 S. Pacheco, Santa Fe, New Mexico 87505, (505) 827-7131.
[2/1/96; 19.15.12.1 NMAC - Rn, 19 NMAC 15.L.1, 10/15/03]

19.15.12.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico.
[2/1/96; 19.15.12.2 NMAC - Rn, 19 NMAC 15.L.2, 10/15/03]

19.15.12.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the Oil and Gas Act which grants the oil conservation division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights and the disposition of wastes resulting from oil and gas operations.
[2/1/96; 19.15.12.3 NMAC - Rn, 19 NMAC 15.L.3, 10/15/03]

19.15.12.4 DURATION: Permanent.
[2/1/96; 19.15.12.4 NMAC - Rn, 19 NMAC 15.L.4, 10/15/03]

19.15.12.5 EFFECTIVE DATE: February 1, 1996 [unless a later date is cited at the end of a section]
[2/1/96; 19.15.12.5 NMAC - Rn, 19 NMAC 15.L.5, 10/15/03]

19.15.12.6 OBJECTIVE: To regulate refining to enable the oil conservation division to fulfill its statutory mandates under the Oil and Gas Act.
[2/1/96; 19.15.12.6 NMAC - Rn, 19 NMAC 15.L.6, 10/15/03]

19.15.12.7 DEFINITIONS: [RESERVED]

19.15.12.8 - 1000 [RESERVED]

19.15.12.1001 REFINERY REPORTS:
Each refiner of oil within the state of New Mexico shall furnish for each calendar month a "Refiner's Monthly Report," form C-113, containing the information and data indicated by such form, respecting oil and products involved in such refiner's operations during each month. Such report for each month shall be prepared and filed according to instructions on the form, on or before the 15th day of the next succeeding month.
[1/1/50...2/1/96; 19.15.12.1001 NMAC - Rn, 19 NMAC 15.L.1001, 10/15/03]

19.15.12.1002 GASOLINE PLANT REPORTS:
A. Each operator of a gasoline plant, cycling plant or any other plant at which gasoline, butane, propane, condensate, kerosene, oil or other liquid products are extracted from natural gas within the state of New Mexico shall furnish for each calendar month a Gas Purchaser's Monthly Report, form C-111, containing the information indicated by such form respecting natural gas and products involved in the operation of each plant during each month. (19.15.12.1002 NMAC shall also be applicable to plants in the state of New Mexico processing carbon dioxide gas into liquid or solid form.)
B. Form C-111 shall be filed in accordance with the provisions of Rule 1111 [now 19.15.13.1111 NMAC].
[1/1/50...2/1/96; 19.15.12.1002 NMAC - Rn, 19 NMAC 15.L.1002, 10/15/03]

HISTORY OF 19.15.12 NMAC:
Pre-NMAC History: The material in this Part was derived from that previously filed with the State Records Center and Archives:
Rule 1001, Refinery Reports, filed 1/8/82.
Rule 1001, Refinery Reports, filed 2/5/91.
Rule 1002, Gasoline Plant Reports, filed 1/8/82.
Rule 1002, Gasoline Plant Reports, filed 2/5/91.

History of Repealed Material: [RESERVED]

Other History:
Rule 1001, Refinery Reports, filed 2/5/91 and Rule 1002, Gasoline Plant Reports, filed 2/5/91 were both renumbered, reformatted and replaced by 19 NMAC 15.L, Refining, effective 2/2/96.
19 NMAC 15.L, Refining (filed 1/18/96) was renumbered, reformatted and replaced by 19.15.12 NMAC, effective 10/15/03.

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 13 REPORTS

19.15.13.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department, Oil Conservation Division, 2040 S. Pacheco, Santa Fe, New Mexico 87505, (505) 827-7131.
[2-1-96; 19.15.13.1 NMAC - Rn, 19 NMAC 15.M.1, 06/30/04]

19.15.13.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico.
[2-1-96; 19.15.13.2 NMAC - Rn, 19 NMAC 15.M.2, 06/30/04]

19.15.13.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the Oil and Gas Act which grants the oil conservation division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights and the disposition of wastes resulting from oil and gas operations.
[2-1-96; 19.15.13.3 NMAC - Rn, 19 NMAC 15.M.3, 06/30/04]

19.15.13.4 DURATION: Permanent.
[2-1-96; 19.15.13.4 NMAC - Rn, 19 NMAC 15.M.4, 06/30/04]

19.15.13.5 EFFECTIVE DATE: February 1, 1996 [unless a later date is cited at the end of a section]
[2-1-96; 19.15.13.5 NMAC - Rn, 19 NMAC 15.M.5, 06/30/04]

19.15.13.6 OBJECTIVE: To provide for the filing of reports to enable the oil conservation division to carry out its statutory mandates under the Oil and Gas Act.
[2-1-96; 19.15.13.6 NMAC - Rn, 19 NMAC 15.M.6, 06/30/04]

19.15.13.7 DEFINITIONS: [RESERVED].

19.15.13.8 - 1099 [RESERVED].

19.15.13.1100 GENERAL:
A. Where to file reports: Unless otherwise specifically provided for in any rule or order of the division, all forms and reports required by these rules shall be filed with the appropriate district office of the division as provided in 19.15.15.1301 NMAC and 19.15.15.1302 NMAC.
B. Additional data: These rules shall not be construed to limit or restrict the authority of the oil conservation division to require the furnishing of such additional reports, data or other information relative to the production, transportation, storing, refining, processing or handling of crude petroleum oil, natural gas or products in the state of New Mexico as may appear to it to be necessary or desirable, either generally or specifically, for the prevention of waste and the conservation of natural resources of the state of New Mexico.
C. Books and records: All producers, injectors, transporters, storers, refiners, gasoline or extraction plant operators, treating plant operators, and initial purchasers of natural gas within the state of New Mexico shall make and keep appropriate books and records for a period of not less than five years, covering their operations in New Mexico, from which they may be able to make and substantiate the reports required by these rules.
D. Written notices, requests, permits and reports: The forms listed below shall be used for the purpose shown in accordance with the instructions printed thereon and the rule covering the use of the form, or any special rule or order pertaining to its use:
(1) Form C-101 Application for Permit to Drill, Deepen or Plug Back
(2) Form C-102 Well Location and Acreage Dedication Plat

(3) Form C-103 Sundry Notices and Reports on Wells
(4) Form C-104 Request for Allowable and Authorization to Transport Oil and Natural Gas
(5) Form C-105 Well Completion or Recompletion Report and Log
(6) Form C-106 Notice of Intention to Utilize Automatic Custody Transfer Equipment
(7) Form C-107 Application for Multiple Completion
(8) Form C-108 Application to Dispose of Salt Water by Injection into a Porous Formation
(9) Form C-109 Application for Discovery Allowable and Creation of a New Pool
(10) Form C-111 Gas Transporter's Monthly Report (Sheet 1 and Sheet 2)
(11) Form C-112 Transporter's and Storer's Monthly Report
(12) Form C-113 Refiner's Monthly Report (Sheet 1 and Sheet 2)
(13) Form C-115 Operators Monthly Report
(14) Form C-115-EDP Operator's Monthly Report (electronic data processing)
(15) Form C-116 Gas-Oil Ratio Tests
(16) Form C-117-A Tank Cleaning, Sediment Oil Removal, Transportation of Miscellaneous Hydrocarbons and Disposal Permit
(17) Form C-117-B Monthly Sediment Oil Disposal Statement
(18) Form C-118 Treating Plant Operator's Monthly Report (Sheet 1 and Sheet 2)
(19) Form C-119 Carbon Black Plant Monthly Report
(20) Form C-120-A Monthly Water Disposal Report
(21) Form C-121 Crude Oil Purchaser's Nomination
(22) Form C-121-A Purchaser's Gas Nomination
(23) Form C-122 Multi-Point and One Point Back Pressure Test for Gas wells
(24) Form C-122-A Gas Well Test Data Sheet-San Juan Basin (Initial Deliverability Test, blue paper; Annual Deliverability Test, white)
(25) Form C-122-B Initial Potential Test Data Sheet
(26) Form C-122-C Deliverability Test Report
(27) Form C-122-D Worksheet for Calculation of Static Column Wellhead Pressure (P_w).
(28) Form C-122-E Worksheet for Stepwise Calculation of (Surface) (Subsurface) Pressure (Pc & Pw)
(29) Form C-122-F Worksheet for Calculation of Wellhead Pressures (Pc or Pw) from Known Bottomhole Pressure (Pf or Ps)
(30) Form C-122-G Worksheet for Calculation of Static Column Pressure at Gas Liquid Interface
(31) Form C-123 Request for the Creation of a New Pool
(32) Form C-124 Reservoir Pressure Report
(33) Form C-125 Gas Well Shut-in Pressure Report
(34) Form C-126 Permit to Transport Recovered Load Oil
(35) Form C-127 Request for Allowable Change
(36) Form C-129 Application for Exception to No-Flare Rule 306
(37) Form C-130 Notice of Disconnection
(38) Form C-131-A Monthly Gas Storage Report
(39) Form C-131-B Annual LPG Storage Report
(40) Form C-133 Authorization to Move Produced Water Exhibit "A"
(41) Form C-134 Application for Exception to Division Order R-8952, (Protection of Migratory Birds Rule Subsection B of 19.15.3.105 NMAC, Subsection H of 19.15.5.312 NMAC, 19.15.5.313 NMAC, or Paragraph (8) of Subsection C of 19.15.9.711 NMAC
(42) Form C-135 Gas Well Connection, Reconnection or Disconnection Notice
(43) Form C-136 Application for Approval To Use An Alternate Gas Measurement Method
(44) Form C-137 Application for Waste Management Facility
(45) Form C-138 Request for Approval to Accept Solid Waste
(46) Form C-139 Application For Qualification of Production Restoration Project and Certification

of Approval
(47) Form C-140 Application For Qualification of Well Workover Project and Certification of Approval
[1-1-50...2-1-96; 19.15.13.1100 NMAC - Rn, 19 NMAC 15.M.1100, 06/30/04]

19.15.13.1101 APPLICATION FOR PERMIT TO DRILL, DEEPEN OR PLUG BACK (Form C-101):

A. Before commencing drilling or deepening operations, or before plugging a well back to another zone, the operator of the well must obtain a permit to do so. To obtain such permit, the operator shall submit to the division five copies of form C-101, application for permit to drill, deepen or plug back, completely filled out. If the operator has an approved bond in accordance with 19.15.3.101 NMAC, one copy of the drilling permit will be returned to him on which will be noted the division's approval, with any modification deemed advisable. If the proposal cannot be approved for any reason, the forms C-101 will be returned with the cause for rejection stated thereon.

B. Form C-101 must be accompanied by three copies of form C-102, well location and acreage dedication plat. (See 19.15.13.1102 NMAC.)

C. If the well is to be drilled on state land, submit six copies of form C-101 and four copies of form C-102, the extra copy of each form being for the state land office.

[1-1-64...2-1-96; 19.15.13.1101 NMAC - Rn, 19 NMAC 15.M.1101, 06/30/04]

19.15.13.1102 WELL LOCATION AND ACREAGE DEDICATION PLAT (Form C-102):

A. Form C-102 is a dual purpose form used to show the exact location of the well and the acreage dedicated thereto. The form is also used to show the ownership and status of each lease contained within the dedicated acreage. When there is more than one working interest or royalty owner on a given lease, designation of the majority owner et al. will be sufficient.

B. All information required on form C-102 shall be filled out and certified by the operator of the well except the well location on the plat. This is to be plotted from the outer boundaries of the section and certified by a professional surveyor, registered in the state of New Mexico, or surveyor approved by the division.

C. Form C-102 shall be submitted in triplicate or quadruplicate as provided in 19.15.13.1101 NMAC.

D. Amended form C-102 (in triplicate or quadruplicate) shall be filed in the event there is a change in any of the information previously submitted. The well location need not be certified when filing amended form C-102.

[1-1-65...2-1-96; 19.15.13.1102 NMAC - Rn, 19 NMAC 15.M.1102, 06/30/04]

19.15.13.1103 SUNDRY NOTICES AND REPORTS ON WELLS (Form C-103):

Form C-103 is a dual purpose form to be filed with the appropriate district office of the division to obtain division approval prior to commencing certain operations and also to report various completed operations.

A. Form C-103 as a notice of intention

(1) Form C-103 shall be filed in triplicate by the operator and approval obtain from the division prior to:

(a) Effecting a change of plans from those previously approved on form C-101 or form C-103.

(b) Altering a drilling well's casing program or pulling casing or otherwise altering an existing well's casing installation.

(c) Temporarily abandoning a well.

(d) Plugging and abandoning a well.

(e) Performing remedial work on a well which, when completed, will affect the original status of the well. (This shall include making new perforations in existing wells or squeezing old perforations in existing wells, but is not applicable to new wells in the process of being completed nor to old wells being deepened or plugged back to another zone when such recompletion has been authorized by an approved form C-101, application for permit to drill, deepen or plug back, nor to acidizing, fracturing or cleaning out previously completed wells, nor to installing artificial lift equipment.)

(2) In the case of well plugging operations, the notice of intention shall include a detailed statement of the proposed work, including plans for shooting and pulling casing, plans for mudding, including weight of mud, plans for cementing, including number of sacks of cement and depths of plugs, and the time and date of the proposed plugging operations. If not previously filed, a complete log of the well on form C-105 (See 19.15.13.1105 NMAC.) shall accompany the notice of intention to plug the well; the bond will not be released until this is complied with.

B. Form C-103 as a subsequent report

(1) Form C-103 as a subsequent report of operations shall be filed in accordance with the section of this rule applicable to the particular operation being reported.

(2) Form C-103 is to be used in reporting such completed operations as:

(a) commencement of drilling operations;

(b) casing and cement test;

(c) altering a well's casing installation;

(d) temporary abandonment;

(e) plug and abandon;

(f) plugging back or deepening;

(g) remedial work;

(h) installation of artificial lifting equipment;

(i) change of operator of a drilling well;

(j) such other operations which affect the original status of the well but which are not specifically covered herein.

C. Information to be entered on form C-103, subsequent report, for a particular operation is as follows: Report of commencement of drilling operations. Within ten days following the commencement of drilling operations, the operator of the well shall file a report thereof on form C-103 in triplicate. Such report shall indicate the hour and the date the well was spudded.

D. Report of results of test of casing and cement job; report of casing alteration: A report of casing and cement test shall be filed by the operator of the well within ten days following the setting of each string of casing or liner. Said report shall be filed in triplicate on form C-103 and shall present a detailed description of the test method employed and the results obtained by such test and any other pertinent information required by 19.15.1.107 NMAC. The report shall also indicate the top of the cement and the means by which such top was determined. It shall also indicate any changes from the casing program previously authorized for the well.

E. Report of temporary abandonment: A report of temporary abandonment of a well shall be filed by the operator of the well within thirty days following completion of the work. The report shall be filed in triplicate and shall present a detailed account of the work done on the well, including location and type of plugs used, if any, and status of surface and downhole equipment and any other pertinent information relative to the overall status of the well.

F. Report on plugging of well

(1) A report of plugging operations shall be filed by the operator of the well within 30 days following completion of plugging operations on any well. Said report shall be filed in triplicate on form C-103 and shall include the date the plugging operations were begun and the date the work was completed, a detailed account of the manner in which the work was performed including the depths and lengths of the various plugs set, the nature and quantities of materials employed in the plugging operations including the weight of the mud used, the size and depth of all casing left in the hole and any other pertinent information. (See 19.15.4.201 NMAC - 19.15.4.204 NMAC regarding plugging operations.)

(2) No plugging report will be approved by the division until the pits have been filled and the location levelled and cleared of junk. It shall be the responsibility of the operator to contact the appropriate district office of the division when the location has been so restored in order to arrange for an inspection of the plugged well and the location by a division representative.

G. Report of remedial work - A report of remedial work performed on a well shall be filed by the operator of the well within 30 days following completion of such work. Said report shall be filed in quadruplicate on form C-103 and shall present a detailed account of the work done and the manner in which such work was performed; the daily production of oil, gas and water both prior to and after the remedial operation; the size and depth of shots; the quantity of and, crude, chemical or other materials employed in the operation, and any other pertinent information. Among the remedial work to be reported on form C-103 are the following:

(1) report on shooting, fluid fracturing or chemical treatment of a previously completed well;
(2) report of squeeze job;
(3) report on setting of liner or packer;
(4) report of installation of pumping equipment or gas lift facilities;
(5) report of any other remedial operations which are not specifically covered herein.

H. Report on deepening or plugging back within the same pool - A report of deepening or plugging back shall be filed by the operator of the well within 30 days following completion of such operations on any well. Said report shall be filed in quadruplicate on form C-103 and shall present a detailed account of work done and the manner in which such work was performed. If the well is recompleted in the same pool, it shall also report the daily production of oil, gas, and water both prior to and after recompletion. If the well is recompleted in another pool, forms C-101, C-102, C-104 and C-105 must be filed in accordance with Sections 1101, 1102, 1104 and 1105 of 19.15.13 NMAC.

I. Report of change of operator of a drilling well - A report of change of ownership shall be filed by the new operator of any drilling well within ten days following actual transfer of ownership or responsibility. Said report shall be filed in triplicate on form C-103 and shall include the name and address of both the new operator and the previous operator, the effective date of the change of ownership or responsibility and any other pertinent information. No change in the operator of a drilling well will be approved by the division unless the new operator has an approved bond in accordance with 19.15.3.101 NMAC. (Form C-104 shall be used to report transfer of operator of a completed well; see 19.15.13.1104 NMAC.

J. Other reports on wells - Reports on any other operations which affect the original status of the well but which are not specifically covered herein shall be submitted to the division on form C-103, in triplicate, by the operator of the well ten days following the completion of such operation.
[1-1-65...2-1-96; 19.15.13.1103 NMAC - Rn, 19 NMAC 15.M.1103, 06/30/04]

19.15.13.1104 REQUEST FOR ALLOWABLE AND AUTHORIZATION TO TRANSPORT OIL AND NATURAL GAS (Form C-104):

A. Form C-104 completely filled out by the operator of the well must be filed in quintuplicate before an allowable will be assigned to any newly completed or recompleted well. (A recompleted well shall be considered one which has been deepened or plugged back to produce from a different pool than previously.) Form C-104 must be accompanied by a tabulation of all deviation tests taken on the well as provided by 19.15.3.111 NMAC.

B. The allowable assigned to an oil well shall be effective at 7:00 o'clock a.m. on the date of completion, provided the form C-104 is received by the division during the month of completion. Date of completion shall be that date when new oil is delivered into the stock tanks. Unless otherwise specified by special pool rules, the allowable assigned to a gas well shall be effective at 7:00 o'clock a.m. on the date of connection to a gas transportation facility, as evidenced by an affidavit of connection from the transporter to the division, or the date of receipt of form C-104 by the division, whichever date is later.

C. No allowable will be assigned to any well until a standard unit for the pool in which the well is completed has been dedicated by the operator, or a non-standard unit has been approved by the division, or a standard unit has been communitized or pooled and dedicated to the well.

D. No allowable will be assigned to any well until all forms and reports due have been received by the division and the well is otherwise in full compliance with these rules.

E. Form C-104 with sections I, II, III and VI, completely filled out shall be filed in quintuplicate by the operator of the well in the event there is a change of operator of any producing well, injection well or disposal well, a change in pool designation, lease name or well number, or any other pertinent change in condition of any such well. When filing form C-104 for change of operator, the new operator shall file the form in the above manner, and shall give the name and address of the previous as well as the present operator. The form C-104 will not be approved by the division unless the new operator has an approved bond in compliance with 19.15.3.101 NMAC.

[1-1-65...2-1-96; A, 7-31-97; 19.15.13.1104 NMAC - Rn, 19 NMAC 15.M.1104, 06/30/04]

19.15.13.1105 WELL COMPLETION OR RECOMPLETION REPORT AND LOG (Form C-105):

A. Within 20 days following the completion or recompletion of any well, the operator shall file form C-105 with the division. It must be filed in quintuplicate and each copy accompanied by a summary of all special tests conducted on the well, including drill stem tests. In addition, one copy of all electrical and radio-activity logs run on the well must be filed with form C-105. If the form C-105 with attached log(s) and summaries is not received by the division within the specified 20-day period, the allowable for the well will be withheld until this rule has been complied with.

B. In the case of a dry hole, a complete record of the well on form C-105 with the above attachments shall accompany the notice of intention to plug the well, unless previously filed. The plugging report will not be approved nor the bond released until this rule has been complied with.

C. Form C-105 and accompanying attachments will not be kept confidential by the division unless so requested in writing by the owner of the well. Upon such request, the division will keep these data confidential for 90 days from the date of completion of the well, provided, however, that the report, log(s) and other attached data may, when pertinent, be introduced in any public hearing before the division or its examiners or in any court of law, regardless of the request that they be kept confidential.

[1-1-65...2-1-96; 19.15.13.1105 NMAC - Rn, 19 NMAC 15.M.1105, 06/30/04]

19.15.13.1106 NOTICE OF INTENTION TO UTILIZE AUTOMATIC CUSTODY TRANSFER EQUIPMENT (Form C-106):

Form C-106, when applicable, shall be filed in accordance with Subsection A of 19.15.5.309 NMAC.

[1-1-65...2-1-96; 19.15.13.1106 NMAC - Rn, 19 NMAC 15.M.1106, 06/30/04]

19.15.13.1107 APPLICATION FOR MULTIPLE COMPLETION (Form C-107):

Form C-107, when applicable, shall be filed in accordance with Subsection A of 19.15.3.112 NMAC.

[1-1-65...2-1-96; 19.15.13.1107 NMAC - Rn, 19 NMAC 15.M.1107, 06/30/04]

19.15.13.1108 APPLICATION FOR AUTHORIZATION TO INJECT (Form C-108):

Form C-108 shall be filed in accordance with Subsection B of 19.15.9.701 NMAC.

[1-1-65...2-1-96; 19.15.13.1108 NMAC - Rn, 19 NMAC 15.M.1108, 06/30/04]

19.15.13.1109 APPLICATION FOR DISCOVERY ALLOWABLE AND CREATION OF A NEW POOL (Form C-109):

Form C-109, when applicable, shall be filed in accordance with 19.15.7.509 NMAC.

[9-1-66...2-1-96; 19.15.13.1109 NMAC - Rn, 19 NMAC 15.M.1109, 06/30/04]

19.15.13.1110 No Rule; there is no form C-110 at present.

[1-1-65...2-1-96; 19.15.13.1110 NMAC - Rn, 19 NMAC 15.M.1110, 06/30/04]

19.15.13.1111 GAS TRANSPORTER'S MONTHLY REPORT (Form C-111):

A. Form C-111, gas transporter's monthly report, shall be filed monthly in accordance with the rules below. It shall be postmarked on or before the 15th day of the second month following the month gas was taken. One copy shall be filed with the appropriate district office of the division and one copy with the Santa Fe office of the division. One additional copy shall also be sent to the Hobbs office of the division. Information on sheet no. 2 of form C-111 shall be itemized by pools, by operators and by leases, in alphabetical order.

B. Form C-111 shall be filed each month by the operator of any gas gathering system, gas transportation system, recycling system, fuel system, gas lift system, gas drilling operation, etc. The form shall cover all natural gas, casinghead gas and carbon dioxide gas taken into any such system during the preceding month and shall show the source of the gas and the disposition thereof.

C. Form C-111 shall also be filed each month by the operator of any gasoline plant, cycling plant or other plant at which gasoline, butane, propane, kerosene, oil or other products are extracted from gas within the state of New Mexico. The form shall cover all natural gas, casinghead gas and carbon dioxide gas taken by any such plant during the preceding month and shall show the source of the gas and the disposition thereof. If a plant operator owns more than one plant in a given division district, sheet no. 1 of form C-111 shall be filed for each such plant. In preparing sheet no. 2, the plant operator shall consolidate all requisitions for all plants in the district, itemized in the order described in the Subsection A of 19.15.13.1111 NMAC.

D. Where gas is taken by the producer and utilized by the producer for any of the above uses, the producer shall file Form C-111 itemizing such gas. The producer shall also include this gas on the operator's monthly report, form C-115. Gas used on the lease from which it was produced for consumption in lease houses, treaters, compressors, combustion engines and other similar equipment, or gas which is flared, shall also be included on the Form C-115 but is not to be included on the form C-111.
[1-1-65...2-1-96; 19.15.13.1111 NMAC - Rn, 19 NMAC 15.M.1111, 06/30/04]

19.15.13.1112 TRANSPORTER'S AND STORER'S MONTHLY REPORT (Form C-112):
Each transporter and each storer of crude petroleum oil and liquid hydrocarbons within the state of New Mexico shall file for each calendar month a transporter's and storer's monthly report, form C-112, containing complete information and data indicated by such form respecting stocks of crude petroleum oil and liquid hydrocarbons on hand and receipts and deliveries of crude petroleum oil and liquid hydrocarbons by pipeline and trucks within the state of New Mexico, and receipts and deliveries from leases to storers or refiners; between transporters within the state; between storers and refiners within the state. Form C-112 shall be filed in duplicate and postmarked on or before the 15th day of the second succeeding month.
[1-1-65...2-1-96; 12-31-96; 19.15.13.1112 NMAC - Rn, 19 NMAC 15.M.1112, 06/30/04]

19.15.13.1113 REFINER'S MONTHLY REPORT (Form C-113):
Every refiner of crude petroleum oil within the state of New Mexico shall furnish for each calendar month refiner's monthly report, form C-113, containing the information and data indicated by such form respecting crude petroleum oil and products involved in such refiner's operation during each month. Such report for each month shall be filed in duplicate and be postmarked on or before the 15th day of the next succeeding month.
[1-1-65...2-1-96; 12-31-96; 19.15.13.1113 NMAC - Rn, 19 NMAC 15.M.1113, 06/30/04]

19.15.13.1114 No Rule; there is no form C-114 at present.
[1-1-65...2-1-96; 12-31-96; 19.15.13.1114 NMAC - Rn, 19 NMAC 15.M.1114, 06/30/04]

19.15.13.1115 OPERATOR'S MONTHLY REPORT (Form C-115):

A. Operator's monthly report, form C-115 or form C-115-EDP, shall be filed on each producing lease and each secondary or other enhanced recovery project or pressure maintenance project injection well within the state of New Mexico for each calendar month, setting forth complete information and data indicated on said forms in the order, format and style prescribed by the division director. Oil production from wells which are producing into common storage shall be estimated as accurately as possible on the basis of periodic tests.

B. The reports required to be filed by 19.15.13.1115 NMAC shall be filed by the operator as follows:

(1) Any operator which operates fewer than one hundred (100) wells in the state of New Mexico shall file a C-115 either electronically or by delivery of a printed copy of the report to the oil conservation division at its Santa Fe office on or before the fifteenth (15th) day of the second month following the month of production, or if such day falls on a weekend or holiday, the first workday following the fifteenth.

(2) Any operator which operates one hundred (100) or more wells in the state of New Mexico shall file a C-115 electronically, either by physical delivery of electronically readable media or by electronic transfer of data, to the oil conservation division at its Santa Fe office on or before the fifteenth day of the second month following the month of production, or if such day falls on a weekend or holiday, the first workday following the fifteenth. Any operator otherwise required to file electronically may apply to the division for exemption from this requirement based upon a demonstration that such electronic filing requirement would operate as an economic or other hardship.

(3) If an operator fails to file a C-115 or if the division finds errors in any C-115, the division shall, within thirty (30) days of the appropriate filing date, prepare and send to the operator an error/omission message which identifies the specific well as to which the report has not been filed or is in error and a statement of the error. The operator to whom the error/omission message is addressed shall respond to the division within thirty (30) days acknowledging receipt of the error/omission message and informing the division of the operator's schedule to file the report or correct the error. If the division does not receive the operator's response within thirty (30) days, the division shall send notice to the operator that operator has failed to comply with the provisions of 19.15.13.1115 NMAC and may be subjected to loss of authority to produce from the affected well if the operator does not respond to the division. Willful failure of the operator to respond to the notice and to correct the error or omission may result in the division informing the operator by certified return receipt letter that thirty (30) days from the date of such letter the division will cancel the C-104 authority of operator to produce or inject into the well. Any operator which receives such notice may contact the division and request that the matter of the cancellation of authority to produce or inject be set for hearing before a hearing officer duly appointed by the division. If the division sends certified return receipt correspondence informing the operator of cancellation of authority to produce and the operator does not request a hearing, the division may cancel the authority of the operator to produce the well on the date set forth in the letter.

(4) The electronic filing requirements set forth in Paragraph (2), Subsection B, of 19.15.13.115 NMAC shall be phased in with all operators of three hundred (300) or more wells being required to file electronically for January 1997 production, all operators of two hundred (200) or more wells being required to file electronically for July 1997 production and all operators of one hundred (100) or more wells being required to file electronically for January 1998 production.

[1-1-65…2-1-96; 19.15.13.1115 NMAC - Rn, 19 NMAC 15.M.1115, 06/30/04]

19.15.13.1116 GAS-OIL RATIO TESTS (Form C-116):

Gas-oil ratio tests shall be made and reported on form C-116 as prescribed in 19.15.5.301 NMAC, Gas-Oil Ratio Tests, and any applicable special pool rules. This form shall be submitted in duplicate.

[1-1-65…2-1-96; 19.15.13.1116 NMAC - Rn, 19 NMAC 15.M.1116, 06/30/04]

19.15.13.1117 TANK CLEANING, SEDIMENT OIL REMOVAL, TRANSPORTATION OF MISCELLANEOUS HYDROCARBONS AND DISPOSAL PERMIT (Form C-117-A) AND MONTHLY SEDIMENT OIL DISPOSAL STATEMENT (Form C-117-B):

A. Form C-117-A, tank cleaning, sediment oil removal, transportation of miscellaneous hydrocarbons and disposal permit, shall be submitted to the appropriate district office of the division in quintuplicate and in accordance with Subsections B, C and H of 19.15.5.311 NMAC.

B. Form C-117-B, monthly sediment oil disposal statement, shall be submitted both to the Santa Fe office and the appropriate district office(s) of the division in accordance with Subsection D of 19.15.5.311 NMAC.

[1-1-65...2-1-96; 19.15.13.1117 NMAC - Rn, 19 NMAC 15.M.1117, 06/30/04]

19.15.13.1118 TREATING PLANT OPERATOR'S MONTHLY REPORT (Form C-118):

Form C-118 shall be submitted in duplicate to the appropriate district office of the division in accordance with 19.15.9.711 NMAC, and shall contain all the information required thereon. Column 1 of sheet 1-A of form C-118 entitled "permit number," has reference to the tank cleaning, sediment oil removal, transportation of miscellaneous hydrocarbons and disposal permit, form C-117-A, for each lot of oil picked up for processing.

[1-1-65...2-1-96; 19.15.13.1118 NMAC - Rn, 19 NMAC 15.M.1118, 06/30/04]

19.15.13.1119 CARBON BLACK PLANT MONTHLY REPORT (Form C-119):

Each operator of a carbon black plant within the state of New Mexico shall file for each calendar month the monthly volume of gas received by him from a gasoline extraction plant or plants, and a monthly volume or volumes

of gas received by him from each lease operator delivering natural gas directly to such plant, together with the opening and closing stocks and the production and deliveries by grades of carbon black or other products produced. Such reports shall be filed in duplicate on form C-119, carbon black plant monthly report, and be postmarked on or before the 15th day of the next succeeding month. In addition, form C-111 shall be filed each month in accordance with 19.15.13.1111 NMAC if the carbon black plant operator makes any purchase directly from a lease or operates any gas gathering or transmission system.
[1-1-65...2-1-96; 19.15.13.1119 NMAC - Rn, 19 NMAC 15.M.1119, 06/30/04]

19.15.13.1120 MONTHLY WATER DISPOSAL REPORT (Form C-120-A): Each operator of a salt water disposal system shall report such operations on form C-120-A. Form C-120-A shall be filed in duplicate (one copy with the Santa Fe office and one copy with the appropriate district office) and shall be postmarked no later than the 15th day of the second succeeding month.
[1-1-65...2-1-96; 19.15.13.1120 NMAC - Rn, 19 NMAC 15.M.1120, 06/30/04]

19.15.13.1121 PURCHASER'S NOMINATION FORMS (Form C-121 and Form C-121-A):

A. Unless requested otherwise by the division director, one copy of form C-121, crude oil purchaser's nomination, shall be submitted to the Santa Fe office of the division not later than the 20th day of each odd-numbered month. Nominations shall be filed by each person expecting to purchase oil from producing wells in New Mexico during the second and third succeeding two months. As an example, nominations submitted by the 20th day of July shall indicate the amount of oil the purchaser desires to purchase daily during September and October

B. One copy of form C-121-A, purchaser's gas nomination, shall be submitted to the Santa Fe office of the division by the first day of the month during which the division will consider at the gas allowable hearing the nominations for the purchase of gas from producing wells in New Mexico during the succeeding month. As an example, purchaser's nominations to take gas from a pool during the month of August would be considered by the division at a hearing during July, and should be submitted to the Santa Fe office of the division by July 1.

C. In addition to the monthly gas nominations, twelve-months nominations shall be filed in accordance with the appropriate pool rules.
[1-1-65...2-1-96; 19.15.13.1121 NMAC - Rn, 19 NMAC 15.M.1121, 06/30/04]

19.15.13.1122 MULTIPOINT AND ONE POINT BACK PRESSURE TEST FOR GAS WELL (Form C-122):

A. Gas well test data sheet - san juan basin (form C-122-A)

B. Initial potential test data sheet (form C-122-B)

C. Deliverability test report (form C-122-C)

D. Worksheet for calculation of static column wellhead pressure (P_w) (form C- 122-D)

E. Worksheet for stepwise calculation of (surface) (subsurface) pressure (P_c & P_w) (P_f & P_s) (form C-122-E)

F. Worksheet for calculation of wellhead pressures (P_c or P_w) from known bottomhole pressure (P_f or P_s) (form C-122-F)

G. Worksheet for calculation of status column pressure at gas liquid interface (form C-122-G). The above forms shall be submitted to the appropriate district office of the division in accordance with the provisions of the "manual for back-pressure testing of natural gas wells," or "gas well testing manual for northwest New Mexico", 19.15.6.401 NMAC of the division rules and regulations, and applicable special pool rules and proration orders. These forms shall be submitted in duplicate except form C-122-A which shall be submitted in triplicate.
[1-1-66...2-1-96; 19.15.13.1122 NMAC - Rn, 19 NMAC 15.M.1122, 06/30/04]

19.15.13.1123 REQUEST FOR THE CREATION OF A NEW POOL (Form C-123): The operator of a well which requires the creation of a pool shall be given written instructions by the appropriate district office regarding the filing of form C-123 in duplicate.
[1-1-65...2-1-96; 19.15.13.1123 NMAC - Rn, 19 NMAC 15.M.1123, 06/30/04]

19.15.13.1124 RESERVOIR PRESSURE REPORT (Form C-124):
Form C-124 shall be submitted in triplicate and shall be used to report bottom hole pressures as required under the provisions of 19.15.5.302 NMAC and any applicable special pool rules.
[1-1-65...2-1-96; 19.15.13.1124 NMAC - Rn, 19 NMAC 15.M.1124, 06/30/04]

19.15.13.1125 GAS WELL SHUT-IN PRESSURE TESTS (Form C-125):
Form C-125 shall be submitted in triplicate and shall be used to report shut-in pressure tests on gas wells as required under the provisions of 19.15.6.402 NMAC and any applicable special pool rules.
[1-1-65...2-1-96; 19.15.13.1125 NMAC - Rn, 19 NMAC 15.M.1125, 06/30/04]

19.15.13.1126 PERMIT TO TRANSPORT RECOVERED LOAD OIL (Form C-126):
Form C-126 shall be submitted in quadruplicate to the appropriate district office of the division and shall be used in conformance with 19.15.7.508 NMAC.
[1-1-65...2-1-96; 19.15.13.1126 NMAC - Rn, 19 NMAC 15.M.1126, 06/30/04]

19.15.13.1127 REQUEST FOR ALLOWABLE CHANGE (Form C-127):
One copy of form C-127 shall be filed by the oil producer with the appropriate district office of the division not later than the 10th day of the month preceding the month for which oil well allowable changes are requested.
[1-1-65...2-1-96; 19.15.13.1127 NMAC - Rn, 19 NMAC 15.M.1127, 06/30/04]

19.15.13.1128 FORMS REQUIRED ON FEDERAL LAND:
A. Federal forms shall be used in lieu of state forms when filing application for permit to drill, deepen or plug back and sundry notices and reports on wells and well completion or recompletion report and log for wells on federal lands in New Mexico. However, it shall be the duty of the operator to submit two extra copies of each of such forms to the BLM, which, upon approval, will transmit same to the division. The following BLM forms will be used in lieu of division forms by operators of wells on federal land:

BLM Form No	Title of Form (Same for both agencies)	Form No.
3160-3 (Nov. 1993)	Application for Permit to Drill, Deepen or Plug Back	C-101
3160-5 (Nov. 1983)	Sundry Notices and Reports on Wells	C-103
3160-4 (Nov. 1983)	Well Completion or Recompletion Report and Log	C-105

B. The above forms as may be revised are the only forms that may be submitted in place of division forms.
C. After a well is completed and ready for pipeline connection, division form C-104 shall be filed along with a copy of form C-105 or BLM form No. 3160-4, whichever is applicable, with the division on any and all wells drilled in the state, regardless of land status. Further, all reports and forms as required under the preceding rules of this section of the rules and regulations that pertain to production must be filed on the proper oil conservation division form as set out in said rule - no other forms will be accepted.
D. Failure to comply with the provisions of this rule will result in the cancellation of form C-104 for the affected well or wells.
[1-1-65...2-1-96; 19.15.13.1128 NMAC - Rn, 19 NMAC 15.M.1128, 06/30/04]

19.15.13.1129 APPLICATION FOR EXCEPTION TO NO-FLARE RULE 306 (Form C-129):
Form C-129, when applicable, shall be filed in accordance with 19.15.5.306 NMAC.
[9-1-72...2-1-96; 19.15.13.1129 NMAC - Rn, 19 NMAC 15.M.1129, 06/30/04]

19.15.13.1130 NOTICE OF DISCONNECTION (Form C-130):
A. Form C-130, notice of disconnection, shall be filed in triplicate with the division by the operator of the well as provided in 19.15.6.407 NMAC.
B. The operator shall state, to the best of his knowledge, the reasons for disconnecting any gas well from gas transportation facilities.
C. The division shall furnish the New Mexico public service commission with any form C-130 indicating that a disconnected gas well may or will be reconnected to a gas transportation facility for ultimate distribution to consumers outside of the state of New Mexico.
[8-23-77...2-1-96; 19.15.13.1130 NMAC - Rn, 19 NMAC 15.M.1130, 06/30/04]

19.15.13.1131 MONTHLY GAS STORAGE REPORT (Form C-131-A) ANNUAL LPG STORAGE REPORT (Form C-131-B):
A. Each operator of an underground natural gas storage project shall report its operation monthly on form C-131-A. Form C-131-A shall be filed in duplicate (one copy to the appropriate district office) and shall be postmarked not later than the 24th day of the next succeeding month.
B. Each operator of an underground liquefied petroleum gas storage project approved by the division shall report its operation annually on form C-131-B.
[7-1-81...2-1-96; 19.15.13.1131 NMAC - Rn, 19 NMAC 15.M.1131, 06/30/04]

19.15.13.1132 [RESERVED].

19.15.13.1133 AUTHORIZATION TO MOVE PRODUCED WATER:
A. Each person who is a transporter of produced water shall obtain approval of form C-133, authorization to move produced water, in accordance with Subsection C of 19.15.9.709 NMAC. prior to any such transportation.
B. Approval of a single form C-133 is valid for all leases served by such transporter.
[2-1-82...2-1-96; 19.15.13.1133 NMAC - Rn, 19 NMAC 15.M.1133, 06/30/04]

19.15.13.1134 [RESERVED].

19.15.13.1135 GAS WELL CONNECTION, RECONNECTION OR DISCONNECTION NOTICE:
Every gas transporter accepting gas for delivery from a wellhead or central point of delivery shall notify the division within thirty (30) days of a new connection or reconnection to or disconnection from the gathering or transportation system by filing form C-135 in duplicate with the appropriate district office of the division.
[2-1-91...2-1-96; 19.15.13.1135 NMAC - Rn, 19 NMAC 15.M.1135, 06/30/04]

19.15.13.1136 APPLICATION FOR APPROVAL TO USE AN ALTERNATE GAS MEASUREMENT METHOD (Form C-136):
A. Form C-136 shall be used to request and approve use of an alternate procedure for measuring gas production from a well which is not capable of producing more than 15 MCFD (Paragraph (1) of Subsection B of 19.15.6.403 NMAC or for any well which has a producing capacity of 100 MCFD or less and is on a multi-well lease (Paragraph (2) of Subsection B of 19.15.6.403 NMAC.)
B. All applicable information required on form C-136 shall be filled out with the required supplemental information attached, and shall be submitted in quadruplicate to the appropriate district office of the division.
[12-23-91; 2-1-96; 19.15.13.1136 NMAC - Rn, 19 NMAC 15.M.1136, 06/30/04]

HISTORY OF 19.15.13 NMAC:
Pre-NMAC History: The material in this Part was derived from that previously filed with the State Records Center and Archives:
Rule 1100, General, 1/8/82.

Rule 1100, Amendment No. 1, General M-Reports, 1/27/82.
Rule 1100, Amendment No. 2, General M-Reports, 5/6/82.
Rule 1100, General M-Reports, 3/17/86.
Rule 1100, General, 10/11/89.
Rule 1100, General, 2/5/91.
Rule 1101, Application for Permit to Drill, Deepen, or Plug Back (Form C-101), 1/8/82.
Rule 1101, Application for Permit to Drill, Deepen, or Plug Back (Form C-101), 2/5/91.
Rule 1102, Well Location and Acreage Dedication Plat (Form C-102), 1/8/82.
Rule 1102, Well Location and Acreage Dedication Plat (Form C-102), 3/15/89.
Rule 1102, Well Location and Acreage Dedication Plat (Form C-102), 2/5/91.
Rule 1103, Sundry Notices and Reports on Wells (Form C-103), 1/8/82.
Rule 1103, Sundry Notices and Reports on Wells (Form C-103), 2/5/91.
Rule 1104, Request for Allowable and Authorization to Transport Oil and Natural Gas (Form C-104), 1/8/82.
Rule 1104, Request for Allowable and Authorization to Transport Oil and Natural Gas (Form C-104), 2/5/91.
Rule 1105, Well Completion or Recompletion Report and Log (Form C-105), 1/8/82.
Rule 1105, Well Completion or Recompletion Report and Log (Form C-105), 2/5/91.
Rule 1106, Notice of Intention to Utilize Automatic Custody Transfer Equipment (Form C-106), 1/8/822.
Rule 1106, Notice of Intention to Utilize Automatic Custody Transfer Equipment (Form C-106), 2/5/91.
Rule 1107, Application for Multiple Completion (Form C-107), 1/8/82.
Rule 1107, Amendment No. 1, Application for Multiple Completion (Form C-107), 1/27/82.
Rule 1107, Application for Multiple Completion (Form C-107), 2/5/91.
Rule 1108, Application for Authorization to Inject (Form C-108), 1/8/82.
Rule 1108, Application for Authorization to Inject (Form C-108), 2/5/91.
Rule 1109, Application for Discovery Allowable and Creation of a New Pool (Form C-109), 1/8/82.
Rule 1109, Application for Discovery Allowable and Creation of a New Pool (Form C-109), 2/5/91.
Rule 1111, Gas Transporter's Monthly Report (Form C-111), 1/8/82.
Rule 1111, Gas Transporter's Monthly Report (Form C-111), 3/17/86.
Rule 1111, Gas Transporter's Monthly Report (Form C-111), 2/5/91.
Rule 1112, Transporter's and Storer's Monthly Report (Form C-112), 1/8/82.
Rule 1112, Transporter's and Storer's Monthly Report (Form C-112), 2/5/91.
Rule 1113, Refiner's Monthly Report (Form C-113), 1/8/82.
Rule 1113, Refiner's Monthly Report (Form C-113), 10/11/89.
Rule 1113, Refiner's Monthly Report (Form C-113), 2/5/91.
Rule 1115, Operator's Monthly Report (Form C-115), 1/8/82.
Rule 1115, Operator's Monthly Report (Form C-115), 2/5/91.
Rule 1116, Gas-Oil Ratio Tests (Form C-116), 1/8/82.
Rule 1116, Gas-Oil Ratio Tests (Form C-116), 2/5/91.
Rule 1117, Sediment Oil Disposition Permits (Form C-117-A and C-117-B), 1/8/82.
Rule 1117, Amendment No. 1, Tank Cleaning, Sediment Oil Removal, Transportation of Miscellaneous Hydrocarbons and Disposal Permit (Form C-117-A) and Monthly Sediment Oil Disposal Statement (Form C-117-B), 1/27/82.
Rule 1117, Tank Cleaning, Sediment Oil Removal, Transportation of Miscellaneous Hydrocarbons and Disposal Permit (Form C-117-A) and Monthly Sediment Oil Disposal Statement (Form C-117-B), 2/5/91.
Rule 1118, Treating Plant Operator's Monthly Report (Form C-118), 1/8/82.
Rule 1118, Amendment No. 1, Treating Plant Operator's Monthly Report (Form C-118), 1/27/82.
Rule 1118, Treating Plant Operator's Monthly Report (Form C-118), 2/5/91.
Rule 1119, Carbon Black Plant Monthly Report (Form C-119), 1/11/82.
Rule 1119, Carbon Black Plant Monthly Report (Form C-119), 2/5/91.
Rule 1120, Monthly Water Disposal Report (Form C-120), 1/11/82.
Rule 1120, Monthly Water Disposal Report (Form C-120), 2/5/91.

Rule 1121, Purchaser’s Nomination Forms (Form C-121 and Form C-121-A), 1/11/82.
Rule 1121, Purchaser’s Nomination Forms (Form C-121 and Form C-121-A), 2/5/91.
Rule 1122, Multipoint and One Point Back Pressure Test for Gas Well (Form C-122), 1/11/82.
Rule 1122, Multipoint and One Point Back Pressure Test for Gas Well (Form C-122), 10/11/89.
Rule 1122, Multipoint and One Point Back Pressure Test for Gas Well (Form C-122), 2/5/91.
Rule 1123, Request for the Creation of a New Pool (Form C-123), 1/11/82.
Rule 1123, Request for the Creation of a New Pool (Form C-123), 2/5/91.
Rule 1124, Reservoir Pressure Report (Form C-124), 1/11/82.
Rule 1124, Reservoir Pressure Report (Form C-124), 2/5/91.
Rule 1125, Gas Well Shut-In Pressure Tests (Form C-125), 1/11/82.
Rule 1125, Amendment No. 1, Gas Well Shut-In Pressure Tests (Form C-125), 2/23/84.
Rule 1125, Gas Well Shut-In Pressure Tests (Form C-125), 2/5/91.
Rule 1126, Permit to Transport Recovered Load Oil (Form C-126), 1/11/82.
Rule 1126, Permit to Transport Recovered Load Oil (Form C-126), 2/5/91.
Rule 1127, Request for Allowable Change (Form C-127), 1/11/82.
Rule 1127, Request for Allowable Change (Form C-127), 2/5/91.
Rule 1128, Forms Required on Federal Land, 1/11/82.
Rule 1128, Forms Required on Federal Land, 2/5/91.
Rule 1129, Application for Exception to No-Flare Rule306 (Form C-129), 1/11/82.
Rule 1129, Application for Exception to No-Flare Rule306 (Form C-129), 2/5/91.
Rule 1130, Notice of Disconnection (Form C-130), 1/11/82.
Rule 1130, Notice of Disconnection (Form C-130), 2/5/91.
Rule 1131, Monthly Gas Storage Report (Form C-131-A) Annual LPG Storage Report (Form C-131-B), 1/11/82.
Rule 1131, Monthly Gas Storage Report (Form C-131-A) Annual LPG Storage Report (Form C-131-B), 2/5/91.
Rule 1133, Authorization to Move Produced Water, 1/27/82.
Rule 1133, Authorization to Move Produced Water, 2/5/91.
Rule 1135, Gas Well Connection, Reconnection or Disconnection Notice, 1/14/91.
Rule 1135, Gas Well Connection, Reconnection or Disconnection Notice, 2/5/91.

History of Repealed Material: [RESERVED].

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 14 PROCEDURE

19.15.14.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department, Oil Conservation Division, 2040 S. Pacheco St., Santa Fe, New Mexico 87505 (505) 827-7131.
[2-1-96; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1, 8-29-03]

19.15.14.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico.
[2-1-96; 19.15.14 NMAC - Rn, 19 NMAC 15.N.2, 8-29-03]

19.15.14.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the Oil and Gas Act which grants the oil conservation division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights and the disposition of wastes resulting from oil and gas operations.
[2-1-96; 19.15.14 NMAC - Rn, 19 NMAC 15.N.3, 8-29-03]

19.15.14.4 DURATION: Permanent.
[2-1-96; 19.15.14 NMAC - Rn, 19 NMAC 15.N.4, 8-29-03]

19.15.14.5 EFFECTIVE DATE: February 1, 1996 [unless a later date is cited at the end of a section.]
[2-1-96; 19.15.14 NMAC - Rn, 19 NMAC 15.N.5, 8-29-03]

19.15.14.6 OBJECTIVE: The objective of this Part is to set forth general provisions and definitions pertaining to the authority of the oil conservation division and the oil conservation commission pursuant to the Oil and Gas Act, NMSA 1978, Sections 70-2-1 through 70-2-38.
[2-1-96; 19.15.14 NMAC - Rn, 19 NMAC 15.N.6, 8-29-03]

19.15.14.7 DEFINITIONS: [RESERVED]

19.15.14.8 - 1200 [RESERVED]

19.15.14.1201 RULEMAKING PROCEEDINGS:

A. Before any rule, including revocation or amendment of an existing rule, shall be made by the division or commission, a public hearing before the commission or a duly appointed division examiner shall be held at such time and place as may be prescribed by the commission in accordance with Section 10-15-1 NMSA 1978.

B. When the commission, the division, an operator or any interested person applies to adopt, amend or rescind any rule, such application shall constitute a request for rulemaking, and the division shall publish notice of the proposed rulemaking:

(1) one time in a newspaper of general circulation in the counties in New Mexico affected by the proposed rule (or if the proposed rule will be of statewide application, in a newspaper of general circulation in this state), with the publication date not less than 20 days prior to the date set for the public hearing;

(2) on the applicable docket for the commission or division hearing at which the matter will be heard, which shall be sent by regular mail or electronic mail to all who have requested such notice, not less than 20 days prior to the public hearing;

(3) one time in the New Mexico register, with the publication date not less than 10 days prior to the public hearing; and

(4) by posting to the division's website not less than 20 days prior to the public hearing.

C. If the rule proposed to be adopted, amended or rescinded is of statewide application, the hearing shall be conducted before the commission in the first instance unless the division director otherwise directs.

D. 19.15.14.1201 NMAC shall not apply to special pool rules, which may be adopted, amended or rescinded in adjudicatory proceedings subject to the notice provisions of Sections 1204 and 1207 of 19.15.14 NMAC.

[1-1-50...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1201, 8-29-03; A, 06/15/04]

19.15.14.1202 EMERGENCY ORDERS AND RULES:

A. Notwithstanding any other provision of 19.15 NMAC, in the event an emergency is found to exist by the division or commission, which requires adoption of a rule or the issuance of an order without a hearing, such emergency rule or order shall have the same validity as if a hearing had been held before the division or commission after due notice. Such emergency rule or order shall remain in force no longer than 15 days from its effective date.

B. Notwithstanding any other provision of 19.15.14 NMAC, in the event an emergency is found to exist by the division or commission, a hearing may be conducted upon any application within less than twenty-three (23) days after the filing thereof, and notice of such hearing may be given within such lesser time than twenty (20) days as the director of the division shall order.

[1-1-50...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1201, 8-29-03; A, 06/15/04]

19.15.14.1203 INITIATING A HEARING:

A. The division, the attorney general, any operator or producer or any other person may apply for a hearing. The application shall be signed by the person seeking the hearing or by an attorney representing that person. Two copies of the application must be filed and shall state:

(1) the name of the applicant;

(2) the name or general description of the common source or sources of supply or the area affected by the order sought;

(3) briefly, the general nature of the order or rule sought;

(4) a list of the names and addresses of persons to whom notice has been sent;

(5) a proposed notice advertisement for publication; and

(6) any other matter required by these rules or order of the division.

B. Applications for hearing before the division or commission must be in writing and received by the division at least 23 days in advance of the hearing on that application.

[1-1-50...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1203, 8-29-03]

19.15.14.1204 PUBLICATION OF NOTICE OF HEARING:

A. The division shall give notice of each hearing before the commission or a division examiner by (1) posting notice on the division's website, and (2) delivering notice by ordinary first class United States mail or electronic mail to each person who has requested in writing to be notified of such hearings.

B. In addition, the division shall give notice of each hearing before the commission by publication once in accordance with the requirements of Chapter 14, Article 11 NMSA 1978, in a newspaper of general circulation in the counties that are affected by the application or, if the effect of the application will be statewide, in a newspaper of general circulation in this state.

[1-1-50...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1204, 8-29-03; A, 06/15/04]

19.15.14.1205 CONTENTS OF NOTICE OF HEARING:

A. Published notices shall be issued in the name of "The State of New Mexico" and signed by the director of the division, and the seal of the commission shall be impressed thereon.

B. The notice shall specify: whether the case is set for hearing before the commission or a division examiner; the number and style of the case; the time and place of hearing; and the general nature of the application. The notice shall also state the name of the applicant. If the application seeks to adopt, revoke or amend special pool rules, establish or alter a non-standard unit, permit an unorthodox location, or establish or affect the allowable of any well or proration unit, the notice shall specify each pool or common source of supply that may be affected if the

application is granted. If the application seeks compulsory pooling or statutory unitization, the notice shall contain a legal description of the spacing unit or geographical area sought to be pooled or unitized. In all other cases, the notice shall reasonably identify the subject matter so as to alert persons who may be affected if the application is granted.
[1-1-50...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1205, 8-29-03; A, 06/15/04]

19.15.14.1206 [RESERVED] [Formerly "PREPARATION OF NOTICES"]

19.15.14.1207 NOTICE REQUIREMENTS FOR SPECIFIC ADJUDICATIONS:

A. Applicants for the following adjudicatory hearings before the division or commission shall give notice, in addition to that required by 19.15.14.1204 NMAC, as set forth below:

(1) Compulsory pooling and statutory unitization.

(a) Notice shall be given to any owner of an interest in the mineral estate of any portion of the lands proposed to be pooled or unitized whose interest is evidenced by a written document of conveyance either of record or known to the applicant at the time of filing the application and whose interest has not been voluntarily committed to the area proposed to be pooled or unitized (other than a royalty interest subject to a pooling or unitization clause).

(b) When notice is given as required in Subparagraph (a) of Paragraph (1) of Subsection A of 19.15.14.1207 NMAC, of an application for compulsory pooling and the application is unopposed by those owners located, the applicant may file under the following alternate procedure. The application shall include the following:

(i) a statement that no opposition is expected and why;

(ii) a map outlining the spacing unit(s) to be pooled, showing the nature and percentage of the ownership interests and location of the proposed well;

(iii) the names and last known addresses of the interest owners to be pooled and the nature and percent of their interests and an attestation that a diligent search has been conducted of all public records in the county where the well is located and of phone directories, including computer searches;

(iv) the names of the formations and pools to be pooled (note: this procedure does not apply to an application to pool a spacing unit larger in size than provided in 19.15.3.104 NMAC or applicable special pool orders);

(v) a statement as to whether the pooled unit is for gas and/or oil production (see note under item (iv) of Subparagraph (b) of Paragraph (1) of Subsection A of 19.15.14.1207 NMAC;

(vi) written evidence of attempts made to gain voluntary agreement including but not limited to copies of relevant correspondence;

(vii) proposed overhead charges (combined fixed rates) to be applied during drilling and production operations along with the basis for such charges;

(viii) the location and proposed depth of the well to be drilled on the pooled units; and

(ix) a copy of the authorization for expenditure (AFE) to be submitted to the interest owners in the well.

(c) All submittals required shall be accompanied by sworn and notarized statements by those persons who prepared the submittals, attesting that the information is correct and complete to the best of their knowledge and belief.

(d) All unopposed pooling applications will be set for hearing. If the division finds the application complete, the information submitted with the application will constitute the record in the case, and an order will be issued based on the record.

(e) At the request of any interested person or upon the division's own initiative, any pooling application submitted shall be set for full hearing with oral testimony by the applicant.

(2) Unorthodox well locations.

(a) Definition "affected persons" are the following persons owning interests in the adjoining spacing units:

(i) the division-designated operator;

(ii) in the absence of an operator, any lessee whose interest is evidenced by a written document of conveyance either of record or known to the applicant as of the date the application is filed; and

(iii) in the absence of an operator or lessee, any mineral interest owner whose interest is evidenced by a written document of conveyance either of record or known to the applicant as of the date the application was filed. In the event the operator of the proposed unorthodox well is also the operator of an existing adjoining spacing unit and ownership is not common between the adjoining spacing unit and the spacing unit containing the proposed unorthodox well, then "affected persons" include all working interest owners in that spacing unit.

(b) If the proposed location is unorthodox by being located closer to the outer boundary of the spacing unit than permitted by 19.15.3.104 NMAC or applicable special pool orders, notice shall be given to the affected persons in the adjoining spacing units towards which the unorthodox location encroaches.

(c) If the proposed location is unorthodox by being located in a different quarter-quarter section or quarter section than provided in special pool orders, notice shall be given to all affected persons.

(3) Non-standard proration unit. Notice shall be given to all owners of interests in the mineral estate to be excluded from the proration unit in the quarter-quarter section (for 40-acre pools or formations), the one-half quarter section (for 80-acre pools or formations), the quarter section (for 160-acre pools or formations), the half section (for 320-acre pools or formations), or section (for 640-acre pools or formations) in which the non-standard unit is located and to such other persons as required by the division.

(4) Special pool orders regulating or affecting a specific pool.

(a) Except for non-standard proration unit applications, if the application involves changing the amount of acreage to be dedicated to a well, notice shall be given to:

(i) all division-designated operators in the pool; and

(ii) all owners of interests in the mineral estate in existing spacing units with producing wells.

(b) If the application involves other matters, notice shall be given to:

(i) all division-designated operators in the pool; and

(ii) all division-designated operators of wells within the same formation as the pool and within one (1) mile of the outer boundary of the pool which have not been assigned to another pool.

(5) Special orders regarding any division-designated potash area. Notice shall be given to all potash lessees, oil and gas operators, oil and gas lessees and unleased mineral interest owners within the designated potash area. (a) through (d). The material on unorthodox locations was moved to Paragraph (2) of Subsection A of 19.15.14.1207 NMAC.

(6) Downhole commingling. Notice shall be given to all owners of interests in the mineral estate in the spacing unit if ownership is not common for all commingled zones within the spacing unit.

(7) Surface disposal of produced water or other fluids. Notice shall be given to any surface owner within one-half mile of the site.

(8) Surface commingling. Notice shall be given as prescribed in 19.15.5.303 NMAC.

(9) Adjudications not listed above. Notice shall be given as required by the division.

B. Type and content of notice. Any notice required by 19.15.14.1207 NMAC shall be sent by certified mail, return receipt requested, to the last known address of the person to whom notice is to be given at least 20 days prior to the date of hearing of the application and shall include a copy of the application, the date, time and place of the hearing, and the means by which protests may be made. When an applicant has been unable to locate all persons entitled to notice after exercising reasonable diligence, notice shall be provided by publication, and proof of publication shall be submitted at the hearing. Such proof shall consist of a copy of the legal advertisement that was published in a newspaper of general circulation in the county or counties in which the property is located or if the effect of the application is statewide, in a newspaper of general circulation in this state.

C. At the hearing, the applicant shall make a record, either by testimony or affidavit signed by the applicant or its authorized representative, that: (a) the notice provisions of 19.15.14.1207 NMAC have been complied with; (b) the applicant has conducted a good-faith diligent effort to find the correct address of all persons entitled to notice; and (c) pursuant to 19.15.14.1207 NMAC notice has been given at that correct address as required by 19.15.14.1207 NMAC. In addition, the record shall contain the name and address of each person to whom notice was sent and, where proof of receipt is available, a copy of the proof.

D. Evidence of failure to provide notice as required in 19.15.14.1207 NMAC may, upon proper showing, be considered cause for reopening the case.

E. In the case of an administrative application where the required notice was sent and a timely filed protest was made, the division shall notify the applicant and the protesting party in writing that the case has been set for hearing and the date, time and place of the hearing. No further notice is required.

[1-1-86…2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1207, 8-29-03; A, 06/15/04]

19.15.14.1208 PLEADINGS, COPIES AND PRE-HEARING STATEMENTS:

A. For pleadings and correspondence filed in cases pending before a division examiner, two copies must be filed with the division. For pleadings and correspondence filed in cases pending before the commission, five copies must be filed with the division. The division will disseminate copies to the members of the commission. The party filing the pleading or correspondence shall at the same time either hand deliver or transmit by facsimile or electronic mail to any party who has entered an appearance therein or the attorneys of record, a copy of the pleading or correspondence. An appearance of any interested party shall be made either by letter addressed to the division or in person at any proceeding before the commission or before a division examiner, with notice of such appearance to the parties of record.

B. Parties to an adjudicatory proceeding who intend to present evidence at the hearing shall file a pre-hearing statement, and serve a copy thereof on opposing counsel of record in the manner provided in Subsection A of 19.15.14.1208 NMAC, at least four days in advance of a scheduled hearing before the division or the commission, but in no event later than the Friday preceding the scheduled hearing. The statement must include: the names of the parties and their attorneys; a concise statement of the case; the names of all witnesses the party will call to testify at the hearing; the approximate time the party will need to present its case; and identification of any procedural matters that are to be resolved prior to the hearing.

[9-15-55...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1208, 8-29-03; A, 06/15/04]

19.15.14.1209 CONTINUANCE OF HEARING WITHOUT NEW SERVICE:

Any hearing before the commission or a division examiner held after due notice may be continued by the person presiding at such hearing to a specified time and place without the necessity of notice of the same being again served or published.

[1-1-50...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1209, 8-29-03; A, 06/15/04]

19.15.14.1210 CONDUCT OF HEARINGS:

A. Hearings before the commission or a division examiner shall be conducted without rigid formality. A transcript of testimony shall be taken and preserved as a part of the permanent records of the division. Any person testifying shall do so under oath. However, relevant unsworn comments and observations by any interested party will be designated as such and included in the record.

B. The division director may order the parties to file prepared written testimony in advance of the hearing for cases pending before the commission. The witness must be present at the hearing and shall adopt, under oath, the prepared written testimony, subject to cross-examination and motions to strike unless the presence of the witness at hearing is waived upon notice to and without objection of the parties. Pages of the prepared written testimony shall be numbered and contain line numbers on the left-hand side.

[1-1-50...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1210, 8-29-03]

19.15.14.1211 POWER TO REQUIRE ATTENDANCE OF WITNESSES AND PRODUCTION OF EVIDENCE:

A. The commission or any member thereof and the division director or the division director's authorized representative have statutory power to subpoena witnesses and to require the production of books, papers, and records in any proceeding before the commission or division. A subpoena will be issued for attendance at a hearing upon the written request of any party. In case of the failure of a person to comply with the subpoena issued, an attachment of the person may be issued by the district court of any district in the state. Any person found guilty of testifying falsely at any hearing may be punished for contempt.

B. A pre-hearing conference may be held prior to the hearing on the merits in cases pending before the division or the commission either upon request of a party or upon notice by the division director or a division examiner. The pre-hearing conference will be to narrow issues, eliminate or resolve other preliminary matters and to encourage settlement. The division director or the division examiner may issue a pre-hearing order following the pre-hearing conference.

[1-1-50…2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1211, 8-29-03]

19.15.14.1212 RULES OF EVIDENCE AND EXHIBITS:

A. Full opportunity shall be afforded all interested parties at a hearing before the commission or division examiner to present evidence and to cross-examine witnesses. In general, the rules of evidence applicable in a trial before a court without a jury shall be applicable, provided that such rules may be relaxed, where, by so doing, the ends of justice will be better served. No order shall be made that is not supported by competent legal evidence.

B. Parties introducing exhibits at hearings before the commission or a division examiner must provide a complete set of exhibits for the court reporter, each commissioner or division examiner and other parties of record.

[1-1-50…2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1212, 8-29-03]

19.15.14.1213 DIVISION EXAMINERS' QUALIFICATIONS AND APPOINTMENT:

The division director shall appoint division examiners. Each division examiner so appointed shall be a member of the staff of the division. Each individual appointed as a division examiner must have at least six years of experience as a geologist, petroleum engineer or licensed lawyer, or at least two years of such experience and a college degree in geology, engineering or law; provided however, that nothing herein shall prevent any member of the commission from serving as a division examiner.

[9-15-55...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1213, 8-29-03]

19.15.14.1214 REFERRAL OF CASES TO DIVISION EXAMINERS:

The division director may refer any matter or proceeding to a division examiner for hearing in accordance with these rules. The division examiner appointed to hear any specific case shall be designated by name.

[9-15-55...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1214, 8-29-03]

19.15.14.1215 DIVISION EXAMINER'S POWER AND AUTHORITY:

The division director may limit the powers and duties of the division examiner in any particular case to such issues or to the performance of such acts as the director deems expedient; however, subject only to such limitations as may be ordered by the director, the division examiner to whom any matter is referred under these rules shall have full authority to hold hearings on such matter in accordance with these rules. The division examiner shall have the power to perform all acts and take all measures necessary or proper for the efficient and orderly conduct of such hearing, including administering oaths to witnesses and receiving testimony and exhibits offered in evidence subject to such objections as may be imposed. The division examiner shall cause a complete record of the proceedings to be made and transcribed and shall certify same to the director as hereinafter provided.

[9-15-55...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1215, 8-29-03]

19.15.14.1216 HEARINGS THAT MUST BE HELD BEFORE COMMISSION:

Notwithstanding any other provisions of these rules, the hearing on any matter shall be held before the commission if:

A. it is a hearing pursuant to Section 70-2-13 NMSA 1978; or

B. the division director desires the commission to hear the matter.

[9-15-55...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1216, 8-29-03]

19.15.14.1217 [RESERVED]
[9-15-55...2-1-96; Repealed 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1217, 8-29-03]

19.15.14.1218 REPORT AND RECOMMENDATIONS FROM DIVISION EXAMINER'S HEARING: Upon the conclusion of any hearing before a division examiner, the division examiner shall promptly consider the proceedings in such hearing, and based upon the record of such hearing the division examiner shall prepare a written report with recommendations for the disposition of the matter or proceeding by the division. Such report shall either be accompanied by a proposed order or shall be in the form of a proposed order and shall be submitted to the division director with the certified record of the hearing.
[9-15-55...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1218, 8-29-03]

19.15.14.1219 DISPOSITION OF CASES HEARD BY DIVISION EXAMINERS: After receipt of the report of the division examiner, the division director shall enter the division's order disposing of the matter.
[9-15-55…2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1219, 8-29-03]

19.15.14.1220 HEARING BEFORE COMMISSION AND STAYS OF DIVISION ORDERS:

A. When an order has been entered by the division pursuant to a hearing held by a division examiner, a party of record adversely affected by the order has the right to have the matter heard de novo before the commission, provided that within 30 days from the date the order is issued the party files with the division a written application for such hearing. If an application is filed, the matter or proceeding shall be set for hearing before the commission.

B. Any party requesting a stay of a division order must file the request with the division and provide copies of the request to the parties of record or their attorneys in the case at the time the request is filed. The request must have attached a proposed stay order. The director may grant stays under other circumstances if such a stay is necessary to prevent waste, protect correlative rights, protect public health and the environment or prevent gross negative consequences to any affected party.

C. Any party of record adversely affected by the order issued by the commission after hearing may apply for rehearing pursuant to 19.15.14.1222 NMAC.
[9-15-55...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1220, 8-29-03]

19.15.14.1221 COPIES OF COMMISSION AND DIVISION ORDERS: Within 10 days after an order, including any order granting or refusing rehearing or order following rehearing, has been issued, a copy of such order shall be mailed by the division to each party or its attorney of record. For purposes of 19.15.14.1221 NMAC only, the parties to a case are the applicant and each person who has entered an appearance in the case, in person or by attorney, either by filing a protest, pleading or notice of appearance with the division or by entering an appearance on the record at a hearing.
[9-15-55...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1221, 8-29-03; A, 06/15/04]

19.15.14.1222 REHEARINGS: Within 20 days after entry of any order of the commission any party of record adversely affected thereby may file with the division an application for rehearing on any matter determined by such order, setting forth the respect in which the order is believed to be erroneous. The commission shall grant or refuse any such application in whole or in part within 10 days after it is filed and failure to act within such period shall be deemed a refusal and a final disposition of such application. In the event the rehearing is granted, the commission may enter a new order after rehearing as may be required under the circumstances.
[1-1-50...2-1-96; A, 7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1222, 8-29-03]

19.15.14.1223 EX PARTE COMMUNICATIONS:

A. In an adjudicatory proceeding, except for filed pleadings, at no time after the filing of an application for hearing shall any party, interested participant or their representatives communicate regarding the issues involved in the application with any commissioner or the division examiner appointed to hear the case when all other parties of record to the proceedings have not had the opportunity to be present.

B. The prohibition in Subsection A of 19.15.14.1223, above, does not apply to those applications that are believed by the applicant to be unopposed. However, in the event that an objection is filed in a case previously believed to be unopposed, the prohibition in A, above, is immediately applicable.
[7-15-99; 19.15.14 NMAC - Rn, 19 NMAC 15.N.1223, 8-29-03]

HISTORY OF 19.15.14 NMAC:
Pre-NMAC History: The material in this Part was derived from that previously filed with the State Records Center and Archives:
Rule 1201, Necessity for Hearing, 1-11-82;
Rule 1201, Necessity for Hearing, 2-5-91;
Rule 1202, Emergency Orders, 1-11-82;
Rule 1202, Emergency Orders, 2-5-91;
Rule 1203, Method of Initiating a Hearing, 1-11-82;
Rule 1203, Method of Initiating a Hearing, 2-5-91;
Rule 1204, Method of Giving Legal Notice for Hearing, 1-11-82;
Rule 1204, Method of Giving Legal Notice for Hearing, 11-5-85;
Rule 1204, Method of Giving Legal Notice for Hearing, 2-5-91;
Rule 1204, Publication of Notice for Hearing, 4-12-91;
Rule 1205, Contents of Notice of Hearing, 1-11-82;
Rule 1205, Contents of Notice of Hearing, 11-5-85;
Rule 1205, Contents of Notice of Hearing, 2-5-91;
Rule 1206, Personal Service of Notice, 1-11-82;
Rule 1206, Preparation of Notices, 11-5-85;
Rule 1206, Personal Service of Notice, 2-5-91;
Rule 1207, Preparation of Notices, 1-11-82;
Rule 1207, Additional Notice Requirements, 11-5-85;
Rule 1207, Additional Notice Requirements, 3-27-87;
Rule 1207, Additional Notice Requirements, 1-6-88;
Rule 1207, Additional Notice Requirements, 2-5-91;
Rule 1208, Filing Pleadings, 1-11-82;
Rule 1208, Filing Pleadings, 2-5-91;
Rule 1209, Continuance of Hearing Without New Service, 1-11-82;
Rule 1209, Continuance of Hearing Without New Service, 2-5-91;
Rule 1210, Conduct of Hearings, 1-11-82;
Rule 1210, Conduct of Hearings, 2-5-91;
Rule 1211, Power to Require Attendance of Witnesses and Production of Evidence, 1-11-82;
Rule 1211, Power to Require Attendance of Witnesses and Production of Evidence, 2-5-91;
Rule 1212, Rules of Evidence, 1-11-82;
Rule 1212, Rules of Evidence, 2-5-91;
Rule 1213, Examiners' Qualifications and Appointment, 1-11-82;
Rule 1213, Examiners' Qualifications and Appointment, 2-5-91;
Rule 1214, Referral of Cases to Examiners, 1-11-82;
Rule 1214, Referral of Cases to Examiners, 2-5-91;
Rule 1215, Examiner's Power of Authority, 1-11-82;
Rule 1215, Examiner's Power of Authority, 2-5-91;
Rule 1216, Hearings Which Must be Held Before the Commission, 1-11-82;
Rule 1216, Hearings Which Must be Held Before the Commission, 2-5-91;
Rule 1217, Examiner's Manner of Conducting Hearing, 1-11-82;

Rule 1217, Examiner’s Manner of Conducting Hearing, 2-5-91;
Rule 1218, Report and Recommendations, Examiner’s Hearings, 1-11-82;
Rule 1218, Report and Recommendations, Examiner’s Hearings, 2-5-91;
Rule 1219, Disposition of Cases Heard by Examiners, 1-11-82;
Rule 1219, Disposition of Cases Heard by Examiners, 2-5-91;
Rule 1220, De Novo Hearing Before Commission, 1-11-82;
Rule 1220, De Novo Hearing Before Commission, 12-30-86;
Rule 1220, De Novo Hearing Before Commission, 2-5-91;
Rule 1221, Notice of Commission and Division Orders, 1-11-82;
Rule 1221, Notice of Commission and Division Orders, 2-5-91;
Rule 1222, Rehearings, 1-11-82;
Rule 1222, Rehearings, 2-5-91.

History of Repealed Material:
Rule 1206, Personal Service of Notice, Repealed 4-12-91.

Other History: Rule 1201, Necessity for Hearing, filed 2-5-91; Rule 1202, Emergency Orders, filed 2-5-91; Rule 1203, Method of Initiating a Hearing, filed 2-5-91; Rule 1204, Publication of Notice for Hearing, filed 4-12-91; Rule 1205, Contents of Notice of Hearing, filed 2-5-91; Rule 1207, Additional Notice Requirements, filed 2-5-91; Rule 1208, Filing Pleadings, filed 2-5-91; Rule 1209, Continuance of Hearing Without New Service, filed 2-5-91; Rule 1210, Conduct of Hearings, filed 2-5-91; Rule 1211, Power to Require Attendance of Witnesses and Production of Evidence, filed 2-5-91; Rule 1212, Rules of Evidence, filed 2-5-91; Rule 1213, Examiners’ Qualifications and Appointment, filed 2-5-91; Rule 1214, Referral of Cases to Examiners, filed 2-5-91; Rule 1215, Examiner’s Power of Authority, filed 2-5-91; Rule 1216, Hearings Which Must be Held Before the Commission, filed 2-5-91; Rule 1217, Examiner’s Manner of Conducting Hearing, filed 2-5-91; Rule 1218, Report and Recommendations, Examiner’s Hearings, filed 2-5-91; Rule 1219, Disposition of Cases Heard by Examiners, filed 2-5-91; Rule 1220, De Novo Hearing Before Commission, filed 2-5-91; Rule 1221, Notice of Commission and Division Orders, filed 2-5-91; Rule 1222, Rehearings, filed 2-5-91 were all renumbered, reformatted and replaced by 19 NMAC 15.N, Procedure, effective 2-1-96.
19 NMAC 15.N, Procedure, filed 1-18-96 was renumbered, reformatted and replaced by 19.15.14 NMAC, Procedure, effective 8-29-03.

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 15 ADMINISTRATION

19.15.15.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department, Oil Conservation Division, 2040 S. Pacheco, Santa Fe, New Mexico 87505, (505) 827-7131.
[2-1-96; 19.15.15.1 NMAC - Rn, 19 NMAC 15.O.1, 07-30-04]

19.15.15.2 SCOPE: All persons/entities engaged in oil and gas development and production within New Mexico.
[2-1-96; 19.15.15.2 NMAC - Rn, 19 NMAC 15.O.2, 07-30-04]

19.15.15.3 STATUTORY AUTHORITY: Sections 70-2-1 through 70-2-38 NMSA 1978 sets forth the and Gas Act which grants the oil conservation division jurisdiction and authority over all matters relating to the observation of oil and gas, the prevention of waste of oil and gas and of potash as a result of oil and gas operations, the protection of correlative rights, and the disposition of wastes resulting from oil and gas operations.
[2-1-96; 19.15.15.3 NMAC - Rn, 19 NMAC 15.O.3, 07-30-04]

19.15.15.4 DURATION: Permanent.
[2-1-96; 19.15.15.4 NMAC - Rn, 19 NMAC 15.O.4, 07-30-04]

19.15.15.5 EFFECTIVE DATE: February 1, 1996. [Unless a later date is cited at the end of a section.]
[2-1-96; 19.15.15.5 NMAC - Rn, 19 NMAC 15.O.5, 07-30-04]

19.15.15.6 OBJECTIVE: The objective of this part is to provide for administration of the authority granted to the Oil Conservation Division under the Oil and Gas Act.
[2-1-96; 19.15.15.6 NMAC - Rn, 19 NMAC 15.O.6, 07-30-04]

19.15.15.7 DEFINITIONS: [RESERVED].

19.15.15.8-1300 [RESERVED].

19.15.15.1301 DISTRICT OFFICES:

A. To expedite administration of the work of the oil conservation division of the New Mexico energy, minerals and natural resources department and the enforcement of its rules and regulations, the state shall be divided into four districts as follows:

(1) district 1: Lea, Roosevelt, and Curry counties, and that portion of Chaves county lying east of the north-south line dividing ranges 29 and 30 east, NMPM; the district office shall be in Hobbs, New Mexico.

(2) district 2: Eddy, Otero, Dona Ana, Luna, Hidalgo, Grant, Sierra, Lincoln, and De Baca counties, and that portion of Chaves county lying west of the north-south line dividing ranges 29 and 30 east, NMPM; the district office shall be in Artesia, New Mexico.

(3) district 3: San Juan, Rio Arriba, McKinley, and Sandoval counties; the district office shall be in Aztec, New Mexico;

(4) district 4: remainder of state; the district office shall be in Santa Fe, New Mexico; each district office shall be under the charge of a district supervisor, an oil and gas inspector, or a deputy oil and gas inspector; unless otherwise specifically required, all matters pertaining to the division shall be taken care of through the district office of the district in which the affected land is located.
[1-1-50...2-1-96; 19.15.15.1301 NMAC - Rn, 19 NMAC 15.O.1301, 07-30-04]

19.15.15.1302 WHERE TO FILE REPORTS AND FORMS:
All reports and forms required by the rules to be filed with the division shall be filed in the number and at the time specified on the form or report or by the applicable rules in 19.15.13 NMAC. Unless otherwise specified, all such reports and forms shall be filed at the district office of the district in which the land that is the subject matter of the report is located. All plugging bonds shall be filed directly with the Santa Fe office of the division. A list of all plugging bonds approved and in force shall be kept in each district office.
[1-1-50...2-1-96; 19.15.15.1302 NMAC - Rn, 19 NMAC 15.O.1302, 07-30-04]

19.15.15.1303 DUTIES AND AUTHORITY OF FIELD PERSONNEL:
Oil and gas inspectors, deputy oil and gas inspectors, scouts, engineers and geologists duly appointed by the division have the authority and duty to enforce the rules and regulations of the division. Only oil and gas inspectors and their deputies shall have discretion to allow minor deviations from requirements of the rules as to field practices where, by so doing, waste will be prevented or burdensome delay or expenses on the part of the operator will be avoided.
[1-1-50...2-1-96; 19.15.15.1303 NMAC - Rn, 19 NMAC 15.O.1303, 07-30-04]

19.15.15.1304 NUMBERING OF DIVISION ORDERS:
A. All orders of the division made after January 1, 1950, pertaining to the allocation of production of oil and gas are prefixed with the letter "A" or "AG" in the case of gas pools and are numbered consecutively, commencing with the number 1, i.e., the first allocation order issued after January 1, 1950, is No. A-1, the next A-1, etc or AG-1 and AG-2.
B. All other orders of the division made after January 1, 1950, are prefixed with the letter "R" and are numbered consecutively, commencing with the number 1, i.e., the first such order issued after January 1, 1950, is No. R-1, the next R-2, etc.
[1-1-50...2-1-96; 19.15.15 NMAC.1304 - Rn, 19 NMAC 15.O.1304, 07-30-04]

History of 19.15.15 NMAC:
Pre-NMAC History: The material in this Part was derived from that previously filed with the State Records Center and Archives:
Rule 1301, District Offices, filed 1-11-82;
Rule 1301, District Offices, filed 2-5-91;
Rule 1302, Where to File Reports and Forms, filed 1-11-82;
Rule 1302, Where to File Reports and Forms, filed 2-5-91;
Rule 1303, Duties and Authority of Field Personnel, filed 1-11-82;
Rule 1303, Duties and Authority of Field Personnel, filed 2-5-91;
Rule 1304, Numbering of Division Orders, filed 1-11-82;
Rule 1304, Numbering of Division Orders, filed 10-11-89;
Rule 1304, Numbering of Division Orders, filed 2-5-91.

History of Repealed Material: [Reserved]

Other History: Rule 1301, District Offices (filed 2-5-91); Rule 1302, Where to File Reports and Forms (filed 2-5-91); Rule 1303, Duties and Authority of Field Personnel (filed 2-5-91); and Rule 1304, Numbering of Division Orders (filed 2-5-91) were all renumbered, reformatted and replaced by 19 NMAC 15.O, Administration, effective 2-1-96.
19 NMAC 15.O, Administration (filed 1-18-96) was renumbered, reformatted and replaced by 19.15.15 NMAC, Administration, effective 07-30-04.

PART P
(RESERVED)

PART Q
(RESERVED)

Appendix D - Oklahoma Regulatory Summary (General)

TITLE 165: CORPORATION COMMISSION
CHAPTER 10: OIL AND GAS CONSERVATION

Effective July 1, 2004

Last Amended
The Oklahoma Register
Volume 21, Number 17
June 15, 2004 publication
Pages 1921 - 2642

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CHAPTER 10. OIL AND GAS CONSERVATION

[**Authority:** 52 O. S. §§ 86.2 through 320, 528 through 614]

[**Source:** Codified 12-31-91]

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SUBCHAPTER 1. ADMINISTRATION

PART 1. GENERAL PROVISIONS

PART 3. SURETY

PART 5. SPACING

PART 7. MARKET DEMAND

PART 9. PURCHASERS AND TRANSPORTERS

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PART 1. GENERAL PROVISIONS

165:10-1-1. Purpose

The rules of this Chapter were promulgated in furtherance of the public policy and statutory laws of the State of Oklahoma to prevent the waste of oil and gas, to assure the greatest ultimate recovery from the State's reservoirs, to protect the correlative rights of all interest owners, and to prevent pollution.

165:10-1-2. Definitions.

The following words and terms, when used in this Chapter, shall have the following meaning unless the context clearly indicates otherwise:

"Agent" means any person authorized by another person to act for him.

"Aquifer" means a geological formation, group of formations, or part of a formation that is capable of yielding a significant amount of water to a well or spring.

"Area of exposure" means an area within a circle constructed with the point of escape of poisonous gas (hydrogen sulfide) as its center and the radius of exposure as its radius.

"Associated gas" means any gas produced from a Commission ordered combination oil and gas reservoir in which allowed rates of production are based upon volumetric withdrawals.

"BS&W" means basic sediment and water which is that portion of fluids and/or solids that settle in the bottom of storage tanks and/or treating vessels and is unsaleable to the first purchaser in its present form. BS&W usually consists of water, paraffin, sand, scale, rust, and other sediments.

"Barrel" means 42 (U.S.) gallons at 60 F at atmospheric pressure.

"Basic sediment pit" means a pit used in conjunction with a tank battery for storage of basic sediment removed from a production vessel or from the bottom of an oil storage tank.

"Blowout" means the uncontrolled escape of oil or gas, or both, from any formation.

"Blowout preventer" means a heavy casinghead control fitted with special gates and/or rams which can be closed around the drill pipe or which completely closes the top of the casing.

"Blowout preventer stack" means the assembly of well control equipment including preventers, spools, valves, and nipples connected to the top of the casinghead.

"Carrier", or **"transporter"**, or **"taker"** means any person moving or transporting oil or gas away from a lease or from any common source of supply.

"Casing pressure" means the pressure within the casing or between the casing and tubing at the wellhead.

"Choke manifold" means an assembly of valves, chokes, gauges, and lines used to control the rate of flow from the well when the blowout preventers are closed.

"Closed drilling fluid/mud system" means a system where drilling fluids/muds are circulated in the well bore and contained in non-earthen tanks.

"Closure" means the practice of dewatering, trenching, filling, leveling, terracing, and/or vegetating a pit site after its useful life is reached in order to restore or reclaim the site to near its original condition.

"Commercial disposal well" means a disposal well which:

(A) Is operated primarily for profit from the disposal of salt water and/or other deleterious substances for a fee; and

(B) Disposes of salt water and/or other deleterious substances transported by truck to the facilities used in conjunction with said disposal well or is a disposal well for which none of its owners is an owner in any of the oil and gas wells which produce the salt water and/or other deleterious substances which will be disposed into said disposal well.

"Commercial pit" is a disposal facility which is authorized by Commission order and used for the disposal, storage, and handling substances or soils contaminated by deleterious substances produced, obtained, or used in connection with drilling and/or production operations. This does not include a disposal well pit.

"Commercial soil farming" means the practice of soil farming or land applying drilling fluids and/or other deleterious substances produced, obtained, or used in connection with the drilling of a well or wells at an off-site location. Multiple applications to the same land are likely.

"Commission" means the Corporation Commission of the State of Oklahoma.

"Common source of supply" or **"pool"** means "that area which is underlaid or which, from geological or other scientific data, or from drilling operations, or other evidence, appears to be underlaid by a common accumulation of oil and/or gas; provided that, if any such area is underlaid, or appears from geological or other scientific data or from drilling operations, or other evidence, to be underlaid by more than one common accumulation of oil or gas or both, separated from each other by strata of earth and not connected with each other, then such area shall, as to each said common accumulation of oil or gas or both, shall be deemed a separate common source of supply." [52. O.S.A. §86.1(c)].

"Completion/fracture/workover pit" means a pit used for temporary storage of spent completion fluids, frac fluids, workover fluids, drilling fluids, silt, debris, water, brine, oil scum, paraffin, or other deleterious substances which have been cleaned out of the wellbore of a well being completed, fractured, recompleted, or worked over.

"Condensate" means a liquid hydrocarbon which:

(A) Was produced as a liquid at the surface,

(B) Existed as gas in the reservoir, and

(C) Has an API gravity greater than or equal to fifty degrees, unless otherwise proven.

"Conductor casing" means a casing string which is often set and cemented at a shallow depth to support and protect the top of the borehole from erosion while circulating and drilling the surface casing hole.

"Conservation Division" means the Division of the Commission charged with the administration and enforcement of the rules of this Chapter.

"Contingency plan" is a written document which provides for an organized plan of action for alerting and protecting the public within an area of exposure following the accidental release of a potentially hazardous volume of poisonous gas such as hydrogen sulfide.

"Contractor" means any person who contracts with another person for the performance of prescribed work.

"Cubic foot of gas" means the volume of gas contained in one cubic foot of space at an absolute pressure of 14.65 pounds per square inch and at a temperature of 60°F. Conversion of volumes to conform to standard conditions shall be made in accordance with Ideal Gas Laws corrected for deviation from Boyle's Law when the pressure at point of measurement is in excess of 200 pounds per square inch gauge.

"Date of completion" means:

(A) For an oil well, the date that the well first produces oil into the lease tanks through permanent wellhead equipment.

(B) For a gas well, the date of completion of a gas well is the date that gas is capable of being delivered to a pipeline purchaser.

(C) For a well, which does not produce either oil or gas, is the date on which attempts to obtain production from the well cease.

"Day" means a period of 24 consecutive hours. For reporting purposes, it shall be from 7:00 a.m. to 7:00 a.m. the following day.

"Deleterious substances" means any chemical, salt water, oil field brine, waste oil, waste emulsified oil, basic sediment, mud, or injurious substance produced or used in the drilling, development, production, transportation, refining, and processing of oil, gas and/or brine mining.

"Design mud weight" means the planned drilling mud weight to be used. This mud weight is used in the design of the casing strings.

"Design wellhead pressure" means the maximum anticipated wellhead pressure which is expected to be experienced on the inside of the casing string and on wellhead equipment. This pressure is used to design the casing string and to select wellhead equipment with sufficient working pressure rating.

"Development" means any work which actively looks toward bringing in production, such as erecting rigs, building tankage, drilling wells, etc.

"Directional drilling" means intentional changing of the direction of the well from the vertical.

"Director of Conservation" means the person in official charge of the Conservation Division.

"Discharge" means the release or setting free by any spilling, leaking, pumping, pouring, emitting, emptying, or dumping of substances.

"Distressed well" means a well authorized by Commission order to produce at an unrestricted rate in the interest of public safety due to technical difficulties which temporarily cannot be controlled.

"Diverter" means a device attached to the wellhead to close the vertical access and direct any flow into a line away from the rig. Diverters differ from blowout preventers in that flow is not stopped but rather the flow path is redirected away from the rig.

"Duly authorized representative" means, for the purpose of underground injection well applications, that person or position having a responsibility for the underground injection well.

"Emergency pit" means a pit used for the storage of excessive or unanticipated amounts of fluids during an immediate emergency situation in the drilling or operation of a well, such as a well blowout or a pipeline rupture. This does not include a spill prevention structure required by local, state, or federal regulations.

"Enhanced recovery operation" means the introduction of fluid or energy into a common source of supply for the purpose of increasing the recovery of oil therefrom according to a plan which has been approved by the Commission after notice and hearing.

"Enhanced recovery well" means a well producing in an enhanced recovery operation in accordance with Commission order.

"Exchangeable Sodium Percentage (ESP)" is the relative amount of the sodium ion present on the soil surface, expressed as a percentage of the total Cation Exchange Capacity (CEC). Since the determination of CEC is time consuming and expensive, a practical and satisfactory correlation between the Sodium Adsorption Ratio (SAR) and ESP was established. The SAR is defined elsewhere in this Section. ESP can be estimated by the following empirical formula:

$$ESP = 100 \quad (-0.0126 + 0.01475 \times SAR) \div 1 + (-0.0126 + 0.01475 \times SAR)$$

"Exempted aquifer" means an aquifer or its portion that meets the criteria in the definition of "underground source of drinking water" or in the definition of "treatable water", but which has been exempted according to the procedures in 165:5-7-28 and 165:10-5-14.

"Facility" means, for the purposes of 165:10-21-15, any building(s), parts of a building, equipment, property, or vehicles that are actively engaged in the reuse, recycling, or ultimate destruction of deleterious substances pursuant to 68 O.S. Supp. 1986, §2357.14-§2357.20.

"Field" means the general area underlaid by one or more common sources of supply.

"Flare pit" means a pit which contains flare equipment and which is used for temporary storage of liquid hydrocarbons which are sent to the flare but are not burned due to equipment malfunction. Flare pits may be used in conjunction with tank batteries or wells.

"Flowing well" means any well from which oil or gas is produced naturally and without artificial lifting equipment.

"Fresh water strata" means a strata from which fresh water may be produced in economical quantities.

"Gas" means any petroleum hydrocarbon existing in the gaseous phase.

(A) Casinghead gas means any gas or vapor, or both, indigenous to an oil stratum and produced from such stratum with oil.

(B) Dry gas or dry natural gas means any gas produced in which there are no appreciable hydrocarbon liquids recoverable by separation at the wellhead.

(C) Condensate gas means any gas which is produced with condensate as defined as "condensate".

"**Gas allowable**" or "**allowable gas**" means the amount of natural gas authorized to be produced from any well by order of the Commission or as provided by statute.

"**Gas lift**" means any method of lifting liquid to the surface by injecting gas into the well bore from which production is obtained.

"**Gas repressuring**" means the injection of gas into a common source of supply to restore or increase the gas energy of a reservoir.

"**GOR (Gas/Oil Ratio)**" means the ratio of the gas produced in standard cubic feet to one barrel of oil produced during any stated period. Condensate and load oil excepted under 165:10-13-6 shall not be considered as oil for purposes of determining GOR.

"**Hardship well**" means a well authorized by Commission order to produce at a specified rate because reasonable cause exists to expect that production below said rate would damage the well and cause waste.

"**Hydrogen sulfide gas (H_2S)**" means a toxic poisonous gas with a chemical composition of H_2S which is sometimes found mixed with and produced with fluids from oil and gas wells.

"**Hydrostatic head**" or "**hydrostatic pressure**" means the pressure which exists at any point in the wellbore due to the weight of the column of fluid or gas above that point.

"**Illegal gas**" means gas which has been produced within the State from any well or wells in violation of any rule, regulation, or order of the Commission, as distinguished from gas produced within the State not in violation of any such rule, regulation, or order which is "legal gas".

"**Illegal oil**" means oil which has been produced within the State from any well or wells in violation of any rule, regulation or order of the Commission, as distinguished from oil produced within the State not in violation of any such rule, regulation, or order which is "legal oil".

"**Intermediate casing**" means the casing string or strings run after setting the surface casing and prior to setting the production string or liner.

"**Kick**" means the intrusion of formation liquids or gas that results in an increase in circulation pit volume. Without corrective measures, this condition can result in a blowout.

"**Land application**" is the application of deleterious substances and/or soils contaminated by deleterious substances to the land for the purpose of disposal or land treatment; also known as soil farming.

"**Lease allowable**" means the total of the allowables of the individual wells on the lease.

"**Liner**" means a length of casing used downhole as an extension to a previously installed casing string to case the hole for further drilling operations and/or for producing operations.

"**Load Ticket**" means a document or bill of lading describing the source, contents and destination of any load of petroleum tank bottoms, BS&W or deleterious substance, the name and address of the company owning or leasing the transporting vehicle, either the Oklahoma Tax Commission Gross production Vehicle Permit number of the vehicle or the Oklahoma Corporation Commission Motor Carrier License number, the date of transport, the name of the company or person owning the lease or storage facility from which the product is being removed, or if different, the name of the company or person owning the product before its removal, the OTC assigned production unit number of the lease or a precise description of the location of non-lease storage from which the product is removed, a description of the product being transported, the name and address of the person or firm who will receive or store the load and the driver's signature.

"**Meter**" means an instrument for measuring and indicating or recording the volumes of gases or liquids.

"**Mud**" means any mixture of water and clay or other material as the term is commonly used in the industry.

"**Multiple zone completion**" means the completion of any well so as to permit the production from more than one common source of supply, with such common sources of supply completely segregated.

"Noncommercial pit" means an earthen pit which is located either on-site or off-site and is used for the handling, storage, or disposal of deleterious substances or soils contaminated by deleterious substances produced, obtained, or used in connection with the drilling and/or operation of a well or wells, and is operated by the generator of the waste. This does not include a disposal well pit.

"Normal pressure" means a formation pore pressure, proportional to depth, which is roughly equal to the hydrostatic pressure gradient of a column of salt water (.465 psi/ft).

"Off-site reserve pit" means a reserve pit used for the handling, storage and/or disposal of drilling fluids/muds and cuttings where all parts of the pit are located further than 300 feet from the well bore.

"Oil" or **"crude oil"**, means, for purposes of these regulations, any petroleum hydrocarbon, except condensate, produced from a well in liquid form by ordinary production methods.

"Oil allowable" or **"allowable oil"** means the amount of oil authorized to be produced from any well by order of the Commission.

"Operator" means the person who is duly authorized and in charge of the development of a lease or the operation of a producing property.

"Overage" means the oil or gas delivered to a carrier, transporter, or taker in excess of the allowable set by the Commission for any given period.

"Owner" means the person or persons who have the right to drill into and to produce from any common source of supply, and to appropriate the production either for himself, or for himself and others.

"Person" means any natural person, corporation, association, partnership, receiver, trustee, guardian, executor, administrator, fiduciary, or representative of any kind, and shall include the plural.

"Plug" means the closing off, in a manner prescribed by the Commission, of all oil, gas, and waterbearing formations in any producing or nonproducing wellbore before such well is abandoned.

"Pollution" means the contamination of fresh water or soil, either surface or subsurface, by salt water, mineral brines, waste oil, oil, gas, and/or other deleterious substances produced from or obtained or used in connection with the drilling, development, producing, refining, transporting, or processing of oil or gas within the State of Oklahoma.

"Pool" See "common source of supply".

"Potential" means the properly determined capacity of a well to produce oil or gas, or both, under conditions prescribed by the Commission.

"Producer" See "Operator" or "Owner".

"Production casing" means the casing string set above or through the producing zone of a well which serves the purpose of confining and/or producing the well production fluids.

"Productivity index" means the daily production of oil in barrels per unit pressure differential between the static reservoir pressure and the stabilized flowing pressure during flow at a stated rate.

"Proration period" means:

(A) The proration period for any well, other than an unallocated gas well, shall be one calendar month which shall begin at 7 a.m. on the first day of such month and end at 7 a.m. on the first day of the next succeeding month unless otherwise specified by order of the Commission.

(B) The proration period for any unallocated gas well shall be one calendar year which shall begin at 7:00 a.m. the first day of such year and end at 7:00 a.m. on the first day of the next succeeding year unless otherwise specified by order of the Commission.

"Public area" means a dwelling place, a business, school, hospital, school bus stop, government building, a public road, all or any portion of a park, city, town, village, or other similar area that can be expected to be populated.

"Public street" or **"road"** means any federal, state, county, or municipal street or road owned or maintained for public access or use.

"Purchaser" or **"transporter"** means any person who acting alone or jointly with any person or persons, via his own, affiliated or designated carrier, transporter, or taker, shall directly or indirectly purchase, take, or transport by any means whatsoever or otherwise remove from any lease, oil or gas, and/or other hydrocarbons produced from any common source of supply in this State, excepting royalty portions from leases owned by that person.

"Radius of exposure" means that radius constructed with the point of escape of poisonous (hydrogen sulfide) gas as its starting point and its length calculated by use of the Pasquill-Gifford equations.

"Reclaimer" or **"reclamation plant"** includes any person licensed by the Oklahoma Tax Commission pursuant to 68 O.S.§1015.1 who reclaims or salvages or in any way removes or extracts oil from waste products associated with the production, storage, or transportation of oil including, but not limited to BS&W, tank bottoms, pit and waste oil, and/or waste oil residue.

"Recomplete" or **"recompletion"** means any operation to:

(A) Convert an existing well from an injection well or disposal well, to a producing well, or

(B) Add or change common sources of supply in an existing well.

"Recycling" is the reuse, processing, reclaiming, treating, neutralizing, or refining of materials and by-products into a product of beneficial use which, if discarded, would be deleterious substances.

"Recycling/reuse pit" means a pit which is used for the recycling or reuse of deleterious substances, is located off-site, and is operated by the generator of the waste.

"Re-enter" or **"re-entry"** is the act of entering a plugged well for the purpose of utilizing said well for the production of oil or gas, for the disposal of fluids therein, for a service well, or for the salvaging of tubing or casing therefrom.

"Remediation pit" means a pit which is used for the handling, storage, or disposal of deleterious substances and/or soils contaminated by deleterious substances which are relocated to the pit for the purpose of remediating a site which is known to be or suspected to be causing pollution.

"Reserve pit" or **"circulation pit"** means a pit located either on-site or off-site which is used in conjunction with a drilling rig for the handling, storage, or disposal of drilling fluids and/or cuttings.

"Reservoir" See "common source of supply".

"Reservoir pressure" means the static or stabilized pressure in pounds per square inch existing at the face of the formation of an oil or gas well.

"Reuse" is the introduction (or reintroduction) into an industrial, manufacturing, or disposal process of a material which would otherwise be classified as a deleterious substance. A material will be considered "used or reused" if it is either:

(A) Employed as an ingredient (including use as an intermediate) in an industrial, manufacturing, or disposal process to make or recover a product.

(B) Employed in a particular function or application as an effective substitute for a commercial product or non-deleterious substance.

"Rotating head" means a rotating, pressure sealing device used in drilling operations utilizing air, gas, foam, or any other drilling fluid whose hydrostatic pressure is less than the formation pressure.

"Secretary" means the duly appointed and qualified Secretary of the Commission or any person appointed by the Commission to act as such Secretary during the absence of the Secretary, his inability, or disqualification to act.

"Separator" means any apparatus for separating oil, gas, and water as they are produced from a well at the surface.

"Seismic shot hole" shall mean any hole drilled to allow explosive charges to provide an energy source for seismic exploration.

"Slick spot" means a small area of soil having a puddled, crusted, or smooth surface and an excess of exchangeable sodium. The soil is generally silty or clayey, is slippery when wet, and is low in productivity.

"Sodium Adsorption Ratio (SAR)" means the index which indicates the relative abundance of sodium ions in solution as compared to the combined concentration of calcium and magnesium ions. It is calculated as follows:

$$\text{SAR} = \frac{(\text{Na ppm}/23.0)}{\text{sq. root of } [\ \{(\text{Ca ppm}/20.02) + (\text{Mg ppm}/12.16)\}\ /\ 2]}$$

where Na=Sodium
Ca=Calcium

Mg=Magnesium

"Soil farming" means the application of oilfield drilling or produced wastes to the soil for the purpose of disposing of the waste without being a detriment to water or land; also known as land application.

"Spill containment pit" means a permanent pit which is used for the emergency storage of oil and/or saltwater spilled as a result of any equipment malfunction.

"Stratigraphic test hole" shall mean any hole drilled to obtain geological information which may lead to the discovery of hydrocarbons. Such wells are drilled without the intention of being completed for hydrocarbon production.

"Subnormal pressure" means the formation pore pressure, proportional to depth, which is less than a hydrostatic pressure gradient of .465 psi/ft.

"Sulfide stress cracking" means the cracking phenomenon which is the result of corrosive action of hydrogen sulfide on susceptible metals under stress.

"Surface casing" means the first casing string designed and run to protect the treatable water formations and/or control fluid or gas flow from the well.

"Tank bottoms" means the liquids and/or solids in a storage facility that are unsaleable to the crude oil first purchaser in its present form. Tank bottoms may consist of a combination of several elements including, but not limited to, crude oil, BS&W, and spent treating fluids.

"Treatable water" means, for purposes of setting surface casing and other casing strings, subsurface water in its natural state, useful or potentially useful for drinking water for human consumption, domestic livestock, irrigation, industrial, municipal, and recreational purposes, and which will support aquatic life, and contains less than 10,000 mg/liter total dissolved solids or less than 5,000 ppm chlorides. Treatable water includes, but is not limited to, fresh water.

"Trenching" means the practice of constructing trenches in or adjacent to a pit for the purpose of relocating all or a portion of the solids so as to facilitate closure.

"Ultimate destruction" means the treatment of a deleterious substance such that both its weight and volume remaining for disposal have been substantially reduced, and there is no demonstrated process or technology commercially available to further reduce its weight and volume and remove or reduce its harmful properties, if any. For the purposes of demonstrating a substantial reduction in weight and volume, any aqueous portion separated from the balance of a waste that meets drinking water standards or is evaporated into the ambient air shall count toward the weight and volume reduction.

"Underage" means the volume of allowable oil or gas not actually delivered to a carrier, transporter, or taker during any given proration period.

"Underground Source of Drinking Water (USDW)" means an aquifer or its portion which:

(A) Supplies any public water system; or

(B) Contains a sufficient quantity of ground water to supply a public water system; and

(i) Currently supplies drinking water for human consumption; or

(ii) Contains fewer than 10,000 mg/l total dissolved solids; and

(C) Is not an exempted aquifer.

"Unit operations" means a unit consisting of a portion of a lease, a lease, or more than one lease or portions thereof which covers contiguous lands containing one or more common sources of supply which has been approved by Commission order as a unit for the purpose of unitized management, after notice and hearing.

"Vacuum" means pressure below the prevailing pressure of the atmosphere.

"Waste" means:

(A) As applied to the production of oil, in addition to its ordinary meaning, "shall include economic waste, underground waste, including water encroachment in the oil or gas bearing strata; the use of reservoir energy for oil producing purposes by means or methods that unreasonably interfere with obtaining from the common source of supply the largest ultimate recovery of oil; surface waste and waste incident to the production of oil in excess of transportation or marketing facilities or reasonable market demands." [52 O.S.A., 86.2]

(B) As applied to gas, in addition to its ordinary meaning, shall include economic waste; "the inefficient or wasteful utilization of gas in the operation of oil wells drilled to and producing from a common source of supply; the inefficient or wasteful utilization of gas in the operation of gas wells drilled to and producing from a common source of supply; the production of gas in such quantities or in such manner as unreasonably to reduce reservoir pressure or unreasonably to diminish the quantity of oil or gas that might be recovered from a common source of supply; the escape, directly or indirectly, of gas from oil wells producing from a common source of supply into the open air in excess of the amount necessary in the efficient drilling, completion or operation thereof; waste incident to the production of natural gas in excess of transportation and marketing facilities or reasonable market demand; the escape, blowing, or releasing, directly or indirectly, into the open air, of gas from well productive of gas only, drilled into any common source of supply, save only such as is necessary in the efficient drilling and completion thereof; and the unnecessary depletion or inefficient utilization of gas energy contained in a common source of supply." [52 O.S.A. §86.3]

(C) The use of gas for the manufacture of carbon black or similar products predominately carbon, except as specifically authorized by the Commission, shall constitute waste.

(D) The flaring of tail gas at gasoline, pressure maintenance, or recycling plants where a market is available.

"Waste oil" shall include, but not be limited to, crude oil or other hydrocarbons used or produced in the process of drilling for, developing, producing, or processing oil or gas from wells, oil retained on cuttings as a result of the use of oil-based drilling muds, or any residue from any oil storage facility on a producing lease or on a commercial disposal operation or pit. The term "waste oil" shall not include any refined hydrocarbons to which lead has been added.

"Waste oil residue" means that portion of waste oil remaining after treatment and after the saleable liquids and water have been extracted. Waste oil residue is a type of waste oil.

"Well log" or **"well record"** means a systematic, detailed and correct record of formations encountered in the drilling of a well.

[**Source:** Amended at 12 Ok Reg 2017, eff 7-1-95; Amended in Rule Making 97000002, eff 7-1-97; Amended in Rule Making 980000034, eff 7-1-99; Amended in Rule Making 200000002, eff 7-1-2000]

165:10-1-3. Scope of rules

All rules of general application in this Chapter promulgated to prevent waste, assure the greatest ultimate recovery from the reservoirs of this state, protect the correlative rights of all interests, and to prevent pollution shall be effective throughout the State of Oklahoma and be in force in all pools except as amended, modified, altered, or enlarged in specific individual pools by orders now in effect or hereafter issued by the Commission.

165:10-1-4. Citation effective date

(a) These rules shall be cited as OAC Title 165 Chapter 10 (OAC 165:10).

(b) The effective date of the rules of this Chapter is as set out below:

(1) Order No. 937 - Effective 06/16/15
(2) Order No. 1299 - Effective 08/20/17
(3) Order No. 1986 - Effective 01/05/22
(4) Order No. 6251 - Effective 04/12/33
(5) Order No. 6252 - Effective 04/15/33
(6) Order No. 6393 - Effective 07/19/33
(7) Order No. 6394 - Effective 07/20/33
(8) Order No. 7263 - Effective 04/10/34
(9) Order No. 8229 - Effective 10/31/33
(10) Order No. 17528 - Effective 01/24/45

(11) Order No. 19334 - Effective 10/24/46
(12) Order No. 29232 - Effective 10/06/54
(13) Order No. 30712 - Effective 09/09/55
(14) Order No. 44297 - Effective 04/01/61
(15) Order No. 47397 - Effective 12/01/61
(16) Order No. 53568 - Effective 12/08/63
(17) Order No. 53749 - Effective 01/03/64
(18) Order No. 62481 - Effective 05/11/66
(19) Order No. 62631 - Effective 06/01/66
(20) Order No. 63817 - Effective 10/04/66
(21) Order No. 64203 - Effective 11/10/66
(22) Order No. 64207 - Effective 12/01/66
(23) Order No. 65747 - Effective 05/05/67
(24) Order No. 66006 - Effective 06/08/67
(25) Order No. 66778 - Effective 09/05/67
(26) Order No. 67113 - Effective 10/09/67
(27) Order No. 67379 - Effective 11/06/67
(28) Order No. 69103 - Effective 06/01/68
(29) Order No. 69104 - Effective 06/01/68
(30) Order No. 69340 - Effective 07/01/68
(31) Order No. 70704 - Effective 01/03/69
(32) Order No. 75248 - Effective 07/01/69
(33) Order No. 77627 - Effective 01/01/70
(34) Order No. 78830 - Effective 01/01/70
(35) Order No. 78831 - Effective 01/01/70
(36) Order No. 79460 - Effective 04/01/70
(37) Order No. 79461 - Effective 04/01/70
(38) Order No. 80401 - Effective 06/01/70
(39) Order No. 80402 - Effective 06/01/70
(40) Order No. 81221 - Effective 08/01/70
(41) Order No. 81222 - Effective 08/01/70
(42) Order No. 83168 - Effective 01-01-71
(43) Order No. 84223 - Effective 04-01-71
(44) Order No. 84224 - Effective 04-01-71
(45) Order No. 84318 - Effective 03-29-71
(46) Order No. 85138 - Effective 06-01-71
(47) Order No. 85139 - Effective 06-01-71
(48) Order No. 87730 - Effective 01-01-72
(49) Order No. 87829 - Effective 01-01-72
(50) Order No. 93381 - Effective 10-05-72
(51) Order No. 93382 - Effective 10-05-72
(52) Order No. 94418 - Effective 01-01-73
(53) Order No. 96671 - Effective 04-01-73
(54) Order No. 87829 - Effective 01-01-72
(55) Order No. 94418 - Effective 01-01-73
(56) Order No. 102096 - Effective 01-01-74
(57) Order No. 109595 - Effective 01-01-75
(58) Order No. 117899 - Effective 03-01-76
(59) Order No. 128534 - Effective 03-01-77
(60) Order No. 128781 - Effective 03-01-77
(61) Order No. 138348 - Effective 03-01-78
(62) Order No. 151077 - Effective 03-23-79
(63) Order No. 161968 - Effective 01-03-80
(64) Order No. 164345 - Effective 03-17-80
(65) Order No. 164346 - Effective 02-14-80
(66) Order No. 164347 - Effective 02-14-80
(67) Order No. 165935 - Effective 04-01-80
(68) Order No. 185407 - Effective 03-09-81
(69) Order No. 185890 - Effective 03-16-81
(70) Order No. 187373 - Effective 04-02-81
(71) Order No. 211505 - Effective 03-30-82
(72) Order No. 228675 - Effective 01-01-83
(73) Order No. 230515 - Effective 01-01-83
(74) Order No. 230781 - Effective 01-01-83

(75) Order No. 246797 - Effective 01-01-84
(76) Order No. 250273 - Effective 01-01-84
(77) Order No. 250466 - Effective 01-01-84
(78) Order No. 260734 - Effective 07-01-84
(79) Order No. 290210 - Effective 01-09-86
(80) Order No. 292212 - Effective 02-10-86
(81) Order No. 299185 - Effective 06-12-86
(82) Order No. 302126 - Effective 10-08-86
(83) Order No. 303650 - Effective 10-02-86
(84) Order No. 304257 - Effective 10-16-86
(85) Order No. 305211 - Effective 11-07-86
(86) Order No. 311872 - Effective 05-06-87
(87) Order No. 312391 - Effective 05-14-87
(88) Order No. 310755 - Effective 06-01-87
(89) Order No. 313445 - Effective 06-12-87
(90) Order No. 313446 - Effective 07-09-87
(91) Order No. 313660 - Effective 06-17-87
(92) Order No. 313932 - Effective 06-25-87
(93) Order No. 314001 - Effective 06-27-87
(94) Order No. 313446 - Effective 07-09-87
(95) Order No. 315275 - Effective 08-19-87
(96) Order No. 320171 - Effective 12-21-87
(97) Order No. 320741 - Effective 01-08-88
(98) Order No. 320742 - Effective 01-08-88
(99) Order No. 321123 - Effective 01-21-88
(100) Order No. 323847 - Effective 05-01-88
(101) Order No. 325144 - Effective 05-02-88
(102) Order No. 326275 - Effective 06-27-88
(103) Order No. 326343 - Effective 06-01-88
(104) Order No. 326344 - Effective 06-01-88
(105) Order No. 327514 - Effective 07-01-88
(106) Order No. 327515 - Effective 07-01-88
(107) Order No. 329661 - Effective 08-26-88
(108) Order No. 329662 - Effective 08-26-88
(109) Order No. 329663 - Effective 08-26-88
(110) Order No. 334130 - Effective 01-04-89
(111) Order No. 337475 - Effective 03-31-89
(112) Order No. 337476 - Effective 03-31-89
(113) Order No. 339860 - Effective 05-07-89
(114) Order No. 341102 - Effective 08-25-89
(115) Order No. 341103 - Effective 08-14-89
(116) Order No. 346071 - Effective 03-29-90
(117) Order No. 346107 - Effective 03-30-90
(118) Order No. 355458 - Effective 03-20-91
(119) Order No. 355461 - Effective 03-20-91
(120) Order No. 355463 - Effective 03-20-91
(121) Order No. 355471 - Effective 03-21-91
(122) Order No. 364365 - Effective 06-25-92
(123) Order No. 364382 - Effective 06-25-92
(124) Order No. 368011 - Effective 05-23-93
(125) Order No. 372796 - Effective 06-25-93
(126) Order No. 381632 - Effective 07-11-94
(127) Order No. 381755 - Effective 07-11-94
(128) Order No. 387223 - Effective 10-20-94
(129) RM No. 950000023 - Effective 07-01-96
(130) RM No. 950000024 - Effective 07-01-96
(131) RM No. 950000025 - Effective 07-11-96
(132) RM No. 960000008 - Effective 07-01-96
(133) RM No. 960000009 - Effective 07-01-96
(134) RM No. 960000018 - Effective 10-15-96
(135) RM No. 970000002 - Effective 07-01-97
(136) RM No. 970000011 - Effective 07-01-98
(137) RM No. 970000025 - Effective 07-11-98
(138) RM No. 980000013 - Effective 07-15-98

(139) RM No. 980000016 Emergency, - Effective 03-30-98
(140) RM No. 980000017 Emergency, - Effective 03-30-98
(141) RM No. 980000020 Emergency, - Effective 01-05-99
(142) RM No. 980000033 - Effective 07-01-99
(143) RM No. 980000034 - Effective 07-01-99
(144) RM No. 980000035 - Effective 07-01-99
(145) RM No. 990000010 - Emergency, - Effective 12-28-99
(146) RM No. 200000002 - Effective 07-01-00
(147) RM No. 200000009 - Emergency, - Effective 11-02-00
(148) RM No. 200000009 - Permanent, - Effective 05-11-01
(149) RM No. 200100005 - Effective 07-01-01
(150) RM No. 200100006 - Effective 07-01-01
(151) RM No. 200100009 - Emergency, - Effective 01-14-02
(152) RM No. 200200017 - Effective 07-01-02

[**SOURCE:** Amended in Rule Making 980000033, eff 7-1-99; Amended in Rule Making 200200017, eff 7-1-02; Amended in Rule Making 200300001, eff 7-1-03]

165:10-1-5. Conservation Division [RESERVED]

165:10-1-6. Duties and authority of the Conservation Division

(a) It shall be the duty of the Conservation Division to administer and enforce the statutes of this State and the rules, regulations, and orders of the Commission relating to the conservation of oil and gas and the prevention of pollution in connection with the exploration, drilling, producing, transporting, purchasing, processing, and storage of oil and gas, and to administer and enforce the applicable provisions of the Natural Gas Policy Act of 1978.
(b) The Conservation Division shall have the right at all times to go upon and inspect any oil and gas properties, pipelines, tank farms, refineries, and other processing plants and pump stations for the purpose of making any investigations or tests to ascertain whether the rules, regulations, and orders of the Commission are being complied with, and shall report to the Commission any violation thereof.
(c) The Conservation Division may require the testing or retesting of any oil, gas, injection, or disposal well upon 48-hour notice. Until the test is completed or excused, no allowable will be assigned the well and the purchaser or taker of oil or gas from such well shall not run oil or gas until authorized by the Conservation Division.
(d) The Director of the Conservation Division may administratively reclassify a well according to the gas-oil ratio as specified in 165:10-13-2 if the retesting of a well pursuant to this Section as reported on Form 1029A indicates a change in the original gas-oil ratio. This administrative reclassification shall only be used for allowable or priority purposes pursuant to 165:10-17-12. The operator shall be notified in writing by the Conservation Division within 15 days of the effective date of any change in classification.
(e) If the operator of the well which has been reclassified objects to said reclassification, he may file a written objection with the Conservation Division within 15 days of receiving notice of the reclassification. At the same time that the objection is filed, the operator shall file an application and notice setting cause for hearing with the Court Clerk Commission. The notice shall be published one time at least 15 days prior to the hearing in a newspaper of general circulation published in Oklahoma County and in a newspaper of general circulation published in each county in which lands embraced in the application are located.
(f) The Conservation Division shall have access to all well records, wherever located. All companies, operators, drilling contractors, drillers, service companies, or other persons shall permit any authorized employee of the Commission to come upon any lease or property operated or controlled by them, and to inspect the records of wells; provided, that information so obtained

shall be confidential. Any person who attempts, by means of any threat or violence, to deter or prevent any authorized employee of the Commission from performing any duty hereunder shall be prosecuted to the fullest extent of the law.
(g) Upon request of the Conservation Division, service companies or other persons shall furnish and file reports and records showing gun perforating, hydraulic fracturing, cementing, shooting, chemical treatment, and all other service operations on any well.

[**SOURCE:** Amended at 9 Ok Reg 2337, eff 6-25-92]

165:10-1-7. Prescribed forms
(a) Required Conservation Division forms may be submitted to the Commission on forms supplied by the Commission or on xerographic copies of Commission forms or by operator computer generated forms. Operator computer generated forms will be printed from Commission designed files made available to operators via the electronic Bulletin Board Service (BBS), Internet (World Wide Web) or magnetic disk. Operator computer generated forms must contain the exact language and wording of Commission forms. Any alteration of Commission forms language and wording may subject the signature party and/or operator to perjury charges.
(b) The following Conservation Division forms are prescribed for filing purposes:

(1) **Form 1000 - Notice of Intention to Drill application:** Operator shall file Form 1000 before any oil, gas, injection, disposal, or service well is drilled, recompleted, or re-entered. Such notice shall include the name(s) and address(es) of the surface owner(s) of the land upon which the well is to be located. The Commission shall process the application and, if approved, return a computer-generated permit to the operator. The Commission shall mail a copy of the permit to drill or re-enter to the land owner(s). Upon approval, the operator will have six months to commence the permitted operations. A six month extension may be granted without fee providing the Conservation Division staff determines that no material change of condition has occurred, if written request for such extension is received from the operator prior to the expiration of the original permit. Only one extension may be granted. A copy of the approved permit shall be posted at the well site. [Reference 165:10-3-1 and 165:10-1-25]

(2) **Form 1000A - Request for Reserve Pit Requirements:** The operator shall file Form 1000A in duplicate for information before any noncommercial pit is constructed. The Commission shall indicate the necessary liner requirements, if any, and return to the operator. [Reference 165:10-7-16]

(3) **Form 1000B - Application to Drill Deep Anode Groundbeds:** Form 1000B is required to be filed for wells drilled for deep anode groundbeds as required by OAC 165:10-7-14. The purpose of Commission Form 1000B is to ensure groundwater is being protected in construction of the deep anode groundbed. [Reference 165:10-7-14]

(4) **Form 1000S - Application to Drill Seismograph and Stratigraphic Test Holes:** The applicant must post a $50,000 bond with the Surety Department in the Oil and Gas Conservation Division. The application must also be accompanied with a plat of the project area. [Reference 165:10-7-31]

(5) **Form 1001 - Notification of Intention to Plug:** Operator shall file notice on Form 1001, in duplicate, five days prior to plugging operations and shall notify the appropriate Commission District Office before work is started. If the well is an exhausted producer, list OTC assigned county and lease number. If the Intent to Plug is cancelled, the operator shall notify the Commission by letter. The operator of each offset producing lease shall be notified prior to the plugging of any well other than a dry hole. [Reference 165:10-11-4, 165:10-11-5, and 165:10-11-6]

(6) **Form 1001A - Notification of Spudding of New Well:** Form 1001A is mailed to the operator with the intent to drill permit. Operator shall file with the Conservation Division within 14 days of spudding a new well or reentering a previously plugged well. [Reference 165:10-3-1]

(7) **Form 1002A - Well completion report:** Operator shall furnish a complete well record on Form 1002A within 30 days after completion of operations to

drill, recomplete, re-enter, or convert to injection or disposal well. Effective for both dry hole and/or producer. If well is an oil or gas producer, list OTC assigned county and lease number. Gas-oil ratio must be shown when Form 1002A is filed. List on a 24-hour basis both oil and gas. [Reference 165:10-3-25]

(A) **Oil well:** GOR less than 15,000:1

(B) **Gas well:** GOR 15,000:1 or more

(8) **Form 1002B - Confidential Filing of Electric Logs:** Operator shall file Form 1002B within 60 days of the running of the last formation evaluation type wire line log to hold logs confidential for one year period. Optional extension for six months may be requested by operator in writing to the Technical Department of the Conservation Division. [Reference 165:10-3-26]

(9) **Form 1002C - Cementing Report to accompany Well Completion Report:** Operator shall file Form 1002C with the Well Completion Report (Form 1002A) describing all cementing operations on surface, intermediate, and production casing strings, including multistage cementing jobs. The form shall be completed and signed by employees of both the operator and the cementing company. [Reference 165:10-3-4(h)]

(10) **Form 1003 - Plugging Record:** Operator will file Form 1003, in duplicate, within 30 days after plugging operations are completed. Both copies are to be mailed to the applicable Commission District Office. If a depleted producer, list OTC assigned county and lease number. [Reference 165:10-11-6 and 165:10-11-7]

(11) **Form 1003A - Notice of Temporary Exemption from Well Plugging:** Form 1003A shall be filed with the appropriate District Office. [Reference 165:10-11-3]

(12) **Form 1003C - Cementing Report to accompany Plugging Record:** operator shall file Form 1003/1003C when well has been plugged. Form 1003/1003C shall be completed and signed by employees of both the operator and the cementing company. [Reference 165:10-11-6 and 165:10-11-7]

(13) **Form 1004 - Monthly Report of Unallocated Natural Gas Wells Production:** Each operator of the required meter under 165:10-17-5 shall make a monthly well on Form 1004 report with the Commission of all natural gas volumes transferred through the meter for the preceding month, by the last day of the month following such transfer. List formation name plus OTC assigned county and lease number. If more than one meter, the operator of each shall file this form. [Reference 165:10-1-47]

(14) **Form 1004B - Notice of Gas Purchase Curtailments:** In any month wherein a first purchaser or first taker has a market demand/supply imbalance and must curtail purchases or takes in compliance with 165:10-17-12, Form 1004B shall be filed by said first purchaser or first taker with the Conservation Division. [Reference 165:10-17-12]

(15) **Form 1005 - Monthly Report of Purchasers** (Gas: subject to field rules): [Reference 165:10-1-47 and 165:10-15-1]

(A) **GAS:** Each operator of the required meter or meters under 165:10-17-5 shall complete computer-generated Form 1005, and return a copy to the Conservation Division indicating the gas amounts transferred through the meter for the preceding month on allocated and special allocated gas wells.

(B) **OIL:** Each first purchaser, or first taker of oil from wells and projects which are capable of producing in excess of their maximum assigned allowables, must complete computer-generated Form 1005 and return a copy to the Conservation Division indicating the amount of oil taken from each well or unit for the preceding month.

(16) **Form 1006 - Surety bond for oil, gas, injection, or disposal wells:** Prior to drilling and/or operating a well, the operator shall furnish the Conservation Division a surety bond ($25,000.00) or other present alternate surety, Form 1006A or 1006C. Operator must file the original copy only with a copy of the power of attorney from the bonding company. The name and address of the Oklahoma resident service agent shall be endorsed on the bond form. [Reference 165:10-1-12]

(17) **Form 1006A - Financial Statement for oil, gas, injection or disposal wells:** Prior to drilling and/or operating a well, the operator shall furnish the Conservation Division a verifiable financial statement (minimum net worth $50,000.00 within the State of Oklahoma) or other present

alternate surety, Form 1006 or 1006C. Operator must file an original copy on Form 1006A, which must be updated annually from the last filing date. [Reference 165:10-1-11]

(18) **Form 1006B - Operator Agreement to plug oil, gas, and service wells within the State of Oklahoma:** Operator shall agree to plug well(s) in compliance with the Commission rules. This agreement must accompany the operator's elective choice of surety (Form 1006, 1006A, or 1006C). The operator is required to file a Form 1006B with the Conservation Division once every twelve (12) months. [Reference 165:10-1-10, 165:10-1-11, 165:10-1-12, 165:10-1-13, and 165:10-1-14]

(19) **Form 1006BR - Recycling, Reclaiming Operator's Agreement to Close the Reclaiming Facility:** Prior to operating a recycling or reclaiming facility the operator shall file an agreement to close the facility in compliance with OCC rules. This agreement must accompany the application for certification (Form 1020A). [Reference 165:10-8-1 and/or 165:10-8-2]

(20) **Form 1006C - Irrevocable commercial letter of credit:** Prior to drilling and/or operating a well, the operator shall furnish the Conservation Division an irrevocable commercial letter of credit ($25,000.00) or other present alternate surety, Form 1006A or 1006. Operator must file the original copy with the bank seal affixed. A letter of credit must be valid for at least a one year period. [Reference 165:10-1-13]

(21) **Form 1006SB - Surety bond for seismic shot hole plugging within the State of Oklahoma:** Before commencing any seismic operation that requires the drilling of shot holes, those companies actually doing the work in the field must secure a bond in the amount of $50,000.00. Seismic companies must file the original Form 1006B only with a copy of the power of attorney from the bonding company. The name and address of the Oklahoma resident service agent shall be endorsed on the bond form. Form 1006S shall be filed with the bond. [Reference 165:10-11-6]

(22) **Form 1007A - IBM operator annual unallocated natural gas wells survey:** Annual Survey Form 1007A will be furnished to all operators at the end of each calendar year in duplicate. The form shall be updated by the operator as of December 31 notifying the Commission of any new wells, wells sold (to whom and address), or abandoned since the last 1007A was filed. Original only shall be forwarded to Conservation Division by February 15th for the previous year's activity. List OTC assigned county and lease number (if not imprinted). See 165:10-17-11 for production penalties on overproduced wells. [Reference 165:10-17-1 and 165:10-17-16]

(23) **Form 1008S - Operators agreement to plug seismic shot holes with the State of Oklahoma:** Before commencing any seismic operation that requires the drilling of shot holes, those companies actually doing the work in the field shall be duly registered with the Conservation Division on Form 1006SB. [Reference 165:10-11-6]

(24) **Form 1010 - Application for Cancelled Underage:** Operator shall file, within 30 days for oil, and six months for special allocated and allocated gas from the date of cancellation, to reinstate cancelled underage; stating reason for this request and notifying all offset operators. List OTC assigned county and lease number. [Reference 165:10-15-5]

(25) **Form 1012 - Annual Fluid Injection Report:** Operators shall file Form 1012 by April 1 of each year covering the previous calendar year (January 1 through December 31) on all enhanced recovery projects, pressure maintenance projects, and salt water disposal wells (commercial disposal wells will report twice per year on January 31 and July 31 for the previous six months) for each UIC well. The completed form will list well identification including API number, the Commission order number, injection volume and pressure, etc., as required on the form. No UIC well is to be operated for injection or disposal unless the Form 1012 is filed by the above dates. [Reference 165:10-5-7].

(26) **Form 1013 - Application for adjusting an allowable for an Excessive Water Exemption or Reservoir Dewatering Oil Spacing unit:** An operator in an unallocated oil pool may be permitted to produce at a full capacity allowable rate, provided that the water- oil ratio at the well is greater than or equal to 3:1 as in excessive water exemption. To qualify for the

reservoir dewatering oil spacing unit allowable shown on Appendix J, the operator must provide data to show that the water - oil ratio is greater than 1:1 [Reference 165:10-15-1, 165:10-15-16, 165:10-15-17 and 165:10-15-18].

(27) **Form 1014 - Application for Permit to Use Earthen Pit:** The operator of a proposed off-site reserve pit, recycling/reuse pit, spill containment pit, or remediation pit must submit Form 1014 in duplicate to the appropriate District Office for approval before constructing or using the pit. [Reference 165:10-7-16]

(28) **Form 1014CS - Application for Commercial Soil Farming:** For a commercial soil farming site which has an order to operate, the operator shall submit a Form 1014CS to the Pollution Abatement Department for prior approval each time that soil farming is proposed to be done. The application must be processed within ten (10) days of submission. [Reference 165:10-9-2]

(29) **Form 1014D - Application for Surface Discharge:** Each application for surface discharge of produced water must be submitted to a Field Operations office on Form 1014D in quadruplicate. Applications will be processed within five working days. [Reference 165:10-7-17 or 165:10-7-32]

(30) **Form 1014HD - Application for Disposal of Hydrostatic Test Water:** Company wishing to discharge water as required by OAC 165:10-7-17, used to test a pipeline or tank, must submit a Form 1014HD to the Pollution Abatement Department for prior approval. [Reference 165:10-7-17]

(31) **Form 1014L - Surface Owner Permission for Land Application:** Each application for land application must include an original Form 1014L, whereby the applicable surface owner gives permission for the applicant to land apply certain deleterious substances to a specific property. [Reference 165:10-7-19 and 165:10-7-26]

(32) **Form 1014N - Application for Commercial Pit Construction:** After a Commission order is obtained, Form 1014N must be submitted for approval by the Manager of Pollution Abatement prior to the construction of each commercial pit authorized by the order. [Reference 165:10-9-1]

(33) **Form 1014S - Application for Land Application:** Each application for land application of materials must be submitted to a Field Operations office on Form 1014S. An original and three copies are required. The applicant must be the operator of the well or other operator responsible for generating the waste to be land applied, except that a commercial pit operator may also apply in case of emergency or for the purpose of facilitating repair or closure, and the Oklahoma Energy Resources Board or its contractor may apply in cases where there is no responsible party. The Form 1014S shall be processed within five working days of submission of all required or requested information. [Reference 165:10-7-19 and 165:10-7-26]

(34) **Form 1014W - Application for waste oil or drill cuttings use by County Commissioners:** Application to apply waste oil, waste oil residue, or freshwater drill cuttings must be made by any Board of County Commissioners on Form 1014W. An original and one copy are required to be submitted to the appropriate District Manager. [Reference 165:10-7-22 and 165:10-7-28]

(35) **Form 1014X - Application for waste oil or drill cuttings use by operators:** Application to apply waste oil, waste oil residue, or freshwater drill cuttings must be made by any operator on Form 1014X. An original and one copy are required to be submitted to the appropriate District Manager. [Reference 165:10-7-27 and 165:10-7-29]

(36) **Form 1015 - Application for Administrative Approval to Dispose of or Inject Water into Well(s):** Applicant shall file an original and six copies of application and one complete set of attachments to the Commission on Form 1015. Applicant will also furnish one copy of the application on Form 1015 to the landowner and a copy of the application to each operator of a producing leasehold within one-half (1/2) mile of the well location. Applicant will submit an affidavit of delivery or mailing not later than five days after the application is filed and shall file proof of publication in an Oklahoma City newspaper and a county newspaper in which the well is located. [Reference 165:10-5-5]

(37) **Form 1015SI - Application for Permit for Simultaneous Injection Well:** Operator shall file original and three copies with the Underground Injection

Control Department on Form 1015SI. A copy of the form will also be supplied to the operator of any producing lease within (1/2) mile of the proposed injection well. [Reference 165:10-5-15]

(38) **Form 1015T - Application for Injection of Reserve Pit Fluids:** Each application for the on-site injection of reserve pit fluids (i.e., drilling mud fluids or fracture fluids) used in drilling or well completion shall be filed with the Underground Injection Control Department by the well operator on Form 1015T. The original and three copies of the application and one complete set of attachments shall be furnished to the Underground Injection Control Department. A copy of the application will also be supplied to the land owner and the operator of any producing lease within 1/2 mile of the proposed well. [Reference 165:10-5-13]

(39) **Form 1015U - Unit-wide application for Injection:** Optionally, the operator can file a unit-wide application for injection (Form 1015U) that fulfills all the requirements of 165:5-7-27 (b) through (e). Upon review and approval, the operator receives a unit-wide order that allows the operator to file an individual well application (Form 1015) and if it fits the unit-wide criteria, the UIC order can be issued immediately without an additional area of review, notice, or protest period. [Reference 165:5-7-27]

(40) **Form 1016 - Back Pressure Test for Natural Gas Wells:** Operators and/or purchasers, on the Form 1016, will report all single-point and four-point potential tests as required by pool rule orders or general rules. List OTC assigned county and lease numbers and special allocated pool numbers, first date of sales, and complete flow data. [Reference 165:10-17-6 and 165:10-17-7]

(41) **Form 1017 - Guymon-Hugoton Field Gas Well Deliverability Tests:** Operators and/or purchasers of gas in this field shall take deliverability tests between January 1 and August 31 of each year, and on the test sheet Form 1017 file the results with the Commission. List OTC assigned lease number for each well. [Reference Orders No. 17867 and 87291]

(42) **Form 1019 - Guymon-Hugoton Field Acreage Statement for Gas Wells:** A fact statement as to acreage attributable to each well shall be filed with the Commission on Form 1019 within 30 days of the well completion with a plat or map showing location of the well. List OTC assigned county and lease number. [Reference Order No. 17867]

(43) **Form 1020A - Application for Certification for the Recycling, Reuse of Deleterious Substances:** Applicant shall file an original Form 1020A with necessary attachments with the Pollution Abatement Department. Form 1020A is filed prior to construction of facility or change of operator. [Reference 165:10-8-1 and/or 165:10-8-2]

(44) **Form 1021 - Application for Priority Hardship Classification:** The applicant shall file Form 1021 and the necessary attachments with the Technical Department for review prior to any hearing for priority one hardship classification. In addition, a formal application for hearing must be filed with the Court Clerk's Office of the Commission. [Reference 165:10-17-12]

(45) **Form 1021A - Application for limited deviation from the priority gas rules:** The applicant shall file Form 1021A and the necessary attachments with the Technical Department for review prior to any hearing for deviation from the priority gas rules. In addition, a formal application for hearing must be filed with the Court Clerk's Office of the Commission. [Reference 165:10-17-12]

(46) **Form 1022 - Application to flare or vent gas:** Operator shall file one copy of Form 1022 to the Technical Department of the Conservation Division listing OTC assigned county lease number. [Reference 165:10-3-15]

(47) **Form 1022A - Application to operate vacuum pump:** Operator shall file one copy of Form 1022A with the required attachments to the Technical Department of the Conservation Division. No filing fee will be required for application to operate a vacuum pump. Notice requirements as set out in OAC 165:5-7-25 shall apply. [Reference 165:10-3-31]

(48) **Form 1023 - Application for multiple completion, multichoke assembly or commingle completion:** Operator will file the original and four copies

of Form 1023 with the required attachments. List OTC assigned county and lease number. [Reference 165:10-3-35; 165:10-3-39; 165:10-3-37]

(49) **Form 1024 - Packer setting affidavit:** Operator will submit Form 1024 as required. [Reference 165:10-3-35 and pertinent field rules]

(50) **Form 1025 - Packer leakage test:** Operator will submit Form 1025 as required. [Reference 165:10-3-35 and pertinent field rules]

(51) **Form 1027 - Bottom hole pressure test:** Operator, on the pink sheet of Form 1027, shall take BHP tests in the manner and during periods prescribed by special field rules. List OTC assigned county and lease numbers. [Reference Special Field Rules and 165:10-13-3]

(52) **Form 1028 - Application for discovery oil allowable:** Operator shall file Form 1028 with the required exhibits and tests within 30 days of completion of each new well in a discovery oil pool. [Reference 165:10-15-7]

(53) **Form 1029A - Production or potential test - oil only:** Operator of each newly completed oil well shall file a potential test Form 1029A not later than 30 days after completion of the well. All tests, if requested, shall be witnessed by another operator.

(54) **Form 1030 - Application for allowable adjustment:** Each operator or other interested parties desiring to adjust the allowable for a well or wells shall file Form 1030 for administrative review and approval. The allowable may be increased, decreased, or transferred as the evidence may indicate for the most efficient rate of production from the well or wells. [Reference 165:10-13-5, 165:10-13-8, 165:10-15-18 and 165:5-7-12]

(55) **Form 1034 - Nominations and purchasers report:** [Reference 165:10-1-49]

(A) **Oil:** Purchasers will furnish nomination data, actual runs from leases, stocks, and other information on Form 1034 to the Conservation Division not later than noon Friday of the week preceding each scheduled market demand hearing. On months in which no market demand hearing is held, Form 1034 shall be filed by the 20th of the month listing crude oil runs for the previous month on line 5 only. Any change in nominations from the previous hearing shall be so indicated on this monthly report.

(B) **Gas:** Purchasers shall file their nominations by letter for wells in special allocated pools no later than one week prior to the market demand hearing.

(56) **Form 1040 - Monthly allocation schedule (gas):** Monthly gas schedule Form 1040 will be forwarded to operators by the Conservation Division indicating the status of special allocated gas wells and their current allowables. Operators will inform the Conservation Division of errors, if any, found in Form 1040 as promptly as possible. Additionally, purchasers will receive the monthly schedule and shall return the production from each well as requested. [Reference 165:10-1-47]

(57) **Form 1062 - Field Operations Inspection Report:** IN-HOUSE USE ONLY.

(58) **Form 1070 - Inventory of authorized existing enhanced recovery wells:** Operators shall file reporting Form 1070 before injecting into any enhanced recovery well. [Reference 165:10-5-3]

(59) **Form 1071 - Inventory of authorized existing disposal wells:** Operators shall file the reporting Form 1071 before disposing into any disposal well. [Reference 165:10-5-3]

(60) **Form 1072 - Notice of (commencement) (termination) of injection:** Within 30 days of either the commencement or termination of injection Form 1072 must be filed. Failure to file Form 1072 within 18 months from the date of authorization results in termination of the Commission order. [Reference 165:10-5-7]

(61) **Form 1073 - Notice of transfer of well operatorship:** The new operator shall file Form 1073 to notify the Conservation Division of any change of operation or purchaser of any oil, gas injection, disposal, or enhanced recovery injection well within 30 days after transfer of the well. [Reference 165:10-5-10 and 165:10-1-15]

(62) **Form 1073I - Notice of transfer of well operatorship:** The new operator shall file Form 1073I to notify the Underground Injection Control Section of any change of operation of any injection, disposal, or enhanced

recovery injection well within 30 days after transfer of the well. [Reference 165:10-5-10 and 165:10-1-15]

(63) **Form 1075 - Mechanical integrity pressure test:** A pressure or monitoring test must be performed on new and existing enhanced recovery injection wells and disposal wells. Information must be submitted on Form 1075 and witnessed by a Field Inspector. Forms shall be submitted to the Conservation Division's Underground Injection Control Department. [Reference 165:10-5-6]

(64) **Form 1081 - Mineral owners escrow account:** Operator shall file, in quadruplicate, Form 1081 annually on anniversary date of first pooling order issued after effective date of Senate Bill 299 (7-1-84) and shall include all applicable orders issued during the twelve-month reporting period. [Reference 165:10-25-1 through 165:10-25-10]

(65) **Form 1085 - Complaint report:** Form 1085 is used by Commission personnel to report violations of General Rules of the Commission to report progress on ongoing remedial actions. Copies are sent to all parties concerned with investigation. Form 1085 combines and replaces old Forms 1034 and 1062. [Reference 165:10-7-7]

(66) **Form 1139 - Application for gross production tax exemption:** Operators shall file one copy of Form 1139 with the required attachments to the Technical Department of the Conservation Division. [Reference 165:10-21-75 through 165:10-21-80]

(67) **Form 1534 - Application for tax rebate:** Operators shall file one original of Form 1534 with the required attachments to the Technical Department of the Conservation Division. To obtain the tax exemption of the gross production tax, the operator shall forward a copy of the Commission order to the Oklahoma Tax Commission, together with any other data required by that agency. [OTC Rule 10.030.03] [Reference 165:10-21-23, 165:10-21-37, 165:10-21-47, 165:10-21-57, 165:10-21-67 and 165:10-21-82.2]

(68) **Form 1535 - Application for classification of reservoir dewatering project for exemption of sales tax on electricity used for such operations:** Operators shall file one original of Form 1535 with the required attachments to the Technical Department of the Conservation Division. To obtain the exemption of sales tax on the sale of electricity and associated delivery and transmission used for reservoir dewatering operations, the operator shall contact the Director’s Office, Taxpayer Assistance Division, Oklahoma Tax Commission, 2501 N. Lincoln Blvd., Oklahoma City, Ok. 73194. [Reference 165:10-21-83, 165:10-21-83.1 and 165:10-21-83.2]

[**SOURCE:** Amended at 12 Ok Reg 2017, eff 7-1-95; Amended at 13 Ok Reg 2373 and 2381, eff 7-1-96; Amended in Rule Making 97000002, eff 7-1-97; Amended in Rule making 980000013, eff 7-15-98; Amended in Rule Making 980000033, eff 7-1-99; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200200017, eff 7-1-02; Amended in Rule Making 200300001, eff 7-1-03]

PART 3. SURETY

165:10-1-10. Operator's agreement; Category A and Category B surety

(a) "Any person who drills or operates any well for the exploration, development or production of oil or gas, or as an injection or disposal well, within this State, shall furnish in writing, on forms approved by the Corporation Commission, his agreement to drill, operate and plug wells in compliance with the rules and regulations of the Commission and the laws of this state, together with evidence of financial ability to comply with the requirements for plugging, closure of surface impoundments, removal of trash and equipment as established by the rules of the Commission and by law." [52 O.S. § 318.1] Any operator violating this Section shall be fined $500.00. To establish evidence of financial ability, the Commission shall require:

(1) Category A surety which shall include a financial statement listing assets and liabilities and including a general release that the information may be verified with banks and other financial institutions. The statement shall prove a net worth of not less than $50,000.00 in U.S. dollars; or

(2) Category B surety shall include an irrevocable commercial letter of credit, cash, a cashier's check, a certificate of deposit, bank joint custody receipt, other approved negotiable instrument, or a blanket surety bond. Except as provided in (3) of this subsection, the amount of such Category B surety shall be in the amount of $25,000.00 in U.S. dollars but may be set higher at the discretion of the Director of the Conservation Division. The Commission is authorized to establish Category B surety in an amount greater than $25,000.00 in U.S. dollars based upon the past performance of the operator and its insiders and affiliates regarding compliance with the laws of this state, and compliance with any rules promulgated thereto including but not limited to the drilling, operation and plugging of wells, closure of surface impoundments, or removal of trash and equipment. Any such Category B surety shall constitute an unconditional promise to pay and be in a form negotiable by the Commission.
(3) The Commission may grant Category B surety in an amount less than $25,000.00 in U.S. dollars to an operator whose statewide well plugging liability is less than $25,000.00 in U.S. dollars. Said Category B surety shall be in an amount that is sufficient to cover the total estimated cost of properly plugging and abandoning each and every well, the operations for which, an operator is responsible. Statewide well plugging liability shall be documented by an affidavit filed on Form 1006D and shall be properly executed by a duly licensed pipe pulling and well plugging company and shall be approved by the Conservation Division. Said affidavit shall state, among other things, an estimated cost of plugging, closure, and removal operations for each well in accordance with 165:10-11-3 through 165:10-11-8 inclusively and shall be accompanied by a Form 1000 (Intent to Drill) if the estimate involves a proposed well or by a Form 1002A (Completion Report) if the estimate involves a well that is a producing, injection, or disposal well. The estimated cost shall not include any salvage value as to recoverable casing, tubing, or well head equipment. The total statewide well plugging liability of an operator utilizing this Category B surety shall be kept current and shall be increased as additional wells are added to the responsibility of the operator and may be decreased as included wells are plugged and abandoned, but in no event shall exceed $25,000.00 in U.S. dollars unless otherwise ordered by the Commission.
(b) Operators of record as of June 7, 1989, who do not have any outstanding contempt citations or fines and whose insiders or affiliates have no outstanding contempt citations or fines may post Category A surety.

(1) New operators, operators who have outstanding fines or contempt citations and operators whose insiders or affiliates have outstanding contempt citations or fines as of June 7, 1989, shall be required to post Category B surety. Operators who have posted Category B surety and have operated under this type surety and have no outstanding fines at the end of three years may post Category A surety.

(2) Operators using Category A surety who are assessed a fine of $2,000.00 or more and who do not pay the fine within the specified time shall be required to post a Category B surety within 30 days of notification by the Commission.

(c) If a bond is required, the bond shall be executed by a corporate surety authorized to do business in this State and shall be renewed and continued in effect until the conditions have been met or release of the bond is authorized by the Commission.
(d) Irrespective of (a), (b), and (c) of this Section, for good cause shown concerning pollution or improper plugging of wells by an operator posting either Category A or Category B surety or by an insider or affiliate of such operator, the Commission, upon application of the Director of the Conservation Division after notice and hearing, may require the filing of additional Category B surety in an amount greater than $25,000.00 in U.S. dollars but not to exceed $100,000.00 in U.S. dollars.
(e) The agreement (Form 1006B-Operator’s Agreement to Plug Oil, Gas and Service Wells Within the State of Oklahoma) provided for in (a) of this Section shall provide that if the Commission determines, after notice and hearing, that the person furnishing the agreement has neglected, failed, or refused to plug and abandon, or cause to be plugged and abandoned, or replug any well or has neglected, failed or refused to close any surface impoundment or remove or cause to be removed trash and equipment in compliance with the rules of this Chapter,

then the person shall forfeit from his bond, letter of credit, or negotiable instrument or shall pay to this State, through the Commission for deposit in the State Treasury, a sum equal to the cost of plugging the well, closure of any surface impoundment, or removal of trash and equipment. The Commission may cause the remedial work to be done, issuing a warrant in payment of the cost thereof drawn against the monies accruing in the State Treasury from the forfeiture or payment. Any monies accruing in the State Treasury by reason of a determination that there has been a noncompliance with the provisions of the agreement (Form 1006B) or the rules and regulations of the Commission, in excess of the cost of remedial action ordered by the Commission, shall be credited to the Conservation Fund. The Commission shall also recover any costs arising from litigation to enforce this provision if the Commission prevails. Provided, before a person is required to forfeit or pay any monies to the State pursuant to this Section, the Commission shall notify the person at his last-known address of the determination of neglect, failure, or refusal to plug or replug any well, or close any surface impoundment, or remove trash and equipment, and said person shall have ten days from the date of notification within which to commence remedial operations. Failure to commence remedial operations shall result in forfeiture or payment as provided in this subsection. If the operator is a corporation, association, partnership, limited liability company or any entity other than an individual, the operator shall file as part of its Form 1006B a complete list, in tabular form, of the names, addresses, telephone numbers, social security numbers or driver license numbers, and percentages of ownership of all officers, directors, partners or principals of the operator and the insiders and affiliates of the operator. The operator shall also file as part of its Form 1006B the current names and addresses of all service agents of the operator and the operator's insiders and affiliates. The operator is required to file a Form 1006B with the Conservation Division every twelve (12) months.

(f) No person shall drill or operate any well, or receive an allowable, without complying with the provisions of this Section.

(g) The Commission shall shut in, without notice, hearing or order of the Commission, the wells of any such person violating the provisions of this Section and such wells shall remain shut in for noncompliance until the required evidence of Category B surety is obtained and verified by the Commission. No taker, transporter, or purchaser of oil or gas shall take, transport, or purchase oil or gas from the wells of any such drillers or operators after receiving a copy of the shut-in order or notice by certified mail of the issuance of such an order.

(h) If title to property or a well is transferred, the transferee shall furnish the evidence of financial ability to plug the well and close surface impoundments required by the provisions of this section, prior to the transfer.

(i) The following words, when used in this Section, shall have the following meaning:

(1) "Affiliate" means an entity which owns twenty percent (20%) or more of the operator, or an entity of which twenty percent (20%) or more is owned by the operator.

(2) "Insider" means officer, director, or person in control of the operator; general partners of or in the operator; general or limited partnership in which the operator is a general partner; spouse of an officer, director, or person in control of the operator; spouse of a general partner of or in the operator; corporation of which the operator is a director, officer, or person in control; affiliate, or insider of an affiliate as if such affiliate were the operator; or managing agent of the operator.

[SOURCE: Amended at 9 Ok Reg 2295, eff 6-25-92; Amended at 13 Ok Reg 2373, eff 7-1-96]

165:10-1-11. Financial statement as surety

(a) A plugging agreement shall be accompanied by surety. The surety requirement may be met by furnishing the operator's current financial statement (Form 1006A) to the Conservation Division, which shall be a full statement of

the operator's assets and liabilities and shall reflect the operator's total net worth of not less than $50,000.00 in U.S. dollars located in this State.
(b) The value of producing oil and gas leaseholds for which the financial statement stands as surety will be deducted from total net worth unless the financial statement is accompanied by the written appraisal of a recognized independent appraiser of oil and gas properties showing the fair market value of the leasehold interest owned by the operator.
(c) The Director of Conservation may require proof in the form of an appraisal or other proof of the fair market value of any asset listed in the financial statement, and the Director of Conservation may also require proof that the financial statement truly shows the net fair market value of all assets over and above all debts and encumbrances.
(d) A current financial statement shall be filed every twelve (12) months on Form 1006A.
(e) Only one operator's name shall appear on each Form 1006A.
(f) Along with the Form 1006A, an operator is required to file a Form 1006B (Operator's Agreement to Plug Oil, Gas and Service Wells Within the State of Oklahoma) with the Conservation Division.
(g) The Commission shall reject the operator's Form 1006A if the operator fails to file the documentation required by this Section with the Conservation Division.

[SOURCE: Amended at 13 Ok Reg 2373, eff 7-1-96]

165:10-1-12. Corporate surety bond
(a) An operator may file a blanket surety bond in the principal amount of $25,000.00 in U.S. dollars on Form 1006 as surety. In the alternative, the operator may file a surety bond of a lesser amount but that is sufficient to cover the total estimated cost of properly plugging and abandoning each and every well, the operations for which, the operator is responsible. Said estimated cost shall be documented on Form 1006D (Affidavit of Well Plugging Cost) for each and every well. Said alternative surety bond shall be increased upward, but not to exceed $25,000.00 in U.S. dollars, as additional wells are added to the operator's responsibilities, unless otherwise ordered by the Commission.
(b) For purposes of (a) of this Section, an operator may file a surety bond issued by a corporation authorized to issue such bonds in the State of Oklahoma.
(c) The Conservation Division shall not accept a bond unless the surety agrees to give the Conservation Division six months written notice before cancellation of a bond prior to expiration of the bond and evidence furnished of acceptable alternate surety if required.
(d) Only one operator's name shall appear on each Form 1006.
(e) Along with the Form 1006, an operator is required to file a Form 1006B (Operator's Agreement to Plug Oil, Gas and Service Wells Within the State of Oklahoma) with the Conservation Division.
(f) The Commission shall reject the operator's Form 1006 if the operator fails to file the documentation required by this Section with the Conservation Division.

[SOURCE: Amended at 13 Ok Reg 2373, eff 7-1-96]

165:10-1-13. Irrevocable commercial letter of credit
(a) At his option, an operator may file an irrevocable commercial letter of credit of a bank in the sum of $25,000.00 in U.S. dollars on Form 1006C as surety. In the alternative, the operator may file an irrevocable commercial letter of credit of a lesser amount but that is sufficient to cover the total estimated cost of properly plugging and abandoning each and every well, the operations for which, the operator is responsible. Said estimated cost shall be documented on Form 1006D (Affidavit of Well Plugging Cost) for each and every well. Said alternative irrevocable commercial letter of credit shall be

increased upward, but not to exceed $25,000.00 in U.S. dollars, as additional wells are added to the operator's responsibilities, unless otherwise ordered by the Commission.
(b) The letter of credit shall be for a term of not less than one year.
(c) The bank issuing the letter of credit shall endorse thereon that the letter of credit shall remain in effect until canceled or revoked by the bank or principal/operator upon six months notice in writing to the Conservation Division and evidence furnished of acceptable alternate surety if required.
(d) Only one operator’s name shall appear on each Form 1006C.
(e) Along with the Form 1006C, an operator is required to file a Form 1006B (Operator’s Agreement to Plug Oil, Gas and Service Wells Within the State of Oklahoma) with the Conservation Division.
(f) The Commission shall reject the operator’s Form 1006C if the operator fails to file the documentation required by this Section with the Conservation Division.

[SOURCE: Amended at 13 Ok Reg 2373, eff 7-1-96]

165:10-1-14. Cashier's check, certificate of deposit, or other negotiable instrument
(a) An operator may deposit cash, a cashier's check, a certificate of deposit, bank joint custody receipt, or other negotiable instrument in the amount of $25,000.00 in U.S. dollars as surety. In the alternative, the operator may deposit cash, a cashier's check, a certificate of deposit, bank joint custody receipt, or other negotiable instrument of a lesser amount but that is sufficient to cover the total estimated cost of properly plugging and abandoning each and every well, the operations for which, the operator is responsible. Said estimated cost shall be documented on Form 1006D (Affidavit of Well Plugging Cost) for each and every well. Said alternate amount shall be increased upward, but not to exceed $25,000.00 in U.S. dollars, as additional wells are added to the operator's responsibilities, unless otherwise ordered by the Commission. However, any instrument must constitute an unconditional promise to pay and be in the form negotiable by the Commission.
(b) A certificate of deposit shall be for a term of no less than three hundred sixty-five (365) days.
(c) Financial institutions issuing certificates of deposit pursuant to this Section shall do so in the following manner: **"Oklahoma Corporation Commission or Oklahoma Corporation Commission and (Name of the Operator)."** Financial institutions issuing the certificates of deposit shall retain the original documents and copies of the certificates of deposit shall be furnished to the Commission.
(d) Along with the negotiable instruments described in (a) of this Section, an operator is required to file a Form 1006B (Operator’s Agreement to Plug Oil, Gas and Service Wells Within the State of Oklahoma) with the Conservation Division.
(e) The Commission shall reject the negotiable instruments described in (a) of this Section if the operator fails to file the documentation required by this Section with the Conservation Division.

[SOURCE: Amended at 13 Ok Reg 2373, eff 7-1-96]

165:10-1-15. Transfer of operatorship of wells
(a) Before the operations of a well can be transferred to a new operator, the following must be submitted:
  (1) The new operator, or transferee, must comply with 165:10-1-10 before a change in operator is approved.
  (2) Change of operator Form 1073 must be signed by both the transferor and transferee, with both stipulating that the facts presented are true and correct as to the area covered and the wells being transferred. Unless otherwise stated, the new operator assumes all responsibility for the wells specified within the boundaries of the outlined area. For transfers

involving more than ten (10) wells, a transferor and transferee may file a single Form 1073 with the Conservation Division indicating the transfer of multiple wells, provided that such multiple well transfer shall be accompanied by a well list containing the following information regarding each well being transferred:

(A) API number of the well;

(B) Well name and number;

(C) Legal location of the well, described by section, township and range.

(3) The well list may be provided in spreadsheet form, if possible, and may be filed in digital format specified by the Conservation Division. In lieu of the spreadsheet, the transferor and transferee, at their option, may file one Form 1073 indicating the transfer of multiple wells with an OCC Form 1002A Completion Report attached for each well transferred. Upon review by the Conservation Division, it may require additional information from the transferor and/or the transferee to assist in identifying the specific well(s) being transferred. The additional information may include, but not be limited to, the quarter, quarter, quarter section calls, footages from the south and west quarter section lines, and the drilling and completion dates.

(4) The Conservation Division shall notify both the transferor and transferee of approval of the transfer of operatorship within thirty (30) days of the Conservation Division's approval of said transfer.

(5) Compliance with 165:5-7-11 when and if operatorship was designated by orders of the Commission in pooling, increased density, and location exception applications.

(b) Before the operatorship of a well can be transferred to a new operator when the current or former operator is unavailable for signature, one of the following may be submitted as proof of operatorship:

(1) A certified copy of a recorded lease or assignment transferring all rights, title, and interest to the wells described on Form 1073 to the new operator.

(2) A certified copy of a journal entry of judgment rendered by a district court of Oklahoma having jurisdiction over the wells described on Form 1073 vesting legal title to the new operator.

(3) A certified copy of bankruptcy proceeding by the federal district court having jurisdiction over the wells described on Form 1073.

(c) If an operator is not in compliance with an enforceable order of the Commission, the Conservation Division shall not approve any Form 1073 transferring well(s) to said operator until the operator complies with the order. The transferor of the well(s) listed on the Form 1073 remains responsible for the well(s) until any transfer is approved by the Commission.

[SOURCE: Amended at 13 Ok Reg 2373, eff 7-1-96; Amended in Rule Making 2000000002, eff 7-1-00]

165:10-1-16. Change of address

Each operator of a well or other facility subject to a permit shall give written notice of his change of address. Such notice shall be sent to the Director of the Conservation Division. It shall be due within 30 days after changing address.

[SOURCE: Amended at 9 Ok Reg 2295, eff 6-25-92; Amended at 13 Ok Reg 2373, eff 7-1-96]

PART 5. SPACING

165:10-1-20. Spacing [RESERVED]

165:10-1-21. General well spacing requirements

Any well drilled for oil or gas to an unspaced common source of supply 2,500 feet or more in depth shall be located not less than 330 feet from any property line or lease line, and shall be located not less than 600 feet from any other producible or drilling oil or gas well when drilling to the same common source of supply; provided and except that in drilling to an unspaced common source of supply that is less than 2,500 feet in depth, the well shall be located not less than 165 feet from any property line or lease line and not less than 300 feet from any other producible or drilling oil or gas well in the same common source of supply; provided, however, that the completed depth of the discovery well shall be recognized as the depth of the common source of supply for the purpose of this Section; provided further, when an exception to this Section is granted, the Commission may adjust the allowable or take such other action as it deems necessary for the prevention of waste and protection of correlative rights.

165:10-1-22. Drilling and spacing units

(a) The Commission may establish drilling and spacing units in any common source of supply as provided by law, and the special orders creating drilling and spacing units shall supersede the provisions of 165:10-1-21. It shall be the responsibility of any operator who proposes to drill a well to ascertain the existence and provisions of special spacing orders.
(b) The drilling of a well or wells into a common source of supply in an area covered by an application pending before the Commission seeking the establishment of drilling and spacing units is prohibited except by special order of the Commission. However, if an Intent to Drill (Form 1000) has been approved by the Commission and operations commenced prior to the filing of a spacing application, the operator shall be permitted to drill and complete the well without a special order of the Commission.
(c) Standard drilling and spacing units shall be either approximately square or rectangular; if rectangular, the drilling and spacing unit shall consist of two approximately square tracts.
(d) Standard square drilling and spacing units shall be those containing approximately 10, 40, 160, or 640 acres; standard rectangular units shall contain approximately 20, 80, or 320 acres.
(e) The drilling and spacing units within any common source of supply of oil or gas shall be of approximately uniform size and shape. In a combination reservoir, the drilling and spacing units within the oil portion of the reservoir shall be of approximately uniform size and shape, and the drilling and spacing units within the gas portion of the reservoir shall be of approximately uniform size and shape; provided, however, the drilling and spacing units within the gas portion of a combination reservoir along the gas-oil contact line or transition zone may be of nonuniform size and shape.

[**SOURCE:** Amended at 9 Ok Reg 2337, eff 6-25-92]

165:10-1-23. Extension of pool rules

(a) Any application to establish pool rules for a common source of supply shall include the entire common source of supply.
(b) To extend pool rules to a drilling and spacing unit, an application shall be filed and notice provided in the same manner as required to establish pool rules. In the event that more than one set of pool rules are in effect within a field, the Commission shall extend the appropriate pool rules consistent with available geological and engineering reservoir information.

165:10-1-24. Permitted well locations within standard drilling and spacing units

(a) The permitted well location within any standard square drilling and spacing unit shall be the center of the unit. The permitted well locations within standard rectangular drilling and spacing units shall be the centers of alternate square tracts constituting the units (alternate halves of the units);

provided, however, a well will be deemed drilled at the permitted location if drilled within the following tolerance areas:

(1) Not less than 165 feet from the boundary of any standard 10-acre drilling and spacing unit or the proper square 10-acre tract within any standard 20-acre drilling and spacing unit.

(2) Not less than 330 feet from the boundary of any standard 40-acre drilling and spacing unit or the proper square 40-acre tract within any standard 80-acre drilling and spacing unit.

(3) Not less than 660-feet from the boundary of any standard 160-acre drilling and spacing unit or the proper square 160-acre tract within any standard 320-acre drilling and spacing unit.

(4) Not less than 1320 feet from the boundary of any standard 640-acre drilling and spacing unit.

(b) The proper square tract of a rectangular drilling and spacing unit established prior to January 1, 1971, for which a slot drilling pattern was prescribed, shall be the northeast quarter and the southwest quarter of the governmental section, quarter section, or quarter quarter section containing two abutting rectangular drilling and spacing units; provided, slot patterns may be established or re-established upon application, notice, and hearing where consistent with available geological and engineering information when necessary to prevent waste or protect correlative rights.

(c) The permitted well location tolerance areas set out in (a) of this Section shall apply to each standard drilling and spacing unit heretofore or hereafter established, notwithstanding the provisions of any special order of the Commission prescribing a different permitted well location tolerance area; provided, however, this Section shall not affect any adjusted allowable or penalty applied to any well by special order of the Commission prior to the effective date of this Section, nor shall any well heretofore drilled within a then permitted tolerance area be deemed outside the permitted tolerance area by reason of this Section.

(d) Wells drilled offpattern without first obtaining an exception after notice and hearing by the Commission are hereby prohibited from producing either oil or gas.

(e) Whenever permission is granted to drill a well at a location other than specified in this Chapter, the allowable or production therefrom, or both, may be adjusted for the protection of the correlative rights of all persons entitled to share in the common source of supply.

(f) Unless the order granting a well location exception provides otherwise, the permission to drill the well at the excepted location shall expire twelve (12) months after the date of the order, unless a well was commenced at the excepted location on or before the expiration date. The order granting the well location exception will thereafter expire when the well is plugged, abandoned, or converted.

(g) An application for an emergency order granting a well location exception may be granted if the applicant has obtained the written consent of the operator of each adjoining or cornering tract of land or drilling and spacing unit, currently producing from the same formation, toward which the well location is proposed to be moved. Provided, however, if the applicant is the operator of the well in an adjoining or cornering tract of land or drilling and spacing unit, currently producing from the same formation, toward which the well location is proposed to be moved, the applicant shall obtain the written consent of each working interest owner in such well.

(1) Letters evidencing the written consent of off-set operators and working interest parties as described in this subsection shall be introduced and received into evidence at the time of the emergency hearing and reviewed. Copies of said letters shall be filed with the Court Clerk of the Commission.

(2) If the written consent described in this subsection cannot be obtained, the applicant may send written notice to said non-consenting party giving that party at least five days notice of the emergency hearing. If said non-consenting party fails to appear, then the emergency application shall be considered and may be granted without the non-consenting party's written consent. The applicant shall file an affidavit of mailing with the Court Clerk to prove the mailing of the five day notice.

(h) If a spacing application is currently pending and the applicant or any party who owns the right to drill needs to commence a well prior to issuance of the spacing order, the applicant or party shall obtain an emergency order to commence such well and an emergency location exception order if:

(1) The proposed well is offpattern according to the existing spacing for any formation involved, or

(2) The well is offpattern according to 165:10-1-21 governing well patterns for unspaced areas.

(i) Whenever an order permits an offpattern well, the order permitting said well may provide, at the request of a party of record in the cause, for said party to have the right, at his sole cost and risk, to attend and monitor the initial potential testing and all subsequent annual testing of the proposed offpattern well. If the order permits witnessing of tests as prescribed above, then the order shall further provide that at least five days prior to the initial potential testing and each subsequent annual testing of the proposed well, the operator of the well shall notify, in writing, all parties of record in the cause who requested to attend and monitor these tests of the date and time upon which said testing shall commence.

165:10-1-25. Replacement well

(a) Approval by the Conservation Division of a Notice of Intent to Drill (Form 1000) for a second well to be drilled in a common source of supply in a single drilling and spacing unit as a replacement well may be permitted when:

(1) The replacement well is to be drilled at a location permitted for the common source of supply by either an order or rule of the Commission; and

(2) The operator of the replacement well is either the operator or a working interest owner in the original unit well; and

(3) The Notice of Intent to Drill for the replacement well is accompanied by an affidavit from the operator, stating that on completion of the second well as a commercial producer, the common source of supply in the first well shall be plugged off immediately. The affidavit shall be attached to Notice of Intent to Drill.

(b) A replacement well shall not receive an allowable to produce oil or gas from the same common source of supply as the first well until:

(1) Said common source of supply in the original well in the drilling and spacing unit is plugged off; or

(2) The Commission issues an order authorizing the replacement well as an increased density well for said common source of supply; or

(3) The Commission issues an order reforming the drilling and spacing units in said common source of supply thereby placing the original well and the replacement well in different drilling and spacing units for the common source of supply.

165:10-1-26. Permitted producing well location within an enhanced recovery project

Any well drilled for or used for the production of oil or gas within any enhanced recovery project shall be located not less than 165 feet from the lease or project line, whichever is the outside boundary.

165:10-1-27. Increased density well

Upon application after notice and hearing, the Commission may issue an order permitting one or more additional wells within a drilling and spacing unit, if each additional well will prevent or assist in preventing the various types of waste prohibited by statute or if each additional well will protect or assist in protecting the correlative rights of interest owners in said common source of supply.

165:10-1-28. Geological correlation chart

The chart initially prepared by Phillips Petroleum and maintained by the Oklahoma City Geologic Society entitled "Geologic Section of Oklahoma and Northern Arkansas", along with ensuing revisions, shall be used as a guideline for stratigraphic nomenclature in all oil and gas conservation applications which are submitted to the Commission.

PART 7. MARKET DEMAND

165:10-1-35. Market demand [RESERVED]

165:10-1-36. Regulation, classification, and naming of pools

(a) When the Commission finds, upon notice and hearing, that oil or gas production from any source of supply exceeds the current market demand therefor or finds that the operation of the reservoir should be regulated in order to prevent waste, increase ultimate recovery, or protect correlative rights, the Commission shall thereupon promulgate appropriate pool rules to accomplish such objectives. Where any of the above findings are made by the Commission, the total production from the pool may be restricted and equitable allocation made to the various wells located therein, or the operation of the reservoir may be otherwise regulated and controlled to insure proper and adequate conservation.
(b) Any pool may be classified or reclassified by the Commission, upon hearing, as an oil pool, gas pool, combination pool, or condensate pool. All pool rules so promulgated shall be based on operating and technical data and shall be consistent with the characteristics attributable to each classification.
(c) All oil and gas pools in the State shall be named by the Commission.

165:10-1-37. Determination of market demand

(a) The Commission shall instruct the Director of Conservation to determine the reasonable market demand for oil, gas, and other hydrocarbon products produced in Oklahoma for consumption in and outside the State for the ensuing proration period(s) that can be produced from each common source of supply on a statewide basis without avoidable waste and with equitable participation in production and markets by all operators and other interested parties.
(b) Waste, in addition to its statutory and ordinary meaning, shall include but not be restricted to economic waste, underground waste, surface waste, and waste incident to the production of oil and gas in excess of the transportation or marketing facilities or reasonable market demand.
(c) Reasonable market demand shall include, but not be restricted to, the demand for oil, gas, and other hydrocarbons for reasonable current requirements for current consumption and use within and outside the State, with such adjustment as may be necessary upward or downward to maintain adequate aboveground stocks of crude oil and its products and underground stocks of natural gas, so as to provide a continuous supply of petroleum products to the consumer and essential strategic supplies for national defense.
(d) In determining the reasonable market demand, the Commission may consider:
   (1) Any statement communicated to the Commission by any purchaser or taker of oil and gas, stating the amount of oil or gas produced from common sources of supply that such purchaser or taker contemplates or intends to purchase during the period of time involved; or in lieu thereof, the capacity of the purchaser's transportation or marketing facilities which will be, during the time involved, available for transporting and/or marketing the oil or gas that may be produced from common sources of supply.
   (2) Official records, reports, and statistical information compiled and kept by the Conservation Division that can be utilized in determining reasonable market demand.
   (3) Reports, facts, and materials by the Bureau of Mines or any other recognized authority that impartially reflects reasonable market demand.

(4) Sworn or unsworn statements of interested parties and any other evidence which the Commission may deem relevant to the determination of reasonable market demand.

(e) For purposes of periodic market demand hearings, the Manager of Production and Proration for the Conservation Division shall prepare exhibits summarizing the nominations from the various interested parties specified in (d) in this Section. Said exhibits shall be available for public inspection not less than five days before the hearing. At the time of hearing, if no one announces any objection to the introduction of said exhibits, then the exhibits shall be admitted into evidence without need for sponsoring testimony.

(f) After the Commission has determined the amount of oil or gas to be produced from all oil and/or gas pools during the following proration period, the amount so determined will be allocated ratably and without discrimination among the various pools within the State.

PART 9. PURCHASERS AND TRANSPORTERS

165:10-1-45. Purchasers and transporters [RESERVED]

165:10-1-46. Reports of purchasers and/or transporters

Purchasers and/or transporters of oil, waste oil, or waste oil residue, including truckers, shall file reports with the Commission as follows:

(1) On or before the last day of the succeeding month, transporters shall file a report showing monthly takings by barrels from leases in all pools in the State, other than wells or leases as specified in (2), (3), (4), and (5) of this Section; a copy of the Gross Production Tax Report made to the Oklahoma Tax Commission will satisfy this requirement.

(2) A report on computer generated Form 1005 showing monthly takings by barrels from leases or wells with capacities greater than the maximum allowable determined by the appropriate rule governing the classification of the oil pool or order of the Commission. The report shall be filed on or before the last day of the succeeding month.

(3) Upon request, storage and nomination information shall be filed on Form 1034.

(4) All truck transporters hauling crude oil shall file a report showing the amount of all crude oil taken by them during the preceding proration period, and showing the source and the disposition of the crude oil, waste oil, or waste oil residue. The report shall be filed on or before the last day of the succeeding month.

(5) All truck transporters hauling crude shall provide their drivers with copies of standard run tickets which must be in the possession of the drivers at all times and which run tickets shall show the source and the disposition of crude oil, including but not limited to waste oil or waste oil residue.

165:10-1-47. Gas volume reports to Conservation Division

(a) On or before the last day of the succeeding month, the person responsible for operating the required meter under 165:10-17-5 for each well classified as an unallocated gas well for allowable purposes shall report to the Conservation Division on Form 1004 the amount of gas in MCF which passed through the meter on a monthly basis.

(b) If a well classified as a gas well for allowable purposes is subject to special pool rules other than the Guymon-Hugoton or South Guymon Fields, the Conservation Division shall mail Form 1005 (Monthly Allocated Schedule) to the operator of record for each such well(s) on or before the 15th day of each month. The operator of record shall, in turn, complete said form by listing the gas volume sold on a monthly basis in MCF by well and return a copy to the

Conservation Division on or before the last day of the month succeeding the sales.
(c) If a well classified as a gas well for allowable purposes is subject to the special pool rules for the Guymon-Hugoton or South Guymon Fields, the Conservation Division shall mail Form 1005 (Monthly Allocated Schedule) to the operator of record for each such well(s) on or before the tenth day of each month. The operator of record shall, in turn, complete said form by listing the gas volume sold, including gas bought by the landowner, on a monthly basis in MCF by well and return a copy to the Conservation Division on or before the 15th day of the month succeeding the sales.
(d) If there is a split connection at the well site, then the operator of record measuring gas volumes shall be responsible for reporting the total volume sold for each well.
(e) If a well classified as a gas well for allowable purposes is subject to special pool rules (including the Guymon-Hugoton Field), the Conservation Division shall mail Form 1040 to each operator on or before the tenth day of the second succeeding month following the custody transfer indicating the reported volume of gas taken from each well.
(f) If a well classified as a gas well for allowable purposes is subject to multiple gas purchase contracts or interest owners taking their gas in kind, the producing owner shall report and account to the well operator all volumes sold and the identity of all purchasers on or before the last day of the following month after sale of such gas. The operator(s) of the required meter(s) under 165:10-17-5 shall report and account to the well operator all volumes of gas measured by such meter(s) on or before the last day of the following month after measurement. Failure to comply with this subsection will result in such gas production being ordered shut-in.
(g) Failure of an operator to timely file sales volumes on Form 1005 shall result in a zero allowable being assigned to the operator's wells for the month in which the sales volumes would have been used in calculating the field allowable. Allocation factors for a pool shall not be recalculated as a result of the filing of a late Form 1005.

[**Source:** Amended at 12 Ok Reg 2017, eff 7-1-95]

165:10-1-48. Common purchaser and carrier rules
(a) 52 O.S., 1961, Sections 54, 55, 56, and 240 are hereby adopted as common purchaser and common carrier rules as fully as if set out verbatim herein.
(b) No person shall purchase, take, or transport any oil or gas in excess of the allowable fixed by the Commission, or, when notified by the Conservation Division, such oil or gas being produced in violation of any rule, regulation, or order of the Commission; provided, this Section shall not require splitting a tank.

165:10-1-49. Filing of nominations
(a) All purchasers, buyers, and takers of crude oil in Oklahoma shall file their nominations for purchases of crude oil from wells in allocated pools, unallocated pools, and enhanced oil recovery pools with the Conservation Division on Form 1034-0 not later than noon Friday of the week preceding the regularly scheduled market demand hearing.
(b) All operators of natural gas wells in special allocated gas pools shall file their pool nominations on Form 1034-G not later than one week prior to the date of the market demand hearing.
(1) Nominations shall be restricted to the volume not to exceed the wellhead absolute open flow (WHAOF) times calendar days for each well in a pool. For wells in pools where the WHAOF is not utilized, the equivalent well deliverability or calculated rate of flow applicable to that particular pool may be used in lieu of the WHAOF. For wells exempt from testing, nominations shall be restricted to a volume not to exceed the well's minimum, double minimum, or special allowable time calendar days.

(2) Operators shall attach to Form 1034-G a listing of each of their special allocated wells by pool, OTC Lease Number, API Number, well name and number, and location as recorded on Form 1040, plus the applicable WHAOF, deliverability, or rate of flow value as determined by the appropriate well test for that time period. Wells exempt from testing shall be indicated as test-exempt on the list.

(3) Failure of an operator to properly file nominations on Form 1034-G shall result in a zero allowable being assigned to the operator's wells for the month in which the nominations would have been used in calculating the field allowable. Allocation factors for a pool shall not be recalculated as a result of the filing of a late Form 1034-G.

[**Source:** Amended at 12 Ok Reg 2017, eff 7-1-95]

SUBCHAPTER 3. DRILLING, DEVELOPING, AND PRODUCING

PART 1. DRILLING

PART 3. COMPLETIONS

PART 5. OPERATIONS

PART 7. PRODUCTION

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PART 1. DRILLING

165:10-3-1. Required approval of notice of intent to drill, deepen, re-enter, or recomplete; Permit to Drill

(a) **Permit to Drill.**

(1) Except as provided in (1) of this Section, on temporary authorization to commence, the operator shall obtain for the well a Permit to Drill approved by the Conservation Division before:

(A) Spudding a well for the exploration for and production of oil or gas.

(B) Spudding a well for use as an injection, disposal, or service well.

(C) Re-entry into a plugged well.

(D) Recompletion of a well.

(2) A Permit to Drill shall be valid only for each common source of supply listed on the permit.

(3) Any operator who drills, deepens or reenters a well without a permit to drill shall be subject to a fine of $1,000.00.

(b) **Amended or additional Form 1000 requirements.**

(1) **When required.** If the Conservation Division has issued a Permit to Drill for a well, the operator of the well shall submit an amended Form 1000 for the well and obtain an amended Permit to Drill before:

(A) Completing the well in a common source of supply which is not listed on the current unexpired Permit to Drill for the well.

(B) Recompleting the well in a common source of supply which is not listed on the current unexpired Permit to Drill for the well.

(C) Installing less surface casing than the amount approved on the unexpired Permit to Drill for the well.

(D) Deviating from an alternative casing and cementing procedure which the Conservation Division approved on the unexpired Permit to Drill for the well.

(E) Completing a well in a common source of supply at a subsurface location which does not correspond with the surface location on the most recently issued Permit to Drill for the well.

(2) **Effect of amended or additional Permit to Drill on prior Permit to Drill.** Each approved, amended, or additional Permit to Drill for a well cancels any previously issued Permit to Drill for the well.

(c) **Expired or revoked Permit to Drill.** If a Permit to Drill for a well expires or is revoked, the operator shall be subject to the requirements of (a) of this Section.

(d) **Casing and cementing requirements.** Each Permit to Drill shall list the minimum amount of surface casing to be used or an approved alternative casing and cementing program under 165:10-3-4.

(e) **Spud report and well spacing requirements.** In addition to complying with the requirement of obtaining a Permit to Drill, the operator shall comply with the following:

(1) The spud report requirement of 165:10-3-2.

(2) Any well spacing requirements applicable by order or rule of the Commission. Well spacing requirements do not apply to injection or disposal wells.

(f) **Disposal of drilling fluids.**

(1) The operator shall indicate on Form 1000 the proposed method(s) for disposal of drilling fluids. These methods shall include, but not be limited to:

(A) Evaporation/dewatering and leveling of the reserve pit.

(B) Soil farming.

(C) Recycling.

(D) Commercial off-site earthen pit disposal.

(E) Annular injection.

(F) Hauling to a facility or location other than a commercial earthen pit.

(2) If the method in (1)(F) in this subsection is used, the operator shall provide the location to which the drilling fluids are to be hauled.

(3) Issuance of the Permit to Drill shall not be construed as constituting approval of the disposal method(s) indicated. An operator who desires to

dispose of drilling fluids through either evaporation/dewatering and leveling of the reserve pit, soil farming, commercial earthen pit disposal, or annular injection must comply with 165:10-7-16, 165:10-7-19 or 165:10-9-2, 165:10-9-1, or 165:10-5-13 respectively.

(4) If the proposed method for drilling fluid disposal is changed, the operator shall notify the appropriate District Office of the Conservation Division, either by telephone or in writing, within a reasonable time after the change. An amended Form 1000 for the well shall not be required for a change in disposal method.

(g) **Notice to surface owners.**

(1) The operator shall include on each Form 1000 submitted to the Conservation Division, the name and address of each surface owner of record for the wellsite.

(2) For each Permit to Drill other than a Permit to Drill for a recompletion, the Conservation Division shall mail by regular U.S. mail a copy of the Permit to Drill to each surface owner listed on the Form 1000.

(h) **Disapproval for noncompliance with Commission order.** If an operator is not in compliance with an enforceable order of the Commission, the Conservation Division shall not issue any Permit to Drill for the operator, until the operator complies with the order.

(i) **Erroneous approval.** Erroneous issuance of a Permit to Drill shall not excuse noncompliance with any order or rule of the Commission.

(j) **Expiration.**

(1) **Six-month period.** Except as provided in (2) of this subsection for expiration after submission of a completion report, a permit to drill shall expire six months from the date of issuance, unless drilling operations are commenced and thereafter continued with due diligence to completion.

(2) **Six-month extension.** A six month extension may be granted without fee providing the Conservation Division staff determines that no material change of condition has occurred, if written request for such extension is received from the operator prior to the expiration of the original permit. Only one extension may be granted.

(3) **If Form 1002A is filed.** If the operator of the well submits to the Conservation Division a Completion Report (Form 1002A) for the well, the Permit to Drill for the well shall expire on the date the Completion Report is approved by the Conservation Division.

(k) **Posting of Permit to Drill at the wellsite.** During any activity subject to this Section, the operator shall maintain at the wellsite an original or legible copy of the Permit to Drill for inspection by Commission personnel.

(l) **Temporary authorization without approval of a Permit to Drill.** In an emergency, the Manager of the Technical Services Department of the Conservation Division may temporarily authorize commencement of activities without a Permit to Drill for a period up to five working days.

(m) **Limits of authority.** A Permit to Drill does not grant the operator authority to produce, inject or dispose without the required permits or allowable assignment.

[**SOURCE:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended in Rule Making 980000033, eff 7-1-99]

165:10-3-2. Notification of spudding of new well

(a) Except as provided in (c) of this Section, the operator of a new well shall file with the Conservation Division a Notice of Spudding of New Well on Form 1001A within 14 days after spudding of the well.

(b) For the purposes of (a) of this Section, spudding of a new well refers to:

(1) The first boring of the hole in the drilling of a well for the production of oil and gas or for the use as an injection or disposal well.

(2) Reentry into a previously plugged well for purposes of producing oil and gas or for use as an injection or disposal well.

(c) Filing of a Notice of Spudding of a New Well on Form 1001A shall not apply to:

(1) Any workover operation to deepen, plug-back, or recomplete.

(2) An unplugged hole spudded before January 9, 1986.
(3) Recompletion attempts in an unplugged hole for which a Notice of Spudding of New Well has been filed.

165:10-3-3. Surface and production casing

(a) Owners, operators, and drilling contractors shall comply with 165:10-3-4 and 165:10-5-2.
(b) In the event a rupture, break, or opening occurs in the surface or production casing, the owner, operator, or drilling contractor shall take immediate action to repair it and shall report the occurrence to the appropriate District Office or the Manager of Pollution Abatement.
(c) Any operator who fails to timely report a rupture, break, or opening in the surface casing shall be fined $1,000.00, and the well shall be shut down until it is repaired or plugged.

[**SOURCE:** Amended at 9 Ok Reg 2295, eff 6-25-92]

165:10-3-4. Casing, cementing, wellhead equipment, and cementing reports

(a) **Scope.**
(1) This Section governs the following:
(A) Surface casing and cementing requirements.
(B) Alternate casing and cementing procedure used instead of adequate surface casing and cement.
(C) Minimum cementing and testing requirements for intermediate and production casing.
(D) Minimum valve and blowout preventer requirements.
(E) Cementing reports.
(2) This Section shall apply to the following:
(A) Wells drilled or reentered for the production of oil, gas or brine.
(B) Wells drilled or reentered for disposal of oilfield wastes.
(C) Wells drilled for enhanced recovery injection.
(D) Wells drilled in subsurface gas storage units created by order of the Commission.
(E) Other oilfield related service wells.
(b) **Effect on area rules.**
(1) If any area rules promulgated by order of the Commission require less casing and cement than required by this Section, then this Section shall supersede the area rules.
(2) If an applicable area rule promulgated by order of the Commission has more stringent casing and cementing requirements than what are required by this Section, the Conservation Division shall enforce the area rules.
(c) **Surface casing and cementing requirements for wells listed in (a)(2) of this Section:**
(1) **Minimum surface casing requirements.** Unless an alternate casing program is authorized by the Conservation Division or by an order of the Commission, suitable and sufficient surface casing shall be run and cemented from bottom to top with a minimum setting depth which is the greater of:
(A) Ninety feet below the surface, or
(B) Fifty feet below the base of treatable water.
(2) **Penalty for noncompliance.** An operator setting less than the required amount of surface casing or failing to remediate uncirculated cement before resuming operations shall be fined $5,000.00.
(3) **Exceptions to (c)(1).** Operators having wells producing hydrocarbons which were in compliance with the surface casing requirements at the time of completion shall not be required to comply with (1) of this subsection.
(4) **Well to be used for annular injection under 165:10-5-13.** If the operator intends to dispose of drilling or stimulation fluids by annular injection, then the operator shall comply with 165:10-5-13 which requires a surface casing string to be set not less than 200 feet below the base of treatable water, unless a Commission order provides otherwise.

(5) **Depth limitation on setting surface casing.** The well operator shall run and cement the surface casing string required by this subsection before drilling the well more than 250 feet below the base of treatable water, unless otherwise approved on the Permit to Drill.

(6) **Penalties.** Operators failing to obtain permission to drill a well more than 250 feet below the treatable water, or to obtain permission for an alternate casing and cementing procedure may be fined $2,500.00.

(7) **Cementing procedures.**

(A) **Approved methods.** Except as provided in (B) of this paragraph for bradenhead cementing, cement shall be run by either the tubing and pump method, the pump and plug method, or the displacement method.

(B) **Bradenhead cementing prohibited.** Bradenhead cementing is prohibited without written permission from the District Office of the Conservation Division.

(C) **Restrictions on stage cementing.**

(i) **Above 200 feet.** Running cement through small tubulars is permitted above 200 feet in depth without special permission.

(ii) **Below 200 feet.** Below 200 feet in depth, the operator shall obtain permission from the District Office of the Conservation Division before using small tubulars to run cement.

(D) **Steel casing required.** For purposes of the surface casing requirements of this Section, surface casing shall be oil field grade steel casing.

(E) **Witnessing of setting of surface casing.** The operator shall give at least 24 hours notice by telephone to the appropriate District Office or Field Inspector as to the time when surface casing will be run.

(F) **Minimum cement setup time.** The cement behind the surface casing shall set at least eight hours before further drilling.

(G) **Down-hole testing of surface casing and cement.** Before drilling the shoe of the surface casing, the operator shall test the surface casing using the procedure prescribed by (f) of this Section.

(H) **Failure to circulate cement or fall back of cement behind surface casing.**

(i) **Verifying the top of cement.** If no conductor string is set and the cement did not circulate to the surface or falls back more than five feet, the operator shall determine the top of the cement using a method approved by the District Manager or Field Inspector.

(ii) **Top of cement less than 200 feet from the surface.** If the top of the cement is found less than 200 feet from the surface, the operator may circulate cement to surface using small tubulars.

(iii) **Top of cement greater than 200 feet from the surface.** If a conductor string has been set and the cement has been found to be ten feet or more above the base of the conductor string, no corrective action is required. If no conductor string has been set and the top of the cement is greater than 200 feet from the surface, the operator shall perform a corrective cementing operation by circulating cement to the surface from a point 50 feet below the base of the treatable water or from the determined top of the cement, whichever is shallower. The District Manager or Field Inspector may grant permission to circulate cement through small tubulars.

(I) **Insufficient surface casing or mechanical failure.** Within 24 hours after discovery of a problem with the surface casing or cement, the operator shall notify the appropriate District Office of the Conservation Division by telephone of:

(i) Any mechanical failure of the surface casing or cement.

(ii) Discovery of a treatable water formation below the shoe of the surface casing.

(J) **Penalty.** An operator, failing to report a rupture, break, or opening in the surface casing, shall be fined $1,000.00 and the well shut down.

(K) **Notice.** The District Manager or Field Inspector shall be given at least 24 hours notice prior to any cementing operation in order that they may have the opportunity to witness.

(d) **Alternate casing and cementing procedures.**

(1) **Requirement of approval on the Permit to Drill.** Use of an alternative casing and cementing procedure instead of surface casing and cement required by (c) of this Section is prohibited without authorization on the Permit to Drill for the well.

(2) **Disapproval.** The Manager of Technical Department may not issue a permit for an alternate casing string and cementing procedure if one or more of the following conditions exist:

(A) The well will penetrate a known lost circulation zone.

(B) The treatable water bearing formation(s) will be endangered.

(C) The projected depth of the well is less than 100 feet from the top of any authorized secondary project or gas storage facility.

(3) **Applicability of other casing and cementing standards.** Alternate casing and cementing procedures under this subsection are subject to the provisions of (c)(7) of this Section.

(4) **Alternate casing and cementing procedure.**

(A) An operator having permission to run an alternate casing string may, for protection of the treatable water, drill the well to casing point and circulate cement to the surface, or circulate cement from a depth of 100 feet below the base of treatable water to the surface after following the procedures set out in (f) of this Section.

(B) Oil based drilling mud shall be prohibited.

(C) If a well is completed using an alternate casing and cementing procedure, a bond log covering the interval from 100 feet below the base of the treatable water to the surface shall be required. The District Manager may waive this requirement. A completion attempt, in cases where the protection of treatable water is questionable, is strictly prohibited.

(D) Unless extended by the District Manager, the operator shall have 72 hours after drilling and testing is completed to run production casing or plug the well. A minimum of 24 hours prior notice must be given to the appropriate District Office prior to cementing operations so that a Field Inspector may have the opportunity to witness the cementing or plugging procedures. If the well is plugged and abandoned, procedures set out in (e) of this Section shall be followed.

(E) In the event that casing is run and cement does not circulate to the surface, or falls back, the operator shall determine the top of the cement using a method approved by the District Manager.

(5) **Remedial actions.**

(A) If the top of the cement is less than 200 feet from the surface, the operator may circulate cement from that point to the surface using small tubulars or by perforating the casing at that point and circulating cement to the surface.

(B) If the top of the cement is greater in depth than 200 feet, the operator shall perforate the casing at the top of the cement and circulate cement to the surface, or with the written permission of the Field Inspector, use small tubulars.

(C) In the event that a conductor string had been set and the top of the cement is at least ten feet above the base of the conductor casing no remedial action is needed.

(D) Unless waived by the District Office, all corrective cementing operations shall be approved and witnessed by the Field Inspector.

(E) In wells where corrective actions were needed for casing or cementing problems, a completion attempt shall not be made without approval by the District Manager.

(e) **Permanent well marker.** In the event that the well is a dry hole and no casing has been run, then during the plugging of the well the operator shall run and cement from bottom to top at least one joint of casing at the surface not less than 25 feet in length for use as a permanent well marker. The casing used as a well marker shall be oil field grade steel casing with an outside diameter of at least seven inches. The top of the marker shall be three feet below the surface and be capped with a steel plate inscribed or embedded with the well number and date of plugging on the steel plate. An operator failing to run and cement the well marker as required shall be fined $1,000.00 and shall, under the supervision of the Commission, replug the well.

(f) **Minimum cement for additional casing strings.** If additional casing other than surface casing is run, except for temporary purposes, it shall be run, set, and cemented with a calculated volume of cement sufficient to fill the annular space behind the casing string from the base of the casing string to a minimum height which is the greater of five percent of the depth to which the casing string is set or a height of 200 feet. Wells approved for horizontal completion are exempt upon approval of the Conservation Division.
(g) **Pressure testing of casing strings.**
(1) Before drilling the cement plug in a casing string, the operator shall pressure test the installed casing for 30 minutes at a minimum pressure which is the lesser of the surface gauge pressure equal in pounds per square inch to 0.2 of the length of the casing in feet or 1500 psig.
(2) During the 30 minute test, if the surface pressure drops ten percent or more, the operator shall:
(A) Repair and retest the casing until the requirements of this subsection are met; or
(B) Plug the well according to the rules of this Chapter.
(h) **Minimum wellhead equipment for drilling wells.** Except in proven areas where less equipment is known to be adequate, every drilling well shall be equipped with a mastergate, or its equivalent, or an adequate blowout preventer. A flow line valve of proper size and working pressure shall be attached.
(i) **Cementing reports.**
(1) The operator of the well shall submit, attached to Form 1002A Completion Report, a Form 1002C Cementing Report describing all cementing operations on surface, intermediate, and production casing strings, including multistage cementing jobs.
(2) If additional cementing operations occur after submission of the Cementing Report, the operator shall submit an amended Form 1002C for the well.
(j) **Surface casing requirements for re-entry wells.** For a re-entry as defined by 165:10-1-2, casing and cementing requirements at the time of re-entry shall apply.
(k) **Surface casing requirement for recompletions.** For a recompletion as defined by 165:10-1-2, casing and cementing requirements applicable to wells commenced on the latter of the spud date or re-entry date for the well shall apply.
(l) **Casing and cementing requirements for wells converted for injection or disposal.** If a well is converted for use as an injection or disposal well, it shall be subject to the casing and cementing requirements of this Section effective at the time of conversion of the well.
(m) **Casing and cementing requirements for wells penetrating unitized common sources of supply.** Each newly drilled or re-entered well which penetrates a common source of supply in which enhanced recovery operations are being conducted shall be properly cased and cemented from not less than 100 feet below to not less than 100 feet above each unitized common source of supply to prevent migration of formation fluids and contain formation pressure. In the event the well is to be plugged without being cased, the well shall be properly cemented over the aforementioned interval(s) during plugging procedures.
(n) **Insufficient surface casing and cement.** When it has been determined that a treatable water-bearing formation has not been properly cased and cemented, the operator shall take such measures designated by the Director of Conservation or ordered by the Commission to protect any treatable water-bearing formation.

[**SOURCE:** Amended at 9 Ok Reg 2337, eff 6-25-92]

165:10-3-5. Underground storage
(a) **Scope.** This Section shall apply to all operations pertaining to the drilling, completion, recompletion, or remedial work on wells located within the boundaries of an underground storage facility as defined in (b)(4) of this Section.
(b) **Definitions.**

(1) "Underground storage" shall mean storage of natural gas in a subsurface stratum or formation of the earth.
(2) "Natural gas" shall mean gas either while in its natural state or after the same has been processed by removal therefrom of component parts not essential to its use for lights and fuel.
(3) "Storage operator" shall mean any person, firm, or corporation which operates an underground storage facility.
(4) "Underground storage facility" shall mean any subsurface stratum or formation of the earth used for underground storage. Provided that, in the case of a natural gas bearing subsurface stratum or formation, the commercially producible native gas shall have been substantially depleted and the gas therein shall not be used primarily for the secondary recovery of oil in paying quantities from the subsurface stratum or formation.
(5) "Well" means a well drilled or bored or to be drilled or bored within the boundaries of an underground storage facility.
(6) "Well operator" shall be the person, firm, or corporation that is the operator of a well.
(7) "Major remedial work" shall mean any workover operations requiring wire line or pump truck services.
(8) "Good quality cement" means that cement that would obtain a compressive strength to prevent oil, gas, or water migration within an eight (8) hour period.

(c) **Operational procedures.**
(1) Before spudding a well within the boundaries of a gas underground storage facility, the well operator shall mail a copy of the Permit to Drill to the storage operator at the address listed at the Commission. The storage operator will inform the well operator of the estimated depth, thickness, and pressure of the underground storage facility at that location. Failure of the storage operator to provide the data to the well operator shall not be a cause to delay drilling, but the well operator is required to notify the storage operator, by phone a minimum of 24 hours prior to commencing drilling operations at a 24 hour telephone number furnished to the Commission by the storage operator.
(2) A well operator shall comply with the provisions of 165:10-3-4(c). Alternate casing programs shall not be permitted.
(3) Drilling rigs shall be equipped with a blowout preventer. The preventer shall be installed and tested at least 500 psig above the anticipated underground storage facility pressure before drilling below the base of the surface casing.
(4) The storage operator shall receive drilling reports daily and shall be notified at a 24 hour telephone number furnished to the Commission by the storage operator in ample time to witness any tests or logging operations from the surface to 500 feet below the base of the underground storage facility. Any abnormal conditions occurring during the drilling operation, such as abnormal pressures and/or lost circulation, shall be reported immediately to the storage operator.
(5) The well operator shall drill the well in such a manner as to prevent invasion of drilling fluids into, or the escape of natural gas from, the underground storage facility. The well operator shall be required to mud up at least 100 feet above the anticipated depth of the underground storage facility.
(6) If run, a copy of either an open hole porosity or resistivity well log run from the base of surface casing to total depth shall be promptly forwarded to the storage operator. At the option of the well operator, the logs submitted to the storage operator may be terminated 500 feet below the base of the underground storage facility. The storage operator shall be given prior notice of logging operations of the underground storage facility interval and has the option of witnessing the open hole logging operation.
(7) In the event that the well is noncommercial and is to be plugged and abandoned, the well operator shall place a cement plug using a good quality cement, covering from not less than 100 feet below the base to not less than 100 feet above the top of the underground storage facility. The storage operator shall be given prior notice so as to have the option of witnessing

the plugging operation. The field inspector may invoke the provisions of 165:10-11-6 (l), (m), and (n).

(8) In the event that casing is run, the well operator will cause the underground storage facility interval to be covered with steel casing and be cemented from not less than 100 feet below the base to not less than 100 feet above the top of the underground storage facility using a good quality cement. The Commission field inspector for the area and storage operator shall be given prior notice so as to have the option of witnessing the operation.

(9) The well operator shall be required to run a cement bond log through the underground storage facility formation before any completion attempts are made. The storage operator shall be given prior notice so that he will have the option of witnessing the logging operation and be furnished with a copy of the bond log from the top of cement to total depth or, at the option of the well operator, to 500 feet below the base of the underground storage facility. If the integrity of the bond log is questioned by the storage operator, the storage operator may, at its sole risk and expense, run additional logs. No completion work shall be permitted until the fact has been established, between the parties concerned, and the district manager of the Commission, that the integrity of the cement is sound and that the underground storage facility is isolated from the remainder of the bore hole. The remedial work, if needed to protect the storage reservoir, shall be at the risk and expense of the well operator.

(10) The storage operator shall be notified in ample time to witness completion, recompletion, or major remedial work operations. The well site shall be made accessible at all times to the storage operator and all information pertaining to the completion shall be forwarded daily to the storage operator. If the completion, recompletion, or major remedial operations attempt is to be made in any formation within 500 feet in depth to the underground storage facility, the proposed plan of completion shall be forwarded to the storage operator ten days prior to commencement of operations. The storage operator shall have five days after receipt of the proposed plan to forward any objection to the well operator. Completion operations, recompletion, or major remedial operations shall not be permitted until the matter is resolved.

(11) At any time that the storage operator shall reasonably believe that damage may be occurring to the underground storage facility or that gas may be escaping into any other formations or otherwise believe that a well may be compromising the integrity of the underground storage facility, the storage operator may request that the operator of the well conduct specific tests solely at the storage operator's risk and expense. If an agreement cannot be obtained between the parties concerned, the storage operator may bring the matter before the Corporation Commission for determination by application, notice, and hearing following the procedure set out in OAC 165:5-7.

(12) If tests establish that damage is occurring and/or that natural gas is escaping by the continued operation of the well, the well shall be shut down immediately and the remedial operation to rectify the condition shall be commenced within ten days, at the sole risk and expense of the well operator.

(13) All information furnished to the storage operator shall be kept confidential until released in writing by the well operator.

PART 3. COMPLETIONS

165:10-3-10. Fracture and acidizing

In the completion of an oil, gas, injection, disposal, or service well, where acidizing or fracture processes are used, no oil, gas, or deleterious substances shall be permitted to pollute any surface and subsurface fresh water.

165:10-3-11. Swabbing and bailing

In swabbing, bailing, or purging a well, all deleterious substances removed from the borehole shall be placed in adequate pits or tanks, and no such substances shall be permitted to pollute any surface and subsurface fresh water.

165:10-3-12. Leakage prevention in producing oil and gas wells

All wellhead connections, surface equipment, and tank batteries shall be maintained at all times so as to prevent leakage of oil, gas, saltwater, or other deleterious substances.

165:10-3-13. Water pollution prevention in tanks; protection of migratory birds

(a) Tanks for drilling mud or deleterious substances used in the drilling, completion, or recompletion of wells shall be constructed and maintained so as to prevent pollution of surface and subsurface fresh water.
(b) The protection of migratory birds shall be the responsibility of the operator. Therefore, the Conservation Division recommends that to prevent the loss of birds due to oil, all open top tanks containing oil on the surface be protected from access to birds. [See Advisory Notice 165:10-7-3(c)].

165:10-3-14. Waste of oil or gas

Except as provided in 165:10-3-15, waste of oil, condensate, or gas as defined in 165:10-1-2, is hereby prohibited.

PART 3. COMPLETIONS

165:10-3-15. Venting and flaring

(a) **Conditioning a well without a permit.** An operator may blow a producing well without permit if:
  (1) Blowing the well is necessary for efficient operation of the well.
  (2) Blowing the well will not damage any producing formation in the well.
  (3) The operator complies with the H_2S requirements of 165:10-3-16.
(b) **Gas volumes less than or equal to 50 mcf/d.** An operator may vent or flare up to 50 mcf/d without a permit if:
  (1) It is not economically feasible to market the gas.
  (2) A suitable stand, line, or stack is used to prevent a hazard to people.
  (3) H_2S content of gas exceeds 100 ppm, then the gas must be flared.
(c) **Permit to vent or flare gas volumes in excess of 50 mcf/d.**
  (1) The Conservation Division may administratively grant a permit to vent or flare on a daily basis gas volumes in excess 50 mcf/d, if:
    (A) The operator applies for the permit on Form 1022.
    (B) The application lists the location of the well and the maximum daily volume of gas to be vent or flared.
    (C) It is not economically feasible to market the gas.
    (D) A suitable stack, stand, or line will be used to prevent a hazard to people or property.
  (2) The operator shall file an amended application in the event that the amount of gas to be vented exceeds the permitted volume.
(d) **Application for an order permitting venting or flaring.**
  (1) If the Conservation Division denies a Form 1022 application for a well, the operator of a well may apply for an order permitting venting or flaring of gas.
  (2) The application and notice shall be accordance with OAC 165:5-7.
  (3) Upon application, notice, and hearing, the Commission may grant or deny an application made pursuant to OAC 165:5-7.

[**SOURCE:** Amended in Rule Making 980000033]

165:10-3-16. Operation in hydrogen sulfide areas

(a) **Applicability.** Each operator who conducts operations as described in this subsection shall be subject to this Section and shall provide safeguards to protect the general public from the harmful effects of hydrogen sulfide:

(1) Operations including drilling, working over, producing, injecting, gathering, processing, transporting, and storage of hydrocarbon fluids that are part of, or directly related to, field production, transportation, and handling of hydrocarbon fluids that contain gas in the system which has hydrogen sulfide as a constituent of the gas to the extent as specified in (b) of this Section.

(2) This Section shall not apply to:

(A) Operations involving processing oil, gas, or hydrocarbon fluids which are either an industrial modification or products from industrial modifications, such as refining, petrochemical plants, or chemical plants.

(B) Operations involving gathering, storing, and transporting stabilized liquid hydrocarbons.

(C) Operations where the concentration of hydrogen sulfide in the system is less than 100 PPM.

(b) **General provisions.**

(1) Each operator shall determine the hydrogen sulfide concentration in the gaseous mixture in the operation or system. Tests shall be made in accordance with standards as set by ASTM Standard D-2385-81 or other methods approved by the Commission.

(2) For all operations subject to this Section, the radius of exposure shall be determined, except in the cases of storage tanks, by the following Pasquill-Gifford equations or by other methods approved by the Commission such as air dispersion models accepted or approved by the U.S. Environmental Protection Agency:

(A) For determining the location of the 100 ppm radius of exposure: x = [(1.589)(mole fraction H_2S)(Q)] to the power of (.6258).

(B) For determining the location of the 300 ppm radius of exposure: x = [(0.6743) (mole fraction H_2S) (Q)] to the power of (.6258).

(C) For determining the location of the 500 ppm radius of exposure: x = [(0.4546)(mole fraction H_2S)(Q)] to the power of (.6258); **Where: x =** radius of exposure in feet; **Q =** maximum volume determined to be available for escape in cubic feet per day; **H_2S** = mole fraction of hydrogen sulfide in the gaseous mixture available for escape.

(3) The volume used as the escape rate in determining the radius of exposure shall be that specified below as is applicable:

(A) The maximum daily volume rate of gas containing hydrogen sulfide handled by that system for which the radius of exposure is calculated.

(B) For existing gas wells, the current adjusted open flow rate or the operator's estimate of the well's capacity to flow against zero back-pressure at the well head shall be used.

(C) For new wells drilled in developed areas, the escape rate shall be determined by using the current adjusted open-flow rate of offset wells or the field average current adjusted open-flow rate, whichever is larger.

(D) The escape rate used in determining the radius of exposure shall be corrected to standard conditions of 14.65 psia and 60° Fahrenheit.

(4) For drilling of a well in an area where insufficient data exists to calculate a radius of exposure but where hydrogen sulfide may be expected, then a 100 ppm radius of exposure equal to 3,000 feet shall be assumed. A lesser-assumed radius may be considered upon written request setting out the justification for same.

(c) **Storage tank provision.** Storage tanks which are utilized as a part of a production operation, and which are operated at or near atmospheric pressure and where the vapor accumulation has a hydrogen sulfide concentration in excess of 500 ppm, shall be subject to the following:

(1) It shall not be necessary to determine a radius of exposure for storage tanks as described in this Section.

(2) A warning sign shall be posted at the facility. A wind indicator is to be located at the tank battery site so that it may be seen from the entrance to the site and from the storage tanks.
(3) Fencing as a security measure is required when storage tanks are located inside the populated limits of a townsite or city, where conditions cause the storage tanks to be exposed to the public. In other areas where storage tanks may be considered to be a danger the Commission may require a hearing to establish security measures. (See definitions.)
(4) **Vapor safety.**
(A) A vent, flare or vapor recovery system shall be installed on all tanks over 500 ppm H_2S.
(B) The vent pipe shall be required to extend a minimum of 25 ft. horizontally from the center of the last tank.
(5) **Sign requirements.** In satisfying the sign requirement of this subsection, the following will be acceptable:
(A) A sign shall be located within 50 feet of the facility and of sufficient size to be readable from the road or at the entrance to the facility.
(B) The warning sign shall state at a minimum that; hydrogen sulfide has been found and could be present.
(C) New signs constructed to satisfy this subsection shall use the language **"Caution, Poisonous Gas May Be Present"**, using black and yellow colors or **"Danger Poison Gas (Hydrogen Sulfide)"**, using red and white colors or equivalent language. Colors shall satisfy Table 1 of American National Standards Institute Standard 253.1-1967. Signs installed to satisfy this subsection are to be compatible with the regulations of the Federal Occupational Safety and Health Administration.
(d) **Drilling, completion, workover and production operations.** All operators whose operations are subject to this Section, and where the 100 ppm radius of exposure is in excess of 50 feet, shall be subject to the following:
(1) **Warning and marker provision.**
(A) For aboveground and fixed surface facilities, the operator shall post, where permitted by law, clearly visible warning signs on access roads or public streets, or roads which provide direct access to facilities located within the area of exposure.
(B) In populated areas such as townsites and cities where the use of signs is not considered to be appropriate, an alternative warning plan may be approved upon written request to the Commission.
(C) For buried lines subject to this Section, the operator shall comply with the following:
(i) A marker sign shall be installed at public road crossings on both sides of the road as close to the pipeline as possible.
(ii) Marker signs shall be installed along the line, when it is located within a public area or along a public road, at intervals frequent enough in the judgment of the operator so as to provide warning to avoid the accidental rupturing of line by excavation.
(iii) The marker sign shall contain the name of the operator and a 24-hour phone number (including area code), and shall indicate by the use of the words "Warning", "Caution", or "Danger" and "Poison Gas" that a potential danger exists. Markers installed in compliance with the regulations of the Federal Department of Transportation shall satisfy the requirements of this provision. Marker signs installed prior to the June 12, 1987 shall be acceptable provided they are in good condition and indicate the existence of a potential hazard.
(D) In satisfying the sign requirement of this subsection, the following will be acceptable:
(i) Sign of sufficient size to be readable from the road or at the entrance to the facility.
(ii) New signs constructed to satisfy this subsection shall refer to (c) (5) (iii) of this Section.
(2) **Security provision.**
(A) Unattended fixed surface facilities shall be protected from public access when located within one-forth (1/4) mile of a dwelling, place of business, hospital, school, church, government building, school bus stop,

public park, town, city, village, or similarly populated area. This protection shall be provided by fencing and locking, or removal of pressure gauges and plugging of valve openings, or other similar means. For the purpose of this paragraph, surface pipeline shall not be considered as a fixed surface facility.

(B) For well sites, fencing as a security measure is required when a well is located inside populated limits of a townsite or city, where conditions cause the well to be exposed to the public. In other areas considered to be a danger, the Commission may require a hearing to establish security requirements.

(C) The fencing provision will be considered satisfied where the fencing structure is a deterrent to public access.

(e) **Control and equipment safety; contingency plan.**

(1) **Applicability; radius of exposure.** All operations subject to (a) of this Section shall be subject to (2) and (3) of this subsection, if any of the following conditions apply:

(A) The 100 ppm radius of exposure is in excess of 50 feet and includes any part of a "public area" except a public road.

(B) The 500 ppm radius of exposure is in excess of 50 feet and includes any part of a "public road".

(C) The 100 ppm radius of exposure is greater than 3,000 feet.

(2) **Control and equipment safety provision.** Operators subject to this subsection shall either install safety devices and maintain them in an operable condition, or shall establish written safety procedures designed to prevent the undetected continuing escape of hydrogen sulfide. Safety devises should be tested annually and a record kept of such tests.

(3) **Contingency plan provision.** A contingency plan provision shall be developed for each drilling, producing, well servicing, and plant operation that could reasonably result in accidental exposure of the public to a concentration of hydrogen sulfide in excess of 300 ppm. The operator should make appropriate contacts with any public agency listed in the contingency plan. The contingency plan shall provide an organized plan of action for alerting and protecting the public. The details of a contingency plan are determined largely by the time required for a potentially hazardous concentration of hydrogen sulfide to reach a public area and by the population density in the public area. A copy of the contingency plan should be maintained at the location which lends itself best to activation of the plan. A copy shall be submitted to the Conservation Division's District Office.

(A) The plan shall include instructions and procedures for alerting the general public and public safety personnel of the existence of an emergency.

(B) The plan shall include procedures for requesting assistance and for follow-up action to remove the public from an area of exposure.

(C) The plan shall include a call list which shall include the following as they may be applicable:

(i) Local supervisory personnel.
(ii) County Sheriff.
(iii) Department of Public Safety.
(iv) City Police.
(v) Ambulance Service.
(vi) Hospital.
(vii) Fire Department
(viii) Contractors for supplemental equipment.
(ix) District Commission Office.
(x) Local Department of Environmental Quality Office.
(xi) Other public agencies.

(D) The plan shall include a plat detailing the area of exposure. The plat shall include the locations of private dwellings or residential areas, public facilities, such as schools, business locations, public roads, or other similar areas where the public might reasonably be expected within the area of exposure.

(E) The plan shall include provisions for advance briefing of occupied dwellings within the 300 ppm radius of exposure. The following provisions apply;

(i) The hazards and characteristics of hydrogen sulfide.

(ii) The necessity for an emergency action plan.

(iii) the possible sources of hydrogen sulfide within the area of exposure.

(iv) Instructions for reporting a gas leak.

(v) The manner in which the public will be notified of an emergency.

(vi) Steps to be taken in case of an emergency.

(F) In a high density population area, or the case where the population density may be unpredictable, a reaction type of plan, in lieu of advance briefing for public notification, will be acceptable. The reaction plan option must be approved by the Commission.

(G) The plan shall include names and telephone numbers of residents within the area of exposure, except in cases where the reaction plan option has been approved by the Commission.

(H) The plan shall include a list of the names and telephone numbers of the responsible parties for each of the possibly occupied public areas, such as schools, churches, businesses, or other public areas or facilities within the area of exposure.

(f) **Training and requirement provision.** Each operator shall provide appropriate H_2S training for its employees who will be on-site. This training should include:

(1) Hazards and characteristics of hydrogen sulfide.

(2) Effect on metal components of the system.

(3) Operations of safety equipment and life support systems.

(4) First aid in event of an employee exposure.

(5) Use and operation of H_2S monitoring equipment.

(6) Emergency response procedures to include corrective actions, shut-down procedures, evacuation routes, and rescue methods.

(g) **Injection of fluids.** Injection of fluids containing hydrogen sulfide shall not be allowed under the conditions specified in this Section unless first approved by the Commission.

(h) **Venting and flaring.** Venting and flaring of gas shall be conducted in accordance with OAC 165:10-3-15.

(i) **Other requirements.** In addition to any other requirements of this Section, drilling and workover operations and processing plant sites where the 100 ppm radius of exposure is 50 feet or greater shall be subject to the following:

(1) Protective breathing equipment shall be maintained in good operating condition at two or more locations at the site.

(2) Wind direction indicators shall be installed at strategic locations at or near the site and be readily visible from the site.

(3) Automatic hydrogen sulfide detection and alarm equipment that will warn of the presence of hydrogen sulfide gas in harmful concentrations shall be utilized at the site.

(4) The Commission District Office shall be notified of the intention to conduct a drill stem test of a formation containing hydrogen sulfide in sufficient concentration to meet the requirements of this Section.

(j) **Accident notification.** Operators shall immediately notify the appropriate Commission District Office or field inspector of any accidental release of hydrogen sulfide gas of sufficient volume to present a public hazard and hydrogen sulfide related accident resulting in death or hospitalization of personnel.

(k) **Exception provision.** Any application for exception to the provisions of this Section should specify the provisions to which exception is requested, and set out in detail the basis on which the exception is to be requested.

(l) **Referenced organizations and publications.** The following organizations and publications are referenced in this Section:

(1) ANSI - American National Standards Institute 1430 Broadway, New York, New York 10018; Table I, Standard 253.1-1967.

(2) API - American Petroleum Institute 300 Corrigan Tower Building, Dallas, Texas 75201; Publication API RP-55.

(3) ASTM - American Society for Testing and Materials 1916 Race Street, Philadelphia, Pennsylvania 19103; Standard D-2385-81.
(4) EPA - U.S. Environmental Protection Agency, Office or Air Quality Planning and Standards, Technical Support Division, Research Triangle Park, North Carolina 27711; Screen 2 Model User's Guide.

[**SOURCE:** Amended at 13 Ok Reg 2395, eff 7-1-96; Amended in Rule Making 980000013; eff 7-15-98]

165:10-3-17. Well site and surface facilities

(a) **Scope.** This Section shall be applicable to all operators and owners of oil and gas wells, leases, secondary recovery units, converted or newly drilled saltwater disposal or injection wells, and re-entries or reworkings of the above; however, this Section does not cover pits used in connection with oil and gas operations (see 165:10-7-16).
(b) **Removal of fire hazards.** Any material that might constitute a fire hazard shall be removed a safe distance from the well location, tanks, and separator. All waste oil shall be burned or disposed of in a manner to avoid creating a fire hazard.
(c) **Removal of surface trash.**
(1) All surface trash, debris, and junk associated with the operations of the property shall be removed from the premises. Equipment and material that may be useable and related to the operations of the property are not considered trash, debris and junk. With written permission from the surface owner, the operator may, without applying for an exception to 165:10-3-17(b), bury all nonhazardous material at a minimum depth of three feet; cement bases are included.
(2) The District Office or field inspector may issue a Form 1036 for any alleged violation of this subsection. If the operator fails to remove trash, debris, and junk after written notice, the Commission may fine the operator up to $1,000.
(d) **Required lease signs.** Within 30 days after the completion of any producing oil or gas well, a sign shall be posted and maintained at the location showing operator of the well and the operator's business phone number, name of farm, number of the well, and legal description of the well; provided, however, where more than one well is producing on a lease, the operator may post and maintain a sign at the principal lease entrance showing the lease name, operator, legal description, and number of wells, and on each well designate the number of the well. Within 30 days after completion or recompletion of an enhanced recovery injection well or a disposal well, a sign shall be posted and maintained at the well location showing the operator of well, name of farm, well number, legal description of the well, and the Commission order number by which it was authorized. The legal description of each well completed on or after March 1, 1976, shall be posted at the well and shall describe the location of the well to the nearest quarter quarter quarter section and shall show the section, township, and range. On a 160-acre or larger drilling and spacing unit, a sign shall also be posted at the entrance to the well site. The District Office or field inspector may issue Form 1036A for failure to post a required sign. If an operator fails to post a sign as directed, the Commission may fine the operator $50.00 per violation; provided that total fines per incident shall not exceed $500.00 per lease.
(e) **Notice of fire or blowout.** In case of a fire or blowout, the well operator shall notify by telephone or telegraph, as soon as possible, either the Conservation Division or the appropriate District Office of the Conservation Division.
(f) **OTC numbers on stock tanks for oil and condensate.**
(1) On all oil and gas producing leases, the first purchaser of crude oil or condensate shall print its name or affix the company logo and print or affix the OTC Gross Production Division Purchaser Reporting Number on at least one of the storage tanks from which marketable liquids are being delivered.
(2) On all oil and gas producing leases, the well operator shall print or affix the OTC Gross Production Division assigned Production Unit Number and

the OTC Gross Production Division Operator Reporting Number on at least one of the tanks from which marketable liquids are being stored. In the case of an enhanced recovery or unitization operation where several OTC Gross Production Division assigned Production Unit Numbers exist for the wells in the unit, the word "unitized" shall be printed or affixed to one of the storage tanks from which marketable liquids are being delivered to the purchaser.

(3) The identification numbers required in this subsection shall always be clearly legible. All letters and numbers shall be a minimum of two inches in height. Any operator failing to post required information shall be fined $50.00 per violation; provided that total fines per incident shall not exceed $500.00 per well.

(g) **OTC numbers on gas meter or meter house.**

(1) On all gas producing leases, the operator of the well site gas meter required under 165:10-17-5 shall print or affix its name and OTC reporting number on the outside of the meter house or on the outside of the meter itself if no meter house exists.

(2) The operator of the lease shall print its OTC lease number and operator reporting number on the meter house or on outside of the meter if no meter house exists.

(3) The identification required in this subsection shall always be clearly legible. All letters and numbers shall be a minimum of two inches in height.

(h) **Valve and seals on stock tanks.** The operator shall install tank valves such that metal identification seals can be properly utilized. These seals shall be used on all delivery tank valves to lessen unauthorized movement of marketable products.

(i) **Man-ways on frac tanks.** Each frac tank used at the wellsite shall have protective man-ways to prevent persons from accidentally falling into the frac tank.

(j) **Guy line anchors.** All guy line anchors left buried for use in future operations of the well shall be properly marked by a marker of bright color not less than four feet in height and not greater than one foot east of the guy line anchor.

(k) **Well site cleared.** Within 90 days after a well is plugged and abandoned, the well site shall be cleared of all equipment, trash, and debris. Any foreign surface material is to be removed and the location site restored to as near to its natural state as reasonably possible, except by written agreement with the surface owner to leave the surface in some other condition. If the location site is restored but the vegetative cover is destroyed or significantly damaged, a bona fide effort shall be made to restore or re-establish the vegetative cover within 180 days after abandonment of the well.

(l) **Restored surface.** Within 90 days after a lease has been abandoned, surface equipment such as stock tanks, heater, separators, and other related items shall be removed from the premises. The surface shall be restored to as near to its natural state as reasonably possible, except by written agreement with the surface owner to leave the surface in some other condition. If the surface is restored but the vegetative cover is destroyed or significantly damaged, a bona fide effort shall be made to restore or re-establish the vegetative cover within 180 days after abandonment of the lease.

(m) **Leasehold roads.** All leasehold roads shall be kept in a passable condition and shall be made accessible at all times for representatives and field inspectors of the Commission. At the time of abandonment of the property, the area of the road shall be restored to as near to its natural state as reasonably possible, except by written agreement with the surface owner to leave the surface in some other condition. If the road area is restored but the vegetative cover is destroyed or significantly damaged, a bona fide effort shall be made to restore or re-establish the vegetative cover within 180 days after abandonment of the property.

(n) **Extension of time.**

(1) An operator may request an extension of time required in (k), (l), and (m) of this Section for not more than six months by applying to the District Office and showing that there is no imminent danger to the environment and that one of the following conditions exists:

(A) That an agreement with the surface owners is not possible.

(B) That adverse weather conditions exist or existed.
(C) That the equipment needed to conform to (k), (l), and (m) of this Section was not or is not available.
(2) If approved by the District Manager, the extension shall be granted and the surface owner shall be notified by the operator. Any extension beyond six months shall require application, notice and hearing pursuant to OAC 165:5-7-41.

[**SOURCE:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended in Rule Making 980000034]

PART 5. OPERATIONS

165:10-3-25. Completion Reports

(a) **Initial Completion Report.** A Completion Report shall be filed with the Commission on Form 1002A within 30 days after completion of operations regardless of whether or not the well was completed as a dry hole, producer, injection, disposal, or service well. An operator who fails to file a complete and correct Form 1002A Completion Report within the allotted time limit shall be subject to a fine of $250.00.
(b) **Amended Completion Report.** An amended Completion Report shall be filed with the Commission on Form 1002A within 30 days after completion of operations to reenter, recomplete and/or convert to injection or disposal well regardless of whether or not the well was completed as a dry hole, producer, injection, disposal, or service well.
(c) **No allowable without Completion Report.** The Conservation Division shall not assign an allowable to a well without an up-to-date Completion Report on file with the Conservation Division.

[**SOURCE:** Amended at 9 OK Reg 2295, eff 6-25-92]

165:10-3-26. Well logs

(a) **60 days to submit well log(s).** All well logs required by this Section shall be submitted to the Conservation Division within 60 days from the earlier of the date of completion of the well or the date that the last formation evaluation type wireline log was run. An operator who fails to properly submit wireline surveys, if run, shall be subject to a warning with time limit followed by a fine of $250.00.
(b) **Wireline logs.** This Section does not require an operator to run a wireline survey. However, if an operator does run wireline surveys, the operator shall only be required under this Section to submit a resistivity type wireline log and a porosity type wireline log, if available. Resistivity and porosity type wireline logs include but are not limited to spontaneous potential, induction, laterolog, density, and gamma ray neutron logs.
(c) **Other logs to be available upon request.** Dipmeter, velocity, and radioactive tracer logs, if available, shall be submitted to the Technical Services Department upon Commission order or special request of the Conservation Division.
(d) **Requirements for submitting a copy of a log.** A copy of a log submitted under this Section, instead of the original log, shall be a legible finished copy, complete, in one piece and with the well's legal description noted on it. If there are separate runs for multiple casing strings, the operator shall submit the separate runs.
(e) **Obtaining confidential treatment of well log(s).**
(1) Unless the operator requests confidential treatment of a well log(s), any well log(s) submitted to the Conservation Division shall be available for public inspection.
(2) To obtain confidential treatment of a well log, the operator of the well shall:

(A) Place the well log(s) in a sealed envelope with a completed Form 1002B attached to the envelope.
(B) Submit to the Technical Services Department of the Conservation Division the envelope with the log(s) and Form 1002B within 60 days from the earlier of:
(i) The completion date of the well, or
(ii) The date that the last formation evaluation log was run.
(3) A confidential well log under (2)(B) of this Section, shall remain confidential for one year from the date the last log was run on the well. Upon written request, the Conservation Division may administratively extend the period of confidentiality for six months. Under no circumstances shall confidentiality be granted for a period in excess of 18 months from the date the last log was run on the well.
(f) **No allowable before submission of well logs.** The Conservation Division shall not assign an allowable to a well before the operator of the well submits to the Conservation Division any well log required to be submitted under (b) of this Section.

[**SOURCE:** Amended at 9 OK Reg 2295, eff 6-25-92]

3-10-3-27. Deviation from the vertical
(a) **Well location for purposes of well spacing.** For purposes of the well spacing requirements of 165:10-1-21 and 165:10-1-24, the location of a well in a common source of supply is the point at which the wellbore penetrates the top of the common source of supply.
(b) **Presumed bottom hole location.** For purposes of review of Form 1000 applications, the Conservation Division may presume that the location in a common source of supply of a well without a horizontal drainhole is the same as the surface location for the well unless:
(1) The operator submits a bottom hole survey, if the well has been drilled; or
(2) The operator complies with (c)(1) of this Section.
(c) **Permitted and prohibited locations.**
(1) **Offpattern surface location; permitted subsurface location.**
(A) The Conservation Division may approve a Form 1000 for a well to be commenced without a location exception at an offpattern surface location for a common source of supply when:
(i) The Form 1000 lists a subsurface location which is a permitted location for the common source of supply.
(ii) Issuance of a Permit to Drill is conditioned on the operator running a bottom hole survey within 30 days after reaching total depth and on the operator submitting the survey to the Conservation Division within 45 days after the well reaches total depth.
(B) The well shall not receive an allowable for the common source of supply until a bottom hole survey shows that the well is at a permitted location or until the operator obtains a location exception order for the subsurface location.
(2) **Offpattern subsurface location.**
(A) The Conservation Division shall not approve a Form 1000 without a location exception order for an offpattern subsurface location.
(B) Issuance of a Permit to Drill under (1) of this subsection does not permit an operator to have, without a location exception order, an offpattern subsurface location for a common source of supply.
(d) **Required directional and bottom hole surveys.** For good cause, the Commission may order an operator to run directional and/or bottom-hole surveys for a common source of supply in a well:
(1) Upon application, notice, and hearing; or
(2) In any case involving the location of a well, upon motion of an affected party or upon the Commission's own motion.

165:10-3-28. Horizontal drilling

(a) **Scope.** This Section affects a horizontal well with one or more laterals.

(b) **Definitions.**

(1) **"Horizontal well"** shall mean a well drilled, completed, or recompleted in a manner in which the horizontal component of the completion interval in the geological formation exceeds the vertical component thereof and which horizontal component extends a minimum of 150 feet in the formation.

(2) **"Geological formation"** shall mean the common source of supply.

(3) **"Point of entry"** shall mean the point at which the borehole first intersects the top of the common source of supply.

(4) **"True vertical depth"** shall mean that depth at the point of entry in a horizontal borehole perpendicular to the surface as measured from the elevation of the kelly bushing on the drilling rig.

(5) **"Terminus"** shall mean the end point of the borehole in the common source of supply.

(6) **"Lateral"** shall mean the measured distance drilled from the point of entry to the terminus.

(7) **"Horizontal well unit"** shall mean a drilling and spacing unit established by the Commission, after application, notice, and hearing, for a common source of supply into which a horizontal well has been or will be drilled.

(8) **"Directional survey"** shall mean that survey or report showing the location of any point of the wellbore as it relates to the surveyed surface location from the surface to the terminus of each lateral.

(9) **"Date of first production"** shall mean the date hydrocarbons are first produced from the horizontal well, whether or not production occurs during drilling, completion, or through permanent surface equipment.

(10) **"Vertical component"** shall mean the calculated vertical distance from the point of entry to the terminus of the lateral.

(11) **"Horizontal component"** shall mean the calculated horizontal distance from the point of entry to the terminus.

(c) **Drilling and producing on a lease basis or in a conventional drilling and spacing unit.**

(1) This subsection shall apply to a horizontal well, not a part of a horizontal well unit. For purposes of 165:10-1-21, 165:10-1-24, and 165:10-1-25, compliance with well location requirements shall be determined considering:

(A) The location at which the wellbore penetrates the top of the common source of supply.

(B) The location of each lateral and its terminus in the common source of supply.

(2) No operator shall be assigned an allowable to produce oil, gas, or gas condensate from the well until he submits a downhole survey showing that each lateral is at location permitted by general rule or location exception order. For allowable purposes, the well shall be considered as a single wellbore. For a gas well, the Conservation Division shall compute the gross allowable in the manner prescribed for a vertically drilled gas well at that location in the common source of supply. For an oil well, the Conservation Division shall compute the gross allowable using the provisions applicable to a horizontal well unit.

(d) **Horizontal well units.** Subsections (e) through (l) of this Section establish criteria for spacing, pooling, drilling, and producing a horizontal well with one or more laterals.

(e) **Drilling and spacing units.**

(1) A horizontal well may be drilled on any drilling and spacing unit.

(2) A horizontal well unit may be created in accordance with 165:10-1-22 and 165:5-7-6, 165:5-15-8, and 165:5-15-9. Such units shall be created as new units after notice and hearing as provided for by the Rules of Practice, OAC 165:5.

(3) A horizontal well unit may be established for a common source of supply for which there are already established non-horizontal drilling and spacing units, and said horizontal well unit may include within the boundaries thereof more than one existing non-horizontal drilling and spacing unit for the common source of supply.

(A) Horizontal well units may exist concurrently with producing non-horizontal drilling and spacing units.
(B) Horizontal well units shall supersede existing non-developed non-horizontal drilling and spacing units for the duration of the horizontal well unit.

(f) **Single wellbore.**
(1) All laterals in the same common source of supply in a horizontal well with at least one lateral which exceeds 150 feet of total horizontal component shall be considered as a single wellbore for allowable purposes.
(2) Laterals in the same common source of supply directly connected through the wellbore to the same surface location in a horizontal well and which form an angle of 90 degrees or more shall be considered a single lateral in determining projected horizontal displacement for horizontal well unit purposes. The horizontal lateral displacement used to determine the appropriate horizontal well unit where multiple laterals exist shall be the horizontal displacement of the longest lateral, plus the projection of any other lateral on a line that extends in a one hundred eighty degree (180°) direction from the longest lateral.

(g) **Location.** For purposes of 165:10-1-22 and Appendix C (Table HD) to this Chapter, compliance with well location requirements shall be determined considering:
(1) The location of the point of entry.
(2) The location of each lateral in terms of direction and depth.
(3) The terminus of each lateral.

(h) **Determination of unit size and allowable.**
(1) The size of the proposed horizontal well unit shall be determined by the projected length of the horizontal component as shown in Appendix C (Table HD) to this Chapter.
(2) The allowable for the horizontal oil well shall be determined by the actual length of the lateral as shown in Appendix C (Table HD) to this Chapter.

(i) **Horizontal well spacing requirements.**
(1) A horizontal wellbore from its point of entry and along any part of the lateral shall be located not closer than the minimum distance as set out below from any other wellbore completed in or drilling to the same common source of supply except by a special order of the Commission:
(A) Three hundred feet from any other producible or drilling oil or gas well when drilling to the same common source of supply that is less than 2,500 feet in depth.
(B) Six hundred feet from any other producible or drilling oil or gas well when drilling to the same common source of supply that is 2,500 feet or more in depth.
(C) This paragraph does not apply to horizontal wells drilled in a unit created for secondary or enhanced recovery operations pursuant to 52 O.S. 287.1 et seq.
(2) A horizontal wellbore from its point of entry and along any part of the lateral shall be located not less than the minimum tolerance distance from the boundary of the horizontal well unit as follows:
(A) Not less than 165 feet from the boundary of any 10, 20, or 40 acre horizontal well unit.
(B) Not less than 330 feet from the boundary of any 80 or 160 acre horizontal well unit.
(C) Not less than 660 feet from the boundary of any 320 acre or 640 acre horizontal drilling and spacing unit.
(3) Any horizontal wellbore drilled into an unspaced common source of supply may not be located closer to the lease line or voluntary unit or to another wellbore completed in the same common source of supply than the tolerance distance prescribed for a well drilled in a standard horizontal well unit as determined by the length of the horizontal component of the unspaced horizontal wellbore.

(j) **Allowable.**
(1) Horizontal oil well allowables may be established administratively based on Appendix C (Table HD) to this Chapter.

(2) Allowables will be effective as of the date of first production. Underproduction will not be accumulated during drilling.
(3) Bonus allowables will be established for multilaterals by the summation of each individual lateral in an otherwise qualifying horizontal oil well, as provided in (f) of this Section.

(k) **Establishing allowables.** To establish an allowable for a horizontal well, the following must be submitted to the Commission:
(1) Directional survey.
(2) A plat constructed from data gathered from the directional survey showing point of entry, true vertical depth at point of entry, actual length, and direction of the lateral and horizontal component.
(3) An approved copy of Form 1002A.
(4) Total amount of oil or gas that has been produced from the well prior to the date of completion.

(l) **Pooling.** Horizontal well units may be pooled as provided for under 52 O.S. 87.1 and Commission Rules of Practice, OAC 165:5.

165:10-3-29. Oil storage

Oil storage tanks shall be constructed so as to prevent leakage. Dikes or walls, where necessary, shall be constructed so as to prevent oil or deleterious substances from polluting surface and subsurface water.

165:10-3-30. Use of gas for artificial lifting

(a) **Use of gas for artificial lifting of oil.** Gas may be used for the artificial lifting of oil; provided, all gas returned to the surface with the oil is not vented or otherwise wasted

(b) **The use of production.** The use of production from one common source of supply to assist in lifting the production from another common source of supply by commingling the production from both common sources of supply in the tubing string shall be permitted when the operator has authority to commingle the production in the tubing.

(c) **Use of artificial lift.** Artificial lift, initial or subsequent, in conjunction with the separate orifice or choke assembly shall be governed by OAC 165:10-3-37.

[**SOURCE:** Amended in Rule Making 980000033, eff 7-1-99]

165:10-3-31. Use of vacuum

(a) **Prohibited without an order.** Imposing vacuum on an oil or gas bearing formation is prohibited without an order of the Commission.

(b) **Requirement.** A vacuum shall not be permitted unless it can be shown that to use a vacuum as permitted will prevent waste and protect correlative rights.

(c) **Application for an order.** Each application for an order authorizing use of vacuum on a common source of supply shall be made according to 165:5-7-25.

(d) **Records required to be kept by the operator.**
(1) If an operator obtains an order authorizing use of vacuum, the operator shall make a record on a monthly basis of:
(A) The vacuum imposed in pounds per square inch or inches of mercury.
(B) The amount of gas, oil and water production per day.
(2) Any record required to be kept under this Section shall be made available to the Conservation Division upon request.

PART 7. PRODUCTION

165:10-3-35. Multiple zone production

(a) Production from more than one common source of supply from a single well is hereby prohibited except as authorized by the Conservation Division.
(b) For the purpose of this Section, completion of a well so as to separately produce or account for the production from two or more common sources of supply shall be a multiple completion, and the production from more than one common source of supply without segregation of the production shall be commingling.
(c) Any operator violating this Section shall be subject to a fine of $500.00. The Conservation Division may shut down a multiply completed well pending compliance with this Section.

[**SOURCE:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended in Rule Making 980000033, eff 7-1-99]

165:10-3-36. Multiple zone completions
(a) Each application for the approval of the multiple completion of a well shall be filed on Form 1023 and shall be verified.
(b) A copy of the application shall be mailed or delivered to each operator of a producing leasehold within one-half (1/2) mile of the well location. The applicant shall file an affidavit of delivery or mailing not later than five (5) days after the application is filed.
(c) If a written objection to the application is filed within fifteen (15) days after the application is filed, or if hearing is required by the Commission, the application shall be set for hearing and notice thereof shall be given as the Commission shall direct. If no objection is filed and the Commission does not require a hearing, the matter shall be presented administratively to the Director of Conservation or his designee who shall file his report and make his recommendations. If the Conservation Division denies an application, the applicant may request a hearing on said application in accordance with OAC 165:5-7-22.

[**SOURCE:** Amended in Rule Making 980000033, eff 7-1-99]

165:10-3-37. Control of multiply completed wells
(a) Every multiply completed well shall be equipped, operated, produced, and maintained so that there will be no commingling of the production from separate common sources of supply in the well, except as hereinafter provided. The production from each common source of supply shall be separately accounted for or separately stored and measured on the lease. The production shall be measured by either:
(1) A positive displacement dump-type device;
(2) A continuous-flow measuring device; or
(3) A measuring device of any other type authorized by the Commission.
(b) Each application for the approval of production through a multiple choke assembly in a well shall be filed on Form 1023 and shall be verified. The multiple choke assembly must be so designed and located in the wellbore as to prevent commingling within the common sources of supply, but to permit commingling in the tubing string through individual choke orifices. The commingled production shall be measured at the surface and allocated to each common source of supply.
(c) A copy of the application shall be mailed or delivered to each operator of a producing leasehold within one-half (1/2) mile of the well location. The applicant shall file an affidavit of delivery or mailing not later than five days after the application is filed.
(d) If a written objection to the application is filed within 15 days after the application is filed, or if hearing is required by the Commission, the application shall be set for hearing and notice thereof shall be given as the Commission shall direct. If no objection is filed and the Commission does not require a hearing, the matter shall be presented administratively to the Director of Conservation who shall file his report and make his recommendations.

[**SOURCE:** Amended in Rule Making 980000033, eff 7-1-99]

165:10-3-38. Testing of multiply completed wells

The Conservation Division may at any time require a multiply completed well to be tested to determine the effectiveness of the separation of common sources of supply. The tests may be witnessed by representatives of the Conservation Division and may be witnessed by any offset operator. Testing procedures must be acceptable to a representative of the Conservation Division.

[**SOURCE:** Amended in Rule Making 980000033, eff 7-1-99]

165:10-3-39. Commingling of production

(a) **Commingling order required.** Commingling of production from a well from separate common sources of supply is prohibited without a commingling order. A commingling order shall be required when production is from more than one source of supply, without segregation of the production in the wellbore, or is produced separately in the wellbore and then combined together downstream of the wellhead prior to measurement. Commingling downstream of the wellhead shall require Form 1024 (Packer Setting Affidavit) and Form 1025 (Packer Leakage Test) to be filed and approved. The Commission shall assess a fine of $500.00 for non-permitted commingling either down hole or downstream prior to measurement.

(b) **Restrictions.**

(1) Commingling shall only be authorized when it would prevent waste and protect correlative rights.

(2) Commingling shall be prohibited where one producing zone is predominately gas and a second zone is predominately oil, unless the operator can verify in writing, submitted with the application, that no cross flow will occur resulting in reservoir damage.

(c) **Application requirements.** Each application for a commingling order shall comply with OAC 165:5-7-24.

(d) **Commingled allowables.**

(1) **Single allowable for commingled production.** Common sources of supply commingled under this Section receive a single allowable as if they constituted a single common source of supply in the wellbore.

(2) **Gross daily allowable for commingled production.** The gross daily allowable shall be based on the classification of the well as an oil or gas well for allowable purposes under OAC 165:10-13-2.

(A) **Unallocated oil well (GOR < 15,000:1).** The gross daily allowable shall be based on what would be the allowable if commingled production comes from the deepest commingled common source of supply.

(B) **Unallocated gas well (GOR > 15,000:1).** The gross daily allowable shall be a single unallocated gas allowable, as determined by OAC 165:10-17-11(c). Upon request in a commingling application or in any other appropriate application and upon proper notice thereof, the Commission may designate in the commingling order or other appropriate order the specific gas formation, completed and producing in the applicable well, to which the allowable for such well is to be attributed when the Commission determines that such designation is necessary to prevent waste and to protect correlative rights.

(C) **Special allocated gas pool.** The gross daily allowable shall be based on what would be the allowable if the commingled production came from the special allocated gas pool in the well.

(3) **Operator option if multiple pool rules exist.** If more than one common source of supply under a commingling order for a gas well is subject to gas pool rules, the order shall designate which set of pool rules is applicable for allowable purposes.

(4) **Net daily allowable.** The net daily allowable is the gross daily allowable under (3) of this subsection:

(A) Reduced accordingly by any penalty against any of the commingled common sources of supply under the order.

(B) Reduced accordingly by any overage carried forward against a commingled common source of supply.
(C) Increased by any underage carried forward for the well under applicable allocated or special allocated pool rules.

[**SOURCE:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended in Rule Making 980000033, eff 7-1-99]

165:10-3-40. Production of brine
(a) All wells in excess of 300 feet in depth and producing brine for the extracting of minerals shall be under the full jurisdiction of the Conservation Division.
(b) The establishment of a unitized area for the purpose of efficient operations, prevention of waste, and the protection of correlative rights may be formed by following the procedures set out in 165:5-7-21
(c) Category B surety shall be a requirement for all brine producing wells or units. [See 165:5-7-21(f)]

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SUBCHAPTER 5. UNDERGROUND INJECTION CONTROL

Section

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165:10-5-1. Classification of underground injection wells

Underground injection wells shall be classified as follows:

(1) **Enhanced recovery injection well.** An enhanced recovery injection well is a well which injects fluids to increase the recovery of hydrocarbons.

(2) **Disposal well.** A disposal well is a well which injects, for purposes other than enhanced recovery, those fluids brought to the surface in connection with oil or natural gas production.

(3) **Storage well.** A storage well is a well used to inject, for storage purposes, hydrocarbons which are liquid at standard temperature and pressure.

(4) **Simultaneous injection well.** A well that injects or disposes of salt water at the same time it is producing oil and/or gas to the surface.

[SOURCE: Amended at 13 Ok Reg 2387, eff 7-1-96]

165:10-5-2. Approval of enhanced recovery injection wells or disposal wells

(a) The subsurface injection or disposal of any substance for any purpose is prohibited except upon approval of the Commission pursuant to 165:10-5-5 or 165:10-5-12 and 165:10-5-13. This authorization may be conditioned upon the applicant taking corrective action to protect treatable water as specified by the Commission in its order. The Commission shall fine an operator $5,000.00 for any violation of this subsection.

(b) Except as provided in (c) and (d) in this Section, every well used for injection or disposal shall be cased and tested in accordance with 165:10-3-4 and 165:10-5-6.

(c) The testing requirements of 165:10-5-6 shall not apply to wells permitted by Commission order for subsurface injection of onsite reserve pit fluids.

(d) The Conservation Division may approve a Form 1015 application to convert for injection or disposal an existing well which does not comply with 165:10-3-4 if:

(1) The operator attaches to the Form 1015 application a description of an alternate method of protecting treatable water.

(2) The Conservation Division approves the proposed alternate method.

(3) The application is filed in accordance with OAC 165:5-7 if a hearing is required.

(4) The application is not protested.

(e) Any newly drilled or newly converted injection or disposal well which is within one-half (1/2) mile of any active or reserve municipal water supply well shall not be approved without notice and hearing, and the Commission shall not issue an order authorizing injection or disposal into said well until the applicant proves by substantial evidence that said well shall not pollute said water supply well. A commercial disposal well shall not be approved within a designated wellhead protection area.

[**SOURCE:** Amended at 9 Ok Reg 2295; Amended at 9 Ok Reg 2337, eff 6-25-92]

165:10-5-3. Authorization for existing enhanced recovery injection wells and existing disposal wells

(a) Each enhanced recovery injection well authorized under order of the Commission on the effective date of this Section is an existing enhanced recovery injection well. Injection is prohibited in any existing enhanced recovery injection well unless the operator has included that well on a completed Form 1070 submitted to the Commission within one year following the effective date of this Section. Form 1070 (Inventory of Authorized Existing Enhanced Recovery Injection Wells) shall include each well name, location, authorizing Commission order number (including all orders authorizing exceptions), date of order, maximum authorized injection rate, and maximum authorized injection pressure.

(b) Each disposal well being operated under order of the Commission on the effective date of this Section is an existing disposal well. Injection is prohibited in any existing disposal well unless the operator has included that well on a completed Form 1071 submitted to the Commission within one year following the effective date of this Section. Form 1071 (Inventory of Authorized Existing Disposal Wells) shall include each well name, location, authorizing Commission order number (including all orders authorizing exceptions), date of order, maximum authorized injection rate, and maximum authorized injection pressure.

165:10-5-4. Application for approval of enhanced recovery projects

(a) An enhanced recovery project shall be permitted only by order of the Commission after notice and hearing.

(b) The application for an order authorizing an enhanced recovery project shall contain the following:

(1) The names and addresses of the operator or operators of the project.

(2) A plat showing the lease, group of leases, or unit included within the proposed project; the location of the proposed injection well or wells, and the location of all oil and gas wells including abandoned and drilling wells and dry holes; and the names of all operators offsetting the area encompassed within the project.

(3) The common source of supply in which all wells are currently completed.

(4) The name, description, and depth of each common source of supply to be affected.

(5) A log of a representative well completed in the common source of supply.

(6) A description of the existing or proposed casing program for injection wells and the proposed method of testing casing.

(7) A description of the injection medium to be used, its source, and the estimated amounts to be injected daily.

(8) For a project with an allocated pool, a tabulation showing recent gas-oil ratio and oil and water production tests for each of the producing oil and gas wells.

(9) The proposed plan of development of the area included within the project.

(c) A copy of the application and notice of hearing shall be mailed to the owner or owners of the surface of the land upon which the project is located and to each operator offsetting the project as shown on the application within five days after the application is filed. An affidavit of compliance with this Section shall be filed on or before the hearing.

165:10-5-5. Application for approval of enhanced recovery injection and disposal operations

(a) Each application for approval of a well for use as an injection well or disposal well shall be filed in accordance with 165:5-7-27.

(b) In addition to the requirements of 165:5-7-27, the Resource Conservation Department may request the applicant to submit the following information as a prerequisite to approval of the application:

(1) For those wells included in 165:5-7-27(b)(1) which penetrate the top of the injection interval, a tabulation of the wells indicating the following information, if available, from public records:

(A) Dates the wells were drilled.

(B) The present status of the wells.

(C) The identity of any abandoned well which was improperly plugged or remains unplugged.

(2) A list of the following information, if available, to the applicant:

(A) The shut-in bottom hole formation pressure in psi; or the stabilized shut-in surface pressure and fluid level in the proposed injection well.

(B) The permeability of the proposed injection zone expressed in millidarcies.

(C) The porosity of the proposed injection zone expressed as a percentage of pore volume.
(D) Documentation of the methods used to arrive at the data requested above.

(c) An order authorizing an enhanced oil recovery injection well or a disposal well or a commercial disposal well will expire and become null and void if no well completion report (Form 1002A) is filed within six months from the date of completion or recompletion of the well.

(d) In addition to the well construction requirements as set out in 165:10-3-1, commercial saltwater disposal wells shall comply with the following requirements:

(1) At a minimum, the well shall be constructed with a wellhead, surface casing, production casing, tubing, and packer.
(2) The surface casing shall be set and cemented at least fifty (50) feet below the base of the treatable water bearing zone.
(3) The production casing must be set and cemented through the injection zone with the cement circulated behind the casing to a height at least two hundred fifty (250) feet above the disposal zone. A cement bond log showing quality and placement of the cement must be furnished to and approved by the Commission before the application will be approved. The production casing will not be allowed to also serve as the surface casing.
(4) The annulus between the tubing and the casing must be open from the surface to the packer to allow for pressure testing and monitoring of the injection tubing and packer and the annulus filled with a packer fluid that protects against corrosion.
(5) The packer must be set at least within seventy-five (75) feet of the top of the perforations.
(6) Adequate gauges shall be installed on each annulus to allow proper monitoring of the disposal operation.
(7) Tubing must be internally coated or lined to prevent corrosion from injected fluids. PVC, Plastic Coated, Stainless Steel or Fiberglass will qualify.
(8) The packer must either internally coated or stainless steel.
(9) Commercial disposal wells authorized with a positive injection pressure must be equipped with a down hole shut-off device with a seal divider installed between the packer and the tubing. A Stainless Steel Profile Nipple and an "ON-OFF" Tool will qualify under this Section.

(e) No Commercial disposal well will be permitted whose injection pressure approaches or exceeds the demonstrated frac gradient of the injection zones(s).

(f) All permitted injection zones must be completed for injection. Authorization for any zones not initially completed as an injection zone will expire within 60 days following initial completion or recompletion date.

[**Source:** Amended at 11 Ok Reg 3691, eff 7-11-94]

165:10-5-6. Testing and monitoring requirements for enhanced recovery injection wells and disposal wells

(a) **Mechanical integrity during injection.** The operator of an injection, disposal or commercial disposal well must maintain mechanical integrity in order to continue operation of the well.

(b) **Initial pressure test requirements for wells permitted on or after December 2, 1981.**

(1) **Mandatory initial mechanical test.** Before commencement of operation, each well authorized for enhanced recovery injection or disposal by a Commission order issued on or after December 2, 1981, must pass an initial pressure test of the casing tubing annulus according to the minimum testing standards of (2) of this subsection, unless a Commission order permits other test procedures of the mechanical integrity of the well. Any operator failing to comply with initial mechanical integrity testing and reporting requirements shall be subject to a fine of $500.00.
(2) **Minimum testing standards for initial tests.** For each initial test required by (1) of this subsection, the minimum testing standards are:

(A) **Witnessing of the test.** The test shall be witnessed by an authorized representative of the Conservation Division. It shall be the responsibility of the well operator to secure the presence of the Commission representative.
(B) **Down-hole equipment.** Injection and disposal shall be through adequate tubing and packer.
(C) **Aboveground extensions and fittings.** Adequate aboveground extensions shall be installed in each annulus in the well. In addition, the operator shall install a one-fourth (1/4) inch female fitting, with cutoff valve to the tubing, so that the amount of injection pressure may be measured by the Commission representative using a gauge having a one-fourth (1/4) inch male fitting.
(D) **Packer setting depth under the order.** The mechanical packer shall be set within 20 feet of the packer setting depth prescribed by the order permitting the well for injection.
(E) **Verification of packer setting depth.** The Commission District Manager may require the operator of the well to verify the packer setting depth by running a wireline or other method approved by the Manager of the Underground Injection Control Department.
(F) **Minimum testing pressure.** Noncommercial disposal and injection wells shall be tested as follows:
(i) If the maximum authorized injection pressure for the well is less than 300 psig under the order permitting the well for injection, the minimum testing pressure shall be 300 psig.
(ii) If the maximum authorized injection pressure is greater than 300 psig under the order permitting the well for injection, the minimum testing pressure shall be the lesser of 1000 psig or the maximum authorized injection pressure under the order permitting the well.
(G) **Thirty minute minimum testing period.** The minimum testing period shall be 30 minutes at the testing pressure.
(H) **Ten percent maximum permitted bleed-off.** The maximum permitted bleed-off during the testing period shall be ten percent of the maximum testing pressure used.
(I) **Test report on Form 1075.** The operators shall submit the results of the mechanical integrity test on Form 1075 within 30 days from the date the test is performed.
(J) **Cement circulated above injection zone.** The minimum cement height circulated above the injection or disposal zone in the annulus between the casing and the borehole shall be 250 feet.
(K) **Packer setting depth.** The packer must be set at a depth which is at least 50 feet below the depth of the top of cement behind the production casing.
(3) **Alternative testing procedures.** Operators can test at a maximum of 500 psi if there is in place an automatic and continuous pressure monitor on the tubing-casing annulus that will shut-in the well if there is a significant pressure increase on the annulus. Application for this alternative test procedure shall be made in writing to the Manager of the UIC Department.
(4) **Use of fluid seal without a mechanical packer.** Use of a fluid seal without a mechanical packer is prohibited.

(c) **Initial pressure test requirements for wells permitted prior to December 2, 1981.**
(1) **Mandatory initial pressure test or monitoring test.**
(A) Each well authorized for enhanced recovery injection or disposal by Commission order issued prior to December 2, 1981, must pass an initial mechanical integrity test according to the minimum testing standards of (2) of this subsection.
(B) In lieu of casing test required in (A) of this paragraph, the operator shall monitor and record during actual injection the pressure in the casing-tubing annulus monthly and report the pressure annually on Form 1075. A measurable positive pressure must be maintained at the casing valve and be continuously measured to qualify.
(2) **Minimum testing standards for initial mechanical integrity tests.**

(A) **Wells with casing-tubing annulus.** The minimum testing standards of (a)(2) of this Section for an initial test of a well with a casing tubing annulus shall apply with the following modifications:

(i) The District Manager shall have the option to waive witnessing of the test.

(ii) If the test is not witnessed, the well operator shall submit documentation of the test to the Conservation Division within 30 days after the test on Form 1075.

(iii) The minimum testing pressure shall be 200 psig.

(B) **Wells without a casing-tubing annulus or wells with perforations above the packer.** The minimum testing standards for an initial test of a well without a casing-tubing annulus or wells with perforations above the packer are:

(i) **Witnessing of the test.** The test shall be witnessed by an authorized representative of the Conservation Division unless the District Manager for the Conservation Division waives the requirement of witnessing the initial test. It shall be the responsibility of the well operator to secure the presence of the commission representative for witnessing the test.

(ii) **Documentation for unwitnessed tests.** If the test is not witnessed, then the operator shall submit on Form 1075 documentation of the test to the Conservation Division within 30 days after the test.

(iii) **Aboveground extensions and fittings.** The operator shall install a one-fourth (1/4) inch female fitting, with cutoff valve to the tubing, so that the amount of injection pressure may be measured by the Commission representative using a gauge having a one-fourth (1/4) inch male fitting.

(iv) **Setting depth for plug.** For purposes of the test, a mechanical packer, retrievable bridge plug, or seating nipple plug shall be placed in the injection string not more than 75 feet above the top of the injection interval.

(v) **Pressure testing of tubing string.** The well operator shall pressure test the tubing string for at least 30 minutes. The minimum testing pressure shall be the greater of 300 psig, or the maximum authorized injection pressure provided that the actual working injection pressure for the well may be used instead of the maximum authorized injection pressure when necessary to prevent damage to the casing or packer.

(vi) **Ten percent maximum permitted bleedoff.** The maximum permitted bleedoff during the testing period shall be ten percent of the maximum testing pressure used.

(vii) **Radioactive tracer survey.** A radioactive tracer survey shall be run demonstrating that the injected fluid is going into the authorized zone when there is no cement bond log or cementing reports to demonstrate sufficient cement behind pipe to isolate the injection zone or to insure the packer is properly set.

(viii) **Pressure test using a gas media.** In lieu of a pressure test using a liquid testing media, the UIC Department may approve a mechanical integrity test using a gas media if it conforms to a method previously approved by the EPA.

(ix) **Test report on Form 1075.** The operator shall submit the results of the mechanical integrity test on Form 1075 to the Conservation Division within 30 days after the test.

(d) **Subsequent mechanical integrity test requirements.**

(1) **Pressure test every five years.** Unless a well has been approved by an order of the Commission for other testing procedures or monitoring, each well permitted for injection shall demonstrate mechanical integrity at least once every five years according to the minimum testing standards of (3) of this subsection. Any operator failing to comply with periodic mechanical integrity testing and reporting requirements shall be subject to a fine of $500.00.

(2) **Required retest if down-hole equipment is moved or replaced.** After a well passes a pressure test required by this Section, if the operator moves the packer or replaces either the packer or the tubing, then the operator

shall retest the well according to the minimum testing standards of (3) of this subsection.

(3) **Minimum testing standards.**

(A) **Wells with casing-tubing annulus.** For a five year test or retest required by this subsection, the minimum testing standards of (a)(2) of this Section shall apply to wells with casing-tubing annulus with the following modifications:

(i) The District Manager shall have the option to waive witnessing of the test.

(ii) If the test is not witnessed, the well operator shall submit documentation of the test to the Conservation Division within 30 days after the test.

(iii) The minimum testing pressure shall be:

(I) 200 psig for a noncommercial well.

(II) 300 psig or the authorized injection pressure, whichever is greater, for commercial disposal wells.

(B) **Wells without a casing-tubing annulus or wells with perforations above the packer.** For a five year test or retest required by this subsection, the minimum testing reporting standards of (b)(3)(B) of this Section, shall apply to wells without a casing-tubing annulus or wells with perforations above the packer.

(C) **Wells with automatic monitoring of positive tubing-casing pressure.** Subsequent pressure tests will not be required if there is in place a pressure monitor on the annulus to demonstrate the maintenance of a certain, positive pressure. This monitor will be connected to an automatic alarm or a continuous chart recorder. Application for this alternative shall be made in writing to the Manager of the UIC Department. Monitoring records will be sent annually attached to Form 1012 to the UIC Department.

(e) **Monitoring requirements.**

(1) **Report on Form 1075.** In lieu of a mechanical integrity test every five years, the operator of a well permitted for injection or disposal may demonstrate the mechanical integrity by:

(A) Monitoring and recording the injection rate, volume, and casing-tubing annulus pressure monthly.

(B) Submitting to the Conservation Division the results of monthly monitoring for the calendar year on Form 1075 by the first day of April of the next calendar year.

(2) **Required positive casing-tubing annulus pressure.** A measurable positive pressure must be maintained at the casing valve and be continuously measured to qualify for mechanical integrity.

(f) **Testing requirements for commercial disposal wells.**

(1) **Before commencement of operation.** Before commencement of operation, each commercial disposal well must pass a pressure test of the casing tubing annulus.

(2) **Minimum testing standards.**

(A) The test shall be witnessed by an authorized representative of the Conservation Division.

(B) The well shall be tested at the maximum authorized injection pressure, but not less than 300 psig.

(C) The minimum testing period shall be thirty (30) minutes.

(D) The maximum allowable change in pressure during the testing period shall be ten percent (10%) of the testing pressure.

(E) The results of the test shall be submitted on Form 1075 within 30 days from the date of the test.

(3) **Subsequent mechanical integrity tests.**

(A) The well shall be tested a minimum of every twelve (12) months.

(B) After a well passes a pressure test required by this Section, if the operator moves the packer or replaces the packer or tubing, then the operator shall notify the Commission and retest the well according to the minimum testing standards of (2) of this subsection.

(4) **Alternative testing procedures.** Operators can test at a maximum of 500 psi if there is in place an automatic and continuous pressure monitor on the tubing-casing annulus that will shut-in the well if there is a significant

pressure increase on the annulus. Application for this alternative test procedure shall be made in writing to the Manager of the UIC Department.

[SOURCE: Amended at 9 Ok Reg 2295; Amended at 9 Ok Reg 2337, eff 6-25-92; Amended at 11 Ok Reg 3691, eff 7-11-94; Amended at 13 Ok Reg 2387, eff 7-1-96; Amended in Rule Making 97000002, eff 7-1-97; Amended in Rule Making 200000002, eff 7-1-2000]

165:10-5-7. Monitoring and reporting requirements for wells covered by 165:10-5-1

(a) **Scope.** This Section applies to:
(1) Notice of Commencement of Injection and Disposal Operations on Forms 1012 and 1072.
(2) Annual Report of Injection Projects, saltwater disposal wells and LPG storage wells on Form 1012.
(3) Notice of Voluntary Termination of Operations on Form 1072.
(4) Notice of mechanical failure or down-hole problems.

(b) **Annual report of enhanced recovery injection projects, saltwater disposal wells and LPG storage wells.**
(1) **Submit Form 1012 by April 1st.** Each operator of a saltwater disposal well, LPG storage well or an authorized waterflood, pressure maintenance project, gas repressuring project, or other enhanced recovery project shall submit annually Form 1012 for every well to the Conservation Division as follows:
(A) Form 1012 shall be submitted by April 1st for the previous calendar year for all noncommercial wells.
(B) For commercial disposal wells Form 1012 shall be submitted February 28 and August 31, for the previous six months.
(2) **Failure to submit Form 1012.** Any operator who fails to submit the report on Form 1012 as required by (c)(1) of this Section shall be subject to a fine of $500.00 and:
(A) Injection into the project is prohibited until the operator submits Form 1012 for each injection well.
(B) The order is voidable.
(3) **Required monthly monitoring.** On a monthly basis, the operator of each enhanced recovery injection well and disposal well and LPG storage well shall monitor and record the injection rate and surface injection pressure for the well.
(4) **All UIC wells.** Saltwater disposal wells, injection wells and storage wells shall be reported on Form 1012 individually according to the order authorizing disposal.

(c) **Monitoring requirements for commercial disposal well.**
(1) The operator of a commercial disposal well shall monitor and record the casing tubing annulus pressure and the injection pressure on a daily basis.
(2) The operator of a commercial saltwater disposal well shall make available upon request of the Commission a log of all loads of deleterious substances disposed at the well. The log shall be kept on file for a period of at least five (5) years. The log of record shall include at a minimum, the amount, the location of the source, and the operator and/or owner of the source of the deleterious substance.

(d) **Notice of voluntary termination.**
(1) If an operator permanently terminates injection into a well, the operator shall submit to the Conservation Division Form 1072 within 30 days after termination of injection. Form 1072 shall state:
(A) The legal description of the well.
(B) The reason for termination.
(C) The status of other wells, if the well is in an enhanced recovery project.
(2) Submission of Form 1072 to permanently terminate injection shall terminate the authority under the order.

(e) **Notice of mechanical integrity problem.**

(1) **Notice of mechanical failure or down-hole problem.** When a mechanical problem occurs, then:

(A) The well operator shall notify the Field Inspector for Conservation within 24 hours after discovery of the problem.

(B) Within five days after discovery of the problem, the well operator shall submit to the Manager of Underground Injection Control written notice of the failure and a plan to repair and/or retest the well.

(C) Repair shall be reported on the annual Form 1012 for the well.

(D) Any operator failing to timely notify the Commission shall be subject to a fine of $1,500.00.

(2) **Shutdown.**

(A) **Administrative shutdown.** The Conservation Division may shut down a well if a mechanical failure or down-hole problem indicates that injected substances are not or may not be entering the injection interval authorized by order of the Commission.

(B) **Administrative authority to recommence injection.**

(i) If a well is shut down under (1)(A) of this subsection, the well operator shall be responsible for proving to the satisfaction of the Manager of Underground Injection Control:

(I) The mechanical integrity of the well for injection.

(II) That the injected substances are going into and are confined to the permitted injection interval.

(ii) Upon submission of proper proof of the satisfactory capability of the well for injection, the Manager of Underground Injection Control may authorize recommencement of injection.

(C) **Resolution of disputes by order of the Commission.** In the event of a dispute between the Manager of Underground Injection Control and any person as to the suitability of a well for injection, the affected person may seek relief by order of the Commission. Upon application, notice, and hearing meeting the requirements of 165:5-7-27(c) and (d) for protested applications, the Commission may issue an order determining whether or not the well should be used for further injection.

(3) **Notice of unreported repairs.** Any prior unreported repair of the well shall be reported on the next annual Form 1012 to be submitted to the Manager of the UIC Department.

[SOURCE: Amended at 9 Ok Reg 2295, eff 6-25-92; Amended at 11 Ok Reg 3691, eff 7-11-94; Amended at 13 Ok Reg 2389, eff 7-1-96]

165:10-5-8. Liquid hydrocarbon storage wells

Authorization for storage wells will be granted by order of the Commission after notice and hearing, provided there is a finding that the proposed operation will not endanger fresh water strata.

165:10-5-9. Duration of underground injection well orders

(a) Subject to 165:10-5-10, orders authorizing injection into enhanced recovery injection wells and disposal wells shall remain valid for the life of the well, unless revoked by the Commission for just cause or lapses and becomes null and void under the provisions of 165:10-5-5(c) or 165:10-5-7(f).

(b) An order granting underground injection may be modified, vacated, amended, or terminated during its term for cause. This may be at the Commission's initiative or at the request of any interested person through the prescribed complaint procedure of the Conservation Division. All requests shall be in writing and shall contain facts or reasons supporting the request.

(c) An order may be modified, vacated, amended, or terminated after notice and hearing if:

(1) There is a substantial change of conditions in the enhanced recovery injection well or the disposal well operation, or there are substantial changes in the information originally furnished.

(2) Information as to the permitted operation indicates that the cumulative effects on the environment are unacceptable.

(d) If an operator fails to submit to the Conservation Division any initial report required by this Section within eighteen (18) months after the effective date of the order permitting the well, then the terms of the order permitting the well or enhanced recovery project shall expire.

[**Source:** Amended at 11 Ok Reg 3691, eff 7-11-94]

165:10-5-10. Transfer of authority to inject

(a) An order authorizing an enhanced recovery well(s), salt water disposal well, commercial salt water disposal well, or hydrocarbon storage well(s) shall not be transferred from one operator to another without the following:

(1) Notice in writing to the Commission on Form 1073I. For transfers involving more than ten (10) wells, a transferor and transferee may file a single Form 1073I with the Conservation Division indicating the transfer of multiple wells, provided that such multiple well transfer shall be accompanied by a well list containing the following information for each well transferred:

(A) API number of the well;

(B) Well name and number;

(C) Legal location of the well, described by section, township and range; and

(D) The Commission Order number(s) authorizing the injection, disposal, or hydrocarbon storage activity.

(2) The well list may be provided in spreadsheet form, if possible, and may be filed in digital format specified by the Conservation Division. In lieu of the information listed in subparagraphs (a)(1)(A) through (D), the transferor and transferee, at their option, may file one Form 1073I indicating the transfer of multiple wells with an OCC Form 1002A Completion Report attached for each well transferred. Upon review by the Conservation Division, it may require additional information from the transferor and/or the transferee to assist in identifying the specific well(s) being transferred. The additional information may include, but not be limited to, the quarter, quarter, quarter section calls, footages from the south and west quarter section lines, and the drilling and completion dates, and initial injection, disposal or storage dates.

(3) Notice in writing to the Commission on Form 1075 demonstrating that a mechanical integrity test was performed within one year prior to the date of transfer. For commercial disposal wells, the Mechanical Integrity Test shall be conducted within 30 days prior to the date of transfer.

(4) The performance of the mechanical integrity test required in (a)(2) of this subsection shall not apply to any operator transfer when the following conditions are present:

(A) The interest of the currently designated operator is transferred to its subsidiary or parent company, or a subsidiary of a parent company;

(B) The interest of the currently designated operator is transferred to a surviving or resulting corporation or business entity due to, respectively, a merger, consolidation or reorganization involving the transferor and transferee. As used in this subparagraph, "business entity" means a domestic or foreign partnership, whether general or limited; limited liability company; business trust; common law trust, or other unincorporated business; or

(C) The currently designated operator undergoes a name change. The relief afforded by this subparagraph is not applicable to situations where the name change involves the following conditions:

(i) The assignment of a new Federal Employer Identification number by the Internal Revenue Service to the new company;

(ii) The name change is accompanied by a change in the majority of partners in a partnership;

(iii) The name change is associated with a divorce between a husband and wife when the husband and wife comprise a partnership;

(iv) The name change is associated with the death of one spouse in a partnership comprised of a husband and wife;
(v) The name change involves a sole proprietorship; or
(vi) The name change is associated with such other circumstances where the Commission determines upon application, notice and hearing that the relief provided in this subparagraph is not applicable, or that an exception to any exclusion should be granted.
(vii) As used in this subparagraph, the term "partnership" means a domestic or foreign partnership, whether general or limited.

(b) The Commission shall, within 30 days therefrom, return a copy of Form 1073I to the new and previous operator, designating approval or denial of the transfer of authority to inject for the subject well(s).

[**SOURCE:** Amended at 13 Ok Reg 2390, eff 7-1-96; Amended in Rule Making 97000002, eff 7-1-97; Amended in Rule Making 200000002, eff 7-1-00]

165:10-5-11. Notarized reports

In lieu of notarization, all Conservation Division reports shall contain the following statement signed and dated by the responsible party representing the entity which is submitting the report:
"I declare that I have knowledge of the contents of this report, which was prepared by me or under my supervision and direction, with the data and facts stated herein to be true, correct, and complete to the best of my knowledge and belief".

165:10-5-12. Application for administrative approval for the subsurface injection of onsite reserve pit fluids

Except upon a case-by-case approval of the Commission pursuant to 165:10-5-13, the subsurface injection of reserve pit fluids is prohibited into:
(1) A newly drilled well which is to be plugged and abandoned, or
(2) The casing annulus of:
(A) A well being drilled.
(B) A recently completed well.
(C) A well which has been worked over.

165:10-5-13. Application for permit for one time injection of reserve pit fluids

(a) **General.**
(1) Injection of reserve pit fluids shall be limited to injection of only those fluids generated in the drilling, deepening, or workover of the specific well for which authorization is requested.
(2) An annular injection site shall be inspected by a duly authorized representative of the Commission prior to injection.
(3) The applicant shall file with the Underground Injection Control an affidavit of delivery or mailing not later than five days after the application is filed.
(4) An operator who disposes of drilling fluid into the surface casing or annulus without approval from the Manager of Pollution Abatement shall be fined $2,500.00.

(b) **Criteria for approval.**
(1) Casing string injection may be permitted if the following conditions are met and injection will not endanger treatable water:
(A) Surface casing injection may be authorized provided that surface casing is set and cemented at least 200 feet below the base of treatable water, except as otherwise provided by the Commission; or
(B) Intermediate casing injection may be authorized provided that intermediate casing is set at least 200 feet below the base of treatable water, except as otherwise provided by the Commission.

(2) Injection pressure shall be limited so that vertical fractures will not extend to the base of treatable water.
(3) **Required form and attachments.** Each application for annular injection shall be submitted to the UIC Department on Form 1015T in quadruplicate. The forms must be properly completed and signed. Attached to one copy of the form shall be the following:
(A) Affidavit of mailing a copy of the Form 1015T or Form 1000 to the landowner and to each operator of a producing lease within 1/2 mile of the subject well.
(B) Cement Bond Log of subject well (if run).
(4) **Expiration of the permit.** The permit shall expire on its own terms three months after the date of issuance of the permit.
(c) **Emergency authority to inject into the annulus.** The Manager of the UIC Department may grant emergency authority to inject pit fluids into the annulus provided an imminent environmental endangerment exists.
(d) **Protest period.** If no protest is received within 15 days of the mailing of Form 1015T, the application shall be submitted for administrative approval. If a protest is received within the protest period, the operator shall, within 30 days, set and give proper notice of a date for hearing on the Pollution Docket before an Administrative Law Judge.

[SOURCE: Amended at 9 Ok Reg 2295, eff 6-25-92; Amended at 13 Ok Reg 2390, eff 7-1-96]

165:10-5-14. Exempt aquifers
(a) Upon application after notice and hearing, the Commission may issue an order designating an underground source of drinking water (USDW) as an exempted aquifer if the USDW:
(1) Does not currently serve as a source of drinking water.
(2) Cannot now and has no reasonable future prospect of serving as a source of drinking water because:
(A) It is mineral, hydrocarbon or geothermal energy producing source; or
(B) It is situated at a depth or location which makes recovery of water for drinking water purposes economically or technologically impractical; or
(C) It is so contaminated that it would be economically or technologically impractical to render that water fit for human consumption.
(b) For purposes of 165:10-3-4 and 165:10-5-2 through 165:10-5-13, an exempted aquifer shall not be considered as productive of treatable water.
(c) Each application under subsection (a) of this Section shall comply with 165:5-7-28.
(d) Each order designating a USDW as an exempted aquifer shall be subject to approval by the U.S. Environmental Protection Agency.

165:10-5-15. Application for permit for simultaneous injection well.
(a) **General.**
(1) Simultaneous injection of salt water without a valid permit from the Underground Injection Control Department will be subject to a fine of up to $5,000 per day of operation.
(2) A simultaneous injection facility shall be inspected by a representative of the commission prior to operation.
(b) **Criteria for approval.**
(1) Simultaneous injection may be permitted if the following conditions are met and injection will not adversely affect offsetting production nor endanger treatable water.
(A) Injection zone is located below the producing zone in the borehole.
(B) Injection pressure is limited to less than the local fracture gradient.
(C) If injection is by gravity flow, no Area of Review will be required.

(D) If injection is by positive pump pressure, a 1/4 mile Area of Review will be required. If unplugged or mud-plugged boreholes are located within the 1/4 mile radius, the operator of the proposed simultaneous injection well will be required to reconcile these boreholes prior to a permit being issued.
(E) Simultaneous injectors must meet the requirements of 165:10-3-4 as they apply to producing wells.
(F) Simultaneous injectors may be authorized to accept produced water from other wells. The UIC Department will determine on a case-by-case basis whether such a well warrants designation as a simultaneous injector, or whether the well requires a Commission order.

(2) **Required form and attachments.** Each application for simultaneous injection shall be submitted to the UIC Department on Form 1015SI in quadruplicate. The forms must be properly completed and signed. Attached to one copy of the application form shall be the following:
(A) Affidavit of mailing a copy of the completed Form 1015SI to each operator of a producing lease within 1/2 mile of the subject well.
(B) Schematic diagram of the well showing all casing and tubing strings, packers, perforations and pumps.

(3) **Monitoring, testing and reporting requirements for simultaneous injection wells.**
(A) Upon receiving a permit, operator shall file an amended Completion Report Form 1002A within 30 days of recompletion.
(B) Mechanical integrity will be demonstrated by filing annual reports of surface casing pressure, production casing pressure and fluid level.
(C) Annual Report Form 1012 shall be submitted prior to April 1 of each year for the previous calendar year.

(4) If no protest is received within 15 days of the mailing of Form 1015SI, the application shall be submitted for administrative approval. If a protest is received within the protest period, the operator shall, within 30 days, set and give proper notice of a date for hearing on the Pollution Docket before an Administrative Law Judge.

(c) **Expiration of the permit.** The permit shall expire on its own terms if the subject well is not recompleted or if a revised Form 1002A is not submitted within 180 days from the date on the permit.

[SOURCE: Added at 13 Ok Reg 2391, eff 7-1-96]

SUBCHAPTER 7. POLLUTION ABATEMENT

PART 1. GENERAL PROVISIONS

PART 2. ANODE GROUNDBEDS

PART 3. STORAGE AND DISPOSAL OF FLUIDS

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PART 1. GENERAL PROVISIONS

165:10-7-1. Pollution abatement [RESERVED]

165:10-7-2. Administration and enforcement of rules

The Manager of Pollution Abatement shall supervise and coordinate the administration and enforcement of the rules of this Subchapter under the direction of the Director of Conservation and the Commission.

165:10-7-3. Cooperation with other agencies

(a) The rules of this Subchapter shall not be construed as modifying the rights, obligations, or duties of any person under any law of this State or under any order, rule, or regulation of the Oklahoma Water Resources Board, State Department of Health, Oklahoma Wildlife Conservation Commission, State Board of Agriculture, Department of Pollution Control, or any other agency of this State with respect to the pollution of fresh water.
(b) Whenever a written complaint against any person is filed with the Commission alleging pollution as prohibited by 165:10-7-5, the Manager of Pollution Abatement shall immediately initiate such action as may be necessary or appropriate to abate the pollution.
(c) OPERATORS TAKE NOTE: Federal statutes, such as the Bald Eagle Protection Act (16 U.S.C. Sections 668-668d), the Migratory Bird Treaty Act (16 U.S.C. Sections 703-711), the Endangered Species Act (16 U.S.C. Sections 1531-1542), and the Lacey Act Amendments of 1981 (16 U.S.C. Sections 3371-3378), dictate substantial fines and penalties for persons who allow birds of certain species to become fatally injured due to incidental contact with oil or oil by-products. These fines may be levied upon persons allowing such fatalities to occur, whether accidental or not. Misdemeanor and felony convictions may include imprisonment. Information on affected bird species, regulations under these Acts, and measures which can be taken to prevent such occurrences, such as the netting or covering of open-topped tanks and pits which contain oil or oil by-products, can be obtained from the U.S. Fish and Wildlife Service Office in Oklahoma City or the nearest Oklahoma Department of Wildlife Office.

165:10-7-4. Water quality standards

(a) **Scope.** The Commission hereby adopts the State water quality standards established and promulgated by the Oklahoma Water Resources Board (OWRB) or its successors effective October 7, 1987, and additions and revisions as lawfully published in the Oklahoma Register effective as provided by statute. The Commission's Oil and Gas Conservation Division (Conservation Division) shall implement the water quality standards with regard to its particular jurisdictional areas as referred to in (c).
(b) **General considerations.**
(1) The primary goal of the implementation of the water quality standards in the context of a remediation project subject to Commission jurisdiction shall be the protection and/or restoration of the beneficial use of the land, the soil and any surface or subsurface waters of the State adversely impacted or impaired by pollution from a Commission regulated site or facility.
(2) A remediation project utilizing the water quality standards shall adhere to the general practices appearing in the Conservation Division's *Oklahoma Water Quality Standards Implementation Plan (WQSIP)*.
(3) Where appropriate, a remediation project utilizing the water quality standards shall follow the use support assessment protocols (OWRB-OAC 785:46-7) as specified in *Oklahoma Water Quality Standards Implementation Plan*.

(c) **Specific areas of Conservation Division jurisdiction.** Compliance with the water quality standards for specific areas of the Conservation Division’s jurisdiction requires compliance with rules applicable to these operations, found in Oklahoma Corporation Commission Oil and Gas Conservation rules OAC 165, Chapter 10. Responsible parties shall refer to and comply with the rules in OAC 165:10 that pertain to each of the environmental jurisdictional areas listed below as (1) through (10). The completion of a remediation project pursuant to this paragraph and compliance with rules pertaining to specific areas of Conservation Division jurisdiction shall be considered compliance with the water quality standards. The partial listing of rules in the Commission's "Guidance Document of Technical Measures" for technology-based pollution prevention measures in areas of jurisdictional responsibility (1) through (8) and (10), listed below, is for guidance only and is not intended to be an exhaustive notation. Similar applicable rules for jurisdictional area (9), below, are listed in the WQSIP. Review of the Conservation Division rules will be made on a case by case basis to determine compliance:

(1) Field operations for geologic and geophysical exploration for oil, gas and/or brine, including seismic shot holes, stratigraphic test holes or other test wells.

(2) Exploration, drilling, development, production or processing of oil, gas and/or mineral brine at the lease site.

(3) The exploration, drilling, development and operation of wells used in connection with the recovery, injection, or disposal of mineral brines including construction, operation, maintenance, closure and abandonment of the facilities and activities.

(4) Reclaiming and/or recycling facilities associated with the exploration, drilling, development, production or transportation of oil and/or gas (including the processing of saltwater, crude oil, natural gas condensate, tank bottoms or basic sediment from crude oil tanks, pipelines, pits and equipment).

(5) Underground injection control pursuant to the federal Safe Drinking Water Act and 40 CFR parts 144 through 148 for Class II injection wells, Class V wells used for the recovery, injection or disposal or mineral brines as defined in the Oklahoma Brine Development Act.

(6) Tank farms for storage of crude oil and petroleum products located outside the boundaries of refineries, petrochemical manufacturing plants, natural gas liquid extraction plants, or other facilities that are not subject to the jurisdiction of the Oklahoma Department of Environmental Quality.

(7) Construction and operation of pipelines and associated rights-of-way, equipment, facilities or buildings used in the transportation of oil, gas, petroleum, petroleum products, anhydrous ammonia or mineral brine, or in the treatment of oil, gas or mineral brine during the course of transportation [not including pipelines in natural gas liquids extraction plants, refineries, or reclaiming facilities other than those specified in OAC 165:10-7-4(c)(6)].

(8) The handling, transportation, storage and disposition of saltwater, drilling fluids, mineral brines, waste oil and other deleterious substances produced from or obtained or used in connection with the drilling, development, production, and operation of oil and gas wells at any facility or activity specifically subject to Commission jurisdiction or other oil and gas extraction facilities and activities.

(9) Spills of deleterious substances associated with facilities and activities specified in OAC 165:10-7-4(c)(8) or otherwise associated with oil and gas extraction and transportation activities.

(10) Groundwater protection for activities subject to the jurisdictional areas of environmental responsibility of the Commission.

(d) **Monitoring of sites.** Before consideration for closure by the Conservation Division or the Commission, the responsible party shall monitor a remediation project subject to implementation of the water quality standards for a period of one (1) year, unless:

(1) Otherwise provided by Commission order, or

(2) As directed by the Manager of Pollution Abatement or designated Conservation Division staff.

(e) **Public participation; Resolution of complaint or disagreement with Conservation Division staff.**

(1) In any case where the Conservation Division determines the need for public participation in the resolution of a pollution complaint involving the implementation of the water quality standards or other issues relating to pollution, the Conservation Division may file an application and notice of hearing to request resolution of the complaint by adjudicative hearing and Commission order.

(2) In any case where a pollution complaint involving the implementation of the water quality standards or other issues relating to pollution cannot be resolved administratively between the responsible party and the complainant or because of a disagreement with the Conservation Division's Manager of Pollution Abatement, Manager of Field Operations, or other Conservation Division staff, regarding the complaint, the responsible party or the complainant may file an application and notice of hearing to request resolution of the complaint by adjudicative hearing and Commission order.

[**SOURCE:** Amended in Rule Making 200100005, eff 7-1-01]

165:10-7-5. Prohibition of pollution

(a) **General.** Pollution is prohibited. All operators, contractors, drillers, service companies, pit operators, transporters, pipeline companies, or other persons shall at all times conduct their operations in a manner that will not cause pollution.

(b) **Workable coal seams.** Sections 305, 306, 307, and 308 of Title 52, Oklahoma Statutes Annotated, governing the drilling, operations, and plugging of oil and gas wells in workable coal beds are hereby adopted as rules of the Commission as fully as if set out verbatim herein.

(c) **Reporting nonpermitted discharges (spills, etc.).**

(1) All operators, contractors, drillers, service companies, pit operators, transporters, pipeline companies, or other persons conducting operations regulated by the Commission shall:

(A) Report verbally, with respect to their operations, to the Commission District Office or Field Inspector within 24 hours of discovery:

(i) Any non-permitted discharge of deleterious substances of ten bbls. or more (single event) to the surface.

(ii) Any discharge of a deleterious substance, regardless of quantity, to the waters of the State.

(B) File a written or oral report with the District Office within ten working days specifying the following:

(i) Name of party reporting, firm name, and telephone number.

(ii) Legal location.

(iii) Lease or facility name.

(iv) Operator.

(v) Circumstances surrounding discharge and whether discharge was to water or soil.

(vi) Date of occurrence.

(vii) Volumes discharged.

(viii) Type of materials discharged.

(ix) Method of cleanup (if any) undertaken and completed.

(x) Volumes recovered.

(C) Maintain adequate records of each non-permitted discharge reflecting the information, time, and manner of reporting pursuant to this Section for a minimum of three (3) years.

Such documents shall be produced upon demand by an authorized representative of the Commission.

(D) Report hazardous substances that meet reportable quantities under Comprehensive Environmental Response Compensation and Liability Act (CERCLA) (40 C.F.R. Part 302) in the format as required under this subsection.

(2) Any operator, contractor, driller, service company, pit operator, transporter, or pipeline company who fails to comply with provisions of this rule may be fined $500.00 per incident.

[**SOURCE:** Amended at 9 Ok Reg 2295; Amended at 9 Ok Reg 2337, eff 6-25-92; Amended in Rule Making 97000002, eff 7-1-97]

165:10-7-6. Protection of municipal water supplies

The Commission, upon application of any municipality or other governmental subdivision, may enter an order establishing special field rules within a defined area to protect and preserve fresh water and fresh water supplies.

165:10-7-7. Informal complaints, citations, red tags, and shut down of operations

(a) This Section applies only to Field Operations Department of the Oil and Gas Conservation Division.
(b) For an alleged violation of an order or provision of this Chapter, a district manager or field inspector may attempt to contact the alleged violator or his agent, in person or by telephone. In addition, the district manager of field inspector may notify the alleged violator by mailing or delivering either Form 1036. The Form 1036 shall warn a person about an alleged violation, and it shall specify a time period for compliance. The Form 1036A shall be used for purposes of the monetary fines procedure in 165:10-7-9. Mailing of either form may be to the last known address of the alleged violator according to Commission records.
(c) Where surface or subsurface pollution is apparent, a district manager or field inspector may direct an alleged violator to take steps necessary to stop and/or clean up pollution. Said steps may include a temporary shut down of the lease or facility. If an alleged violator cannot be located, the district manager or field inspector may take emergency action necessary to abate pollution.
(d) If a district manager or field inspector issues a Form 1036, an inspection of the lease or facility shall be made after the compliance period shown on the form. If the inspection shows that the alleged violator failed to comply as directed, the district manager or field inspector may:
(1) Issue a Form 1036A, where applicable,
(2) Refer the matter to the Office of General Counsel for prosecution, and/or
(3) Temporarily shut down the lease or facility until further notice from the Commission.
(e) In shutting down a lease or facility, the district manager or field inspector shall affix at the site a red tag (directive to shut down). If the alleged violator removes or ignores a red tag, the Commission shall levy a monetary fine against him. The fine shall be $5,000.00.

[**Source:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended at 12 Ok Reg 2017, eff 7-1-95]

165:10-7-8. Inspection and enforcement [RESERVED]

165:10-7-9. Scheduled monetary fines

(a) **Scope.** This Section prescribes amounts and procedure for imposing monetary fines arising from the categories of rule violations shown on Schedules A and B, Appendix E and F, respectively to this Chapter.
(b) **Issuance of complaint-citations.**
(1) If the Conservation Division discovers an alleged violation in any category on Schedule A, it may issue a complaint-citation on Form 1036A.

Said form shall describe the alleged rule violation, and it shall prescribe a monetary fine.

(2) If the Conservation Division discovers an alleged violation in any category on Schedule B, it may issue a complaint-citation on Form 1036A. Said form shall describe the alleged rule violation. It shall establish a time period for compliance without a monetary fine. It shall prescribe a Schedule B fine if the alleged violator fails to comply with Commission rules within the specified time period for compliance.

(c) **Notice.** Any complaint-citation (OCC Form 1036A) issued under this Section shall be mailed or delivered to the alleged violator at the last known address shown on Commission records.

(d) **Hearing option.**

(1) Any alleged violator shall have the option to pay the prescribed fine or contest it at an evidentiary hearing. Payment of the fine within the time provided on the complaint-citation shall be considered and accepted as a plea of no contest.

(2) To obtain an evidentiary hearing, the alleged violator must request it at the preliminary hearing described on the complaint-citation. Failure to timely request an evidentiary hearing may result in an order assessing the fine prescribed by the complaint-citation.

(3) Appeal from any report of the Administrative Law Judge shall be to the panel of Commissioners in accordance with the Rules of Practice, OAC 165:5.

(e) **Payment of fines.** A person may pay a fine with cash, a money order, or check; provided, that any cash payment must be made at a Commission cashier's window. All checks must be made payable to the Oklahoma Corporation Commission. A copy of the complaint-citation must accompany payment to ensure proper credit.

(f) **Additional enforcement measures.**

(1) The Conservation Division and the Secretary of the Corporation Commission may issue one or more complaint-citations to a person who fails to bring a lease and/or facility into compliance with the rules of this Chapter.

(2) Until payment in full or payment schedule has been determined, the Conservation Division may shut-down any lease and/or facility associated with an overdue fine assessed by Commission order after notice and hearing.

[**SOURCE:** Added at 9 Ok Reg 2295, eff 6-25-92]

PART 2. ANODE GROUNDBEDS

165:10-7-14. Anode groundbeds

(a) **Definitions.** The following words or terms, when used in this Section, shall have the following meaning, unless the context clearly indicates otherwise:

(1) **"Anode"** means the electrode of an electrochemical cell at which oxidation occurs.

(2) **"Cathodic protection"** means a technique used to reduce the corrosion of a metal surface by making that surface the cathode of an electrochemical cell.

(3) **"Deep anode groundbed"** means one or more anodes installed vertically at a depth of fifty (50) feet or more below the earth's surface in a drilled hole for the purpose of providing cathodic protection.

(4) **"Shallow anode groundbed"** means one or more anodes installed either vertically or horizontally at a nominal depth of less than fifty (50) feet.

(5) **"Annular space"** means the space between the surface casing and the borewall or the space between two or more strings of casing placed in the borehole.

(6) **"Operator"** means the person who is duly authorized and in charge of the development of the operation of the pipeline or the development of a lease for the production of hydrocarbons.

(b) **Permit to drill.**

(1) The operator shall make application on Form 1000B and obtain a permit to drill a deep anode groundbed.
(2) A permit to drill shall be valid only for one or more deep anode groundbeds within a designated 10 acre tract.
(3) The Commission shall approve or deny the application within 30 days of date of receipt.
(4) Any contractor drilling a deep anode groundbed shall be licensed within the State of Oklahoma.
(5) Any operator who drills a deep anode groundbed without a permit shall be subject to a fine of one thousand dollars ($1,000.00).

(c) **Expiration.** A permit to drill shall expire six (6) months from the date of issuance, unless drilling operations are commenced.

(d) **Posting of permit to drill at the site.** During any activity subject to this Section the operator shall maintain at the site a legible copy of the permit to drill for inspection.

(e) **Notice.** The Commission's District Manager or Field Inspector shall be given at least twenty-four (24) hours notice prior to commencing drilling operations.

(f) **Notice of failure to comply with permit conditions.** The operator shall notify the district office or the field inspector within twenty-four (24) hours of any failure to comply with the construction requirements approved on the permit.

(g) **Deep anode groundbed abandonment.**
(1) In the event the hole is lost during drilling, the hole will be plugged as soon as possible.
(2) Upon abandonment of a deep anode groundbed, the hole shall be plugged within thirty (30) days of abandonment.

(h) **Construction standards.**
(1) **Shallow anode groundbeds.**
(A) Shallow anode groundbeds shall be constructed in order to prevent runoff water from entering the anode system or the commingling of water from separate groundwater bearing formations.
(B) Vertical shallow groundbeds shall be sealed by backfilling the hole with native cuttings or an approved sealing material.
(2) **Deep anode groundbeds.**
(A) Deep anode groundbeds shall be constructed in order to prevent runoff water from entering the anode system or the commingling of groundwater formations with different water quality.
(B) Surface casing shall be set a minimum of twenty (20) feet below ground level, or at a depth previously approved by the Oil and Gas Division's Technical Department.
(C) If surface casing is not placed in the hole, the hole shall be filled with bentonite or cement from the top of the Coke Breeze Column to three (3) feet below surface. Native cuttings or soil shall be used to fill the remaining portion of the hole.
(D) The annular space between the casing and drilled hole shall be a minimum of two (2) inches to allow for a proper seal.
(E) The sealing material for the annular space for surface casing shall be bentonite, cement or a material previously approved by the Oil and Gas Division's Technical Department.
(F) Centralizers shall be used at a minimum of one (1) for every twenty-five (25) feet of surface casing run in the hole unless previously approved by the Oil and Gas Division's Technical Department on form 1000B.
(G) The groundbed shall be capped to prevent the entry of foreign material. Allowances for a vent pipe will be approved.

(i) **Groundbed materials.** Groundbed materials that do not contaminate groundwater shall be required at all times.

(j) **Plugging requirements.**
(1) All wires and vent pipe must be cut off at the top of the ten (10) foot surface plug, and the vent pipe must be securely capped and plugged.
(2) Cased holes shall be filled to at least ten (10) feet from the surface with native cuttings, anode materials, cement or with a material approved by the Pollution Abatement Department.

(3) Cement or bentonite shall be placed in the hole at a minimum of ten (10) feet below the surface to within three (3) feet of the surface. The remainder of the hole shall be filled with native cuttings, soil or a material approved by the Pollution Abatement Department.
(4) If the standard method is inadequate to stop artesian flow, alternate remedies must be employed to do so.
(5) All holes shall be properly completed or plugged to protect groundwater.

[**SOURCE:** Added in Rule Making 97000002, eff 7-1-97]

PART 3. STORAGE AND DISPOSAL OF FLUIDS

165:10-7-15. Drilling or seismic activity near superfund sites or hazardous waste facilities

Any drilling or seismic activity related to oil or gas exploration or production shall be prohibited within 500 feet of the boundary of any superfund site pursuant to the Comprehensive Environmental Response Compensation and Liability Act (CERCLA), 42 U.S.C. Sections 9601, et. seq., or active hazardous waste treatment, storage, or disposal facility. A current listing of all superfund sites and active hazardous waste facilities is available from the Manager of Pollution Abatement. Seismic work, monitoring wells, or recovery wells necessary for identification, monitoring, or remediation of the superfund site or hazardous waste facility shall be exempt from this Section. Any request for exception to this Section shall comport with the requirements generally for filing of applications under the Commission's Rules of Practice (see 165:5-7-1); in addition, notice shall be given to the Oklahoma State Department of Health, 1000 Northeast Tenth Street, Oklahoma City, Oklahoma 73152.

165:10-7-16. Use of noncommercial pits

(a) **Scope.** This Section shall cover the permitting, construction, operation, and closure requirements for any noncommercial pit. A noncommercial pit is an earthen pit which is located either on-site or off-site and is used for the handling, storage, or disposal of drilling fluids and/or other deleterious substances produced, obtained, or used in connection with the drilling and/or operation of a well or wells, and is operated by the generator of the waste. This does not cover disposal well pits. (See 165:10-7-20 and 165:10-9-3.)
(b) **Liner requirements.**
(1) **Reserve/circulation and/or completion/fracture/workover pits.**
(A) To assist in determining the construction requirements for a particular proposed reserve/circulation pit, either on-site or an off-site, the operator of the pit shall indicate on Form 1000 the type of mud system(s) to be used, the maximum and average anticipated chloride concentration of the mud (based on drilling records in the area), whether or not pit fluids will be segregated, and shall furnish other information required by this Section or requested by the Commission's Technical Department.
(B) The Commission's Technical Department shall evaluate the site based upon Oklahoma Geological Survey maps and other pertinent information and shall assign one of the following categories to any proposed reserve/circulation pit, designating same on Form 1000 and indicating whether or not a liner is required:
(i) **Category 1A - Geomembrane liner.**
(I) **Water based drilling fluid containment and/or water-based completion/fracture/workover fluid containment located over a alluvial deposit or in a near surface static water level environment.** Any pit used to contain water-based drilling fluids, cuttings and/or completion/ fracture/ workover fluids located in alluvial deposit area or an area where the static water table is

within 10 feet of the surface shall utilize a geomembrane liner for all drilling fluids and cuttings and/or completion/ fracture/ workover fluids.

(II) **Water-based drilling fluid containment and/or water-based completion/fracture/workover fluid containment located within a wellhead protection area.** Any pit used to contain water-based drilling fluids, cuttings and/or completion/fracture/workover fluids located within a wellhead protection area (WPA) as identified by the Wellhead Protection Program (42 U.S.C. Section 300h-7, Safe Drinking Water Act), or within one mile of an active municipal water well for which the WPA has not been delineated, shall be required to have a geomembrane liner.

(ii) **Category 1B - Soil liner or geomembrane liner.**

(I) **Water-based drilling fluid containment and/or water-based completion/fracture/workover fluid containment located over a terrace deposit.** Any pit used to contain water-based drilling fluids, cuttings and/or completion/ fracture/ workover fluids located over a terrace deposit shall be required to have either a soil liner or a geomembrane liner.

(II) **Water-based drilling fluid containment and/or water-based completion/fracture/workover fluid containment located over a bedrock aquifier or Hydrologically Sensitive Area(HSA).** Any pit used to contain water-based drilling fluids, cuttings and/or completion/ fracture/workover fluids located over any bedrock aquifer or HSA and is used to contain water-based drilling fluids and/or cuttings and/or completion/fracture/workover fluids with chlorides in excess 5,000 mg/l shall be required to have a soil liner or a geomembrane liner. A separate unlined pit may be used to contain fluids and/or cuttings with a chloride content of less than of 5,000 mg/l.

(iii) **Category 2 - Water-based/other situations.** Any pit which is used to contain water-based drilling fluids, cuttings and/or completion/fracture/workover fluids with a set of conditions different from Categories 1A and 1B shall not be required to be lined.

(iv) **Category 3 - Oil-based.** Any pit used to contain oil-based drilling fluids, cuttings and/or completion/fracture/workover fluids shall be required to have a geomembrane liner.

(v) **Category 4 - Air-based.** Any pit used to contain the cuttings from an air-based system shall not be required to be lined.

(2) **Other type pits.**

(A) Any basic sediment pit shall be required to have a geomembrane liner.

(B) Any emergency pit shall not be required to be lined.

(C) Any flare pit shall not be required to be lined.

(D) Any recycling/reuse pit, spill containment pit, or remediation pit shall conform to the same criteria for determining liner requirements for reserve/circulation and/or completion/fracture/workover pits, pursuant to (b)(1) of this Section.

(3) **Converted pits.** Any pit that is to be converted from one use to another, e.g., reserve pit to completion or fracture pit, shall have the more stringent liner requirements, pursuant to (c)(6) and (c)(7) of this Section.

(4) **Offsite pits.** Any offsite pit shall conform to the liner requirements in this Section and will require a permit. The operator of the proposed pit shall submit Form 1014 in duplicate to the appropriate District Office for review and approval. No offsite reserve pit may be permitted or constructed at a spacing closer than one pit per governmental quarter quarter section and a distance less than 600 feet from any other pit. Any offsite reserve pit may be reclassified or considered as a commercial pit, pursuant to 165:10-9-1, if it is constructed or used at a spacing closer than one reserve pit per governmental quarter quarter section. Closure of any offsite reserve pit shall not warrant the permitting of another offsite reserve pit within the same governmental quarter quarter section. For use of a pit without a permit, the pit operator may be fined up to $1,000.00.

(5) **Variances.** Any variance from the liner requirements of this Section may be granted by the Manager of the Technical Department after receipt of a written request and supporting documentation required by the Department.

(c) **Construction requirements.**

(1) **Field or area rules.** Any noncommercial pit which is to be constructed or used in an area covered by a field or area rule shall be subject to the more stringent requirements of either this Section or the field or area rule.

(2) **Stockpiling of topsoil.** Prior to constructing any noncommercial pit, except an emergency pit, all top soil within the top twelve inches shall be stripped and stockpiled for use as the final cover of fill at the time of closure. The top soil may be stockpiled in the berms, provided it is not mixed with other materials and can be readily distinguishable from other materials at the time of closure.

(3) **Exclusion of runoff water.** Any noncommercial pit shall be constructed and maintained so that runoff water from outside the location is not allowed to enter it.

(4) **Flood protection.** Any noncommercial pit which is constructed in any area subject to frequent flooding according to the Soil Conservation Service County Soil Survey shall have berms substantial enough to prevent overtopping or washing out.

(5) **Constructing on fill.** Any noncommercial pit which requires a liner and is constructed on fill shall be constructed so that the maximum level of the solid contents will be maintained at least three feet below the natural ground level.

(6) **Soil liners.**

(A) Soil materials used or to be used in a soil liner shall undergo permeability testing either before or after construction, unless exempt pursuant to (B) of this paragraph.

(i) Pre-construction permeability testing shall consist of laboratory permeability tests on at least two specimens of representative soil liner materials compacted in the laboratory to approximately 90 percent of the material's Standard Proctor Density (ASTM D-698).

(ii) Post-construction permeability testing shall consist of at least two laboratory permeability tests on undisturbed samples of the completed soil liner or one field permeability test on the completed soil liner. Particular emphasis shall be placed on selecting the location(s) for permeability tests or test samples where nonuniformity in soil texture or color can be observed.

(iii) Laboratory permeability test procedures must conform to one of the methods described for fine-grained soils in the Corps of Engineers Manual EM-1110-2-1906 Appendix VII. In no case shall the pressure differential across the specimen exceed five feet of water per inch of specimen length. Field permeability tests shall be conducted only by the double ring infiltrometer method as described in ASTM D-3385. Permeability tests may be discontinued prior to flow stabilization upon satisfactory evidence that the permeability rate is less than 1.0×10^{-6} cm/sec.

(iv) If permeability testing shows that addition of bentonite or other approved material is needed to assist the native soils in meeting the permeability standard, it shall be applied at a minimum rate specified by the testing or engineering firm. Any bentonite used for liner material shall not have been previously used in drilling muds.

(B) Permeability testing requirements for soil materials may be exempt if laboratory testing of a minimum of two representative samples of the soil materials found throughout the entire depth of the proposed excavation indicates that the plasticity index is greater than 16 (ASTM D-4318) and that the amount passing the No. 200 U.S. standards sieve is greater than 60 percent (ASTM D-1140).

(C) Any soil liner shall be constructed by disturbing the soil to the depth of the bottom of the liner, applying fresh water as necessary to the soil materials to achieve a moisture content wet of optimum, then recompacting it with heavy construction equipment, such as a footed roller, until the required density is achieved, pursuant to (H) of this paragraph.

(D) Any soil liner shall cover the bottom and interior sides of the pit entirely.

(E) Any soil liner shall be installed on a slope no steeper than 3:1 (horizontal to vertical).

(F) Any soil liner shall have a minimum thickness of six inches (after compaction), and shall have a maximum coefficient of permeability of 1.0 x 10^{-6} cm/sec, unless it conforms to (G) of this paragraph.

(G) A soil liner may have a coefficient of permeability greater than 1.0 x 10^{-6} cm/sec if it is greater in thickness and constructed in accordance with the following:

(i) A minimum twelve inch compacted soil liner shall have a maximum coefficient of permeability of 2.0 x 10^{-6} cm/sec.

(ii) A minimum 18 inch compacted soil liner shall have a maximum coefficient of permeability of 3.0 x 10^{-6} cm/sec.

(iii) A compacted soil liner may not be constructed thicker than 18 inches for the purpose of meeting a coefficient of permeability greater than 3.0 x 10^{-6} cm/sec.

(iv) Any soil liner with a minimum twelve inch or 18 inch thickness shall be constructed in maximum lifts of six inches (after compaction). Each lift shall be scarified before placement of the next lift and shall conform to (H) of this paragraph.

(H) Any soil liner shall be field tested for compaction, unless a post-construction permeability test is performed, pursuant to (A)(ii) of this paragraph.

(i) A minimum of six compaction tests shall be performed on any soil liner; a minimum of four widely spaced tests in the bottom of the pit and two tests on different slopes of the pit are required, unless otherwise directed by a Field Operations representative. Particular emphasis shall be placed on selecting locations for compaction tests where nonuniformity in soil texture or color can be observed.

(ii) Compaction tests shall be conducted in accordance with ASTM methods D-2922 or D-1556.

(iii) The soil materials of any liner shall be compacted to at least 90 percent of the Standard Proctor Density (ASTM D-698).

(7) **Geomembrane liners.**

(A) Any geomembrane liner that is installed in a reserve/circulation pit, spill prevention pit, or remediation pit, completion/fracture/workover pit, basic sediment pit, or recycling/reuse pit shall have a minimum thickness of 20-mil.

(B) Any geomembrane liner used in a noncommercial pit shall be chemically compatible with the type of substances to be contained and shall have ultraviolet light protection.

(C) Any geomembrane liner shall be placed over a specially prepared, smooth, compacted surface void of sharp changes in elevation, rocks, clods, organic debris, or other objects.

(D) Any geomembrane liner shall be continuous, although it may include seams, and shall cover the bottom and interior sides of the pit entirely. The edges shall be securely placed in a minimum twelve inch deep anchor trench around the perimeter of the pit.

(8) **Certification of liner.** The operator of any noncommercial pit that is constructed with a soil or geomembrane liner shall secure an affidavit signed by the installer, certifying that the liner meets minimum requirements and was installed in accordance with Commission rules. It shall be the operator's responsibility to maintain the affidavit and all supporting documentation pertaining to the liner (e.g., permeability and compaction test results, bentonite receipts, and geomembrane liner specifications from the manufacturer), and shall make them available at all times for review by any representative of the Conservation Division.

(d) **Operation and maintenance requirements.**

(1) **Freeboard.** The fluid level of any noncommercial pit shall be maintained at all times at least 24 inches below the lowest elevation on the top of the berm.
(2) **Reserve/circulation pits.** The operator of any reserve/circulation pit shall limit its contents to the fluids and cuttings from a single well.
(3) **Off-site reserve pits.** A waterproof sign shall be posted within 25 feet of any off-site reserve pit and shall bear the name of the operator, legal description to the quarter quarter quarter section, permit number, and emergency telephone number.
(4) **Recycling/reuse pits.**
(A) Any pit permitted for drilling mud recycling or reuse may contain the fluids and cuttings from multiple wells, provided that those wells are operated by the pit operator.
(B) A waterproof sign shall be posted within 25 feet of any recycling/reuse pit and shall bear the name of the operator, legal description to the quarter quarter quarter section, permit number, and emergency telephone number.
(5) **Prevention of pollution.**
(A) All noncommercial pits shall be constructed, used, operated, and maintained at all times so as to prevent pollution. In the event of a nonpermitted discharge from a noncommercial pit, sufficient measures shall be taken by the operator to stop or control the loss of contents, and reporting procedures pursuant to 165:10-7-5(c) shall be followed. Any materials lost from a pit shall be cleaned up as directed by any Field Operations representative. For a willful non-permitted discharge from a noncommercial pit, the operator may be fined up to $2,000.00.
(B) The protection of migratory birds shall be the responsibility of the operator. Therefore, the Conservation Division recommends that to prevent the loss of birds, oil be removed or the surface area covered by the oil be protected from access to birds. [See Advisory Notice 165:10-7-3(c)].

(e) **Closure requirements.**
(1) **Designation of disposal method.** The operator of any reserve/circulation pit shall indicate the proposed method of disposal of drilling fluids and/or cuttings on Form 1000 as required by 165:10-3-1(f). Options shall be limited to the following, unless written approval is granted by a Field Operations representative:
(A) Evaporation/dewatering and backfilling.
(B) Chemical solidification of pit contents.
(C) Annular injection (requires permit).
(D) Land application (requires permit).
(E) Disposal in permitted commercial pit.
(F) Disposal at permitted commercial soil farming facility.
(G) Disposal at permitted recycling/reuse facility.
(2) **Trenching.**
(A) Before trenching, stirring or otherwise disturbing the bottom of any noncommercial pit, the pit shall be completely dewatered.
(B) Trenching, stirring, or other similar practice shall be prohibited for any lined pit.
(3) **Lined pits.**
(A) When closing any noncommercial pit with a soil or geomembrane liner, extreme care shall be taken to preserve the integrity of the liner.
(B) For any lined reserve/circulation pit, completion/fracture/workover pit, recycling/reuse pit, or basic sediment pit, all free liquids shall be removed or chemically solidified with nonhazardous material.
(C) For any lined oil-based reserve/circulation pit, all cuttings remaining in the pit shall be chemically solidified with nonhazardous material.
(D) Soil cover, pursuant to (5) of this subsection, shall follow.
(4) **Soil cover.** Closure procedures for any noncommercial pit shall include a minimum of three feet of soil cover over any remaining pit contents, with all stockpiled topsoil being applied last. The materials shall be mounded or sloped to encourage runoff. A variance from this provision may be granted by a Field Operations District Office for justifiable cause. A

written request and supporting documentation is required. The Field Operations office shall respond in writing within five working days either approving or disapproving the request.

(5) **Erosion control.** Any noncommercial pit shall be closed in such a manner that any future erosion will not cause the discharge of the pit contents. This may require vegetative cover and/or a diversion terrace(s).

(6) **Notification to District Office.** The operator of any noncommercial pit shall notify the appropriate Field Inspector or District Office at least 48 hours prior to commencing closure, and for reserve/circulation pits shall advise if the disposal method is different from that indicated on Form 1000. The operator shall also notify the Field Inspector or District Office within 48 hours after reclamation of the site has been completed.

(7) **Time limits.** Any noncommercial pit shall be closed within the time limits set forth in this paragraph. Any extension of time for pit closure must be requested by the operator, who shall file an application pursuant to OAC 165:5-7-33. A legal change of operator of any noncommercial pit shall not extend the time limit for closure. If a noncommercial pit is converted from one type of use to another, the last use shall determine the time limit for closure.

(A) Any Category 1A, 1B or ~~3~~ 2 reserve/circulation pit, either on-site or off-site, shall be closed within twelve months after drilling operations cease.

(B) Any Category 3 reserve/circulation pit, either on-site or off-site shall be closed within six months after drilling operations cease.

(C) Any Category 4 pit shall have closure procedures commenced within 30 days and completed within 90 days after drilling operations cease.

(D) **Completion/fracture/workover pits.**

(i) Any reserve/circulation pit converted to a completion/fracture/workover pit shall be closed within six (6) months after drilling operations cease. Upon request by the operator, a six (6) month extension shall be granted by the Conservation Division, after review by a field inspector to confirm the pit is in compliance with 165:10-7-16 (c) and (d)requirements.

(ii) Any completion/fracture/workover pit not converted from a reserve/circulation pit shall be closed within 60 days after completion, fracture, or workover operations cease.

(E) Any emergency pit shall be emptied of its contents as soon as possible and closed within 60 days after the emergency situation ceases to exist.

(F) Any flare pit shall be closed within 30 days of abandonment of a lease.

(G) Any spill containment pit shall be closed within 30 days of abandonment of a lease.

(H) Any basic sediment pit shall be closed within 60 days after use of the pit ceases.

(I) Any recycling/reuse pit shall be closed within twelve months after operations cease.

(J) Any remediation pit shall be closed immediately after receipt of all contaminated materials.

(8) For failure to comply with any closure requirement, the operator may be fined up to $1,000.00.

(9) **Waiver of closure requirements.** Exemption from closure and transfer of responsibility for any noncommercial pit to the surface owner or other party shall be requested by filing an application pursuant to OAC 165:5-7-34. No approval shall be granted unless the analyses of the fluids show that the following ranges or concentrations are not exceeded:

(A) pH - 6.0-9.5 s.u.
(B) Chlorides - 3500 mg/l
(C) Total Dissolved Solids (TDS) - 7000 mg/l
(D) Chromium (Total) - 10 mg/l
(E) Arsenic - 20 mg/l

[**Source:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended at 12 Ok Reg 2017, eff 7-1-95; Amended in Rule Making 980000035, eff 7-1-99]

165:10-7-17. Surface discharge of fluids

(a) **Scope.** This Section shall cover the surface discharge of hydrostatic test water, storm water from diked areas, and produced water from tanks or other containment vessels.

(b) **Discharge of hydrostatic test water.**

(1) Hydrostatic test water used in the testing of new pipeline segments, new casing, new tubing, new tanks and new vessels, may be discharged as necessary without a permit, notification to the Commission, or adherence to any other provisions of this Section, provided the following conditions are met:

(A) **Low chlorides.** Chloride concentration does not exceed 1000 mg/l.

(B) **Sheen.** There shall be no visible sheen or discoloration as a result of testing; however, certain dyes used to establish mechanical integrity may be approved.

(C) **Notice to District Office.** Any discharges exceeding 1,000 barrels shall require notification to the appropriate District Office.

(2) Hydrostatic test water used in the testing of existing tanks, vessel lines and transmission pipelines may be discharged upon notification to the Oklahoma Corporation Commission appropriate District Office on Form 1014HD provided that the following conditions are met:

(A) **Oil and grease.** The oil and grease content of the discharge water shall not exceed 15 mg/l.

(B) **Sheen.** There shall be no visible sheen or discoloration as a result of testing; however, certain dyes used to establish mechanical integrity may be approved.

(C) **Total Suspended Solids (TSS).** The TSS shall not exceed 45 mg/l.

(D) **pH.** The pH shall not be less than 6.5 nor exceed 9 s.u.

(E) **Foreign material.** The discharge must be free from foreign material such as welding scrap tank sediments or sand blasting waste material.

(F) **Soil erosion.** Standard soil erosion prevention procedures shall be required.

(3) Hydrostatic test water that meets the requirements listed in (b) (2) of this Section may be discharged in volumes less than 15 bbls without filing Form 1014HD.

(4) Hydrostatic test water that will be discharged to land and not directly into waters of the state and which may exceed the discharge parameters specified in (b) (2), shall be discharged only upon submission and approval by the Pollution Abatement Department of a plan for one-time discharge.

(5) Hydrostatic test water not covered under (b)(1) from transmission lines and tanks that contain waste products that are listed as hazardous waste under the Resource Conservation and Recovery Act and have not been cleaned or pigged must meet the following discharge requirements in addition to (b)(2) of this Section:

(A) The following parameters may not be exceeded: Benzene, .028 MG/L; toluene, .3 MG/L; phenol, .250 MG/L.

(B) EPA analytical method 8020 shall be used unless approved by the Manager of Pollution Abatement.

(c) **Discharge of storm water.** Storm water accumulations in any diked area built for the containment of tank battery spills may be discharged as necessary without a permit, notification to the Commission, or adherence to any other provisions of this Section, provided the following conditions are met:

(1) **No hydrocarbons.** A visual inspection of the storm water is made and there is no sheen or other visible evidence of hydrocarbons being present.

(2) **Low chlorides.** Chloride concentration does not exceed 1000 mg/l.

(3) **Conditions recorded.** The operator records the conditions required by (1) and (2) in this subsection for each discharge, maintains those records for a period of three (3) years, and makes them available upon request to any representative of the Field Operations Department.

(d) **Discharge of produced water.**

(1) **Site restrictions.** Discharge of produced water shall only occur on land having an Exchangeable Sodium Percentage (ESP) no greater than 15, pursuant to

(f)(3) of this Section, and all of the following characteristics as determined by the appropriate Soil Conservation District or by a qualified soils expert:

(A) A maximum slope of five percent.

(B) Depth to bedrock at least 20 inches.

(C) Slight salinity (defined as electrical conductivity less than 4,000 micromhos/cm) in the topsoil or upper six inches of the soil.

(D) A water table deeper than six feet from the soil surface, except a perched water table.

(E) A minimum distance of 100 feet from any stream designated by Oklahoma Water Quality Standards (available for viewing at the Commission's Oklahoma City Office and District Offices) or any fresh water pond, lake, or wetland (designated by the National Wetlands Inventory Map Series, prepared by the U.S. Fish and Wildlife Service and available for viewing at the Commission's Oklahoma City Office).

(2) **Water quality limitations.** A surface discharge permit shall not be issued if the produced water to be discharged exceeds either of the following concentrations:

(A) Total Dissolved Solids (TDS) - 5000 mg/l.

(B) Oil and Grease - 1000 mg/l.

(e) **Sampling requirements.**

(1) **Contact with District Office.** The appropriate District Office shall be contacted at least two working days prior to sampling to allow a Commission representative an opportunity to witness the sampling of the receiving soil and produced water to be discharged. A variance from this provision may be granted by a Field Operations office for justifiable cause. A written request and supporting documentation shall be required. The Field Operations office shall respond in writing within five working days after receipt, either approving or disapproving the request.

(2) **Produced water.** Produced water to be discharged shall be sampled using the following procedure, unless exempt pursuant to (f)(4) of this Section.

(A) Prior to sampling, fresh water shall not be added to any tank or other containment vessel for dilution or any other purpose.

(B) A sample of the produced water to be discharged shall be taken from the bottom of the tank or other containment vessel. A minimum two quart sample shall be placed into a foil or teflon covered, glass container. The container shall be filled completely to exclude air and delivered to the laboratory within seven days. No samples shall be altered in any way.

(C) Another sample of the produced water to be discharged (approximately one pint) shall be properly labeled and delivered or otherwise provided to a Field Operations office or Field Inspector, unless exempt by the District Manager.

(3) **Receiving soil.** Soil samples shall be taken from the proposed discharge area and analyzed, unless exempt pursuant to (f)(4) of this Section. A minimum of 20 representative surface core samples (0-6 inches) must be taken from each sample area, combined and thoroughly mixed, then a minimum one pint composite sample taken and placed in a clean container for delivery to the lab. No sample area shall exceed 40 acres.

(f) **Analysis requirements.**

(1) **Certified laboratory.** The samples of soil and produced water shall be analyzed by a laboratory operated by the State of Oklahoma or certified by the Oklahoma Water Resources Board, unless exempt pursuant to (4) of this subsection.

(2) **Parameters for produced water.** Parameters for analysis of the produced water shall include, but not be limited to, Total Dissolved Solids (TDS) and Oil and Grease.

(3) **Parameters for soil.** Parameters for analysis of the receiving soil shall include, but not be limited to, Electrical Conductivity or Total Soluble Salts (TSS) and Exchangeable Sodium Percentage (ESP).

(4) **Exemptions.** A Field Operations office may exempt the analysis of produced water if an analysis of the produced water from a well located within one mile and producing from the same formation has been previously submitted. Analysis of the receiving soil may be exempt if an analysis of the same soil type(s) within one mile of the proposed discharge site has been previously submitted.

(g) **Application for permit.**

(1) **Permit required.** No person shall discharge produced water from a tank or other containment vessel without applying for and obtaining a permit issued under this subsection. An operator discharging produced water without a permit shall be fined $1,000.00.

(2) **Who may apply.** Only the operator of the well associated with the tank or other containment vessel, the contents of which are sought to be discharged, may apply for a surface discharge permit.

(3) **Required form and attachments.** Each application for surface discharge of produced water shall be submitted to a Field Operations office on Form 1014D in quadruplicate. The forms shall be properly completed and signed. Attached to at least one of the forms shall be the following:

(A) A copy of written notice to the surface owner that the applicant intends to discharge produced water as per 165:10-7-17 to a specific portion of real property as designated by legal description.

(B) If the operator has an agent, a contractual agreement between the parties or an affidavit designating the contractor or agent.

(C) A well prepared map or diagram, drawn to scale, showing the proposed and potential discharge areas.

(D) Site suitability report, pursuant to (d)(1) of this Section, provided by a qualified soils expert (include qualifications).

(E) Analysis of produced water, unless exempt pursuant to (f)(4) of this Section.

(F) Soil analysis, unless exempt pursuant to (f)(4) of this Section.

(G) Other information as required by this Section or requested by a Field Operations office.

(4) **Review period.** The Field Operations office shall review the application, either approve or disapprove it, and return a copy of Form 1014D within five working days of submission of all required or requested information. If approved, a permit number shall be assigned to Form 1014D; if disapproved, the reason(s) shall be given. The applicant may make application for a hearing if it is not approved.

(h) **Maximum application rate.**

(1) **Soil loading standards.** The maximum application rate shall be calculated by the Field Operations office using the following soil loading standards. (Soil loading standards are based upon standards set forth in "Diagnosis and Improvement of Saline and Alkaline Soils," U.S. Agriculture Handbook 60. Pub. U.S. Salinity Laboratory, Riverdale, California, 1954. "Critical Concentrations for Irrigation Water Supplies," Water Quality Criteria, 1972 Ecological Research Series, EPA R2-73033, March, 1973).

(A) Total Soluble Salts - 6,000 lbs/acre (less TSS in soil).

(B) Oil and Grease - 500 lbs/acre.

(2) **Determination of most limiting parameter.** The maximum application rate shall be restricted by the most limiting parameter. It may require more than one application to achieve the maximum application rate while avoiding runoff. The Field Operations office shall indicate on the permit what the maximum application rate shall be after making the following calculations:

PROCEDURE FOR CALCULATING APPLICATION RATE OF TOTAL SOLUBLE SALTS (TSS)

______ppm TSS in soil[1] X 2 = ______lbs/ac TSS in soil

6000 lbs/ac TSS - ______ lbs/ac TSS in soil = Maximum TSS (lbs/ac) to be applied

Maximum TSS (lbs/ac) ______ ÷ (______ ppm TSS in water[1] X .000001) = Maximum lbs/ac of water to be applied ______

Maximum lbs/ac ______ ÷ ______lbs/bbl[2] = Maximum bbls/ac ______

PROCEDURE FOR CALCULATING APPLICATION RATE OF OIL AND GREASE

500 lbs/ac ÷ (______ppm in water X .000001) = Maximum lbs/ac of water to be applied ______

Maximum lbs/ac ______ ÷ ______ lbs/bbl[2] = Maximum bbls/ac ______

[1]Electrical Conductivity (EC expressed in micromhos/cm) may be used to estimate TSS: EC x 0.64 = ppm TSS.
[2]Based on documented weight of composite sample.

(i) **Conditions of permit.** Any discharge of produced water that is done under this Section shall be subject to the following conditions or stipulations of the permit.

(1) **Presence of representative.** A representative of the operator shall be on the discharge site at all times that water is being applied. A variance from this provision may be granted by a Field Operations office for justifiable cause. A written request and supporting documentation shall be required. The Field Operations office shall respond in writing within five working days after receipt, either approving or disapproving the request.

(2) **Weather restrictions.** Surface discharge shall not be done:

(A) During precipitation events or when precipitation is imminent.

(B) When the soil moisture content is at a level such that the soil would not readily take the addition of water.

(C) When the ground is frozen.

(D) By spray irrigation when the wind velocity is such that even distribution of water cannot be accomplished or the buffer zones, pursuant to (3) of this subsection, cannot be maintained.

(3) **Buffer zones.** Surface discharge shall not be done within the following buffer zones:

(A) Fifty feet of a property line boundary.

(B) Fifty feet of any stream not designated by Oklahoma Water Quality Standards.

(C) Three hundred feet of any actively-producing water well used for domestic or irrigation purposes.

(D) Eight hundred feet of any actively-producing water well used for municipal purposes.

(4) **Application rate.** The maximum application rate of produced water stipulated by the permit shall not be exceeded. Application of produced water outside the approved plot shall be prohibited. Accurate records shall be kept as to the quantities discharged and the dates of each discharge.

(5) **Discharge method.** Discharge of produced water shall be uniform over the approved discharge plot and shall be made by spray irrigation or other method approved by the Commission prior to use. The flood irrigation method shall be limited to those fields that normally are irrigated in that manner.

(6) **Runoff or ponding prohibited.** No runoff or ponding of discharged water shall be allowed during application.

(7) **Annual report.** An annual report shall be submitted by February 1 of each year and shall be made on Form 1014P. Attached to the annual report shall be current (within three months) analyses of the produced water and soil from the discharge plot, pursuant to (8) of this subsection.

(8) **Additional testing.** The produced water and soil shall be sampled and analyzed, pursuant to (e)(1) through (e)(3) and (f)(1) through (f)(3) of this Section, on an annual basis just prior to filing of the annual report. When a soil analysis indicates that 75 percent of the maximum application rate of TSS or Oil and Grease [(h) of this Section] has been applied or when the ESP exceeds 11, sampling shall be done quarterly or semiannually as determined by the Field Operations office.

(9) **Expiration of permit.** The permit shall expire by its own terms when testing, pursuant to (8) of this subsection, indicates that the concentration of TDS or Oil and Grease in the water exceeds the limitations of (d)(2) of this Section, or more than 98 percent of the maximum application rate of TSS or Oil and Grease [(h) of this Section] has been applied or the ESP exceeds 15.

(10) **Violations.** If the applicant violates the conditions of the permit or this Section, the surface discharge shall be discontinued and the Field Operations office shall be contacted immediately. The Field Operations office may revoke the permit and/or require the operator to do remedial work. If the permit is not revoked, surface discharge may resume with Field Operations' approval. If the permit is revoked, the operator may make application for a hearing to reinstate it.

[SOURCE: Amended at 9 Ok Reg 2295, eff 6-25-92; amended at 13 Ok Reg 2381, eff 7-1-96; Amended in Rule Making 97000002, eff 7-1-97]

165:10-7-18. Discharge to surface waters

Discharge of deleterious substances to streams or other surface waters is prohibited except by order of the Commission; unless permitted by a valid National Pollutant Discharge Elimination System (NPDES) Permit issued by U.S. EPA.

165:10-7-19. One-time land application of water-based fluids from earthen pits and tanks

(a) **Authority for land application.** No person shall land apply fluids except as provided by 165:10-9-2, 165:10-7-17, or this Section. Any operator failing to obtain a permit shall be fined $2,000.

(b) **Scope.** This Section shall cover the land application of water-based drilling fluids and cuttings from earthen pits, tanks, or other containment structures; however, this Section shall not be exclusive of other authorities for land application listed in (a) of this Section. Any land application made under this Section shall be done on a one-time basis from a single well to land that has not been previously permitted and used for this practice or similar practices.

(c) **Site suitability restrictions.** Land application shall only occur on land having all of the following characteristics below, as field verified by a soil scientist or other qualified person pre-approved by the Commission. Any variance from site suitability restrictions must be approved by the Oil and Gas Conservation Division (see (f)(2)(C) of this Section).

(1) **Maximum slope.**

(A) Five percent for all application methods except spray irrigation;

(B) Eight percent for the spray irrigation method.

(2) **Depth to bedrock.** Depth to bedrock must be at least 20 inches.

(3) **Soil texture.** A soil profile (as defined by USDA soil surveys) containing at least twelve inches (may be cumulative) of one of the following soil textures between the surface and the water table, unless a documented impeding layer of shale is present: loam, silt loam, silt, sandy clay loam, silty clay loam, clay loam, sandy clay, silty clay, or clay.

(4) **Salinity.** Slight salinity [defined as Electrical Conductivity (EC) less than 4,000 micromhos/cm] in the topsoil, or upper six inches of the soil, and a calculated Exchangeable Sodium Percentage (ESP) less than 10.0.

(5) **Depth to water table.** No evidence of a seasonal water table within six (6) feet of the soil surface as verified by field observation and published data.

(6) **Distance from water bodies.** A minimum distance of 100 feet from the land application site boundary to any perennial stream and 50 feet to any intermittent stream shown on the appropriate United States Geological Survey (U.S.G.S.) topographic map (available for viewing at the Commission's Oklahoma City Office and District Offices) and a minimum of 100 feet to any freshwater pond, lake, or wetland. [Designated by the National Wetlands Inventory Map Series, prepared by the U.S. Fish and Wildlife Service, available for viewing at the Commission's Oklahoma City Office (also, see (h)(6) of this Section)].

(7) **Site specific concerns.** Void of slick spots within or adjacent to the land application area, where subsurface lateral movement of water is unlikely, or areas void of concentrated surface flow such as gullies or waterways.

(d) **Sampling requirements.**

(1) **Notice to Field Inspector.** The appropriate Field Inspector shall be contacted at least two working days prior to sampling of the receiving soil and sampling of the drilling fluids and/or cuttings to be land applied from an earthen pit. This is to allow a Commission representative an opportunity to be present.

(2) **Receiving soil.** Sampling of the receiving soil shall be performed by, or under the supervision of, a soil scientist or other qualified person pre-approved by the Commission. Soil samples shall be taken from the proposed application area and analyzed. A minimum of four representative core samples from the surface (0-6 inches) and subsurface (14-20 inches) must be taken from each ten acres, or part thereof. Each group of surface core samples representative of a ten-acre area (or less) shall be combined and thoroughly mixed. A minimum one-pint composite sample shall be taken and placed in a clean container for delivery to the laboratory. Alternatively, soil samples may be composited by the laboratory. All subsurface samples shall be handled in the same manner.

(3) **Drilling fluids and/or cuttings.**

(A) **Earthen pits.** Drilling fluids and/or cuttings to be land applied shall be sampled using the following procedure:

(i) Prior to sampling, fresh water (except natural precipitation) shall not be added to any pit for dilution or any other purpose.

(ii) A minimum of four samples, each from different quadrants of the pit and representative of the materials to be land applied, must be taken if the volume to be land applied is 25,000 bbls. or less. If more than 25,000 bbls. are to be land applied, a minimum of four quadrant samples plus one sample for each 5,000 bbls. over 25,000 bbls. will be required. The samples shall be combined and thoroughly mixed, then a minimum two quart composite sample placed into a foil or teflon covered glass container. The container shall be filled completely to exclude air and delivered to the laboratory within seven days. No samples shall be altered in any way.

(iii) After samples have been taken for analysis from a pit, the operator shall not allow the addition of fluids or other materials, except natural precipitation or fresh water to decrease the viscosity of the fluid.

(B) **Tanks.** Sampling of the drilling fluids and/or cuttings shall occur after the application has been approved. A minimum of one representative sample must be taken from each tank or other containment structure, the contents of which are to be land applied.

(e) **Analysis requirements.**

(1) **Testing.**

(A) The composite sample(s) of soil shall be tested by a laboratory proficient in testing soils. Either a 1:1 extract or saturated paste extract shall be used for sample preparation.

(B) Methods of analysis.

(i) **Earthen pits.** The composite sample(s) of drilling fluids and/or cuttings shall be analyzed by a laboratory operated by the State of Oklahoma or certified by the Oklahoma Department of Environmental Quality.

(ii) **Tanks.** Samples of the drilling fluids and/or cuttings may be tested on-site. A filter press shall be used for preparation of samples. Tests must be performed by a person who is knowledgeable and experienced in the chemical testing of fluids. Acceptable on-site testing protocol may be obtained from a Field Operations office.

(2) **Parameters for receiving soil.** Parameters for analysis of the receiving soil shall include at a minimum EC and ESP.

(3) **Parameters for drilling fluids and/or cuttings.**

(A) **Earthen pits.** Parameters for analysis of the drilling fluids and/or cuttings shall include at a minimum EC and Oil and Grease (O&G). Dry Weight shall also be determined if a significant amount of solids will be land applied.

(B) **Tanks.** EC shall be a required parameter for analysis of drilling fluids and/or cuttings. Dry weight shall also be determined if a significant amount of solids will be land applied.

(f) **Application for permit.**

(1) **Who may apply.** Only the operator of a well or the operator's designated agent may apply for a land application permit under this Section, except that a commercial pit operator may also apply in case of emergency or for the purpose of facilitating repair or closure.

(2) **Required form and attachments.** Each application for land application of drilling fluids and/or cuttings shall be submitted to a Field Operations office on Form 1014S. An original and three copies shall be required. Attached to at least one of the copies shall be the following:

(A) Written permission from the surface owner to allow the applicant to land apply drilling fluids and/or cuttings. For purposes of obtaining such consent, the applicant shall use Form 1014L.

(B) A topographic map and the most recent aerial photograph (minimum scale 1:660) with the proposed and potential land application areas delineated as well as the location of cultural features such as buildings, water wells, etc. Both the topographic map and aerial photograph must show all areas within 1,320 feet of the boundary of the land application area.

(C) A site suitability report, pursuant to subsections (c) and (h)(6) of this Section, based on an on-site investigation and signed by a soil scientist or other qualified person. The report shall include detailed information concerning the site and shall discuss how all site characteristics were determined. Any requests for a variance to site suitability restrictions must be accompanied by a written justification that has been developed or approved by a soil scientist or other qualified person. The justification shall provide explanation as to safeguards which will assure that conditions of the permit will be met and there will be no adverse impacts from the land application.

(D) Analysis of drilling fluids and/or cuttings (for earthen pits only).

(E) Analyses of soil samples.

(F) Loading calculations.

(G) Copies of all chains-of-custody related to sampling.

(H) Manufacturer, model number, and specifications of testing equipment to be used (for tanks only).

(I) If there is an agent, a notarized affidavit designating same, signed by the operator.

(J) Other information as required by this Section or requested by a Field Operations office.

(3) **Review period.** The Field Operations office shall review the application, either approve or disapprove it, and return a copy of Form 1014S within five working days of submission of all required or requested information. If approved, a permit number shall be assigned to Form 1014S; if disapproved, the reason(s) shall be given. The applicant may make application for a hearing if it is not approved.

(g) **Calculating maximum application rate.**

(1) **Earthen pits.**

(A) The maximum application rate shall be calculated by the applicant or the applicant's designated agent based on the analyses of the pit materials and the soil of the application area. The averaging of TDS values of soil sampling areas shall not be permitted. If the entire application area is larger than ten acres, requiring separate soil sampling areas, the applicant or the applicant's designated agent shall use the highest soil TDS value of any sampling area in calculating the maximum application rate for the entire application area, and shall also calculate the maximum application rate of each ten acre (or less) application area using the respective TDS values of each soil sampling area. The applicant or the applicant's designated agent shall decide which of the two loading rates to use and notify the District Office when notification of commencement of land application is given, pursuant to (h)(1) of this Section.

(B) Soil loading formulas contained in Appendix I shall be used.

(C) The maximum application rate shall be restricted by the most limiting parameter. The Field Operations office shall indicate on the permit the maximum application rate and the minimum acreage that must be used.

(2) **Tanks.**

(A) The applicant shall calculate the maximum application rate based on the analysis of each tank or other containment vessel to be land applied and the soil of the application area. The averaging of TDS values of soil sampling areas shall not be permitted. If the entire application area is larger than ten acres, requiring separate soil sampling areas, the applicant shall have the option of using the highest soil TDS value of any sampling area in calculating the maximum application rate for the entire application area, or calculating the maximum application rate of each ten-acre (or less) application area using the respective TDS value of each soil sampling area.

(B) Soil loading formulas contained in Appendix I shall be used.

(C) Based on the maximum application rate, the applicant or its designated agent shall determine where the fluids will be applied and supervise the land application process.

(h) **Conditions of permit.** Any land application which is performed under this Section shall be subject to the following conditions or stipulations of the permit:

(1) **Notice to Field Inspector.** The applicant shall notify the appropriate Field Inspector at least 24 hours prior to the commencement of land application to allow a Commission representative an opportunity to be present.

(2) **Compliance agreement.** Any person responsible for supervision of land application shall have signed a compliance agreement with the Commission.

(3) **Presence of representative.** A representative of the applicant shall be on the land application site at all times during which fluids and/or cuttings are being applied. The representative shall be an employee of the applicant, designated agent, contractor, or other person pre-approved by the Commission.

(4) **Materials to be land applied.** Land application shall be limited to water-based drilling fluids and/or cuttings.

(5) **Weather restrictions.** Land application, including incorporation, shall not be done:

(A) During precipitation events or when precipitation is imminent.

(B) When the soil moisture content is at a level such that the soil cannot readily take the addition of drilling fluids.

(C) When the ground is frozen.

(D) By spray irrigation when the wind velocity is such that even distribution of materials cannot be accomplished or the buffer zones, pursuant to (6) of this subsection, cannot be maintained.

(6) **Buffer zones.** Land application shall not be done within the following buffer zones, as identified in the site suitability report:

(A) Fifty feet of a property line boundary.

(B) Three hundred feet of any actively producing water well used for domestic or irrigation purposes.

(C) One-quarter (1/4) mile of any actively producing water well used for municipal purposes.

(7) **Land application rate.** The maximum calculated application rate of drilling fluids and/or cuttings shall not be exceeded. It may require more than one pass to achieve the maximum application rate while avoiding runoff or ponding, pursuant to (9) of this subsection. Application of drilling fluids and/or cuttings outside the approved plot shall be prohibited.

(8) **Land application method.**

(A) Application of drilling fluids and/or cuttings shall be uniform over the approved land application plot, shall not be applied at a rate to cause permanent vegetation damage, and shall be made by a method approved by the Commission prior to use. The flood irrigation method shall be limited to those fields that normally are irrigated in that manner.

(B) For earthen pits, if more than 500 lbs/acre of Oil and Grease or 50,000 lbs/acre of Dry Weight materials are applied, the materials shall be incorporated into the soil by use of the injection method, or by disking or use of some other method approved by the Commission prior to use within 15 days after application.

(9) **Runoff or ponding prohibited.** No runoff of land applied materials shall be allowed during application. Ponding is prohibited, except where the flood irrigation method is approved. In order to comply with this rule, some applications will require the use of more than the minimum calculated acreage and/or a drying period between applications.
(10) **Vegetative cover.** If the vegetative cover is destroyed or significantly damaged by disking, injection, or other practice associated with land application, a bona fide effort shall be made to restore or reestablish the vegetative cover within 180 days after the land application is completed. Additional efforts shall be made until the vegetative cover is fully restored or reestablished.
(11) **Time period.**
(A) **Earthen pits.** Land application shall be completed within 90 days from the date of the permit. At the end of the 90 day period, the permit shall expire by its own terms. To renew the permit, the applicant shall resample the fluids and/or cuttings to be land applied, submit a new analysis, and receive a notification of renewal from a Field Operations office.
(B) **Tanks.** Land application shall be completed within 180 days after drilling ceases.
(12) **Post-application report.** A post-application report shall be submitted by the operator or the operator's agent to the Manager of Field Operations within 30 days of the completion of land application. The report shall give specific details of the land application, including test results of materials applied and loading rate calculations (for tanks only), volumes of materials applied, and an aerial photograph (minimum scale 1:660) delineating the actual area where materials were applied. The report shall contain a statement certifying that the land application was done in accordance with the approved permit.
(13) **Violations.** If the applicant violates the conditions of the permit or this Section, the land application shall be discontinued and the Field Operations office shall be contacted immediately. The Field Operations office may revoke the permit and/or require the operator to do remedial work. If the permit is not revoked, land application may resume with Field Operations' approval. If the permit is revoked,` the operator may make application for a hearing to reinstate it.
(14) **Requirements to close pit.** Neither filing an application nor receiving a permit under this Section shall extend the time limit for closing a reserve pit pursuant to 165:10-7-16, or a commercial pit pursuant to 165:10-9-1.
(i) **Variances.** A variance from the time provisions of (d)(1), (h)(1), (h)(8)(B) or (h)(10) of this Section may be granted by a Field Operations office for justifiable cause. A written request and supporting documentation shall be required. The Field Operations office shall respond in writing within five working days after receipt, either approving or disapproving the request.

[**SOURCE:** Amended in Rule Making 97000002, eff 7-1-97]

165:10-7-20. Noncommercial disposal or enhanced recovery well pits used for temporary storage of saltwater
(a) **Scope.** This Section shall apply to any production operation_where a pit is used for temporary storage of saltwater, except (c)(7) of this Section, which shall apply to any noncommercial well, regardless of whether or not a pit is used.
(b) **Construction requirements.**
(1) **Splash pad/apron.** A splash pad/apron shall be constructed at the unloading area of any noncommercial disposal well or enhanced recovery pit to the design and dimensions necessary to contain and direct all materials unloaded into the pit, unless the pit is of such design that discharge directly into it presents no spill potential.
(2) **Pit specifications.** Except as provided by (4)(A) of this subsection, any noncommercial disposal or enhanced recovery well pit shall be constructed of concrete or steel or be lined with a geomembrane liner according to the following:

(A) Concrete pits must be steel reinforced and have a minimum wall thickness of six inches.
(B) Steel pits must have a minimum wall thickness of three-sixteenths (3/16) inch. A previously used steel pit may be installed, provided it is free of corrosion or other damage.
(C) Geomembrane liners must:
(i) Have a minimum thickness of 30 mils, be chemically compatible with the type of wastes to be contained, and have ultraviolet light protection.
(ii) Be placed over a specially prepared, smooth, compacted surface void of sharp changes in elevation, rocks, clods, organic debris, or other objects.
(iii) Be continuous (may include seams) and cover the bottom and interior sides of the pit entirely. The edges must be securely placed in a minimum twelve inch deep anchor trench around the perimeter of the pit.

(3) **Certification of liner.** The operator of any saltwater storage pit that is constructed with a geomembrane liner shall secure an affidavit signed by the installer, certifying that the liner meets minimum requirements and was installed in accordance with Commission rules. It shall be the operator's responsibility to maintain the affidavit and all supporting documentation pertaining to the liner, such as geomembrane liner specifications from the manufacturer, etc., and shall make them available to a representative of the Conservation Division upon request.

(4) **Monitoring of site.**
(A) If not constructed according to one of the three methods in (2) of this subsection, any noncommercial disposal or enhanced recovery well pit shall be required to have a leachate detection system or at least one monitor well, unless it can be shown that the pit is not located over a hydrologically sensitive area, i.e., a principal bedrock aquifer, the recharge or potential recharge area of a principal bedrock aquifer, or an unconsolidated alluvium or terrace deposit, according to the Oklahoma Geological Survey "Maps Showing Principal Groundwater Resources and Recharge Areas in Oklahoma" (available for viewing at the Commission's Oklahoma City Office or District Offices). The District Manager may require more than one monitor well if he has reason to believe one would not be sufficient to adequately monitor the site.
(B) Any monitor well shall be installed within 100 feet of the pit. An existing nearby water well may be used as a monitor well upon written approval by the District Manager or Manager of Field Operations.
(C) Any new monitor well shall be drilled through the first aquifer encountered, but need not extend below 100 feet if no aquifer is encountered, and shall be completed by a licensed monitor well driller. If documentation can be submitted prior to drilling to show that no water will be encountered within 100 feet, the District Manager may allow the monitor well(s) to be drilled to a lesser depth or eliminated.
(D) Any new monitor well shall have:
(i) A minimum two inch diameter PVC casing with a sealing cap on the bottom.
(ii) Casing consisting of a slotted liner in the saturated zone, or bottom ten feet if none is encountered, and be gravel packed or sand packed as appropriate to the installation.
(iii) Bentonite placed in the annular space of the well above the slotted liner for an interval of at least two feet to form an adequate seal.
(iv) Well cuttings returned to the annular space above the bentonite seal for well stability.
(v) A minimum of two of the top six feet of annular space around the casing filled with cement.
(vi) A minimum three inch thick concrete apron placed at the surface to a minimum two foot radius from the casing.
(vii) A removable and lockable cap placed on top of the casing. The cap must remain locked at all times, except when a well is being sampled.

(E) Within 30 days of installation, construction details for any leachate detection system or specific completion information for any monitor well and a diagram of the location of any monitor well in relation to the pit shall be submitted to the Manager of Field Operations.

(c) **Operation and maintenance requirements.**

(1) **Fencing.** All noncommercial disposal or enhanced recovery well surface facilities that have a pit shall be completely enclosed by a minimum four strand barbed wire fence or equivalent protection as approved by the District Manager. Said fence shall be constructed in such a manner as to prevent livestock from entering the pit area.

(2) **Site maintenance.** The normal access surface of any well site that has a pit, including the access road(s), shall be maintained in a condition that will safely and easily allow access.

(3) **Exclusion of runoff water.** No pit shall be allowed to receive runoff water.

(4) **Freeboard.** The fluid level in any concrete or steel noncommercial disposal or enhanced recovery well pit shall be maintained at all times at least six inches below the top of the pit wall. Any geomembrane lined pit shall have a minimum of 18 inches of freeboard at all times.

(5) **Temporary storage only.** No pit shall be used as permanent storage for salt water.

(6) **Sampling of monitor wells or leachate detection systems.**

(A) Sampling of monitor wells and leachate detection systems shall occur once every six months, during the months of January and July.

(B) The appropriate District Manager shall be notified at least 24 hours in advance of sampling to allow a Commission representative an opportunity to witness the sampling.

(C) Samples shall be collected, preserved, and handled by the operator according to EPA approved standards (RCRA Groundwater Monitoring Technical Enforcement Guidance Document, EPA, OSWER-9950.1, September, 1986, pp. 99-107) and analyzed for pH, chlorides (Cl^-) and total dissolved solids (TDS) by a laboratory certified or operated by the State of Oklahoma. Analysis of additional parameters may be required as determined by the District Manager or Manager of Field Operations. A copy of each analysis and a statement as to the depth to groundwater encountered in each well, or an affidavit that no water was encountered, shall be forwarded to the Manager of Field Operations, within 30 days of sampling.

(7) **Prevention of pollution.** All noncommercial disposal or enhanced recovery wells shall be maintained at all times so as to prevent pollution. In the event of a nonpermitted discharge from surface facilities, sufficient measures shall be taken immediately to stop, contain, and control the loss of materials. Reporting of said discharge shall be in compliance with 165:10-7-5(c). Any materials lost due to such discharge shall be cleaned up as directed by a representative of the Conservation Division of the Commission.

(8) **Oil film.** The operator of a saltwater pit shall be responsible for the protection of migratory birds. Therefore, the Conservation Division recommends that to prevent the loss of birds due to oil films, all open top tanks and pits containing fluid be kept free of oil films or sludge or be protected from access to birds. [See Advisory Notice 165:10-7-3(c)]

(d) **Closure requirements.**

(1) **Time limit.** Within 180 days of the cessation of operations, all associated pits shall be emptied of all contents, and either removed or filled with soil. All monitor wells shall be plugged with bentonite or cement, unless exempt in writing by the District Manager or Manager of Field Operations. The site shall be revegetated within one (1) year.

(2) **Burial.** If any concrete, steel, geomembrane, or other materials associated with the site are to be left on-site, they shall be buried under a minimum soil cover of three feet, pursuant to 165:10-3-17.

(e) **Prospective application to existing facilities.** All provisions of this Section, except those in (b)(2) and (b)(3), shall apply to all existing pits within the scope of this Section which are, or have been, in operation prior to the effective date of this Section. Operators shall have one (1) year from the effective date of this Section in which to bring their facilities into compliance with the applicable provisions of this Section. Failure to comply with any applicable provision may result in revocation of the authority to operate.

(f) **Variances.**

(1) A variance from the time requirements of (c)(6), (d)(1), or (e) of this Section may be granted by the District Manager or Manager of Field Operations for justifiable cause. A written request and justifiable explanation is required. The District Manager or Manager of Field Operations shall respond in writing within five working days, either approving or disapproving the request.

(2) Any variance from the liner requirements as required under (b)(2) of this Section may be granted by the manager of Field Operations after receipt of a written request and supporting documentation required by the department.

[**SOURCE:** Amended in Rule Making 980000034, eff 7-1-99]

165:10-7-21. Refining and processing of oil and gas

(a) All deleterious substances obtained or used in the processing and refining of oil and gas shall be disposed of in a manner that will prevent the pollution of fresh water.

(b) Chemicals, gasolines, oil, and other deleterious substances shall be stored, where necessary, in tanks or containers of a material and of a construction and in a manner that will prevent the escaping, seepage, or draining of such liquids into any fresh water.

165:10-7-22. Permits for County Commissioners to apply waste oil, waste oil residue, or crude oil contaminated soil to roads

(a) **Prohibition against application of waste oil, waste oil residue, or crude oil contaminated soil without permit.** This Section prohibits any Board of County Commissioners from applying waste oil, waste oil residue, or crude oil contaminated soil to a street or road without a permit.

(b) **Permit by District Office.** A District Manager for the Conservation Division may issue to a Board of County Commissioners for a county within the district a permit to apply waste oil, waste oil residue, or crude oil contaminated soil to a street or road within the county.

(c) **Permit requirements.**

(1) **Use of Form 1014W.** The application and permit to apply waste oil, waste oil residue, or crude oil contaminated soil shall be made on Form 1014W.

(2) **Telephone permits.** In case of emergency, a District Manager may issue a permit by telephone. If an applicant obtains a permit by telephone, then the applicant shall file Form 1014W and attachment within five working days after receipt of the permit by telephone.

(3) **Conditions for permit.**

(A) Waste oil, waste oil residue, and contaminated soils applied under this Section shall consist of crude oil and materials produced with crude oil only and shall not contain any refined oils such as motor oils, lubricants, compressor oils or hydraulic fluids.

(B) If required by the District Manager, a hydrocarbon analysis shall be submitted with Form 1014W. The analysis shall be performed by a state-certified laboratory in accordance with OCC-approved methods.

(C) Waste oil, waste oil residue, and crude oil contaminated soil shall be applied in such a manner that pollution of surface or subsurface waters will not likely occur and public and private property adjoining the street or road will be protected.

(D) During operations for road oiling, all necessary signs, lights, and other safety and warning devices shall be used to alert road users to conditions. A sign shall be posted with the contractor or authority's name and phone number to contact in case of emergency.

(E) Following completion of the project there shall be a uniform soil/oil base (all liquid worked in), with no visible free-standing oil.

(F) Proper care shall be taken to avoid runoff of oil or water into borrow ditches or adjacent areas.

(G) No road oiling shall be conducted:

(i) When the temperature is less than 45° F.

(ii) In any area where water collects and stands.

(iii) Where soil moisture content or road conditions such as soil type, tight soil conditions, packed soil conditions, or grade limits prevent rapid absorption of the oil.

(d) **Notice to District Office.** The Board of County Commissioners receiving the permit shall notify the District Office at least two days prior to commencement of road oiling under a permit.

(e) **Site inspection.** At his discretion, a District Manager may request a Field Inspector of the Conservation Division or an Enforcement Officer of the Transportation Division to inspect the site at any time during the road oiling operation to ensure compliance with this Section.

(f) **Duration of permit.** The permit shall state the duration of the permit, and it shall also state that if the application fails to comply with either the terms of the permit or the terms of this Section, then the permit shall terminate automatically.

(g) **Disapproval or cancellation of permits.**

(1) If a District Manager receives a complaint about a road oiling permit, he shall cause an investigation of the complaint to be made as soon as practicable. During the investigation, the District Manager may direct the applicant to cease road oiling under a permit. If necessary, the District Manager may verbally revoke the permit.

(2) If a District Manager disapproves an application or cancels a permit, the applicant may apply to the Commission for an order under OAC 165:5-7-41.

[**Source:** Amended at 12 Ok Reg 2017, eff 7-1-95]

165:10-7-23. Disposal of waste oil

(a) All waste oil and waste oil residue shall be disposed of in one of the following ways:

(1) Transfer or sale to a reclaimer or transporter.

(2) Transfer or sale to County Commissioners.

(3) Administrative approval from the Conservation Division.

(b) All operators or owners of pits, tanks, commercial disposal operations, or reclaimers shall maintain books and records describing the disposition of all waste oil or waste oil residue. A copy of the run or load ticket will satisfy this requirement if the information required in (c) of this Section is contained therein.

(c) The following information shall be contained in said books and records and subject to audit and inspection by representatives of the Commission for a minimum period of three years:

(1) The amount of waste oil or waste oil residue removed.

(2) The location of the waste oil or waste oil residue prior to disposal.

(3) The destination of waste oil or waste oil residue as reported by transporter.

(4) The name of the transporter of waste oil or waste oil residue.

165:10-7-24. Waste management practices reference chart

(a) **Scope.** This Section provides reference guidelines for the disposal of wastes under the jurisdiction of the Commission which are generated by oil and gas operators and pipeline companies. Hazardous waste as defined at 40 CFR 261.3 is regulated by the Oklahoma Department of Environmental Quality.

(b) **Waste materials and disposal options.** Consistent with EPA's policy on source reduction, recycling, treatment and proper disposal, operators shall use waste management practices as listed in (c) of this Section which describes the various management practices for the following waste materials. For any of the following waste materials where option (16) of subsection (c) is listed, option (16) shall be considered before any other option.

(1) Produced water: Options 1, 7 & 9
(2) Weighted water: Options 1 & 7
(3) Used treatment fluids and other flowback wastes: Options 1, 2, 5 & 7
(4) Water based mud: Options 1, 2, 5, 6, 7, 8 & 19
(5) Water based mud cuttings: Options 1, 2, 3, 4, 5, 6, 7, 8, 12 & 19
(6) Oil based mud: Options 1, 2, 3, 5, 7 & 22
(7) Oil based mud cuttings: Options 1, 2, 3, 4, 5, 7, 8, 12 & 14
(8) Crude oil: Options 1, 4, 12, 13 & 14
(9) Used motor, gear, lube, compressor and hydraulic oils: Options 1, 15 & 16
(10) Used solvents: Options 1, 15 & 16
(11) Oily debris: Options 1, 3, 13 & 20
(12) Filter media and backwash: Options 1, 3, 7, 15, 16 & 20
(13) Glycol, amine, and caustic wash: Options 1 & 7
(14) Iron sponge: Options 3 & 20
(15) Molecular sieve: Options 3 & 20
(16) Produced sand/sediment: Options 3, 7, 8, 17 & 20
(17) Tight emulsions: Options 1, 4, 8, 12, 14 & 17
(18) Unused treatment chemicals: Options 1, 15 & 16
(19) Tank bottoms from E&P: Options 1, 3, 4, 7, 8, 10, 12, 14 & 17
(20) Paraffin: Options 1, 3, 4, 12, 14, 15, 16 & 20
(21) Asbestos insulation: Options 3 & 15
(22) Non-asbestos insulation: Options 3, 15 & 20
(23) Used batteries: Options 1, 3, 15 & 16
(24) Oils containing PCBs: Option 11
(25) Oils not containing PCBs: Options 1, 15 & 16
(26) Empty oil and chemical drums: Options 1, 3 & 15
(27) Salt contaminated soils: Options 5, 6, 8 & 17
(28) Crude oil contaminated soils: Options 1, 3, 4, 8, 10, 12, 14, 17 & 22
(29) Pit sludges from wellsites, disposal well pits and gathering systems: Options 1, 3, 4, 7, 8, 12, 17 & 20
(30) Gathering line pigging wastes: Options 1, 3, 7 & 20
(31) Gas plant sweetening wastes: Options 1, 3, 7 & 20
(32) Gas plant dehydration wastes: Options 1, 3 & 7
(33) Cooling tower blowdown from gas plants: Options 7 & 15
(34) Wastes from subsurface natural gas storage: Options 1, 3, 7 & 20
(35) Wastes other than refined product removed from produced water and other well fluids prior to injection or disposal: Options 1, 7, 8, 17 & 20
(36) Gases removed from the production stream: Options 1, 7, 13 & 18
(37) Waste crude oil and light hydrocarbons (gas condensate) in reserve pits, other impoundments or tankage at wellsites: Options 1, 7, 8, 13 & 17
(38) Contaminated ground water (except refined products): Options 1, 7, 21 & 22
(39) Pipeline sludge and other deposits removed from pipe or equipment on E&P gathering systems: Options 1, 3, 7, 8, 10, 17 & 20
(40) Residues and truckwash from inside the tank of trucks used to transport saltwater, drilling mud or spent completion fluids: Options 1, 3, 7 & 20
(41) Sewage and wastes from portable toilets: Option 15
(42) Crude pipeline pigging wastes, contaminated soil and residue from transmission and trunk lines: Options 1, 3, 4, 8, 12, 15, 16, 17 & 22
(43) Water or soil contaminated by refined product from E&P operations: Options 1, 16, 21 & 22
(44) Rigwash and supply water: Options 1, 5, 7 & 8
(45) Storm water and hydrostatic test water from E&P operations: Options 1, 7, 9 & 22
(46) Spent filters: Options 1 & 3
(47) Trash and debris: Options 15 & 20
(48) Refined petroleum product releases: Options 1, 3, 8, 13, 16, 17 & 22

(49) Refined petroleum product pigging wastes: Options 1, 3, 8, 15, 16, 17 & 22
(50) Water or soil contaminated by refined products from pipelines: Options 1, 16, 21 & 22
(51) Hydrostatic test water from pipelines: Options 1, 9, 16 & 22
(52) Tank bottoms from crude pipeline facilities: Options 1, 3, 4, 8, 10, 12, 14, 16, 17 & 22
(53) Tank bottoms from refined product pipeline facilities: Options 1, 3, 14, 15, 16, 17 & 22

(c) **Disposal options and rule reference guide.** The following waste disposal options are referenced in (b) of this Section:
(1) Reclaim and/or recycle.
(2) Burial (in accordance with 165:10-7-16).
(3) Landfills regulated by the Oklahoma Department of Environmental Quality.
(4) Road applications by County Commissioners (in accordance with 165:10-7-22 and 165:10-7-28).
(5) Noncommercial pits (in accordance with 165:10-7-16).
(6) Commercial mud disposal pits (in accordance with 165:10-9-1).
(7) Underground injection (in accordance with 165:10-5-1 through 165:10-5-14).
(8) Land application (in accordance with 165:10-7-19 and 165:10-7-26).
(9) Discharge (in accordance with 165:10-7-17).
(10) Reclaim and/or recycle (in accordance with 165:10-7-23).
(11) In accordance with EPA; Code of Federal Regulations (CFR), Title 40, Part 761.60 through 761.79.
(12) Application to lease roads, well locations, and production sites (in accordance with 165:10-7-27 and 165:10-7-29).
(13) Open burning in accordance with Oklahoma Department of Environmental Quality regulations.
(14) Disposal of waste oil as specified in 165:10-7-23.
(15) Disposal in accordance with Oklahoma Department of Environmental Quality regulations.
(16) If the waste is determined to be a hazardous waste under the Federal Resource Conservation and Recovery Act (RCRA), disposal will be determined by the Oklahoma Department of Environmental Quality; if a non-hazardous waste, Option 17 may be used or other disposal option as approved by the Commission.
(17) On-site or in-situ bioremediation/remediation.
(18) Flaring or venting (in accordance with 165:10-3-15).
(19) Commercial soil farming (in accordance with 165:10-9-2).
(20) Burial as approved by the Commission.
(21) Surface discharge as approved by the Commission.
(22) Land application as approved by the Commission.

[**Source:** Amended at 12 Ok Reg 2039, eff 7-1-95; Amended in Rule Making 97000002, eff 7-1-97; Amended in Rule Making 200200017, eff 7-1-02]

165:10-7-25. One-time land application of water-based fluids from tanks or other containment vessels [REVOKED]

[**SOURCE:** Amended at 9 Ok Reg 2295, eff 6-25-92; Revoked in Rule Making 97000002, eff 7-1-97]

165:10-7-26. One-time land application of contaminated soils and petroleum hydrocarbon based drill cuttings

(a) **Authority for land application.** No person shall land apply soils or drill cuttings contaminated by salt or petroleum hydrocarbons except as provided by this Section. Any operator failing to obtain a permit shall be fined $2,000.00.
(b) **Scope.** This Section shall cover the land application of soils and drill cuttings contaminated by salt and/or petroleum hydrocarbons. Petroleum hydrocarbon-contaminated soils land applied under this Section shall meet the

RCRA criteria for exempt or non-exempt/nonhazardous waste. [Reference 40 CFR Subtitle C and EPA publication EPA530-K-95-003 "Crude Oil and Natural Gas Exploration and Production Wastes: Exemption from RCRA Subtitle C Regulation]. Hazardous waste as defined at 40 CFR 261.3 is regulated by the Oklahoma Department of Environmental Quality. Any land application made under this Section shall be done on a one-time basis to land that has not been previously used for this practice or similar practices.

(c) **Receiving site suitability restrictions.** Land application shall only occur on land having all of the characteristics below, as field verified by a soil scientist or other qualified person pre-approved by the Commission~~÷~~. Any variance from site suitability restrictions must be approved by the Oil and Gas Conservation Division (see (g)(2)(C) of this Section).

(1) **Maximum slope.** A maximum slope of five percent for all application methods.

(2) **Depth to bedrock.** Depth to bedrock will be at least 40 inches if crude oil contaminated soils or petroleum hydrocarbon-based drill cuttings are to be applied; 20 inches if salt contaminated soils are to be applied.

(3) **Soil texture.** A soil profile (as defined by USDA soil surveys) containing at least twelve inches (may be cumulative) of one of the following soil textures between the surface and the water table, unless a documented impeding layer of shale is present: loam, silt loam, silt, sandy clay loam, silty clay loam, clay loam, sandy clay, silty clay, or clay.

(4) **Salinity.** Slight salinity [defined as Electrical Conductivity (EC) less than 4,000 micromhos/cm] in the topsoil, or upper six inches of the soil, and a calculated Exchangeable Sodium Percentage (ESP) less than 10.0.

(5) **Depth to water table.** No evidence of a seasonal water table within six (6) feet of the soil surface as verified by field observation and published data.

(6) **Distance from water bodies.** A minimum distance of 100 feet from the land application site boundary to any perennial stream and 50 feet to any intermittent stream found on the appropriate United States Geological Survey (U.S.G.S.) topographic map (available for viewing at the Commission's Oklahoma City Office and District Offices); and a minimum of 100 feet to any freshwater pond, lake, or wetland designated by the National Wetlands Inventory Map Series, prepared by the U.S. Fish and Wildlife Service (available for viewing at the Commission's Oklahoma City Office). Also, see (h)(6) of this Section.

(7) **Site specific concerns.** Void of slick spots within or adjacent to the land application area, where subsurface lateral movement of water is unlikely, or areas void of concentrated surface flow such as gullies or waterways.

(d) **Sampling requirements.**

(1) **Notice to Field Inspector.** The appropriate Field Inspectors shall be contacted at least two working days prior to sampling of the receiving soil and materials to be land applied. This is to allow a Commission representative an opportunity to be present.

(2) **Receiving soil.** Sampling of the receiving soil shall be performed by, or under the supervision of, a soil scientist or other qualified person pre-approved by the Commission. Soil samples shall be taken from the proposed application area and analyzed. A minimum of four representative surface core samples from the surface (0-6 inches) and subsurface (14-20 inches) must be taken from each ten acres, or part thereof. Each group of surface core samples representative of a ten-acre area (or less) shall be combined and thoroughly mixed. A minimum one pint composite sample shall be taken and placed in a clean container for delivery to the laboratory. Alternatively, soil samples may be composited by the laboratory. All subsurface samples shall be handled in the same manner.

(3) **Materials to be land applied.** Representative samples of the materials to be land applied shall be taken, composited into a minimum one-pint sample, and placed in a clean container for delivery to the laboratory. Alternatively, materials to be land applied may be composited by the laboratory.

(e) **Analysis requirements.**

(1) **Salt contaminated soils or drill cuttings.** Analysis requirements will be dependent upon the loading method that is chosen. For most applications, loading based on Total Dissolved Solids (TDS) will be most appropriate. However, applicants proposing to land apply on a site in western Oklahoma, where the soils commonly contain moderate to high levels of gypsum, may benefit from using the loading formula based on Chlorides (Cl).

(A) Samples of soil and materials to be land applied shall be tested by a laboratory proficient in testing soils. Either a 1:1 extract or saturated paste extract shall be used for sample preparation for TDS or Cl loading. A saturated paste moisture equivalent is necessary where the saturated paste sample preparation method is used.

(B) Parameters for analysis of the receiving soil shall include at a minimum EC, TDS, and ESP for TDS loading. For Chloride loading, parameters shall include Chlorides (dry weight basis) and ESP.

(C) Parameters for analysis of soils or drill cuttings contaminated by salt shall include at a minimum EC for TDS loading and both EC and Cl for Chloride loading.

(2) **Soils and drill cuttings contaminated by petroleum hydrocarbons.**

(A) Samples of soil and materials to be land applied shall be tested by a laboratory proficient in testing soils.

(B) Parameters for analysis of the receiving soil shall include at a minimum EC and ESP.

(C) Parameters for analysis of soils or drill cuttings contaminated by petroleum hydrocarbons shall include at a minimum a test of the appropriate carbon range(s), which is determined by the nature of the waste material. These include Gasoline Range Organics (GRO) - C6 to C10 (EPA test method 8015/8020 M), Diesel Range Organics (DRO) - C10 to C28 (extractable procedure), and Oil and Grease - C20 to C50+ (EPA test method 1664).

(f) **Application rates.**

(1) **Calculations.** The maximum application rate for TDS (or Cl) and GRO, DRO, or O & G shall be calculated by the applicant based upon the analyses of the materials to be land applied and the soil of the application area. For salt contaminated soils or drill cuttings, if the application area encompasses more than one soil sampling area, the rate shall be calculated in one of two ways, depending on how the application will be made. The applicant may either calculate the maximum application rate for the entire application area based upon the highest soil TDS (or Cl) value of any sampling area (averaging not allowed), or calculate it for each ten acre (or less) application area using the respective soil TDS (or Cl) values of each sampling area.

(2) **Soil loading formulas.** The maximum application rate for any application area shall be restricted by the most limiting parameter. To determine this, the soil loading formulas in Appendix I of this Chapter shall be used as applicable.

(3) **Variances.** In special situations, a request for a variance relating to soil loading of petroleum hydrocarbons may be administratively approved by the Manager of Field Operations. The applicant shall submit a written request explaining the circumstances or conditions which warrant a variance and shall also submit a management plan for reducing the petroleum hydrocarbon content in the soil to two percent or less.

(g) **Application for permit.**

(1) **Who may apply.** Only the operator responsible for generating the waste to be land applied or the operator's designated agent may apply for a land application permit, except that the Oklahoma Energy Resources Board or its designated contractor may make application to land apply materials for which there is no responsible party.

(2) **Required form and attachments.** Each application for land application of soils contaminated by salt and/or crude oil or petroleum hydrocarbon-containing deleterious substances shall be submitted to a Field Operations office on Form 1014S. An original and three copies shall be required. Attached to at least one of the copies shall be the following:

(A) Written permission from the surface owner to allow the applicant to land apply, incorporate, and fertilize materials. For purposes of obtaining such consent, the applicant shall use Form 1014L.

(B) A topographic map and the most recent aerial photograph (minimum scale 1:660) with the proposed and potential land application areas delineated as well as the location of cultural features such as buildings, water wells, etc. Both the topographic map and aerial photograph must show all areas within 1320 feet of the boundary of the land application area.

(C) Receiving site suitability report, pursuant to subsections (c) and (h)(6) of this Section, based on an on-site investigation and signed by a soil scientist or other qualified person. The report shall include detailed information concerning the site and shall discuss how all site characteristics were determined. Any requests for a variance to site suitability restrictions must be accompanied by a written justification that has been developed or approved by a soil scientist or other qualified person. The justification shall provide explanation as to safeguards which will assure that conditions of the permit will be met and there will be no adverse impacts from the land application.

(D) Analyses of receiving soil samples.

(E) Analyses of contaminated soil or petroleum hydrocarbon-based drill cuttings.

(F) For contaminated soils, an investigation report and diagram, drawn to scale, detailing the areal extent and depth of the contamination; and sampling procedures which were used to assure that representative samples were taken.

(G) Loading calculations.

(H) Copies of all chains-of-custody related to sampling.

(I) If there is an agent, a notarized affidavit designating same, signed by the operator.

(J) Other information as required by this Section or requested by a Field Operations office.

(3) **Review period.** The Field Operations office shall review the application, either approve or disapprove it, and return a copy of Form 1014S within five working days of submission of all required or requested information. If approved, a permit number shall be assigned to Form 1014S; if disapproved, the reason(s) shall be given. The applicant may make application for a hearing if it is not approved.

(h) **Conditions of permit.** Any land application which is performed under this Section shall be subject to the following conditions or stipulations of the permit:

(1) **Notice to Field Inspector.** The applicant shall notify the appropriate Field Inspector at least 24 hours prior to the commencement of land application to allow a Commission representative an opportunity to be present.

(2) **Compliance agreement.** Any person responsible for supervision of land application shall have signed a compliance agreement with the Commission.

(3) **Presence of representative.** A representative of the applicant shall be on the land application site at all times during which materials are being applied. The representative shall be an employee of the applicant, designated agent, contractor, or other person pre-approved by the Commission.

(4) **Materials to be land applied.** Land application under this Section shall be limited to soils and drill cuttings contaminated by salt and/or petroleum hydrocarbons. Petroleum hydrocarbon-contaminated soils or drill cuttings land applied under this Section shall meet the RCRA criteria for exempt or non-exempt/nonhazardous waste. Hazardous waste as defined at 40 CFR 261.3 is regulated by the Oklahoma Department of Environmental Quality.

(5) **Weather restrictions.** Land application, including incorporation, shall not be done:

(A) During precipitation events or when precipitation is imminent.

(B) When the soil moisture content is at a level such that the soil cannot readily take the addition of materials.

(C) When the ground is frozen.

(6) **Buffer zones.** Land application shall not be done within the following buffer zones, as identified in the site suitability report:
(A) Fifty feet of a property line boundary.
(B) Three hundred feet of any actively producing water well used for domestic or irrigation purposes.
(C) One-quarter (1/4) mile of any actively producing water well used for municipal purposes.
(7) **Land application rate.** The maximum calculated application rate of materials shall not be exceeded. Under no circumstances shall land applied materials exceed a two inch depth. Furthermore, no runoff or ponding of land applied materials shall be allowed. It may require more than one pass or lift to achieve the maximum application rate while avoiding runoff or ponding.
(8) **Land application method.** Application of materials shall be uniform over the approved land application area, and shall be made by a method approved by the Commission prior to use. Land applied materials shall be incorporated into the soil by disking or chiseling during or immediately after application to a minimum depth of two times the depth of ~~a~~ applied materials; however, if any contaminated sandy soil~~s~~ is applied to any clayey soil, incorporation shall be to a minimum depth of four times the depth of the applied materials.
(9) **Fertilizer.** For any land application involving petroleum hydrocarbon-contaminated soils and/or drill cuttings, fertilizer shall be applied at an appropriate rate as indicated by soil testing for available N-P-K to adjust the average carbon-nitrogen ratio in order to enhance biodegradation of the petroleum hydrocarbons and assist in reestablishing vegetation. In the absence of soil testing, Nitrogen, Phosphorus, and Potassium shall be applied at a rate of 160-40-40 lbs. per acre (actual N-P-K).
(10) **Vegetative cover.** A bona fide effort shall be made to restore or reestablish the vegetative cover within 180 days after the land application is completed. Additional efforts shall be made until the vegetative cover is fully restored or reestablished.
(11) **Time period.** Land application shall be completed within 30 days of the anticipated completion date shown on the approved application form.
(12) **Post-application report.** A post-application report shall be submitted by the operator or the operator’s agent to the Manager of Field Operations within 30 days of the completion of land application. The report shall give specific details of the land application, including volumes of materials applied and an aerial photograph (minimum scale 1:660) delineating the actual area where materials were applied. The report shall contain a statement certifying that the land application was done in accordance with the approved permit.
(13) **Violations.** If the applicant violates the conditions of the permit or this Section, the land application shall be discontinued and the Field Operations office shall be contacted immediately. The Field Operations office may revoke the permit and/or require the operator to do remedial work. If the permit is not revoked, land application may resume with Field Operations' approval. If the permit is revoked, the operator may make application for a hearing to reinstate it.
(i) **Variances.** A variance from the time provisions of (d)(1), (h)(1), (h)(10) or (h)(11) of this Section may be granted by a Field Operations office for justifiable cause. A written request and supporting documentation shall be required. The Field Operations office shall respond in writing within five working days after receipt, either approving or disapproving the request.

[**Source:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended at 12 Ok Reg 2039, eff 7-1-95; Amended in Rule Making 97000002, eff 7-1-97]

165:10-7-27. Application of waste oil, waste oil residue, or crude oil contaminated soil by oil and gas operators and pipeline companies
(a) **Scope.** This Section shall cover the application of waste oil, waste oil residue, or crude oil contaminated soil by oil and gas operators and pipeline companies to lease roads, pipeline service and tank farm roads, well locations,

and production sites. Hazardous waste as defined at 40 CFR 261.3 is regulated by the Oklahoma Department of Environmental Quality.

(b) **Permit by District Office.** A District Manager for the Conservation Division may issue to an oil or gas operator or pipeline company within the District a permit for road application of waste oil, waste oil residue, or crude oil contaminated soil to lease roads, pipeline service and tank farm roads, well locations, and production sites within the District. This subsection prohibits any operator from applying waste oil, waste oil residue, or crude oil contaminated soil without a permit. Any operator or pipeline company violating this subsection shall be fined $2,000.00.

(c) **Permit requirements.**

(1) **Use of Form 1014X.** The application to apply waste oil, waste oil residue, or crude oil contaminated soil shall be made on Form 1014X. The original and one copy are required.

(2) **Landowner permission.** Attached to the application shall be a copy of written permission by the surface owner to allow the operator or pipeline company to apply waste oil, waste oil residue, or crude oil contaminated soil as per this Section to a specific portion of real property as designated by legal description. For purposes of obtaining such consent, the applicant shall use Form 1014L.

(3) **Telephone permits.** In case of an emergency, a District Manager may issue a permit by telephone. If an operator or pipeline company obtains a permit by telephone, the operator or pipeline company shall file Form 1014X and attachments within five working days after receipt of the permit by telephone.

(4) **Conditions for permits.**

(A) Waste oil, waste oil residue, and contaminated soils applied under this Section shall consist of crude oil and materials produced with crude oil only. Hazardous waste as defined at 40 CFR 261.3 is regulated by the Oklahoma Department of Environmental Quality.

(B) If required by the District Manager, a hydrocarbon analysis shall be submitted with Form 1014X. The analysis shall be performed by a state-certified laboratory in accordance with OCC-approved methods.

(C) Waste oil, waste oil residue, and crude oil contaminated soil shall be applied in such a manner that pollution of surface or subsurface waters will not likely occur and public and private property adjoining the application area will be protected.

(D) During application, any necessary signs, lights and other safety and warning devices shall be used as traffic requires to alert users to conditions. A sign shall be posted with the contractor's or operator's name and phone number to contact in case of an emergency.

(E) No application shall be conducted:

(i) When the temperature is less than 45° F.

(ii) In any area where water collects and stands.

(iii) Where conditions such as grade, soil moisture content, soil type, tight soil conditions, or packed soil conditions cause runoff or prevent rapid absorption of the oil.

(F) Following completion of the project, there shall be a uniform soil/oil base (all liquids worked in), with no visible free-standing oil.

(G) Proper care shall be taken to avoid runoff of oil into borrow ditches or adjacent areas.

(d) **Notice to Field Inspector.** The operator or pipeline company receiving the permit shall notify the appropriate Field Inspector at least two days prior to commencement of application.

(e) **Site inspection.** At his discretion, a District Manager may request a Field Inspector of the Conservation Division or an Enforcement Officer of the Transportation Division to inspect the site at any time during the application operation to ensure compliance with this Section.

(f) **Duration of permit.** The permit shall state the duration of the permit, not to exceed 60 days. If a complaint is received or the operator or pipeline company fails to comply with either the terms of the permit or this Section, the District Manager may direct the operator or pipeline company to cease application until the problem is resolved. If necessary, the District Manager may verbally revoke the permit and/or require the operator or pipeline company to perform remedial work.

If a District Manager disapproves an application or cancels a permit, then the applicant may apply to the Commission for an order under 165:5-7-41.

[**Source:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended at 12 Ok Reg 2017, eff 7-1-95; Amended in Rule Making 97000002, eff 7-1-97]

165:10-7-28. Application of freshwater drill cuttings by County Commissioners

(a) **Scope.** This Section shall cover the one-time application of freshwater drill cuttings by a Board of County Commissioners to a street or road.

(b) **Permits by District Office.** A District Manager for the Conservation Division may issue to any Board of County Commissioners within the District a permit for road application of freshwater drill cuttings to a street or road within the county. This Section prohibits any Board of County Commissioners from applying freshwater drill cuttings without a permit.

(c) **Site restrictions.** Application of freshwater drill cuttings shall only occur on sites having an:

(1) Electrical Conductivity (EC) no greater than 6,000 micromhos/cm; and

(2) Exchangeable Sodium Percentage (ESP) less than 15.0.

(d) **Sampling requirements.**

(1) The appropriate Field Inspector shall be contacted at least two working days prior to sampling to allow a Commission representative an opportunity to witness the sampling of the receiving soil and freshwater drill cuttings to be applied.

(2) The receiving soil shall be sampled using the following procedure:

(A) A minimum of five samples shall be taken for each one-half (1/2) mile section of road (or borrow ditch) and composited into one sample for analysis.

(B) Sampling shall be to a minimum depth of six inches.

(3) The freshwater cuttings shall be sampled by taking a minimum of one representative sample for every five cubic yards of freshwater cuttings to be applied and composited into one quart sample for analysis.

(e) **Analysis requirements.**

(1) The composite samples of soil and drill cuttings shall be analyzed by a laboratory which tests soils.

(2) The parameters for the receiving soil shall include ESP and either EC or Total Dissolved Solids (TDS).

(3) The parameters for the drill cuttings shall include TDS.

(f) **Maximum application rate.**

(1) The maximum application rate shall be calculated by the Board of County Commissioners using the following formula:

PROCEDURE FOR CALCULATING APPLICATION RATE OF TOTAL DISSOLVED SOLIDS (TDS)

______ ppm TDS in receiving soil x 2 = ______ lbs/ac TDS in receiving soil.

10,000 lbs/ac TDS - _______ lbs/ac TDS in receiving soil = Maximum TDS (lbs/ac) to be applied _________.

Maximum TDS (lbs/ac) to be applied ________ ÷ (_______ ppm TDS in cuttings x .000001) = Maximum lbs/ac of cuttings to be applied _______.

Actual weight of drill cuttings ________ lbs/cu ft x 27 = ________ lbs/cu yd.

Maximum lbs/ac to be applied _______ ÷ _______ lbs/cu yd = ________ cu yds/ac to be applied.

Total volume _______ cu yds ÷ _______ cu yds/ac = Minimum acres required ________.

(2) Calculations shall be submitted with the application.

(g) **Permit requirements.**

(1) **Use of Form 1014W.** The application to apply freshwater drill cuttings shall be made on Form 1014W. The original and one copy are required.
(2) **Telephone permits.** In case of an emergency, a District Manager may issue a permit by telephone. If any Board of County Commissioners obtains a permit by telephone, the applicant shall file Form 1014W within five working days after receipt of the permit by telephone.
(3) **Conditions for permits.**
(A) The method to be used for application of freshwater drill cuttings shall not pollute surface or subsurface waters and shall protect public and private property adjoining the application area.
(B) During application, any necessary signs, lights and other safety and warning devices shall be used to alert users to conditions. A sign shall be posted with the contractor's or authority's name to contact in case of an emergency.
(C) All free liquids shall be removed before cuttings are applied.
(D) Following completion of the project, there shall be a uniform soil/cuttings base.
(h) **Notice to Field Inspector.** The Board of County Commissioners receiving the permit shall notify the appropriate Field Inspector at least two days prior to commencement of the application.
(i) **Site inspection.** At his discretion, a District Manager may request a Field Inspector of the Conservation Division or an Enforcement Officer of the Transportation Division to inspect the site at any time during the application operation to ensure compliance with this Section.
(j) **Duration of permit.** The permit shall state the duration of the permit, not to exceed 60 days. If a complaint is received or the Board of County Commissioners fails to comply with either the terms of the permit or this Section, the District Manager may direct the Board of County Commissioners to cease application until the problem is resolved. If necessary, the District Manager may verbally revoke the permit and/or require the Board of County Commissioners to perform remedial work. If a District Manager disapproves an application or cancels a permit, then the applicant may apply to the Commission for an order under 165:5-7-41.

165:10-7-29. Application of freshwater drill cuttings by oil and gas operators
(a) **Scope.** This Section shall cover the one-time application of freshwater drill cuttings by oil and gas operators to private access areas, well locations, and production sites.
(b) **Permits by District Office.** A District Manager for the Conservation Division may issue to an operator within the District a permit for application of freshwater drill cuttings to private access areas, well locations, and production sites within the District. This Section prohibits any operator from applying freshwater drill cuttings without a permit. Any operator violating this subsection shall be fined $2,000.00.
(c) **Site restrictions.** Application of freshwater drill cuttings shall only occur on sites having an:
(1) Electrical Conductivity (EC) no greater than 6,000 micromhos/cm; and
(2) Exchangeable Sodium Percentage (ESP) less than 15.0.
(d) **Sampling requirements.**
(1) The appropriate Field Inspector shall be contacted at least two working days prior to sampling to allow a Commission representative an opportunity to witness the sampling of the receiving soil and freshwater drill cuttings to be applied.
(2) The receiving soil shall be sampled using the following procedure:
(A) A minimum of five samples shall be taken for each one-half (1/2) mile section of road (or borrow ditch), well location, or production facility and composited into one sample for analysis.
(B) Sampling shall be to a minimum depth of six inches.
(3) The freshwater cuttings shall be sampled by taking a minimum of one representative sample for every five cubic yards of freshwater cuttings to be applied and composited into one quart sample for analysis.

(e) **Analysis requirements.**
(1) The composite samples of soil and drill cuttings shall be analyzed by a laboratory which tests soils.
(2) The parameters for the receiving soil shall include ESP and either EC or Total Dissolved Solids (TDS).
(3) The parameters for the drill cuttings shall include TDS.
(f) **Maximum application rate.**
(1) The maximum application rate shall be calculated by the operator using the following formula:

PROCEDURE FOR CALCULATING APPLICATION RATE OF TOTAL DISSOLVED SOLIDS (TDS)

_______ ppm TDS in receiving soil x 2 = ________ lbs/ac TDS in receiving soil.

10,000 lbs/ac TDS - ______ lbs/ac TDS in receiving soil = Maximum TDS (lbs/ac) to be applied _______.

Maximum TDS (lbs/ac) to be applied _______ ÷ (_______ ppm TDS in cuttings x .000001) = Maximum lbs/ac of cuttings to be applied _______.

Actual weight of drill cuttings _______ lbs/cu ft x 27 = _______ lbs/cu yd.

Maximum lbs/ac to be applied _______ ÷ _______ lbs/cu yd = _______ cu yds/ac to be applied.

Total volume _______ cu yds ÷ _______ cu yds/ac = Minimum acres required _______.

(2) Calculations shall be submitted with the application.
(g) **Permit requirements.**
(1) **Use of Form 1014X.** The application to apply freshwater drill cuttings shall be made on Form 1014X. The original and one copy are required.
(2) **Landowner permission.** Attached to the application shall be a copy of written permission by the surface owner to allow the operator to apply freshwater drill cuttings as per this Section to a specific portion of real property as designated by legal description.
(3) **Telephone permits.** In case of an emergency, a District Manager may issue a permit by telephone. If an operator obtains a permit by telephone, the applicant shall file Form 1014X within five working days after receipt of the permit by telephone.
(4) **Conditions for permits.**
(A) The method to be used for application of freshwater drill cuttings shall not pollute surface or subsurface waters and shall protect public and private property adjoining the application area.
(B) During application, any necessary signs, lights, and other safety and warning devices shall be used as traffic requires to alert users to conditions. A sign shall be posted with the contractor's or operator's name to contact in case of an emergency.
(C) All free liquids shall be removed before cuttings are applied.
(D) Following completion of the project, there shall be a uniform soil/cuttings base.
(h) **Notice to Field Inspector.** The operator receiving the permit shall notify the appropriate Field Inspector at least two days prior to commencement of the application.
(i) **Site inspection.** At his discretion, a District Manager may request a Field Inspector of the Conservation Division or an Enforcement Officer of the Transportation Division to inspect the site at any time during the application operation to ensure compliance with this Section.
(j) **Duration of permit.** The permit shall state the duration of the permit, not to exceed 60 days. If a complaint is received or the operator fails to comply with either the terms of the permit or this Section, the District Manager may direct the operator to cease application until the problem is resolved. If necessary, the District Manager may verbally revoke the permit

and/or require the operator to perform remedial work. If a District Manager disapproves an application or cancels a permit, then the applicant may apply to the Commission for an order under 165:5-7-41.

[**SOURCE:** Amended at 9 Ok Reg 2295, eff 6-25-92]

165:10-7-30. Enhanced recovery project surface facilities [REVOKED]

[**SOURCE:** Added at 9 Ok Reg 2337, eff 6-25-92; Revoked in Rule Making 980000034, eff 7-1-99]

165:10-7-31. Seismic and stratigraphic operations

(a) **Scope.**

(1) This Section shall cover the permitting, bonding, and plugging requirements for seismic exploration activities and stratigraphic test holes. Check-shots and vertical seismic profiles or other downhole wellbore seismic operations are excluded from this Section.

(2) For the purposes of this Section, seismic operation shall mean the drilling of seismic shot holes and use of surface energy sources such as weight drop equipment, thumpers, hydro pulses and vibrators. This definition does not include surveying of the seismic area or the activity of conducting private negotiations between parties.

(3) For the purposes of this Section, technical information and data shall be defined as pre-plats as referenced in (b)(2)(B) and post-plats as referenced in subsection(e).

(b) **Seismic and stratigraphic test permitting.**

(1) Before commencing any seismic or stratigraphic test hole operations in the State of Oklahoma, those companies who actually do the work in the field, hereinafter referred to as the applicant, shall:

(A) Be duly registered with the Commission, including provision of a permanent address.

(B) Post a financial surety guarantee with the Commission.

(C) Provide to the Commission the name and business or field address of the contractor responsible for the operations being conducted.

(D) Notify all surface owners of property where seismic or stratigraphic test operations will occur at least fifteen (15) days prior to commencement of operations. It shall be sufficient notice pursuant to this Section when notice is given to the current surface owner(s) as shown by the records of the applicable county treasurer's office. If the applicant has obtained from the surface owner specific written permission to conduct such operations prior to commencement of operations, such action shall be considered sufficient notification for the purposes of this Section and the 15 day notice requirement shall not be required. Notification by U.S. mail shall be sufficient for the purposes of this Section, provided the notice is postmarked at least fifteen (15) days prior to commencement of any seismic or stratigraphic test operations.

(E) The notice shall include a copy of the oil or gas lease or seismic permit or other legal instrument of similar nature authorizing the use of the surface for seismic or stratigraphic test hole operation(s) and shall contain the following information:

(i) Name of the company for whom the applicant is conducting the seismic or stratigraphic test operation(s) and

(ii) Anticipated date of commencement of operation(s).

(F) Applicants must obtain a permit from the Conservation Division for each seismic or stratigraphic test operation.

(2) The applicant shall make application on the Commission's Form 1000S.

(A) The permit shall be valid for only one operation as approved on Form 1000S.

(B) A pre-plat of the operation area shall be attached to the application showing the location of the operation area delineated to the nearest section.
(C) Post a performance bond in the amount of $50,000, or other form of surety in an amount as approved by the Conservation Division. The performance bond may be filed for each operation, or may be filed on an annual basis to cover all operations that may be undertaken during the year. If the performance bond is filed for a single operation, the amount may be approved by the Conservation Division for less than $50,000 or in another form of financial surety guarantee, depending on the nature of the seismic or stratigraphic operation involved, the number of shot holes or surface energy source points, the cost of the operation and the size of the applicant's business. The form of surety shall not include letters of credit or financial statements. Such bond(s) or other surety may be released upon request made no sooner than thirty (30) days subsequent to the completion of the applicant's operation(s), which have been permitted under such bond(s) or other surety, upon satisfactory inspection or review by Conservation Division personnel.
(D) The permit shall expire twelve (12) months from the issue date, unless operations are commenced.
(E) The Conservation Division shall approve or deny the application within thirty (30) days of receipt of the application. The Conservation Division may act upon an application or amended application on an expedited basis.
(F) During any activity subject to this subsection, the applicant shall maintain at the site a copy of the approved permit, Form 1000S, for inspection.
(G) All technical information, excluding the Form 1000S, but including any plats, relative to the permitted operation shall remain confidential or the Conservation Division shall destroy the records. The plats and any other technical data submitted, shall be filed in the Technical Services Department of the Conservation Division. Upon request of the Manager of Field Operations, the technical data may be reviewed by Field Operations to ensure compliance with Commission rules.

(3) Unless the applicant can demonstrate to the Conservation Division's District Office that another method will provide sufficient protection to groundwater supplies and long term land stability, the following guidelines shall be observed:
(A) Standard plugging method. All holes shall be filled to within four feet from the surface with bentonite, native cuttings, or an appropriate substitute. The remainder of the shot hole shall be filled and tamped with native cuttings or soil.
(B) Special methods. In areas where the standard plugging method has been shown to be inadequate for the prevention of groundwater contamination, the Conservation Division may designate the area as a special problem area. In such event, the Conservation Division will provide to the best of its ability, a clear geographical description of such area and the recommended, or required, hole plugging methods. Should the applicant encounter conditions such that the standard method appears inadequate for the prevention of groundwater contamination, the applicant shall inform the Conservation Division.
(i) Artesian flow. If the standard method is inadequate to stop artesian flow, alternate remedies must be employed to do so.
(ii) Water well conversion. Applicants are prohibited from allowing the conversion of seismic shot holes or stratigraphic test holes to water wells.
(iii) Groundwater protection. Alternative plugging procedures and materials may be utilized when the applicant has demonstrated to the Conservation Division's satisfaction that the alternatives will protect usable quality water.
(iv) Timeliness. All seismic shot holes or stratigraphic test holes shall be plugged as soon as possible and shall not remain unplugged for a period of more than 30 days after the drilling of the hole.

(c) No seismic shot hole blasting shall be conducted within two hundred (200) feet of any habitable dwelling, building, or water well without written permission from the owner of the property or within 500 feet of any superfund site or hazardous waste facility.
(d) Any person, firm, corporation or entity which conducts any seismic or stratigraphic test hole operations without a permit as provided in this Section, or in any other manner violates the rules of the Commission governing such operation shall be subject to a penalty up to One Thousand Dollars ($1,000.00) per violation per day after completion of the informal complaints procedure provided in OAC 165:10-7-7 and notice and hearing pursuant to the Commission's contempt proceedings.
(e) Within 30 days after completing a seismic or stratigraphic test hole operation, the applicant receiving the permit shall submit a copy of the approved Form 1000S certifying the plugging of all seismic shot holes or stratigraphic test holes in compliance with Section (b)(3)(A) or Section (b)(3)(B) above. In addition to the Form 1000S, a post-plat or acceptable form of survey showing the actual location of all seismic shot holes or all stratigraphic test holes shall be included.
(f) **Complaints.** A complaint alleging violations of this Section may be filed with the Commission against any person, firm or corporation conducting seismic and stratigraphic operation(s). The Commission may determine if and when a complaint has been adequately resolved, pursuant to the informal complaints process of OAC 165:10-7-7, and, if an environmental complaint, pursuant to the citizen complaint procedure of OAC 165:5-1-25.

[**SOURCE:** Added in Rule making 980000034, eff 7-1-99]

165:10-7-32. Application to reclaim and/or recycle produced water for surface activities related to drilling, completion, workover, and production operations from oil and gas wells

(a) **Authority to reclaim and/or recycle produced water.** No person shall use produced water for any other purpose except as provided by this section. Any operator failing to obtain a permit may be fined up to $500.00.
(b) **Scope.** This Section shall cover the reclaiming and/or recycling of produced water from oil and gas wells for a single well location for the purpose of water supply for surface activities used for a specific permitted use. This does not include the use of produced water for down- hole operations referred to as weighted water under OAC 165:10-7-24(b)(2).
(c) **Quality of produced water.** For the purposes of this rule shall be limited to Total Dissolved Solids (TDS) content not to exceed 5,000 mg/l and oil and grease content not to exceed 1,000 mg/l.
(d) **Storage of produced water.** If the produced water is stored in tanks, the tanks shall be legibly marked "recycle" water.
(e) **Log of load tickets.** The operator shall maintain copies of the load tickets from wells that the produced water was obtained. Such copies shall be made available to the OCC Inspector upon request.
(f) **Notification to OCC District Office.** The Operator shall orally notify the District Office when produced water is to be initially hauled to the permitted facility.
(g) **Application for permit.**
   (1) The operator of the well must apply for the permit for the reclamation of produced water.
   (2) Required Application. Each application for the reclaiming and/or recycling of produced water shall be submitted to the Field Operations District office on Form 1014D.
   (3) A copy of written notice to the surface owner that the applicant intends to use produced water as per 165:10-7-32 to a specific portion of their real property as designated by legal description. For purposes of notice, a written waiver from the surface owner may also be submitted.

[**SOURCE:** Added in Rule making 200300001, eff 7-1-03]

SUBCHAPTER 8. COMMERCIAL RECYCLING
PART 1. HYDROCARBON RECYCLING/RECLAIMING FACILITIES

Section

PART 3. DRILLING WASTE RECYCLING/RECLAIMING FACILITIES

[**Authority:** 52 O.S. Sections 139 and 141 (Supp. 1993)]

[**Source:** Codified 7-11-94]

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PART 1. HYDROCARBON RECYCLING/RECLAIMING FACILITIES

165:10-8-1. Scope

This Part shall cover the permitting, construction, operation, and closure requirements for any recycling/reclaiming facility.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-2. Definitions

The following words and terms, when used in this Subchapter, shall have the following meaning, unless the context clearly indicates otherwise:

"Tank bottom hydrocarbon recycling/reclaiming facility" means a recycling/reclaiming operation at a tank bottom reclaiming facility which is authorized by the Commission to recycle and/or reclaim marketable crude oil or condensate produced or used in the exploration or production of oil and gas. The facility shall comply with OAC 710:45-15-3.

"Hydrocarbon recycling/reclaiming facility at a saltwater disposal site" means a recycling/reclaiming operation at a Class II saltwater disposal site which is authorized by the commission to recycle and/or reclaim marketable crude oil or condensate produced or used in the exploration or production of oil and gas. The facility shall comply with OAC 710:45-15-3.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Amended in Rule Making 200000002, eff 7-1-00]

165:10-8-3. Permit required

(a) **Who may apply.** The applicant for a recycling/reclaiming facility shall be the owner and/or lease holder of the site.
(b) **Compliance with Part.** Before issuance of a permit, the applicant shall comply with this Part and if pits are to be used for storage, the applicant shall comply with 165:10-9-1, except at Class II saltwater disposals.
(c) **OCC Form 1020A.** Application shall be filed on OCC Form 1020A.
(d) **An Oklahoma Tax Commission Reclaimer License.** The applicant shall have obtained a reclaimer license number under OAC 710:45-15-2. This number will be used by the Corporation Commission for its permit number.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Amended in Rule Making 200000002, eff 7-1-00]

165:10-8-4. Application requirements

(a) **Permit required.** No recycling/reclaiming facility shall be constructed, enlarged, or used without approval on Form 1020A.
(b) **Site limitations.** Recycling/reclaiming facilities shall not be restricted by site limitations unless pits are to be used.
 (1) Tank bottom hydrocarbon recycling/reclaiming facilities with pits that are to be used for storage in the operation shall comply with OAC 165:10-9-1.
 (2) Hydrocarbon recycling/reclaiming facilities at a saltwater disposal site with pits that are used for unloading saltwater shall comply with OAC 165:10-9-3.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Amended in Rule Making 200000002, eff 7-1-00]

165:10-8-5. Surety requirements for reclaimers

(a) **Agreement to close.** Any operator of a recycling/reclaiming facility shall file with the Oil and Gas Conservation Division an agreement to properly close and reclaim the site in accordance with approved closure and reclamation procedures upon termination of recycling/reclaiming operations. The agreement shall be on forms available from the Conservation Division and shall be accompanied by surety. The agreement shall provide that if the Commission finds that the operator has failed or refused to close the facility or take remedial action as required by law and the rules of the Commission, the surety shall pay to the Commission the full amount of the operator's obligation up to the limit of the surety.

(b) **New facilities.** Category A (165:10-1-11) or Category B (165:10-1-13) surety shall be required for coverage of the closure costs, including well pluggings and general site restoration. These costs shall be calculated upon the projected costs of closure for the facility, based on estimated costs of earth work, remediation, revegetation, plugging, etc. Such information shall be provided by the applicant and reviewed, adjusted and ordered by the Commission.

(c) **Existing facilities.** For facilities in operation prior to the effective date of this Part, the Commission can require, by order, the establishment of an escrow account to cover the costs of closure, by using a per barrel fee to be deposited into the account. Any interest the account earns until the total amount is collected shall be reinvested in the account. Any interest accrued after the account balance is full shall be returned to the operator.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-6. Design and construction requirements

(a) **Spill prevention.** Each facility shall be designed and constructed utilizing good engineering practices. Design and construction standards shall be determined on a case-by-case basis by the Commission. Each such facility shall be designed and constructed to prevent escape of deleterious substances.

(b) **Unloading pits or sumps.** All unloading areas at tank bottom hydrocarbon recycling/reclaiming facilities that use a pit to receive fluids and skimming pits shall be approved on OCC Form 1014.

(c) **Required exhibits.** Complete construction plans, drawings, and written specifications for the proposed facility shall be submitted to the Manager of Pollution Abatement for review and approval. Design and construction standards shall be determined on a case-by-case basis by the Commission. Applicants shall consult with the Commission prior to the construction of the proposed facility. The Commission may apply existing technological standards and/or establish new standards, as it deems appropriate to the proposed site and activities. All plans, drawings, and specifications shall be prepared by or under the supervision of a qualified expert.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Amended in Rule Making 200000002, eff 7-1-00]

165:10-8-7. Operation and maintenance requirements

(a) **Fencing.** All recycling/reclaiming facilities shall be completely enclosed by a fence at least four feet in height. No livestock shall be allowed inside the fence. Final construction is subject to approval by the Manager of Pollution Abatement.

(b) **Sign.** A waterproof sign bearing the name of the operator, legal description, permit number, and emergency phone number shall be posted within 25 feet of the entrance gate to the facility and shall be readily visible.

(c) **Site security.** Receiving of any recycling/reclaiming material shall occur only when there is an attendant on duty. All sites shall be secured by a locked gate when an attendant is not on duty. A key or combination to the lock shall be provided to the appropriate Field Inspector for the purpose of carrying out inspections.

(d) **Acceptable materials.** Operators of a recycling/reclaiming facility shall only receive substances as defined in 165:10-1-2 "Deleterious substances."
(e) **Oil film.** OPERATORS TAKE NOTE: Federal statutes, such as the Bald Eagle Protection Act (16 U.S.C. Sections 668-668d), the Migratory Bird Treaty Act (16 U.S.C. Sections 703-711), the Endangered Species Act (16 U.S.C. Sections 1531-1542), and the Lacey Act Amendments of 1981 (16 U.S.C. Sections 3371-3378), dictate substantial fines and penalties for persons who allow birds of certain species to become fatally injured due to incidental contact with oil or oil by-products. These fines may be levied upon persons allowing such fatalities to occur, whether accidental or not. Misdemeanor and felony convictions may include imprisonment. Information on affected bird species, regulations under these Acts, and measures which can be taken to prevent such occurrences, such as the netting or covering of open-topped tanks and pits which contain oil or oil by-products, can be obtained from the U.S. Fish and Wildlife Service Office in Oklahoma City or the nearest Oklahoma Department of Wildlife Office.
(f) **Aesthetics.**

(1) All surface trash, debris, junk and scrap or discarded material connected with the operations of the facility shall be removed from the premises. With written permission from the surface owner, the operator may, without applying for an exception to 165:10-3-17(b), bury all nonhazardous material at a minimum depth of three feet; cement bases are included.

(2) The District Office or field inspector may issue a Form 1085 for any alleged violation of this subsection. If the operator fails to conduct cleanup as directed, the Commission may fine the operator $500.00 for a first offense. For a subsequent offense, the fine shall be $1,000.00, and the facility shall be shut down until completion for cleanup operations.

(g) **Structural integrity.** All recycling/reclaiming facilities shall be used, operated, and maintained at all times so as to prevent the escape of their contents. Any condition that threatens the structural stability of any diked portion or the storage facility shall be repaired in a timely manner.
(h) **Prevention of pollution.** All recycling/reclaiming facilities shall be used, operated, and maintained at all times so as to prevent pollution. In the event any non permitted discharge occurs, sufficient measures shall be taken to stop or control the loss of materials, and reporting procedures in accordance with 165:10-7-5(c) shall be followed. Any materials lost due to such discharge shall be cleaned up as directed by a representative of the Conservation Division.
(i) **Fines.** For a willful non-permitted discharge from the facility, the operator shall be fined $5,000.00.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Amended in Rule Making 200000002, eff 7-1-00]

165:10-8-8. Reporting
(a) **Annual report on Form 1014A.** The operator of any recycling/reclaiming facility shall submit an annual report on Form 1014A to the Manager of Pollution Abatement, by February 1 of each year. In lieu of Commission Form 1014A, operators may submit Oklahoma Tax Commission Form 323A for the twelve calendar months of the previous year by February 1st.
(b) **Daily log for tank bottom at a hydrocarbon recycling/reclaiming facility.** The operator shall maintain a daily log and at a minimum shall include the date, volume, source (generator) and type of material. In addition, copies of any chemical analysis of materials or material safety data sheets shall be maintained.
(c) **Daily load tickets for hydrocarbon recycling/reclaiming facilities at salt water disposal facilities.** The operator shall keep the load tickets for saltwater and other deleterious substances received at the saltwater disposal facilities for a minimum of three years at the operator's office.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Amended in Rule Making 200000002, eff 7-1-00]

165:10-8-9. Closure requirements
(a) **Notification.** The Manager of Pollution Abatement Department shall be notified in writing whenever a recycling/reclaiming facility shall be closed, or portions thereof, or becomes inactive unless it is shut down by the Commission.
(b) **Closed facility.** A recycling/reclaiming facility may be considered closed or inactive if the operator closes the facility, the operator is unable to furnish documentation to show that there has been receipt of deleterious substances during the last twelve months, the facility has been shut down by the Commission, or authority to operate has lapsed or is vacated by Commission order.
(c) **Closure plan.** An approved closure plan shall be submitted to the Pollution Abatement Department. Estimate of cost of closure shall be made part of the plan.
(d) **Monitor wells.** Monitor wells, if required, shall be plugged with bentonite or cement, upon approval in writing by the Manager of Pollution Abatement.
(e) **Pits.** When closing any pit with a geomembrane liner, extreme care shall be taken to preserve the integrity of the liner. All free liquids and sediments shall be removed.
(f) **Burial.** If any concrete, steel, geomembrane, or other materials associated with the site are to be left on-site, they shall be buried under a minimum soil cover of three (3) feet, pursuant to 165:10-3-7.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-10. Additional requirements
The requirements set forth in this Part are minimum requirements. Additional requirements may be made upon a showing of good cause.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-11. Variances
Except as otherwise provided in this Subchapter, variances from provisions of this Part may be granted by the Manager of Pollution Abatement or by order after application, notice, and hearing.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

PART 3. DRILLING WASTE RECYCLING/RECLAIMING FACILITIES

165:10-8-25. Scope
This Part shall cover the permitting, construction, operation, and closure requirements for any drilling waste recycling/reclaiming facility.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-26. Definitions
The following words and terms, when used in this Subchapter, shall have the following meaning, unless the context clearly indicates otherwise:
"Drilling waste recycling/reclaiming facility" means a recycling/reclaiming operation which is authorized by the Commission to recycle and/or reclaim drilling waste produced or used in the exploration or production of oil and gas into a marketable product for resale which has undergone at least one treatment process and is to be used for something other than drilling or plugging mud.

This definition does not?include the reuse of drilling mud used in drilling or plugging operations.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-27. Pit requirements
(a) **Who may apply.** The applicant for a drilling waste recycling/reclaiming facility shall be the owner and/or lease holder of the site.
(b) **Compliance with Part.** Before issuance of a permit, the applicant shall comply with this Part and if pits are to be used for storage, the applicant shall also comply with 165:10-9-1.
(c) **OCC Form 1020A.** Application shall be filed on OCC Form 1020A.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-28. Application requirements
(a) **Permit required.** No drilling waste recycling/reclaiming facility shall be constructed, enlarged, reconstructed, or used without approval on Form 1020A.
(b) **Site limitations.** Drilling waste recycling/reclaiming facilities shall not be restricted by site limitations unless pits are to be used. If pits are to be used for storage in the operation, the applicant shall also comply with 165:10-9-1.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-29. Surety requirements for reclaimers
(a) **Agreement to close.** Any operator of a drilling waste recycling/reclaiming facility shall file with the Oil and Gas Conservation Division an agreement to properly close and reclaim the site in accordance with approved closure and reclamation procedures upon termination of drilling waste recycling/reclaiming operations. The agreement shall be on forms available from the Conservation Division and shall be accompanied by surety. The agreement shall provide that if the Commission finds that the operator has failed or refused to close the facility or take remedial action as required by law and the rules of the Commission, the surety shall pay to the Commission the full amount of the operator's obligation up to the limit of the surety.
(b) **New facilities.** For new facilities, a Category A (165:10-1- 11) or Category B (165:10-1-13) surety shall be required for coverage of the closure costs, including well pluggings and general site restoration. These costs shall be calculated upon the projected costs of closure for the facility, based on estimated costs of earth work, remediation, revegetation, plugging, etc. Such information shall be provided by the applicant and reviewed, adjusted if necessary, and ordered by the Commission.
(c) **Existing facilities.** For facilities in operation prior to the effective date of this Section, the Commission can require, by order, the establishment of an escrow account to cover the costs of closure, by using a per barrel fee to be deposited into the account. Any interest the account earns until the total amount is collected shall be reinvested in the account. Any interest accrued after the account balance is full shall be returned to the operator.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-30. Design and construction requirements
(a) **Spill prevention.** Each facility shall be designed and constructed utilizing good engineering practices. Design and construction standards shall

be determined on a case-by-case basis by the Commission. Each facility shall be designed and constructed to prevent escape of deleterious substances.
(b) **Unloading pits or sumps.** All unloading areas that use a pit to receive fluids and skimming pits shall be approved on OCC Form 1014.
(c) **Required exhibits.** Complete construction plans, drawings, and written specifications for the proposed facility shall be submitted to the Manager of Pollution Abatement for review and approval. Design and construction standards shall be determined on a case-by-case basis by the Commission. Applicants shall consult with the Commission prior to construction of the proposed facility. The Commission may apply existing technological standards and/or establish new standards, as it deems appropriate to the proposed site and activities. All plans, drawings, and specifications shall be prepared by or under the supervision of a qualified expert.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-31. Operation and maintenance requirements
(a) **Fencing.** The drilling waste recycling/reclaiming facility shall be completely enclosed by a fence at least four feet in height. No livestock shall be allowed inside the fenced area. Final construction is subject to approval by the Manager of Pollution Abatement.
(b) **Sign.** A waterproof sign bearing the name of the operator, legal description, permit number, and emergency phone number shall be posted within 25 feet of the entrance gate to the facility and shall be readily visible.
(c) **Site security.** Receiving of any drilling waste recycling/reclaiming material shall occur only when there is an attendant on duty. All sites shall be secured by a locked gate when an attendant is not on duty. A key or combination to the lock shall be provided to the appropriate Field Inspector for the purpose of carrying out inspections.
(d) **Acceptable materials.**
(1) Operators of a drilling waste recycling/reclaiming facility shall only receive substances as defined in 165:10- 1-2 "Deleterious Substances."
(2) Water based mud shall be stored separately from oil based mud.
(e) **Open pits.** Any open recycling pit or tank shall be covered to prevent access to birds.
(f) **Aesthetics.**
(1) All surface trash, debris, junk and scrap or discarded material connected with the operations of the facility shall be removed from the premises. With written permission from the surface owner, the operator may, without applying for an exception to 165:10-3-17(b), bury all nonhazardous material at a minimum depth of three feet; cement bases are included.
(2) The District Office or field inspector may issue a Form 1036 for any alleged violation of this subsection. If the operator fails to conduct cleanup as directed, the Commission may fine the operator $500.00 for a first offense. For a subsequent offense, the fine shall be $1,000.00, and the facility shall be shut down until completion for cleanup operations.
(g) **Structural integrity.** All drilling waste recycling/reclaiming facilities shall be used, operated, and maintained at all times so as to prevent the escape of their contents. Any condition that threatens the structural stability of any diked portion or the storage facility shall be repaired in a timely manner.
(h) **Prevention of pollution.** All drilling waste recycling/reclaiming facilities shall be used, operated, and maintained at all times so as to prevent pollution. In the event any non permitted discharge occurs, sufficient measures shall be taken to stop or control the loss of materials, and reporting procedures in accordance with 165:10-7-5(c) shall be followed. Any materials lost due to such discharge shall be cleaned up as directed by a representative of the Conservation Division.
(i) **Fines.** For a willful non-permitted discharge from the facility, the operator shall be fined $5,000.00.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-32. Reporting

(a) **Annual report on Form 1014A.** The operator of any drilling waste recycling/reclaiming facility shall submit an annual report on Form 1014A to the Manager of Pollution Abatement, by February 1 of each year.
(b) **Daily log.** The operator shall maintain a daily log that at a minimum shall contain the date, volume, source (generator) and type of material and in addition copies of any chemical analysis or materials or D.O.T. material safety data sheets.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-33. Closure requirements

(a) **Notification.** The Manager of Pollution Abatement Department shall be notified in writing whenever a drilling waste recycling/reclaiming facility shall be closed, or portions thereof, or becomes inactive unless it is shut down by the Commission.
(b) **Closed facility.** A drilling waste recycling/reclaiming facility may be considered closed or inactive if the operator closes the facility, the operator is unable to furnish documentation to show that there has been receipt of deleterious substances during the last twelve months, the facility has been shut down by the Commission, or authority to operate has lapsed or is vacated by Commission order.
(c) **Closure plan.** An approved closure plan shall be submitted to the Pollution Abatement Department. Estimate of cost of closure shall be made part of the plan.
(d) **Monitor wells.** Monitor wells, if required, shall be plugged with bentonite or cement, upon approval in writing by the Manager of Pollution Abatement.
(e) **Pits.** When closing any pit with a geomembrane liner, extreme care shall be taken to preserve the integrity of the liner. All free liquids and sediments shall be removed.
(f) **Burial.** If any concrete, steel, geomembrane, or other materials associated with the site are to be left on-site, they shall be buried under a minimum soil cover of three (3) feet, pursuant to 165:10-3-7.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-34. Additional requirements

The requirements set forth in this Part are minimum requirements. Additional requirements may be made upon a showing of good cause.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-35. Variances

Except as otherwise provided in this Subchapter, variances from provisions of this Part may be granted by the Manager of Pollution Abatement or by order after application, notice, and hearing.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

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SUBCHAPTER 9. COMMERCIAL DISPOSAL FACILITIES

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165:10-9-1. Use of commercial pits

(a) **Scope.** This Section shall cover the permitting, construction, operation, and closure requirements for any commercial pit. A commercial pit is a disposal facility which is authorized by Commission order and used for the disposal, storage, and handling of deleterious substances or soils contaminated by deleterious substances produced, obtained, or used in connection with drilling and/or production operations. This does not cover disposal well pits. (See 165:10-9-3 and 165:10-7-20.)

(b) **Application requirements.**

(1) **Who may apply.** The applicant for a commercial pit shall be the owner of the land (or person having a written firm option to purchase the land at the time the application is filed) on which the proposed pit is to be located: if leased, both the owner and lessee shall be joint applicants.

(2) **Compliance with rules.** Before issuance of an order, the applicant shall comply with Commission Rules of Practice 165:5-7-1, 165:5-7-35, 165:5-3-1, and this Section.

(3) **Exhibits.** Two complete sets of all exhibits which shall be relied upon by the applicant shall be submitted to the Pollution Abatement Department of the Commission, pursuant to 165:5-7-35. Those exhibits shall include, but are not limited, to the following:

(A) A lithologic log of test borings, identifying the subsurface materials encountered and the depth at which groundwater was encountered pursuant to (c)(2)(D) of this Section.

(B) Results of permeability tests of the proposed liner materials, pursuant to (e)(7) of this Section.

(C) A topographic map of the commercial pit site.

(D) The appropriate Soil Conservation Service (SCS) soil survey aerial photo and legend.

(E) A detailed drawing of the site, with complete construction plans drawn to scale by or under the supervision of a registered professional engineer.

(F) A plan for closure of the pit(s) which shall provide for a minimum three feet of soil cover and shall specifically state how all aspects of closure shall be accomplished, including volume and fate of liquids and solids, earthwork to close the pit(s) (including placement of stockpiled topsoil), and revegetation of the site.

(G) An itemization of projected hauling, closure, reclamation, maintenance, and monitoring costs.

(H) A plan for post-closure maintenance and monitoring which shall address maintenance of the site as well as monitoring and plugging of wells. Exemption from the plugging of monitor wells may be obtained upon written request and approval of the Manager of Pollution Abatement.

(I) A plan for operation which shall address the method(s) by which excess water will be disposed.

(c) **Restrictions.**

(1) **Order required.** No commercial earthen pit shall be constructed, enlarged, reconstructed, or used without a Commission order.

(2) **Site limitations.**

(A) No commercial earthen pit shall be constructed or used unless an investigation of the soils, topography, geology, and hydrology conclusively shows that storage of water-based drilling fluids and/or cuttings at the site will not be harmful to groundwater, surface water, soils, plants, or animals in the surrounding area. No abandoned mine, strip pit, quarry, canyon, or streambed shall be used for disposal of oilfield wastes, nor shall a pit be constructed or used in such a setting.

(B) No commercial pit shall be constructed or used on any site that is located within a 100-year flood plain.

(C) No commercial pit shall be constructed or used within a wellhead protection area (WPA) as identified by the Wellhead Protection Program (42 USC Section 300h-7, Safe Drinking Water Act), or within one mile of an active municipal water well for which the WPA has not been delineated.

(D) No commercial pit shall be constructed unless it can be shown that there will be a minimum of 25 feet between the bottom of the pit and the groundwater level of the first aquifer. To ascertain this and to demonstrate the subsurface profile of the site, a minimum of three test borings (the exact number of locations to be determined by the Pollution Abatement Department) shall be drilled to a minimum depth of 25 feet below the proposed bottom of the pit and into the first aquifer encountered. Test borings need not extend deeper than 50 feet below the bottom of the pit if an aquifer has not been encountered before that depth. All boreholes converted to monitor wells shall conform to (e)(15) of this Section. All boreholes not converted to monitor wells shall be plugged from top to bottom with bentonite, cement, and/or other method approved by the Pollution Abatement Department within 30 days of drilling completion.

(E) After July 1, 1992, no commercial pit shall be constructed or used within the following distances from the city limits of an incorporated municipality unless previously authorized by Commission order:

(i) Three miles if population is 20,000 or less.

(ii) Five miles if population is greater than 20,000.

(3) **Means of water disposal.** No commercial pit shall be constructed or used unless the operator can show that there will be an ongoing means of disposal of excess water pursuant to (b)(3)(I) of this Section.

(d) **Surety requirements.**

(1) **Agreement with Commission.** Any operator of a commercial pit shall file with the Manager of Document Handling for the Conservation Division an agreement to properly close and reclaim the site in accordance with approved closure and reclamation procedures upon termination of disposal operations due to abandonment, shutdown, full pits, or other reason. The agreement shall be on forms available from the Conservation Division and shall be accompanied by surety. The agreement shall provide that if the Commission finds that the operator has failed or refused to close the pits or take remedial action as required by law and the rules of the Commission, the surety shall pay to the Commission the full amount of the operator's obligation up to the limit of the surety.

(2) **Surety amount and type.** The Commission shall establish the amount of security in the order for the authority to construct, enlarge, or operate a commercial pit. The amount of security shall be based on factors such as dimensions of the pit and costs of hauling, closure, reclamation, and monitoring. The amount may be subject to change for good cause. Upon approved closure of a pit, the Manager of Pollution Abatement may administratively reduce the surety requirement to an amount which would cover the cost of monitoring the site and plugging the monitor wells. Security shall be maintained for as long as monitoring is required. The type of security shall be a corporate surety bond, certificate of deposit, irrevocable letter of credit, or other type of security approved for the pit by order of the Commission. Any type of surety that expires shall be renewed prior to 30 days before the expiration date. All joint escrow accounts shall be made current every 30 days.

(3) **Posting surety before permit is issued.** An operator shall post surety with the Commission before a construction permit is issued, pursuant to (e)(1) of this Section.

(e) **Construction requirements.**

(1) **Permit required.** Prior to constructing any pit, a commercial pit operator shall obtain a permit from the Manager of Pollution Abatement. Application shall be made on Form 1014N. For use of a commercial pit without a permit, the pit operator shall be fined $5,000.00.

(2) **Runoff water prohibited.** No runoff water from surrounding land surfaces shall be allowed to enter a pit.

(3) **Stockpiling of topsoil.** Prior to constructing a pit, all topsoil within the top twelve inches of soil on the site shall be stockpiled for use as the final cover at the time of closure. The topsoil may be stockpiled in the outside slopes of the berms, provided it is not used for structural purposes and can be readily distinguishable from other soil materials at the

time of closure. In cases where topsoil is stockpiled in the berms, it shall be shown in the as-built drawings pursuant to (e)(16) of this Section.

(4) **Monitoring by engineer.** A registered professional engineer or an engineer-in-training working under the supervision of a registered professional engineer (RPE) shall monitor the construction of any commercial pit to assure that approved design specifications and Commission rules are adhered to. A minimum of three on-site visits to the site shall be made; one pre-construction, one during construction, and one post-construction. At least the post-construction on-site visit shall be made by the RPE.

(5) **Maximum fluid depth.** Any pit shall be constructed to contain a maximum fluid or sediment depth of seven feet, with a minimum freeboard of three feet.

(6) **Maximum dimensions.** Any pit shall not be constructed to dimensions greater than that approved in the order. Furthermore, the maximum width of a pit or pit cell shall not exceed 175 feet if closure must be accomplished from one side or two adjacent sides; 350 feet if closure can be accomplished from at least two opposite sides or three adjacent sides. Pit dimensions shall be measured at the maximum allowable fluid level.

(7) **Soil liners.**

(A) Soil materials to be used in a soil liner shall undergo permeability testing before construction. Pre-construction permeability testing shall consist of laboratory permeability tests on at least two specimens of representative soil liner materials compacted in the laboratory to approximately 95 percent of the material's Standard Proctor Density (ASTM D-698).

(B) Laboratory permeability test procedures must conform to one of the methods described for fine-grained soils in the Corps of Engineers Manual EM-1110-2-1906 Appendix VII. In no case shall the pressure differential across the specimen exceed five feet of water per inch of specimen length.

(C) If permeability testing shows that addition of bentonite or other approved material is needed to assist the native soils in meeting the permeability standard, it shall be applied at a minimum rate specified by the testing or engineering firm. Any bentonite used for liner material shall not have been previously used in drilling muds.

(D) Any soil liner shall be constructed by disturbing the soil to the depth of the bottom of the liner, applying fresh water as necessary to the soil materials to achieve a moisture content wet of optimum, then recompacting it with heavy construction equipment, such as a footed roller, until the required density is achieved, pursuant to (H) of this paragraph. The liner shall be constructed in maximum six inch lifts (after compaction), with each lift being scarified before placement of the next lift.

(E) Any soil liner shall cover the bottom and interior sides of the pit entirely.

(F) Any soil liner shall be installed on a slope no steeper than 3:1 (horizontal to vertical).

(G) Any soil liner shall have a minimum thickness of 18 inches (after compaction) and shall have a maximum coefficient of permeability of 1.0×10^{-7} cm/sec.

(H) Any soil liner shall be field tested for compaction, unless a post-construction permeability test is performed pursuant to (I) of this paragraph.

(i) A minimum of six compaction tests shall be performed on any soil liner; a minimum of four widely spaced tests in the bottom of the pit and two tests on different slopes of the pit are required, unless otherwise directed by a Conservation Division representative. Particular emphasis shall be placed on selecting locations for compaction tests where nonuniformity in soil texture or color can be observed.

(ii) Compaction tests shall be conducted in accordance with ASTM methods D-2922 or D-1556.

(iii) The soil materials of any liner shall be compacted to at least 95 percent of the Standard Proctor Density.

(I) Post-construction permeability testing shall consist of at least two laboratory permeability tests on undisturbed samples of the completed soil liner.

(i) Particular emphasis shall be placed on selecting the location(s) for permeability tests or test samples where nonuniformity in soil texture or color can be observed.

(ii) Field permeability tests shall be conducted only by the double ring infiltrometer method as described in ASTM D-3385. Permeability tests may be discontinued prior to flow stabilization upon satisfactory evidence that the permeability rate is less than 1.0 x 10^{-7} cm/sec.

(8) **Geomembrane liners.**

(A) Any geomembrane liner that is installed in a commercial pit shall have a minimum thickness of 30 mil.

(B) Any geomembrane liner used in a commercial pit shall be chemically compatible with the type of substances to be contained and shall have ultraviolet light protection.

(C) Any geomembrane liner shall be placed over a specially prepared, smooth, compacted surface void of sharp changes in elevation, rocks, clods, organic debris, or other objects.

(D) Any geomembrane liner shall be continuous, although it may include seams, and shall cover the bottom and interior sides of the pit entirely. The edges shall be securely placed in a minimum twelve inch deep anchor trench around the perimeter of the pit.

(9) **Width of the crown.** The crown (top) of any berm shall be a of minimum eight feet in width.

(10) **Slopes.** The inside slope of any exterior berm (having fluid on one side) shall not be steeper than 3:1 (horizontal to vertical) and the outside slope 2.5:1. The slopes of any interior berm (having fluid on both sides) shall not be steeper than 3:1.

(11) **Earthwork compaction.** All earthwork, except as noted in (7)(H)(iii) of this subsection, shall be compacted to achieve a minimum 90% Standard Proctor Density and shall be applied in lifts where some method of bonding is achieved between lifts, with each lift not to exceed eight inches prior to compaction.

(12) **Pipe installation.** Any pipe, tinhorn, culvert, or conduit in the berm between two adjoining pits shall be placed so that there is a minimum of 36 inches between the top of the pipe, tinhorn, culvert, or conduit and the lowest point in the top of the berm separating the pits.

(13) **Splash pad.** All pits which receive fluids directly from a vacuum truck shall have a splash pad at the point where fluids are received unless a waiver is obtained from the Manager of Pollution Abatement by showing that erosion of the liner will not occur. The pad must be constructed of materials and to the dimensions necessary to effectively prevent the liner from eroding.

(14) **Fluid level marker.** A minimum of one stationary fluid level marker shall be erected in each pit or cell. The marker shall be erected in a location within the pit or cell where it can be easily observed. The marker shall be of such design that the maximum fluid level at any time may be clearly identified. The marker shall be mounted on a suitable post set in concrete or other method approved by the Manager of Pollution Abatement. That portion of the post hole which lies in the soil liner zone shall be backfilled with bentonite pellets. Details of the proposed marker installation shall be approved by the Manager of Pollution Abatement prior to installation. Markers shall be installed under the supervision of a registered professional engineer, licensed land surveyor, or other person approved by the Manager of Pollution Abatement prior to installation.

(15) **Monitor wells.** All commercial pits shall have a minimum of three monitor wells; one upgradient and two downgradient. The exact number and location of wells shall be approved by the Pollution Abatement Department prior to installation. No monitor well shall be installed more than 250 feet from a commercial pit, nor shall any existing water well be used as a monitor well unless approved by the Manager of Pollution Abatement. Monitor wells installed prior to the effective date of this Section may be accepted

by the Manager of Pollution Abatement if it can be shown that they adequately monitor a site. All new monitor wells shall be drilled through the first aquifer encountered, but need not extend more than 50 feet below the bottom of a pit if no aquifer is encountered, and shall be completed by a licensed monitor well driller. If documentation can be submitted prior to drilling to show that no water will be encountered within 50 feet below the bottom of the pit, the Manager of Pollution Abatement may require that monitor wells be drilled to a lesser depth. All new monitor wells shall meet the following requirements:

(A) A minimum two inch diameter PVC casing shall be used with a sealing cap on the bottom.

(B) The casing shall consist of a slotted liner in the saturated zone, or bottom ten feet if none is encountered, and shall be gravel-packed or sand-packed as appropriate to the installation.

(C) Bentonite shall be placed in the annular space of the well above the slotted liner for an interval of at least two feet to form an adequate seal.

(D) Uncontaminated well cuttings may be returned to the annular space above the bentonite seal for well stability.

(E) A minimum of two of the top six feet of the annular space around the casing shall be filled with cement.

(F) A minimum three inch thick concrete apron shall be placed at the surface to a minimum two foot radius from the casing.

(G) A removable and lockable cap shall be placed on top of the casing. The cap shall remain locked at all times, except when the well is being sampled.

(H) Within 30 days of installation, specific completion information for all monitor wells shall be submitted to the Manager of Pollution Abatement.

(16) **As-built drawing.** A detailed, as-built drawing of the pit(s) and monitor wells by or under the supervision of a registered professional engineer shall be submitted to the Manager of Pollution Abatement before operation of the pit(s) commences.

(17) **Liner certification.** An affidavit signed by the person who was responsible for installing the pit liner, certifying that the liner meets minimum requirements and was installed in accordance with Commission rules, shall be submitted to the Manager of Pollution Abatement before operation of the pit commences. Supporting documentation shall also be submitted, such as post-construction permeability or compaction test results, bentonite receipts, and geomembrane liner specifications from the manufacturer.

(18) **Pit approval.** Acceptance of fluids into a pit shall not commence until a representative of the Conservation Division has inspected and approved the pit.

(19) **Hydrologically sensitive areas.** If the proposed site is known to be located over a hydrologically sensitive area (hydrologically sensitive areas and hydrologically very sensitive areas are determined by the Technical Department and based upon Oklahoma Geological Survey maps), in addition to the foregoing construction requirements, the additional requirements shall apply:

(A) The total depth of a pit shall not exceed eight feet, and the total designed fluid or sediment depth shall not exceed five feet.

(B) A soil liner having a minimum thickness of three feet and a coefficient of permeability no greater than 1.0×10^{-8} cm/sec or a minimum 60-mil geomembrane liner shall be required.

(C) The Manager of Pollution Abatement shall determine the minimum depth of all monitor wells.

(f) **Operation and maintenance requirements.**

(1) **Vegetative cover.** Vegetative cover shall be established on all areas of earthfill immediately after pit construction or during the first planting season if pit construction is completed out of season. The cover shall be sufficient to protect those areas from soil erosion and shall be maintained.

(2) **Fencing.** All commercial pits shall be completely enclosed by either a woven wire fence at least four feet in height or a woven wire fence at least

three feet in height with two strands of barbed wire. No livestock shall be allowed inside the fence.

(3) **Sign.** A waterproof sign bearing the name of the operator, legal description, most current order number, and emergency phone number shall be posted within 25 feet of the entrance gate to any commercial pit and shall be readily visible.

(4) **Site security.** Dumping into a commercial pit shall occur only when there is an attendant on duty. All sites shall be secured by a locked gate when an attendant is not on duty. A key or combination to the lock shall be provided to the appropriate Field Inspector for the purpose of carrying out inspections.

(5) **Fluid level.** Drilling fluids and/or cuttings shall not be accepted into a commercial pit unless the fluid level can be maintained at an elevation no higher than the maximum level of the fluid level marker.

(6) **Acceptable materials.**

(A) No operator of a commercial pit shall receive any substances other than water-based drilling fluids and/or cuttings or salt contaminated soils.

(B) No operator of a pit permitted prior to July 9, 1987, shall receive fluids and/or cuttings with a chloride content greater than 3500 mg/l. No operator of a pit permitted after July 9, 1987, shall receive fluids and/or cuttings with a chloride content greater than 5000 mg/l.

(C) A sample from each incoming load shall be collected, filtered using a standard API filter press, and tested for chlorides.

(D) The date, volume, source, and chloride level of each load received shall be entered into a log book. The log book shall be available for inspection by a representative of the Conservation Division of the Commission at all times. Log books shall be kept for a minimum of five years after closure is completed.

(7) **Pit contents.** No pit permitted prior to July 9, 1987, shall contain fluids and/or cuttings with a chloride content greater than 5,000 mg/l. No pit permitted after July 9, 1987, shall contain fluids and/or cuttings with a chloride content greater than 10,000 mg/l. The contents of each pit or pit cell shall be sampled and analyzed by the operator at least once every six months (during January and July) after operations commence. More frequent sampling may be required by the Manager of Pollution Abatement. The following procedures shall be used:

(A) The appropriate Field Inspector shall be notified at least 24 hours in advance of sampling to allow a Commission representative an opportunity to witness the sampling.

(B) Samples shall be collected and handled by the operator according to EPA-approved standards. (RCRA Groundwater Monitoring Technical Enforcement Guidance Document, EPA, OSWER-9950.1, September 1986, pp. 99-107.)

(C) A minimum of five samples per 50,000 bbls., or part thereof, is required for each pit or pit cell. Samples must be taken from different horizontally and vertically distributed locations in each pit or pit cell.

(D) The samples shall be combined and thoroughly mixed, then a minimum two pint composite sample taken for analysis.

(E) If requested by a representative of the Conservation Division, each composite sample shall be split and an adequate portion (approximately one pint) shall be properly labeled and delivered or otherwise provided to the appropriate District Office or Field Inspector.

(F) All samples delivered to the laboratory shall be accompanied by a chain of custody form.

(G) All composite samples must be analyzed for chlorides by a laboratory certified by the Oklahoma Water Resources Board or operated by the State of Oklahoma. Analysis of additional parameters may be required, as determined by the Manager of Pollution Abatement.

(H) A copy of each analysis shall be forwarded to the Pollution Abatement Department within 30 days of sampling.

(8) **Oil film.**

(A) No commercial pit shall contain an oil film covering more than one acre or more than ten percent of the surface area of the pit, whichever is less.

(B) The protection of migratory birds shall be the responsibility of the operator. Therefore, the Conservation Division recommends that to prevent the loss of birds, oil films be removed, or the surface area covered by the film be protected from access to birds. (See Advisory Notice in 165:10-7-3(c).)

(9) **Aesthetics.** All commercial pit sites shall be maintained so that there is no junk iron or cable, oil or chemical drums, paint cans, domestic trash, or debris on the premises.

(10) **Structural integrity.** All commercial pits shall be used, operated, and maintained at all times so as to prevent the escape of their contents. All erosion, cracking, sloughing, settling, animal burrows, or other condition that threatens the structural stability of any earthfill shall be repaired immediately upon discovery.

(11) **Monitor wells.** Sampling of monitor wells shall begin prior to accepting any drilling fluids and/or cuttings into a new facility and within 30 days of drilling completion on existing facilities, and shall be done at least once every six months (during January and July) after operations commence until three years after closure is completed. Sampling of greater frequency of duration may be required by the Manager of Pollution Abatement. The following procedures shall be used:

(A) The appropriate Field Inspector shall be notified at least 24 hours in advance of sampling to allow a Commission representative an opportunity to witness the sampling.

(B) Samples shall be collected and handled by the operator according to EPA-approved standards. (RCRA Groundwater Monitoring Technical Enforcement Guidance Document, EPA, OSWER-9950.1, September 1986, pp. 99-107.)

(C) If requested by a representative of the Conservation Division, an adequate portion of each sample (approximately one pint) shall be properly labeled and delivered or otherwise provided to the appropriate District Office or Field Inspector.

(D) All samples delivered to the laboratory shall be accompanied by a chain of custody form.

(E) All samples must be analyzed for pH and chlorides by a laboratory certified by the Oklahoma Water Resources Board or operated by the State of Oklahoma. Analysis of additional parameters may be required, as determined by the Manager of Pollution Abatement.

(F) A copy of each analysis and a statement as to the depth to groundwater encountered in each well, or an affidavit that no water was encountered, shall be forwarded to the Pollution Abatement Department within 30 days of sampling.

(12) **Prevention of pollution.** All commercial pits shall be used, operated, and maintained at all times so as to prevent pollution. In the event of a nonpermitted discharge from a commercial pit, sufficient measures shall be taken to stop or control the loss of materials, and reporting procedures in 165:10-7-5(c) shall be followed. Any materials lost due to such discharge shall be cleaned up as directed by a representative of the Conservation Division. For a willful non-permitted discharge, the pit operator shall be fined $5,000.00.

(g) **Annual report.** The operator of any commercial pit shall submit an annual report on Form 1014A to the Manager of Pollution Abatement, by February 1 of each year.

(h) **Closure requirements.**

(1) **Notification.** The Manager of Pollution Abatement shall be notified in writing whenever a commercial pit becomes inactive, is abandoned, full of sediment, or operation of the pit ceases for any reason. A commercial pit may be considered to be inactive by the Commission if:

(A) The pit has been shut down by the Commission because of a violation which results in the filing of an application for an order to vacate the operator's authority.

(B) The authority to operate has been terminated by failure to comply with (j) of this Section.
(C) The operator is unable to furnish documentation to show that there has been receipt of drilling fluids and/or cuttings into the pit during the previous twelve months.

(2) **Time limit.** Closure of all commercial pits shall be commenced within 60 days and completed within one year of cessation of pit operations, pursuant to (1) of this subsection. In cases where extenuating circumstances arise, one extension of six months may be administratively approved in writing by the Manager of Pollution Abatement. Closure shall be in accordance with an approved closure plan. A progress report shall be submitted to the Manager of Pollution Abatement, every three months (during January, April, July, and October) after cessation of pit operations until closure is completed.

(3) **Restrictive covenant.** A restrictive covenant shall be filed with the County Clerk of the county in which a commercial pit is located. The document shall accurately describe the pit location and shall specifically restrict the current or future landowners of the pit site from puncturing the final cover of the pit or otherwise disturbing the site to the extent that pollution could occur.

(4) **Penalty for failure to meet closure requirements.** An operator failing to meet the closure requirements set out in this subsection shall be fined $1,000.00.

(i) **Additional requirements.** The requirements set forth in this Section are minimum requirements. Additional requirements may be made upon a showing of good cause that an operator has a history of complaints for failure to comply with Commission rules and regulations, the site has certain limitations, or other conditions of risk exist.

(j) **Application to existing pits.** Subsections (a), (c)(1), (d), (e), (f), (g), (h), and (i) of this Section shall apply to all commercial pits permitted or ordered prior to the adoption of this Section. All pits permitted, but yet to be constructed as of the effective date of this Section, shall be subject to all of the construction requirements under (e) of this Section.

(k) **Variances.** Except as otherwise provided in this Section, variances from provisions of this Section may be granted for good cause by order after application, notice, and hearing.

[**SOURCE:** Amended at 9 Ok Reg 2295; Amended at 9 Ok Reg 2337, eff 6-25-92]

165:10-9-2. Commercial soil farming

(a) **Order and permit required.** No person shall conduct commercial soil farming without an order of the Commission and an approved permit.

(b) **Site suitability restrictions.** Commercial soil farming shall only occur on a tract of land having all of the following characteristics [paragraphs (1) through (5) shall be determined by the appropriate Soil Conservation District or a qualified soils expert]:

(1) A maximum slope of five percent.
(2) Depth to bedrock no less than 20 inches.
(3) A soil profile containing at least twelve inches of one of the following U.S.D.A. soil textures:
(A) loam
(B) silt loam
(C) silt
(D) sandy clay loam
(E) clay loam
(F) silty clay loam
(G) sandy clay
(H) silty clay or clay
(4) No flooding potential.
(5) Slight salinity (defined as electrical conductivity less than 4,000 micromhos/cm) in the topsoil or upper six inches of the soil.
(6) An Exchangeable Sodium Percentage (ESP) less than 15.

(7) A water table deeper than 25 feet from the soil surface, excluding perched water tables (submit basis for this determination).
(8) A minimum distance of 100 feet from any stream designated by Oklahoma Water Quality Standards or any fresh water pond, lake, or wetland (available for viewing at the Commission's Oklahoma City or District Offices).

(c) **Application requirements.**

(1) **Who may apply.** The applicant or joint applicant for commercial soil farming shall be the owner of the land (or person having a firm option, in writing, to purchase the land) which is to be used for soil farming.
(2) **Order required.** The Commission may issue an order upon compliance with Commission Rules of Practice 165:5-7-1, 165:5-7-35, 165:5-3-1, and this Section.
(3) **Required exhibits.** All exhibits intended to support an application shall be filed pursuant to 165:5-7-35. The exhibits shall include the following:
(A) A site suitability report, pursuant to (b) of this Section, provided by the appropriate Soil Conservation District or a qualified soils expert (include qualifications). The report must contain a U.S.D.A. Soil Survey map, or when Soil Survey map does not have adequate detail, a map prepared by a qualified soils expert. A legend and soil type description shall be attached.
(B) Plan of conservation management practices covering needs of storm water disposal and erosion control.
(C) A well-prepared map or diagram, drawn to scale, showing the size and configuration of the individual soil farming plots.
(D) A topographic map of the subject area.
(E) Initial soil analysis.
(F) A detailed discussion of the method of application and provisions for preventing runoff from the application area.

(d) **Sampling requirements.**

(1) **Contact with District Office.** The District Office shall be contacted at least two working days prior to sampling to allow a Commission representative an opportunity to witness the sampling of the receiving soil and pit(s) to be soil farmed.
(2) **Receiving soil.** Subsequent to the preparation of a conservation plan or site suitability report, soil samples shall be taken from the proposed soil farming plot and analyzed. Analysis shall be submitted pursuant to (c)(3)(E) of this Section. Soil sampling shall follow this procedure:
(A) If the site contains soil types from different parent material, separate areas shall be established for soil sampling and loading calculations.
(B) A sample area shall not exceed 40 acres.
(C) A minimum of 20 representative surface core samples (0-6 inches) and 20 representative subsurface core samples (18-30 inches) must be taken from each sample area. The samples shall be composited for analysis of a single surface core sample and a single subsurface core sample.
(3) **Pit materials.** Pit materials to be soil farmed shall be sampled using the following procedure:
(A) A minimum of five samples per 50,000 bbls., or part thereof, each representative of the materials to be soil farmed, is required for each pit or pit cell. Samples must be taken from different horizontally and vertically distributed locations in each pit or pit cell.
(B) The samples shall be combined and thoroughly mixed, then a minimum two pint composite sample shall be taken for TDS analysis, a minimum three pint composite sample taken for oil and grease analysis, and a minimum two pint composite sample taken for heavy metal analysis.
(C) If requested by a representative of the Conservation Division, each composite sample for TDS analysis shall be split and an adequate portion (approximately one pint) properly labeled and delivered or otherwise provided to the appropriate District Office or Field Inspector.
(D) After samples have been taken for analysis from a pit or pit cell which is the subject of a soil farming application, the operator shall not allow the addition of fluids or other materials, except natural precipitation or fresh water, to decrease the viscosity of the fluid.

(e) **Analysis requirements.**

(1) **Approved laboratory.** Soil and pit samples shall be analyzed by a laboratory operated by the State of Oklahoma or certified by the Oklahoma Water Resources Board.

(2) **Soil.** Parameters for analysis of soil shall include, but are not limited to pH, Total Soluble Salts (TSS) or Electrical Conductivity, and Exchangeable Sodium Percentage (ESP).

(3) **Pit contents.** Parameters for analysis of pit contents shall include, but are not limited to, the following: pH, Total Dissolved Solids (TDS), Electrical Conductivity, Arsenic, Chromium and Oil and Grease. Arsenic and Chromium may be analyzed by either Nitric Acid Extraction or Acetic Acid Extraction ("Test Methods for Evaluating Solid Waste," SW846, second edition, U.S. EPA). The analysis shall specify which method of extraction was used.

(f) **Maximum application rate.**

(1) **Loading limits.**

(A) The maximum application rate (loading limit) shall be calculated by the operator using the calculations in (g) of this Section and the following soil loading standards:

(i) Total Soluble Salts: 6,000 lbs/acre (less TSS in soil).

(ii) Arsenic: 80 lbs/acre.

(iii) Chromium: 40 lbs/acre.

(iv) Oil and Grease: 40,000 lbs/acre.

(v) Total Dry Weight: 200,000 lbs/acre.

(B) Limitations in (A) of this paragraph are based upon standards set forth in the following publications:

(i) "Diagnosis and Improvement of Saline and Alkaline Soils," U.S. Agriculture Handbook, No. 60, U.S. Salinity Laboratory, Riverdale, California, 1954

(ii) "Critical Concentrations for Irrigation Water Supplies," Water Quality Criteria, 1972 Ecological Research Series, EPA-R2-73-033, March, 1973

(iii) H.R. Moseley, "Summary and Analysis of API Onshore Drilling Mud and Produced Water Environmental Studies," American Petroleum Institute Bulletin, No. D-19, 1983

(2) **Determination of most limiting parameter.** The maximum application rate shall be restricted by the most limiting parameter. It may require more than one application to achieve the maximum application rate while avoiding runoff. The operator shall indicate on Form 1014CS the maximum application rate and the minimum acreage that will be used.

(3) **Records required.** Accurate records shall be kept for each parameter as to when, where (which application area), and how much is applied. The operator shall make such records available at all times for inspection by a representative of the Conservation Division. Additionally, an annual report shall be submitted to the Manager of Pollution Abatement, pursuant to (k) of this Section.

(4) **Additional soil sampling required.** Additional soil sampling and analysis of a plot shall be done prior to each soil farming application when records show that 60 percent of the maximum application rate in (1) of this subsection of any parameter except total weight is reached. Requirements of (d) and (e) of this Section shall be met. Soil farming shall not be permitted on a plot if the analysis indicates that more than 95 percent of the maximum application rate of any parameter has been reached or if the ESP is greater than 15.

(g) **Calculations.** The procedures described in Appendix H of this Chapter shall be used in calculating the maximum application rate.

(h) **Operation requirements.**

(1) **Surety required.**

(A) Any operator of a commercial soil farming site shall file with the Manager of Document Handling for the Conservation Division an agreement to clean up pollution, restore the site, and/or plug monitor wells, if necessary, upon termination of operations. The agreement shall be on forms available from the Conservation Division and shall be accompanied by surety. The agreement shall provide that if the Commission finds that the operator has failed or refused to comply with the rules or take remedial action as required by law and this Section, the surety shall pay to the Commission the full amount of the operator's obligation up to the limit of the surety.

(B) The Commission shall establish the amount of security in the order for the authority to operate a commercial soil farming site. The security shall be based upon $10,000 per 40 acres, or part thereof. The amount may be subject to change for good cause. The security shall be maintained for as long as monitoring is required. The type of security shall be a corporate surety bond, certificate of deposit, irrevocable letter of credit, or other type of security approved by order of the Commission. Any type of surety that expires shall be renewed prior to 30 days before the expiration date. All joint escrow accounts shall be made current every 60 days.

(2) **Sign required.** A waterproof sign bearing the name of the operator, legal description, order number, and emergency phone number shall be posted within 25 feet of the entrance to any commercial soil farming site and shall be readily visible.

(3) **Monitor wells.**

(A) Any commercial soil farming operation shall be required to have a minimum of two monitor wells, one upgradient and one downgradient, unless it can be shown that the site is not located over a hydrologically sensitive area, i.e., a principal bedrock aquifer, the recharge or potential recharge area of a principal bedrock aquifer, or an unconsolidated alluvium or terrace deposit, according to the Oklahoma Geological Survey "Maps Showing Principal Groundwater Resources and Recharge Areas in Oklahoma" (available for viewing at the Commission's Oklahoma City Office and District Offices) or other maps approved by the Commission. The exact number and location of wells shall be established by the Pollution Abatement Department.

(B) No monitor well shall be installed more than 250 feet from a commercial soil farming operation, nor shall any existing water well be used as a monitor well, unless approved by the Manager of Pollution Abatement. Monitor wells installed prior to the effective date of this Section may be accepted by the Manager of Pollution Abatement if it can be shown that they adequately monitor a site.

(C) All new monitor wells shall be drilled through the first aquifer encountered, but need not extend below 100 feet if no aquifer is encountered, and shall be completed by a licensed water well driller. If documentation can be submitted prior to drilling to show that no water will be encountered within 100 feet, then the District Manager may require that monitor wells be drilled to a lesser depth.

(D) All new monitor wells shall meet the following requirements:

(i) A minimum four inch diameter PVC casing shall be used with a sealing cap on the bottom.

(ii) The casing shall consist of a slotted liner in the saturated zone, or bottom ten feet if none is encountered, and shall be gravel-packed or sand-packed as appropriate to the installation.

(iii) Bentonite shall be placed in the annular space of the well above the slotted liner for an interval of at least two feet to form an adequate seal.

(iv) Well cuttings shall be returned to the annular space above the bentonite seal for well stability.

(v) A minimum of two of the top six feet of the annular space around the casing shall be filled with cement.

(vi) A minimum three inch thick concrete apron shall be placed at the surface to a minimum two foot radius from the casing.

(vii) A removable and lockable cap shall be placed on top of the casing. The cap shall remain locked at all times, except when the well is being sampled.

(E) Within 30 days after installation, specific completion information for all monitor wells and a diagram of their locations in relation to the soil farming site shall be submitted to the Manager of Pollution Abatement.

(4) **Sampling of monitor wells.** Sampling of monitor wells shall begin prior to the first soil farming application and shall be done once every six months (during January and July) after operations commence until one year after the last application is made, then once every year for three years according to the following:

(A) The appropriate District Manager shall be notified at least 24 hours in advance of sampling to allow a Commission representative an opportunity to witness the sampling.

(B) Samples shall be collected and handled by the operator according to EPA-approved standards ("RCRA Groundwater Monitoring Technical Enforcement Guidance Document," EPA, OSWER-9950.1, September, 1986, pp.99-107.)

(C) If requested by a representative of the Conservation Division, an adequate portion of each sample (approximately one pint) shall be properly labeled and delivered or otherwise provided to the appropriate District Office or Field Inspector.

(D) All samples must be analyzed for pH and chlorides by a laboratory certified by the Oklahoma Water Resources Board or operated by the State of Oklahoma. Analysis of additional parameters may be required, as determined by the Manager of Pollution Abatement.

(E) A copy of each analysis and a statement as to the depth to groundwater encountered in each well, or an affidavit that no water was encountered, shall be forwarded to the Pollution Abatement Department within 30 days of sampling.

(i) **Conditions of permits.** Each permit issued under this Section shall be subject to the following conditions:

(1) **Required form.** A completed Form 1014CS shall be submitted to the Manager of Pollution Abatement for approval prior to commencement of soil farming. A new Form 1014CS shall be submitted each time that soil farming is proposed to be done. Approval or disapproval shall issue on Form 1014CS within ten days of submission.

(2) **Notice to Commission.** The applicant, by agreement with the appropriate District Office, shall schedule the commencement of soil farming no less than 24 hours prior thereto, to allow a Commission representative to be present to witness the work. The applicant shall also notify the appropriate District Office of completion of each soil farming application within 24 hours. Written notice of commencement and completion shall be submitted to the Manager of Pollution Abatement within 48 hours.

(3) **Presence of representative.** A representative of the applicant shall be on the soil farming site at all times during application of the pit materials to the land.

(4) **Type muds to be soil farmed.** Commercial soil farming is limited to water-based type muds and/or cuttings. Soil farming of oil-based muds and/or cuttings shall be prohibited.

(5) **Weather restrictions.** Commercial soil farming shall not be done:

(A) During precipitation events or when precipitation is imminent.

(B) When the soil moisture content is at a level such that the soil would not readily take the addition of drilling fluids.

(C) When the ground is frozen.

(D) By spray irrigation when the wind velocity is such that even distribution of materials cannot be accomplished or the buffer zones, pursuant to (6) of this subsection, cannot be maintained.

(6) **Buffer zones:** No commercial soil farming shall be done within the following buffer zones:

(A) One hundred feet of a property line boundary.

(B) Fifty feet of any stream not designated by Oklahoma Water Quality Standards.

(C) Three hundred feet of any actively-producing water well used for domestic, irrigation or industrial purposes.

(D) One thousand three hundred feet of any actively-producing water well used for municipal purposes.

(7) **Application rate.** The maximum application rate of drilling fluids and/or cuttings stipulated by the permit shall not be exceeded. Furthermore, the minimum required acreage within the approved soil farming

plot, as designated by the permit, shall be fully utilized. Application of drilling fluids and/or cuttings outside the approved plot shall be prohibited.

(8) **Soil farming method.**

(A) Application of pit contents shall be uniform over the soil farming plot and shall be made by injection, spray irrigation, or other method approved by the Commission prior to use. The flood irrigation method shall be limited to those fields that normally are irrigated in that manner.

(B) An application of more than 50,000 lbs/acre of dry weight materials or more than 500 lbs/acre of oil and grease shall be incorporated into the soil by injection, disking, or other method approved by the Commission. If the injection method is not used, incorporation must be made within a reasonable time period after completion of application, not to exceed 14 days unless extended by the Pollution Abatement Department pursuant to a written request.

(C) When the spray irrigation method is used and solids eventually accumulate on the soil surface to a one-eighth (1/8) inch depth, then the materials shall be incorporated prior to subsequent soil farming.

(9) **Runoff or ponding prohibited.** No runoff or ponding of soil farmed materials shall be allowed during application.

(10) **Automatic termination.**

(A) If the applicant violates the order, permit, or this Section, soil farming shall be discontinued and the Pollution Abatement Department shall be contacted immediately. The Pollution Abatement Department may revoke the permit and/or require the operator to do remedial work. If the permit is not revoked, soil farming may resume with the approval of the Pollution Abatement Department.

(B) Soil farming shall be carried out within two months from the date of approval of the permit. At the end of the two month period, the permit shall expire by its own terms. The Manager of Pollution Abatement may, upon written request, separately grant up to two extensions of the permit for periods of two months each.

(11) **Prevention of pollution.** All commercial soil farming facilities shall be operated and maintained at all times so as to prevent pollution. In the event of a nonpermitted discharge from a commercial soil farming facility, sufficient measures shall be taken to stop or control the loss of materials and reporting procedures in 165:10-7-5 (c) shall be followed. Any materials lost due to such discharge shall be cleaned up as directed by a representative of the Conservation Division.

(12) **Vegetative cover.** If the vegetative cover is destroyed or significantly damaged by disking, injection, or other practice associated with soil farming, the vegetative cover shall be reestablished within one year after the last soil farming application.

(j) **Additional requirements.** The requirements set forth in this Section are minimum requirements. Additional requirements may be made upon a showing of good cause that an operator has a history of complaints for failure to comply with Commission rules, or the site has certain limitations, or other conditions of risk exist.

(k) **Annual report.** The operator of any commercial soil farming facility shall submit an annual report on Form 1014A to the Manager of Pollution Abatement by February 1 of each year.

(l) **Prospective application to existing operations.** Subsections (d), (e), (f), (g), (h), (i), (j), (k) and (m) of this Section shall apply to all commercial soil farming operations for which an order or permit was obtained prior to the adoption of this Section. All affected operators shall have their facility in compliance with all of the noted subsections by December 31, 1988. Failure to be in compliance by that date shall result in termination of the authority to operate.

(m) **Variances.** Except as provided in this Section, variances from provisions of this Section may be granted for good cause by order after application, notice, and hearing.

[**Source:** Amended at 12 Ok Reg 2017, eff 7-1-95]

165:10-9-3. Commercial disposal well surface facilities

(a) **Scope.** This Section shall apply to the surface facilities of any commercial disposal well.

(b) **Site restriction.** No commercial disposal well pit shall be constructed in any area that floods according to the Soil Conservation Service County Soil Survey (available for viewing at the Commission's Oklahoma City Office or District Offices).

(c) **Construction requirements.**

(1) **Dikes.** A dike shall be constructed and maintained around any storage tank or group of tanks. The diked area shall be capable of totally containing at least one and one-half (1 1/2) times the volume held by the largest storage tank.

(2) **Leak containment.** A means for containing leaks shall be provided at all pumps and connections.

(3) **Splash pad/apron.** A splash pad/apron shall be constructed at the unloading area of any pit to the design and dimensions necessary to contain and direct all materials unloaded into the pit. If a pit is not used, an apron shall be constructed at the unloading area to the design and dimensions necessary to direct any spills into containment.

(4) **Pit specifications.** Any commercial disposal well pit shall be constructed of concrete or steel or shall be lined with a geomembrane liner. The following specifications shall be met:

(A) Any concrete pit shall be steel-reinforced and have a minimum wall thickness of six inches.

(B) Any steel pit shall have a minimum wall thickness of three-sixteenths (3/16) inch. If a previously used steel pit is installed, it shall be free of corrosion or other damage.

(C) Any geomembrane liner shall meet these requirements:

(i) The geomembrane liner shall have a minimum thickness of 30-mils, shall be chemically compatible with the type of wastes to be contained, and shall have ultraviolet light protection.

(ii) The geomembrane liner shall be placed over a specially prepared, smooth, compacted surface void of sharp changes in elevation, rocks, clods, organic debris, or other objects.

(iii) The geomembrane liner shall be continuous (may include seams) and shall cover the bottom and interior sides of the pit entirely. The edges shall be securely placed in a minimum twelve inch deep anchor trench around the perimeter of the pit.

(5) **Certification of liner.** The operator of any commercial disposal well pit that is constructed with a geomembrane liner shall secure an affidavit signed by the installer, certifying that the liner meets minimum requirements and was installed in accordance with Commission rules. It shall be the operator's responsibility to maintain the affidavit and all supporting documentation pertaining to the liner, such as geomembrane liner specifications from the manufacturer, etc., and shall make them available to a representative of the Conservation Division upon request.

(6) **Monitor wells or leachate detection system.**

(A) Any commercial disposal well pit shall be required to have a leachate collection system or a minimum of three monitor wells, one upgradient and two downgradient.

(B) No monitor well shall be installed more than 100 feet from a commercial disposal well pit, nor shall any existing water well be used as a monitor well, unless written approval is given by the District Manager or Manager of Field Operations.

(C) All new monitor wells shall be drilled through the first aquifer encountered, but need not extend below 100 feet if no aquifer is encountered, and shall be completed by a licensed water well driller. If documentation can be submitted prior to drilling to show that no water will be encountered within 100 feet, the District Manager may require that monitor wells be drilled to a lesser depth.

(D) All new monitor wells shall meet the following requirements:

(i) A minimum four inch diameter PVC casing shall be used with a sealing cap on the bottom.
(ii) The casing shall consist of a slotted liner in the saturated zone, or bottom ten feet if none is encountered, and shall be gravel-packed or sand-packed as appropriate to the installation.
(iii) Bentonite shall be placed in the annular space of the well above the slotted liner for an interval of at least two feet to form an adequate seal.
(iv) Well cuttings shall be returned to the annular space above the bentonite seal for well stability.
(v) A minimum of two of the top six feet of annular space around the casing shall be filled with cement.
(vi) A minimum three inch thick concrete apron shall be placed at the surface to a minimum two foot radius from the casing.
(vii) A removable and lockable cap shall be placed on top of the casing. The cap shall remain locked at all times, except when a well is being sampled. A key to each well shall be made available to the appropriate District Manager or Field Inspector upon request.

(E) Within 30 days of installation, construction details for any leachate detection system or specific completion information for all monitor wells and a diagram of their locations in relation to the pit they monitor shall be submitted to the Manager of Field Operations.

(d) **Operation and maintenance requirements.**

(1) **Sign.** A waterproof sign shall be erected and maintained within 25 feet of the entrance road to any commercial disposal well, shall be readily visible, and shall contain the name of the operator, order number, legal description, and emergency phone number.

(2) **Fencing.** All commercial disposal well surface facilities that have a pit shall be completely enclosed by a minimum four strand barbed wire fence or equivalent protection using woven wire and/or barbed wire. No livestock shall be allowed inside the fence.

(3) **Site maintenance.** The normal access surface of any commercial disposal well site, including the access road(s), shall be maintained in a condition that will safely and easily accommodate a passenger car during all weather conditions.

(4) **Exclusion of runoff water.** No commercial disposal well pit shall be allowed to receive runoff water.

(5) **Freeboard.** The fluid level in any concrete or steel commercial disposal well pit shall be maintained at all times at least 6 inches below the top of the pit wall. Any geomembrane lined pit shall have a minimum of 18 inches freeboard at all times.

(6) **Temporary storage only.** No pit shall be used as permanent storage for salt water.

(7) **Sampling of monitor wells.**

(A) Sampling of monitor wells shall occur once every six months, during the months of January and July.

(B) The appropriate District Manager shall be notified at least 24 hours in advance of sampling to allow a Commission representative an opportunity to witness the sampling.

(C) Samples shall be collected, preserved, and handled by the operator according to EPA-approved standards (RCRA Groundwater Monitoring Technical Enforcement Guidance Document, EPA, OSWER-9950.1, September, 1986, pp. 99-107) and analyzed for pH, chlorides and Total Dissolved Solids (TDS) by a laboratory certified by the Oklahoma Water Resources Board or operated by the State of Oklahoma. Analysis of additional parameters may be required, as determined by the District Manager or Manager of Field Operations.

(D) If requested by the District Manager, each sample shall be split and an adequate portion (approximately one pint) properly labeled and delivered upon request or otherwise provided to the appropriate District Office or Field Inspector. A copy of each analysis and a statement as to the depth to groundwater encountered in each well, or an affidavit that no water was encountered, shall be forwarded to the Manager of Field Operations, within 30 days of sampling.

(8) **Prevention of pollution.** All commercial disposal well pits shall be used, operated, and maintained at all times so as to prevent pollution. In the event of a nonpermitted discharge from surface facilities of a commercial disposal well, sufficient measures shall be taken to stop or control the loss of materials and reporting procedures in 165:10-7-5(c) shall be followed. Any materials lost due to such discharge shall be cleaned up as directed by a representative of the Conservation Division.

(9) **Oil film.** The operator of a saltwater disposal system shall be responsible for the protection of migratory birds. Therefore, the Conservation Division recommends that to prevent the loss of birds due to oil films, all open top tanks and pits containing fluid be kept free of hydrocarbons, or be protected from access to birds. [See Advisory Notice 165:10-7-3(c).]

(e) **Closure requirements.**

(1) **Time limit.** Within 90 days of the cessation of operation of any commercial disposal well, all associated pits shall be emptied of all contents and filled with soil. All monitor wells shall be plugged with bentonite or cement, unless exempt in writing by the District Manager or Manager of Field Operations. The site shall be revegetated within 180 days.

(2) **Geomembrane-lined pits.** When closing any commercial disposal well pit with a geomembrane liner, extreme care shall be taken to preserve the integrity of the liner. All free liquids shall be removed or chemically solidified. A geomembrane cap shall be placed over the top of any remaining contents to completely encapsulate them. Any geomembrane cap shall have a minimum thickness of twelve mils and shall be chemically compatible with the type of substances to be encapsulated. Burial, pursuant to (3) of this subsection, shall follow.

(3) **Burial.** If any concrete, steel, geomembrane, or other materials associated with a commercial disposal well site are to be left on-site, they shall be buried under a minimum soil cover of three feet, pursuant to 165:10-3-17.

(f) **Prospective application to existing facilities.** All provisions of this Section except (4) and (5) of subsection (c) shall apply to all existing commercial disposal well pits which are, or have been, in operation prior to the effective date of this Section. Operators shall have 180 days from the effective date of this Section in which to bring their facilities into compliance with the applicable provisions of this Section. Failure to comply with any applicable provision may result in revocation of the authority to operate.

(g) **Variances.** A variance from the time requirements of (d)(7) or (e)(1) of this Section may be granted by the District Manager or Manager of Field Operations for justifiable cause. A written request and supporting documentation is required. The District Manager or Manager of Field?Operations shall respond in writing within five working days, either approving or disapproving the request.

[**Source:** Amended at 11 Ok Reg 3691, eff 7-11-94]

SUBCHAPTER 11. PLUGGING AND ABANDONMENT

Section

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165:10-11-1. License for pulling pipe and plugging wells

(a) No person shall contract to pull casing or plug oil, gas, injection, disposal, or other service wells, or contract to salvage casing therefrom, or purchase wells for the purpose of salvaging casing therefrom until a license has been secured from the Commission.

(1) The application for such license shall state:

(A) The name of the applicant.

(B) The names and addresses of all partners, chief officers, and directors.

(C) The experience of applicant.

(D) Evidence of financial responsibility of the applicant.

(E) The counties in which the applicant will operate.

(2) Notice that an application has been filed shall be published by the applicant in a newspaper of general circulation in Oklahoma County and in the county where the applicant's principal place of business is located. The applicant shall file proof of publication prior to the hearing or administrative approval. The notice shall include:

(A) The name of the applicant.

(B) Generally what operations the applicant intends to conduct for which applicant is financially responsible.

(C) The counties in which applicant will operate.

(3) If a written objection to the application is filed within 15 days after the application is published or if a hearing is required by the Commission, the application shall be set for hearing and notice thereof shall be given as the Commission shall direct. If no objection is filed and the Commission does not require a hearing, the matter shall be presented administratively to the Manager of Field Operations who shall file a report and make recommendations to the Commission.

(b) The license shall not be transferable and may at any time be revoked by the Commission upon complaint, notice, and hearing.

(c) Any person violating this Section may be fined up to $2,500.00. Any operation in violation of this Section shall be shut down pending compliance with this Section.

[**SOURCE:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended in Rule Making 97000002, eff 7-1-97]

165:10-11-2. Operating requirements for licensees

(a) This Section shall apply to each licensee under 165:10-11-1.

(b) If a licensee prepares the Notice of Intent to Plug (Form 1001 and/or the Plugging Report (Form 1003), then the licensee shall:

(1) Include the following on any submitted form:

(A) The name and address of the well operator if the licensee is serving as a contractor for the operator of the well.

(B) The name and address of the person or entity hiring the licensee if the licensee is serving as the contractor for any person who is not an operator of the well.

(C) That he is acting independently if the licensee either purchased the well for salvage or contracted with the landowner to plug the well in exchange for casing and/or other well equipment.

(2) Mail a copy of Form 1001 to the last known operator of the well to be plugged, as shown by the records of the Conservation Division.

(c) For purposes of this subsection, the term "plugged well" shall refer to a well for which the Conservation Division has a plugging record. A licensee shall comply with the requirements of 165:10-1-10 and 165:10-3-1 before entering a plugged well if:

(1) The licensee is not hired by the operator of the well to conduct the re-entry operation.

(2) The owner of the well is either the licensee or the surface owner of the tract on which the well was drilled.

(3) The Commission has not contracted with the licensee to replug the well.
(d) A licensee shall be responsible for the plugging of a well if:
(1) The licensee is the owner of the well or the licensee is the operator of the well.
(2) The licensee enters a well without having contracted with the operator or with a party other than the operator who has authority to authorize the licensee to enter the well on behalf of such party.
(e) Any violation of this Section will subject licensee to a fine, to suspension or revocation of licensee's license issued pursuant to 165:10-11-1, and to proceedings as authorized by statute in the district court.

[**SOURCE:** Amended in Rule Making 97000002, eff 7-1-97]

165:10-11-3. Duty to plug and abandon

(a) **Scope.** This Section applies to:
(1) Joint and several liability of the owners and operator of a well for plugging.
(2) Time periods for plugging wells:
(A) Without casing.
(B) With only surface casing and cement.
(C) With production casing.
(3) Wells exempted from plugging.
(4) Notice of Temporary Exemption from Plugging granting permission to postpone plugging of a well.

(b) **Joint and several liability of owners and operators.** Any working interest owner and operator of any oil, gas, disposal, injection, or other service well or any seismic, core, or other exploratory hole, whether cased or uncased, shall be jointly and severally liable and responsible for the plugging thereof in accordance with this Subchapter.

(c) **Time period for plugging well without casing.** Each well in which neither production casing nor surface casing has been run shall be properly plugged within 72 hours after drilling or testing is completed. However, should the lack of production and surface casing create a fire hazard or a risk of contaminating the environment or formations containing oil, gas, or known treatable water, said well shall be properly plugged within 24 hours after drilling and testing is completed. The well marker requirement described in 165:10-3-4 (e) shall be followed.

(d) **Time period for plugging well with only surface casing and cement.** Each well in which only surface casing has been run and cemented in conformance with 165:10-3-4 shall be properly plugged within 90 days after drilling or testing is completed unless the lack of production or intermediate casing creates a fire hazard or risk of contaminating the environment or formations containing oil, gas, or known treatable water, in which case or cases the well shall be plugged within 24 hours.

(e) **Time period for plugging well with production casing.** Unless exempted under provisions contained elsewhere in this Section, any well which has production casing in place shall be plugged within one year after the latter of:
(1) Cessation of drilling if the well was not completed or tested; or
(2) Cessation of the latter of completion or testing if the well has not produced; or
(3) Cessation of production.
(4) From April 1, 1998, to March 31, 1999, the time period for plugging of any producing well with production casing in place that has ceased production shall be two years. The Commission shall review the need for the continued effectiveness of this provision during the time period set forth above on a quarterly basis. This provision shall not apply to any well that poses a public health, safety or pollution threat to the environment and surface or subsurface waters of the state.

(f) **Operators failing to commence timely plugging operations.** An operator who fails to commence plugging operations as required in (c), (d), and (e) of this Section after due notice from the District Office or the appropriate field inspector may be fined up to $1,000.00.

(g) **Wells exempted from plugging.** The following wells which have production casing in place shall be exempt from (e) of this Section:

(1) Shut-in gas wells, for the purpose of this Section, shall be considered producing wells in operation.

(2) Any well for which a written order of the Commission granting a specific exception to plugging is in full force and effect.

(3) Supply wells or wells authorized by order of the Commission for injection or disposal purposes and are in compliance with the rules of the Commission.

(4) Any well for which a temporary exemption from the plugging rules has been approved.

[**SOURCE:** Amended at 9 Ok Reg 2295; Amended at 9 Ok Reg 2337, eff 6-25-92; Amended in Rule Making 97000002, eff 7-1-97; Amended in Rule Making 980000035, eff 7-1-99]

165:10-11-4. Notification and witnessing of plugging

(a) **Wells without production casing.** The Conservation Division shall be notified at least 12 hours prior to commencement of plugging operations and a plugging procedure agreed upon for any well without production casing. Each plugging operation may be witnessed by an authorized representative of the Conservation Division.

(b) **Wells with production casing.** A separate Notification of Intention to Plug (Form 1001) for each well with production casing shall be filed, in duplicate, with the Conservation Division at least five days prior to the commencement of plugging operations. The five day notice requirement may be reduced or waived:

(1) If a qualified representative of the Conservation Division is available to witness the plugging operation.

(2) At the discretion of the District Manager of the District in which the well is located or his supervisor.

(c) **Penalty.** An operator or licensed plugger plugging a well without notifying and agreeing on a plugging procedure with the District Office may be fined up to $1,000.00 and may be required by the appropriate District Manager to reenter and replug the well.

[**Source:** Amended at 11 Ok Reg 3691, eff 7-11-94; Amended in Rule Making 97000002, eff 7-1-97]

165:10-11-5. Supervision and witnessing [REVOKED]

[**SOURCE:** Amended at 9 Ok Reg 2295, eff 6-25-92; Revoked in Rule Making 97000002, eff 7-1-97]

165:10-11-6. Plugging and plugging back procedures

(a) **Scope.** This Section establishes minimum standards for plugging and plugging back wells. The standards apply to:

(1) Wells drilled for the production of oil or gas.

(2) Wells drilled or used for disposal or enhanced recovery injection.

(3) Wells used in subsurface gas storage units.

(4) Monitoring wells in enhanced recovery projects or subsurface gas storage units.

(5) Wells plugged back for:

(A) Oil or gas production.

(B) Disposal or injection.

(C) Conversion to a water well.

(6) "Rat hole" or "mouse holes" used in rotary drilling of wells.

(7) Wells used for geophysical or geological exploration.

(8) Wells used for other service operations.

(b) **Alternate plugging materials and procedures**

(1) The Manager of Field Operations, or other designated Conservation Division staff member, may approve the use of an alternate material other than cement or in combination with cement for wells listed in subsection (a), provided alternate plugging materials shall not be used to plug or plug back wells listed in subsection (a)(2), wells drilled or used for disposal or enhanced recovery injection, subsection (a)(3), wells used in subsurface gas storage units, subsection (a)(5)(B), wells plugged back for disposal or injection, and underground injection wells authorized under the Oklahoma Brine Development Act, 17 O.S. Section 500 *et seq*.

(2) The Director of Oil and Gas Conservation, in consultation with the Conservation Division's Field Operations staff and the public, shall develop specific plugging criteria for any type of alternate plugging material authorized for use instead of cement or in combination with cement. The plugging criteria for approved alternate material shall be available to the public for review and copying at the Conservation Division's offices and on the Commission's Internet website.

(3) A District Manager may approve alternate plugging procedures for the use of alternate plugging materials.

(4) A detailed description of the alternate plugging operation shall be included with the Plugging Report (Form 1003).

(5) The District Manager shall note his approval of the alternate plugging procedure on the well's Plugging Report (Form 1003).

(6) Any alternate plugging material or procedure shall conform to the minimum plugging standards relating to formations or depths set forth in the Sections below. Provided, based upon the type of alternate plugging material being utilized, the District Manager approving the alternate procedure may authorize variances to the plugging standards delineated in this Section otherwise applicable to the use of cement, where such variances are necessary to ensure an effective well plugging.

(c) **Application and cross references:**

(1) Subsection (n) of this Section provides for administrative approval of alternative plugging procedures if downhole problems in a wellbore prevent an operator from complying with the minimum standards established by this Section.

(2) Subsection (o) of this Section applies to plugging of "rat holes" and "mouse holes" used at the surface during rotary drilling.

(3) OAC 165:10-11-8 establishes additional procedures for identification and control of wellbores in which certain logging tools have been abandoned.

(4) OAC 165:10-7-31 establishes the minimum standards for plugging wellbores used in seismic exploration.

(5) Subsections (d) through (p) of this Section establish plugging and plug back standards for all other wellbores subject to this Section.

(d) **Formations to be plugged.**

(1) Except as provided in (2) of this subsection, for cased formations, if the operator plugs or plugs back a well, the operator shall plug any formation or formations in communication with a formation that:

(A) Bears H_2S;

(B) Bears oil or gas;

(C) Bears treatable water;

(D) Was used in the wellbore for injection as part of a saltwater disposal well or enhanced recovery injection well; or

(E) Is open in the wellbore below either the shoe of the casing or the base of the liner to be left in the well after plugging.

(2) Paragraph (1) of this subsection shall not apply to any formation behind the pipe left in the hole, unless a formation endangers a treatable water formation or any oil and gas bearing formation.

(e) **Mud requirements.** Before running a plug, the operator shall remove or displace all oil and saltwater in the wellbore, and the operator shall fill the wellbore with drilling mud. The minimum mud weight shall be nine pounds per gallon. The minimum viscosity for the drilling mud shall be 36 (API Full Funnel Method). If the operator removes casing from the wellbore, the operator shall keep the wellbore filled with drilling mud meeting or exceeding the weight and viscosity requirements of this subsection.

(f) **Approved cementing methods.**
(1) **Cement plugs.**
(A) To plug or plug back a well, either the tubing and pump method or the pump and plug method shall be used.
(B) Surface pumping and shut in pressures shall be of sufficient pressure to:
(i) Squeeze off perforations in the casing.
(ii) Prevent the plug from floating upward in the wellbore.
(2) **Bridge plugs.** The operator may run by the bailer method cement required in the casing above a bridge plug as provided by (g) of this Section.
(g) **Use of bridge plugs.**
(1) **Permitted use.** Except as provided in (2) of this subsection for top plugs, a bridge plug may be used to permanently plug off a formation if:
(A) The only openings from the formation into the wellbore are perforations in the casing.
(B) The annulus between the casing and the formation is filled with cement from a depth 50 feet below the base of the formation to a depth 50 feet above the top of the formation.
(C) The bridge plug is set above the top of the perforations in the cemented interval described in (B) of this paragraph.
(D) Sufficient cement is placed on top of the bridge plug to fill the casing from the top of the bridge plug to a depth ten feet above the top of the bridge plug.
(2) **Prohibited use for top plug.** A bridge plug may not be used for a top plug described in (j) of this Section.
(h) **Cement plug for uncased hole below the casing or liner.** If any production casing or liner is to be left in the wellbore, then any uncased hole below the casing or liner shall:
(1) Be filled with cement:
(A) **From** a depth which is the lesser of total depth of the well or 50 feet below the lower of shoe of the casing or base of the liner.
(B) **To** a depth of 50 feet above the lower of the casing shoe or the base of the liner; or
(2) Have a cast iron bridge plug set above the top of the liner with cement.
(i) **Intermediate cement plugs.** If a bridge plug and cement are not used, a cement plug shall be run over any other formation required to be plugged off by this Section. To plug off a formation, the wellbore shall be filled with cement from a depth at least 50 feet below the base of the formation to a depth at least 50 feet above the top of the formation.
(j) **Cement top plug.**
(1) **No treatable water exists.** If no treatable water exists, the wellbore shall be filled with cement from a depth of at least 30 feet to a depth of three feet from the surface.
(2) **Treatable water exists.** Except as provided in (p) of this Section for converting a well to a water well, the wellbore shall be filled with cement as follows:
(A) If there is no surface casing or the base of the surface casing is 25 feet or further above the base of the treatable water, the wellbore shall be filled with cement from a depth of at least 50 feet below the base of the treatable water to a depth the lesser of:
(i) Fifty feet above the base of treatable water; or
(ii) Three feet below surface.
(B) If the surface casing is set at or below the base of the treatable water, the wellbore shall be filled with cement from a depth of at least 50 feet below the base of the surface casing to a depth the lesser of:
(i) Fifty feet above the base of the surface casing; or
(ii) Three feet below surface.
(C) If the cement plug prescribed by (2) of this subsection is not sufficient to bring the level of cement to within three feet from the surface, then the wellbore shall be filled with cement from a depth of at least 30 feet to a depth of three feet from the surface.
(k) **Cutting off surface pipe and identification of the abandoned wellbore.**

(1) This subsection applies to a wellbore plugged for abandonment. It does not apply to a wellbore plugged back for conversion to a water well under (p) of this Section.
(2) After setting the top plugs in a well, the operator shall cut off the casing left in the wellbore three feet below surface, and the operator shall cap the casing in the wellbore with a steel plate.
(3) The operator shall inscribe or embed the well number and date of plugging on the steel plate.

(l) **Tagging the top of the plug.** The Field Inspector for the Conservation Division may require the operator to determine the depth of the top of a plug by running a wireline or tubing string.

(m) **Fall back of cement.** If the cement for a plug falls back during setting below the top depth required by this Section, the operator shall run additional cement until the plug meets the minimum requirements of this Section.

(n) **Alternative plugging procedure for down-hole problems.**
(1) In plugging a well, if the operator encounters a downhole problem which prevents the operator from complying with the standards of this Section, the District Manager may prescribe an alternative plugging procedure provided that the alternative plugging procedure prevents the vertical migration in the wellbore of oil, gas, saltwater, H_2S, and other deleterious substances into a formation bearing oil, gas, or treatable water.
(2) The District Manager shall note his approval of the alternative plugging procedure on the well's Plugging Report (Form 1003).

(o) **Plugging of rat holes and mouse holes.** If a rat hole or mouse hole was used at the surface for drilling the well, it shall be plugged as follows.
(1) The hole shall be filled with drilling mud from bottom to a depth eight feet below the surface.
(2) The operator shall fill the hole with cement from a depth of eight feet to a depth of three feet below the surface.
(3) The operator shall fill the hole with dirt from a depth of three feet to surface.

(p) **Plug back for conversion to a water well.** The District Manager may permit a well operator to plug back a well for permanent use as a water well by:
(1) Setting any bottom hole and intermediate plugs required by this Section.
(2) Setting a top cement plug from the base of treatable water to 50 feet below the base of treatable water.
(3) Obtaining written permission from the owner of the ground water rights for conversion of the well to a water well.
(4) Submitting under 165:10-11-7, a Plugging Report (Form 1003) noting the conversion of the well with a copy of the written permission from the owner of the ground water rights for conversion of the well to a water well.

[**SOURCE:** Amended at 13 Ok Reg 2395, eff 7-1-96; Amended in Rule Making 97000002, eff 7-1-97; Amended in Rule Making 980000013, eff 7-15-98; Amended in Rule making 980000034, eff 7-1-99; Amended in Rule Making 200200017, eff 7-1-02]

165:10-11-7. Plugging record

(a) Within 30 days after plugging a well, the owner or operator of the well shall submit for the well in duplicate to the appropriate District Office of the Conservation Division:
(1) Plugging Record (Form 1003).
(2) Cementing Report (Form 1003C) to accompany Plugging Record (Form 1003).
(3) If a Completion Report (Form 1002A) has not been submitted for the well, Form 1002A shall be attached to the Form 1003.

(b) Any operator failing to comply with this Section may be fined up to $500.00.

[**SOURCE:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended in Rule Making 97000002, eff 7-1-97]

165:10-11-8. Procedures for identification and control of wellbores in which radioactive sources have been abandoned

(a) **Notice and permission to abandon.**

(1) When a radioactive source has been lost and abandoned in a well bore, the operator shall immediately notify the appropriate District Office and request permission to plug or plug-back and/or bypass to conform to the conditions set out in this Section. The District Manager or his designee may exercise the option of witnessing the procedure.

(2) A radioactive source shall not be considered abandoned until all reasonable efforts have been expended to retrieve the source.

(b) **Method of plugging.**

(1) Wells in which radioactive sources have been abandoned shall be mechanically equipped and plugged in such a manner so as to prevent either accidental or intentional mechanical disintegration of the radioactive source.

(2) When a radioactive source has been lost in a well bore and cannot be recovered, the tool shall be covered with a 100 foot plug consisting of standard oil field cement with an approved deflection tool cemented in place at the top of the plug. An additional 100 foot plug colored by red iron oxide shall be run on top of the deflection tool.

(c) **Approval for alternate plugging method.** When an operator, after expending all reasonable efforts, finds that it is not possible to abandon the source as prescribed in (d) of this Section, an alternate plugging procedure must be approved by the Commission prior to use.

(d) **Markers for wells in which a radioactive source has been abandoned.** Upon abandonment of a well in which a radioactive source has been abandoned, and the abandonment procedure has been approved by the Commission, the operator shall cause a permanent plaque to be attached to casing remaining in the well. The plaque shall be attached in such a manner that reentry could not be accomplished without disturbing it. The plaque shall be constructed of a long lasting material and shall contain the following information:

(1) Lease name and well number.
(2) Name of operator.
(3) The source material abandoned.
(4) Total depth of the well.
(5) The depth of the abandoned source.
(6) The date of abandonment.
(7) The activity of the source.
(8) Trefoil radiation symbol with a radioactive warning.

(e) **Plugging reports of wells with lost radioactive sources.** Two copies of the plugging report shall be submitted to the Conservation Division of the Commission. The well operator shall forward one copy to the Radiation Management Section of the Oklahoma Department of Environmental Quality. The report shall contain all of the information required in (d) of this Section. The fact that a radioactive source was abandoned in the wellbore shall be noted under remarks on the Form 1002A.

(f) **Record of abandoned radioactive sources.** The Commission will maintain a current listing of all wells in which radioactive sources have been abandoned.

[**SOURCE:** Amended at 9 Ok Reg 2337, eff 6-25-92; Amended in Rule Making 97000002, eff 7-1-97]

165:10-11-9. Temporary exemption from plugging requirements

(a) **Scope.** The Commission may permit any well which is required to be properly abandoned pursuant to OAC 165:10-11-3 and OAC 165:10-11-5, at the request of an operator, to be temporarily abandoned.

(b) **Application.** An application for a permit to temporarily exempt a well from the plugging requirement shall be made on Form 1003A completed in its entirety, and submitted to the appropriate Conservation Division's District Office.

(c) **Permit.**

(1) Any operator seeking approval for temporary abandonment shall submit a notice of intent to temporarily abandon the well, Form 1003A, to the

appropriate District Office describing the temporary abandonment procedure used.

(2) The permit will be valid for a period of five (5) years. At least 30 days prior to the expiration of any approved temporary abandonment permit, the operator shall return the well to beneficial use in accordance with Commission rules, permanently plug and abandon said well, or apply for a new permit to temporarily abandon the well.

(3) No temporary abandonment will be approved that does not prevent the contamination of treatable water and/or other natural resources and the leakage of any substance at the surface.

(4) If the well fails the tests required herein the problem shall be found, corrected and a new test successfully conducted within 30 days or the well shall be plugged and abandoned in accordance with Commission rules.

(5) Upon successful completion of the work on the temporarily abandoned well, the operator will submit a new request for temporary abandonment to the appropriate District Office.

(d) **Protection of treatable water.** The treatable water shall be protected by one or more of the following:

(1) A drillable, retrievable or temporary bridging plug set above the producing interval and below the top of the cement. The surface shall be capped with a valve in operational condition. A pressure test may be required by the appropriate District Office.

(2) A packer run on tubing and set above the producing interval and below the top of the cement. The well shall be equipped with suitable wellhead packoff equipment and be closed to the atmosphere.

(3) A fluid level test determined by use of equipment approved by the Conservation Division’s Field Operations Department. The fluid level must be no higher than 150 feet below the base of the treatable water. The Field Inspector shall be notified at least 48 hours beforehand to be afforded the opportunity of witnessing the procedure. Fluid level tests must be conducted annually each of the five (5) years during the anniversary month of the permit. Additional tests may be required at any time at the request of the Conservation Division’s Field Operations Department. The wellhead shall be closed to the atmosphere.

(4) A casing inspection log confirming the mechanical integrity of the production casing submitted to the appropriate Conservation Division’s District Office.

(5) Alternate methods of testing may be approved by the Conservation Division’s Field Operations Department by written application and upon showing that such a test will provide information sufficient to determine that the well does not pose a threat to natural resources.

(e) **Surface facilities.** The well site of a well with temporary exemption from the plugging requirements shall be kept in a neat and orderly manner with a legible sign showing the name of the operator, operator telephone number, well name, number, and the legal location.

(f) **Termination of permit.** The permit for a temporary exemption from plugging shall terminate and plugging operations shall commence within 30 days after:

(1) The time interval set has lapsed and a renewal has not been granted.

(2) The lease or unit on which the exempted well was located has become nonproductive.

(3) The fluid level has risen to a point less than 150 feet below the base of the treatable water.

(4) The Conservation Division’s Field Operations Department has determined that the surface area or wellhead equipment requirement does not meet the standards required by the Commission.

(g) **Exception to termination of permit.** An exception to the termination of an exemption from the plugging requirements shall be allowed if:

(1) An application to convert the well to a disposal, injection, or supply well has been filed with the Commission, and proper notice, according to OAC 165:5, has been met.

(2) An application requesting an exception to the plugging rules has been filed with the Commission and an exception has been granted by an order of the Commission.

[**SOURCE:** Added at 9 Ok Reg 2337, eff 6-25-92; Amended in Rule Making 97000002, eff 7-1-97]

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SUBCHAPTER 13. DETERMINATION OF ALLOWABLES – OIL AND GAS WELLS

Section

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165:10-13-1. Oil and gas production [RESERVED]

165:10-13-2. Classification of wells for allowable purposes

(a) For purposes of this Subchapter the terms gas, oil, and gas-oil ratio are defined in 165:10-1-2.
(b) Any well having a gas-oil ratio of 15,000 to one or more shall be classified as a gas well for allowable purposes.
(c) Any well having a gas-oil ratio of less than 15,000 to one shall be classified as an oil well for allowable purposes.
(d) If a well is a multiply completed well under 165:10-3-35, then each zone of the completion shall be classified separately for allowable purposes.
(e) If a well is commingled under 165:10-3-39, the classification of the well for allowable purposes shall be determined by the gas-oil ratio of the commingled production.

165:10-13-3. Production tests on new, re-entered, and recompleted wells

(a) On all new wells, re-entered wells, and recompleted wells classified as oil wells for allowable purposes, in any regular spacing unit(s) and reservoir dewatering oil spacing unit(s), initial production tests shall be performed and reported to the Commission on Form 1029A unless otherwise specified by order of the Commission. The test shall not commence until after recovery of a volume of oil equivalent to or greater than the amount of load oil or other liquids introduced into the well.
(b) On all new wells, re-entered wells, and recompleted wells classified as gas wells for allowable purposes, initial production tests shall be performed and reported to the Commission on Form 1016 unless otherwise specified by order of the Commission.
(c) If special pool rules prescribe, by order of the Commission, the manner in which production tests are to be performed in any separate common source of supply, the production or gas-oil ratio test shall be performed and reported to the Commission in accordance with such special pool rules.

[**SOURCE:** Amended in Rule Making 200100009, eff 7-1-02]

165:10-13-4. Reservoir performance tests

The Commission may require, from time to time, the presentation of such data and facts as may be necessary to indicate reservoir performance and conditions in any oil or gas pool. The Commission may witness or supervise the taking of such reservoir performance tests and keep such records as it deems necessary to properly regulate the operation of any oil or gas pool. Any test requested by the Commission may be witnessed by any operator in the pool. When special pool rules require bottom hole pressure tests, the tests shall be reported to the Conservation Division on Form 1027.

165:10-13-5. Most efficient rate

Subject to the procedural requirements of 165:5-7-12, the Commission may issue an order increasing or decreasing the rate of oil and gas production in an oil pool to correspond to the most efficient rate of production which is consistent with sound engineering and conservation practices as may be justified by the circumstances and evidence submitted.

165:10-13-6. Load oil

Load oil used in well completions which is not produced from the same lease or spacing unit shall not be charged against the well, lease, or unit. The well shall be allowed to produce such load oil in addition to the current monthly allowable. Operators claiming credit for load oil for allowable purposes may file Oklahoma Tax Commission Form 317 not more than 6 months after treating the well.

[**SOURCE:** Amended in Rule Making 980000033, eff 7-1-99]

165:10-13-7. Production from different pools

(a) In the event there are two or more common sources of supply produced through a well or wells on the same lease or drilling and spacing unit and which are not commingled under 165:10-3-39, the production from each common source of supply shall be separately produced, measured, and/or accounted for to the Commission.

(b) If one or more of the zones produced are classified as oil for allowable purposes, the operator of the well shall submit to the Conservation Division a multi-zone report on Form 1011 showing the production from each oil-bearing common source of supply on or before the last day of the succeeding proration period.

165:10-13-8. Transfer of allowables

Subject to the procedural requirement of 165:5-7-12, the Commission may issue an order transferring, after proper adjustment, all or part of an allowable from a well with a high gas-oil ratio or high water-oil ratio to a well having a lower gas-oil ratio or water-oil ratio, if:

(1) The wells produce from the same common source of supply.

(2) The wells are located on the same lease or in the same drilling and spacing unit.

165:10-13-9. Allowable for increased density well

(a) **Allowable production.** Except as otherwise provided by rule or order of the Commission, the allowable production for permitted wells within a drilling and spacing unit producing from the same common source(s) of supply shall be determined as follows:

(1) Each individual well shall be classified for allowable purposes by gas-oil ratio under 165:10-13-2.

(2) Permitted wells of the same classification for allowable purposes shall share a single well allowable.

(3) Permitted wells of different classifications for allowable purposes shall receive allowables as provided by the order of the Commission authorizing the additional well(s).

(b) **Shared single allowable.** If two or more wells in a single drilling and spacing unit are classified as gas wells for allowable purposes, the shared single allowable for the unit shall be determined by the greater of:

(1) A minimum allowable; or

(2) A normal allowable based on the wellhead absolute open flow potential of the best well in the drilling and spacing unit producing from the same common source of supply.

(c) **Additional well.** If an additional well is not of the same classification as any prior permitted well, it shall receive an allowable as provided by the order permitting the well.

(d) **Effect of penalties.** If the allowable for a well in a drilling and spacing unit is subject to a percentage penalty or lid on production, the penalty or lid on production shall apply to the ratable share of production of the shared single allowable for the penalized well as opposed to the entire shared single allowable for the unit.

(1) The ratable share of production of the shared single allowable for an unallocated gas well is that volume of gas which bears the same ratio to the shared single allowable as the wellhead absolute open flow potential for the well bears to the sum of the wellhead absolute open flow potentials for all wells in the drilling and spacing unit of the same classification for allowable purposes.
(2) The ratable share of production of the shared single allowable for a special allocated gas well is that volume of gas which bears the same ratio to the shared single allowable as the unpenalized monthly allowable the well would receive if it were the only well in the unit bears to the sum of such allowables for all the wells in the drilling and spacing unit of the same classification for allowable purposes.
(3) No special allocated well shall receive an allowable less than the defined minimum unit allowable divided by the number of wells in the drilling and spacing unit of the same classification for allowable purposes.
(4) The ratable share of production of the shared single allowable for an oil well is that volume of oil which bears the same ratio to the shared single allowable as the potential for the well bears to the sum of the potentials for all wells in the drilling and spacing unit of the same classification for allowable purposes. If the oil well was assigned a separate allowable under (c) of this Section, the penalty shall apply to the allowable assigned to the well.
(5) The portion of the shared single allowable representing the reduction in the allowable for the penalized well is not allocable to other wells in the drilling and spacing unit.

(e) **Which operator shall file required tests.** If the operators of the wells in a drilling and spacing unit cannot agree as to which operator shall file the required tests and production reports for the unit or as to what proportion of a shared single allowable shall be attributable to each well of the same classification for allowable purposes, the Commission may, after application, notice, and hearing, issue an order determining which operator shall file the tests and reports or what the proportional share of the shared single allowable is attributable to each well or the maximum rate of allowable production for each well.

(f) **Wellhead absolute open flow potential.** For the purpose of this Section, the wellhead absolute open flow potential for a test exempt gas well shall be presumed to equal:
(1) The average daily production for the previous calendar year (or that portion of the previous calendar year if the first sales date was after January 1 of that year), or the minimum allowable that would otherwise be assigned to an unallocated gas well under applicable rules of the Commission as if such well were the only well in the unit, whichever is less, for an unallocated well; or
(2) The product of two multiplied by the monthly allowable for the well under 165:10-17-9 for a special allocated well.

(g) **Testing or reporting requirements.** This Section shall not exempt any well from any testing or reporting requirement imposed by rule or order of the Commission.

[**SOURCE:** Amended at 9 Ok Reg 2337, eff 6-25-92; Amended in Rule Making 980000033, eff 7-1-99]

165:10-13-10. Applications for reinstatement of cancelled underage for oil wells and for unallocated gas wells

(a) **Oil well.**
(1) With respect to an oil well, all underage for the proration period in excess of 15 percent of the allowable shall be automatically cancelled at the end of the proration period, except underage accrued under (4) of this subsection because of the failure to split a tank.
(2) A producer may apply to reinstate cancelled underage if the well is capable of producing in excess of its allowable. The procedure for applying for reinstatement of cancelled underage is described in (c) of this Section.

(3) Except in situations where the operator has failed to comply with applicable well testing and reporting requirements of the Commission, failure or refusal of the purchaser to take the allowable shall be grounds for reinstatement of any underage accumulated because of such failure or refusal. Underage of this nature may be accumulated until balanced by future runs.

(4) The operator shall not be required to sell less than a full stock tank of oil by the end of the proration period to avoid cancellation of underage. Instead, such underage may be accrued until the operator accumulates and sells a volume of oil from the tank amounting to a full tank, and the sale of oil representing such underage shall not be considered as overage.

(b) **Unallocated gas well.**

(1) With respect to any unallocated gas well, of the total underage for the well or unit existing at the end of the proration period, 75% shall be automatically cancelled and 25% shall be automatically carried forward to the next prorationing period.

(2) Said underage carried forward to the next balancing period must be utilized in said balancing period, with that amount of underage carried forward but not used, to be cancelled at the end of the prorationing period.

(c) **Procedure for reinstatement of cancelled underage.**

(1) The operator of an oil well may apply for reinstatement of cancelled underage by application for administrative approval on Form 1010 within 90 days after cancellation of the underage.

(2) If the Conservation Division declines to approve the Form 1010 application, the applicant shall be notified in writing that application, notice, and hearing under 165:5-7-1 are necessary to obtain reinstatement of cancelled underage.

[**SOURCE:** Amended in Rule Making 980000033, eff 7-1-99]

SUBCHAPTER 15. OIL WELL PRODUCTION AND ALLOWABLES

Section

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165:10-15-1. Classification of oil pools and projects

(a) **Types of oil pools.** Each producing oil pool shall be classified by the Commission into one of the following categories:

(1) Discovery oil pool (165:10-15-5).
(2) Allocated oil pool (165:10-15-9).
(3) Unallocated oil pool (165:10-15-12).
(4) Enhanced oil recovery project (165:10-15-14).
(5) Excessive water exempt oil project (165:10-15-16).
(6) Reservoir dewatering oil spacing unit (165:10-15-18).

(b) **Treatment of an oil well located in a gas pool.** An oil well located in a gas pool shall be treated as an unallocated oil well, unless the oil well is subject to one of the following:

(1) Pool rules controlled by volumetric withdrawal.
(2) Discovery oil pool rules.
(3) Allocated oil pool rules.
(4) Some other order of the Commission.

(c) **Discovery oil pools.**

(1) A new oil pool which has complied with the provision of 165:10-15-5 may be granted discovery allowable production rates, administratively, subject to either:

(A) Spacing requirements.
(B) Order of the Commission.

(2) Each permitted discovery oil well shall be subject to discovery oil pool rules until either:

(A) Expiration of the discovery allowable period.
(B) Reclassification of the well or pool.

(d) **Allocated oil pool.**

(1) The Commission shall classify an oil pool as an allocated oil pool when:

(A) At any market demand hearing the total production from an oil pool or from any well within the pool needs to be regulated; or
(B) For good cause shown, upon application, notice, and hearing.

(2) A gas well located in an allocated oil pool that is reclassified as an oil well for allowable purposes shall be subject to allocated oil pool rules.
(3) Each allocated oil well shall be subject to the allocated oil pool rules until the Commission reclassifies the well or pool.

(e) **Unallocated oil pools.**

(1) Classification of unallocated oil pool:

(A) Any pool or area which does not require specific regulation and control by the Commission to restrict production to the market demand, aid in the prevention of waste, assure the maximum ultimate recovery of oil and gas from the pool, or protect correlative rights shall be classified as an unallocated pool.
(B) The Commission shall determine which discovery and allocated pools will be placed in the unallocated classification at each market demand hearing.

(2) Each unallocated oil well shall be subject to unallocated oil pool rules until the Commission reclassifies the well or pool.

(f) **Enhanced oil recovery projects.**

(1) **Authorized pressure maintenance.** The Commission may, upon application, notice, and hearing, authorize the pressure maintenance of a pool or the production of oil by the injection of fluid, fluids, gas, gases, or other material into a common source of supply or a portion thereof, whether unitized or not, where substantial quantities of additional oil may be recovered which could not be recovered under ordinary primary depletion methods. When so authorized, the project will be classified as an Enhanced Oil Recovery Project with one of the following classifications:

(A) Pressure Maintenance Project
(B) Gas Repressuring Project
(C) Waterflood Project
(D) Other Enhanced Recovery Projects

(2) **Status of a gas well reclassified as an oil well.** If a well classified as a gas well in an enhanced oil recovery project is reclassified as an oil

well for allowable purposes, the well shall be subject to the appropriate enhanced oil recovery project rules.

(3) **Termination of enhanced oil recovery status.** Each enhanced oil recovery well shall be subject to enhanced oil recovery project rules until one of the following occurs:

(A) Termination of the enhanced oil recovery project.

(B) The well is reclassified as a gas well for allowable purposes.

(C) The Commission issues an order reclassifying the well or project.

(D) The well is abandoned.

(g) **Excessive water exempt oil projects.**

(1) **Oil production rates.** The Director of Conservation may administratively authorize the production of oil at rates greater than the normal allowable provided the water-oil ratio of the well and/or pool is greater than or equal to 3:1. All applications shall comply with 165:5-7-12.

(2) **Status of a gas well reclassified as an oil well.** If a well classified as a gas well in an excessive water exempt oil project is reclassified as an oil well for allowable purposes, the well shall be subject to excessive water exempt oil project rules.

(3) **Termination of excessive water exempt status.** Each excessive water exempt well shall be subject to excessive water exempt oil project rules until at least one of the following occurs:

(A) The water-oil ratio declines below 3:1.

(B) Termination of the excessive water exempt oil project.

(C) The well is reclassified as a gas well.

(D) The Commission issues an order reclassifying the well or project.

(h) **Allowable for reservoir dewatering oil spacing unit.**

(1) **Oil production rates.** To set an allowable for a well in a reservoir dewatering oil spacing unit, the operator shall refer to Appendix J and submit the appropriate forms and/or application as provided in OAC 165:10-15-18.

(2) **Reclassification of oil well as gas well.** If a well in a reservoir dewatering oil spacing unit is later subject to reclassification as a gas well for allowable purposes, such reclassification will be determined according to general classification procedures based on the its gas/oil ratio pursuant to OAC 165:10-1-6(d) and (e) and 165:10-13-2. If the subject well is designated an excessive water exempt oil project pursuant to OAC 165:10-15-1(g) and 165:10-15-16, reclassification shall be determined by OAC 165:10-15-1(g)(2). If the subject well is assigned an allowable based upon its most efficient rate pursuant to OAC 165:10-13-5, such allowable shall remain in effect under the order establishing the production rate, so that the well will not be reclassified, until its status is modified or terminated by the terms of the instant or a subsequent Commission order.

(3) **Termination of reservoir dewatering oil spacing unit allowable.** The oil allowable assigned a reservoir dewatering oil spacing unit shall remain in effect until one of the following occurs:

(A) The subject well is reclassified as a gas well pursuant to OAC 165:10-1-6 and 165:10-13-2.

(B) The subject well's status as an excessive water exempt oil project is terminated pursuant to OAC 165:10-15-1(g)(3).

(C) The subject well's status under a most efficient rate order is modified or terminated by the terms of the instant or a subsequent Commission order.

[**SOURCE:** Amended in Rule Making 200100009, eff 7-1-02]

165:10-15-2. Overage adjustments for oil wells

No well, lease, unit, or project shall be overproduced in excess of 15 percent of the allowable for the proration period. All overage accrued at the end of the proration period shall be deducted from the allowable for the second succeeding proration period.

165:10-15-3. Effect of percentage penalty on oil wells

If a percentage penalty has been assigned to an oil well, the penalty shall, depending on the status of the well, be subtracted from:

(1) **Discovery status.** The applicable allowable from the Discovery Allowable Table (Appendix B to this Chapter) or the capacity of the well to produce as reported on Form 1029A or the annual Form 1008A, whichever is less.

(2) **If allocated or unallocated per-well status.** The applicable allowable from the Allocated Well Allowable Table (Appendix A to this Chapter) multiplied by the current market demand factor or the capacity of the well to produce as reported on the initial Form 1029A or the annual Form 1008A, whichever is less.

(3) **If unallocated per-lease status.** The shallowest ten acre or less allowable from the Allocated Well Allowable Table (Appendix A to this Chapter) multiplied by the current market demand factor for the penalized well only. The penalty shall be subtracted from the lease allowable.

165:10-15-4. Discovery oil pools [RESERVED]

165:10-15-5. Discovery oil allowables

(a) **Number of barrels of oil per day and duration of the discovery allowable period.** The maximum number of barrels of oil per day and the duration of the discovery allowable period shall be determined from the Discovery Allowable Table (Appendix B to this Chapter) or the Allocated Well Allowable (Appendix A to this Chapter), whichever is greater, provided that the well is in compliance with the other provisions of this Section and other rules pertaining to allowables. If the well is not capable of producing at the discovery rate without causing preventable waste, the temporary discovery allowable shall be the capacity of the well to produce as reported on Form 1029A or the annual Form 1008A, unless otherwise limited by the Commission.

(b) **Effective date of discovery allowable.**

(1) The discovery allowable period for the pool shall begin with the date of first completion of the discovery well of the pool and extend as provided in the Discovery Well Allowable Table (Appendix B to this Chapter).

(2) The discovery allowable period for each well in the pool shall run from the date specified under 165:10-15-7 for each well to the date of termination of the pool, if granted administratively.

(3) If application, notice, and hearing are required, the effective date of the discovery allowable period shall be specified by an order of the Commission, provided that such date shall not precede the date of filing of the application. The date of expiration of the discovery allowable shall still be determined as set forth in (1) of this subsection.

(c) **Gross allowable production.** The gross allowable production for any proration period from a well in a discovery pool may, at the option of the operator, be produced at any time during the proration period; however, in no event shall the production exceed the maximum efficient rate of flow.

165:10-15-6. Production tests and reports for discovery oil pools

(a) **Initial test requirements.** The operator of each well in each discovery pool shall perform an initial potential test and furnish the Conservation Division the results of such test on Form 1029A not later than 30 days after completion of each well. Each individual well shall be tested for not less than six hours and not more than 24 hours with the production calculated and reported at a daily rate (24 hours).

(b) **Witnessing of tests.**

(1) With respect to initial test, the operator shall give twenty-four (24) hour notice of the opportunity to witness said test to the Conservation

Division and the offset operator(s) producing from the same pool, but no waiver or signature of Conservation Division personnel is required on Form 1029A.

(2) Any operator in the pool may witness any official test for any well in the pool. However, any person other than a Commission employee witnesses a test at their sole risk and expense.

[**SOURCE:** Amended at 9 Ok Reg 2337, eff 6-25-92; Amended in Rule Making 980000033, eff 7-1-99]

165:10-15-7. Procedure for obtaining discovery allowable

(a) Any operator desiring a discovery allowable shall file Form 1028 with the material and information specified below:

(1) A resistivity and a porosity type wireline survey of the well in question, if run.

(2) A Completion Report (Form 1002A) and Cementing Report (Form 1002C), completed in detail.

(3) A Potential Test (Form 1029A), completed in detail.

(4) A plat of the area showing all of the following information for each well within one and one-half (1 1/2) miles of the subject well:

(A) Operator.

(B) Well name and number.

(C) Total depth.

(D) Current status of the well (dry, oil, gas, injection, disposal, temporarily abandoned).

(E) Name of interval open, if any.

(F) Perforations, top and bottom, if any.

(G) Average daily production.

(5) An isopach contour map of the productive interval and/or a structural contour map of a nearby marker bed or formation, not separated from the producing interval by an unconformity, which is commonly used in the area. The Conservation Division may require either or both types of maps to determine the discovery status. The Commission may also require additional geological and/or engineering data, such as: stratigraphic cross-sections, structural cross-sections, production, and pressure information.

(b) The Conservation Division may administratively designate a discovery allowable for a well when the operator furnishes the Technical Department with the information specified in (a) of this Section. If the information is provided within 30 days of the date of first production and the application is approved, the effective date of the discovery allowable shall be the date of first production. If the information is provided more than 30 days after the date of first production and the application is approved, the discovery allowable shall be effective the date of filing.

(c) If a gas well in a discovery oil pool is reclassified as an oil well for allowable purposes, the operator must file the appropriate form, information and material specified in (a) of this Section within 30 days of reclassifying the well to obtain a discovery allowable. The allowable shall be effective the date the well was reclassified as an oil well as indicated on Form 1002A. If the application is not received within the specified time period, the application will be processed in accordance with (b) of this Section.

165:10-15-8. Allocated oil pools [RESERVED]

165:10-15-9. Allocated oil allowables

(a) **Effective date of allowables.** The allowable for an allocated well completed or recompleted on or after the first day of the proration period shall become effective the date of completion of the well, provided the operator has complied with the provisions of this Section and other rules governing

allowables. In situations where the operator fails to comply, the allowable shall become effective the date the operator complies with this Section and other rules governing allowables.
(b) **Allowables in allocated pools.** Allowables in allocated pools shall be granted on an individual well basis, subject to appropriate spacing requirements, unless otherwise specified by order of the Commission. The allowable for each allocated well shall be determined as if the well was an unallocated well operating under 165:10-15-12(b) or 165:10-15-12(c)(1), whichever is appropriate, unless adjusted by order of the Commission. The operator shall produce the allowable on each well from that well and no part thereof from any other well.
(c) **Application.** Upon application by the Director of Conservation or any interested party, and after notice and hearing, the Commission may order the wells in a common source of supply to be produced under allowables established by special pool rules in lieu of the provisions of this Section. All requirements as to production tests and allowables shall be set forth by the order of the Commission establishing such special pool rules.

165:10-15-10. Production tests and reports for allocated oil wells

All production tests and reports shall be filed as if the allocated well were an unallocated well operating on a per-well basis allowable under 165:10-15-13(a).

165:10-15-11. Unallocated oil pools [RESERVED]

165:10-15-12. Unallocated oil allowables

(a) **Effective date of allowable.** The allowable for a well completed or recompleted on or after the first day of a proration period shall become effective the date of completion of the well, provided the operator has complied with the provisions of this Section and other rules governing allowables. In situations where the operator fails to comply, the allowable shall become effective the date the operator complies with this Section and other rules governing allowables.
(b) **Well in an unallocated pool.** Each well in an unallocated pool in which drilling and spacing units have been established shall be assigned the applicable allowable on a per-well basis from the Allocated Well Allowable Table (Appendix A to this Chapter) multiplied by the current market demand factor unless adjusted by order of the Commission. The production from each well shall be separately accounted for to the Commission.
(c) **Lease in an unallocated pool.** Each individual lease in an unallocated pool in which drilling and spacing units have not been established shall be assigned allowables, at the option of the operator, on either of the following basis:
 (1) **A per-well basis.** If the operator elects to accept the per-well basis allowable, each well on the lease shall be assigned an allowable applicable to a ten-acre or less allowable at the appropriate depth from the Allocated Well Allowable Table (Appendix A to this Chapter) multiplied by the current market demand factor unless adjusted by order of the Commission. The production from each well shall be separately accounted for to the Commission.
 (2) **A per-lease basis.** If the operator elects to accept the per-lease basis allowable, the allowable for the lease shall be the shallowest ten-acre or less allowable from the Allocated Well Allowable Table (Appendix A to this Chapter) multiplied by the current market demand factor multiplied by the number of wells on the lease unless adjusted by order of the Commission. The production from each lease shall be separately measured and accounted for to the Commission.

165:10-15-13. Production tests and reports for unallocated oil wells

(a) **Per-well basis allowable.**

(1) If the well is an allocated well, or an unallocated well located on lands in which drilling and spacing units have not been established and the operator elected to accept allowables on a per-well basis, or an unallocated well located on lands in which drilling and spacing units have been established, the operator shall file a production test on Form 1029A no later than 30 days after the earlier of:

(A) Making the election,

(B) Completion of the well, or

(C) Recompletion of the well.

Each individual well shall be tested for not less than six hours and not more than 24 hours with the production calculated and reported at a daily rate (24 hours).

(2) Each new well shall be given an allowable equal to the allowable for an unallocated per-well basis well until the production test has been performed with the results reported to the Conservation Division on Form 1029A. The allowable shall be effective for a period not longer than 30 days from completion of the well. No further allowable shall be assigned to the well until compliance with this subsection.

(3) Until an operator submits the required test results for any well, as provided in subsection (a)(1), no allowable shall be assigned to the well. If said test results are filed late, then the allowable shall be effective the first day of the following month after the Conservation Division accepts the test.

(4) All initial tests shall be conducted in the manner set forth in (1) of this subsection.

(5) Annual testing shall not be required.

(b) **Per-lease basis allowables.**

(1) If the well is an unallocated well located on lands in which drilling and spacing units have not been established and the operator elects to accept allowables on a per-lease basis, the operator shall file a production test on Form 1029A with the Conservation Division not later than 30 days after:

(A) Making the election,

(B) Completion of the initial well on the lease,

(C) Completion of a subsequent well on the lease,

(D) Recompletion of any well on the lease, or

(E) Retesting of any well on the lease.

Each well on the lease shall be tested for not less than six hours and not more than 24 hours with the production calculated and reported at a daily rate (24 hours).

(2) Each lease shall be given an additional allowable equivalent to the shallowest ten-acre or less allowable from the Allocated Well Allowable Table (Appendix A to this Chapter) multiplied by the current market demand factor for each new producing well added to the lease until the production test has been performed with the results reported to the Conservation Division on Form 1029A. The additional allowable shall be effective for a period not longer than 30 days from completion of the well. No further additional allowable shall be assigned to the lease until compliance with this subsection.

(3) If an operator fails to submit the required test results for any lease with allowables calculated on a per-lease basis, no allowable shall be assigned to the lease. The operator may submit the results of the test to the Conservation Division on Form 1029A to reinstate the allowable. The allowable shall be effective the first day of the following month after the Conservation Division accepts the test.

(4) No lease shall be granted underage resulting from failure to perform a required test in compliance with this Section.

(5) All initial tests, annual tests and retests shall be conducted in the manner set forth in (1) of this subsection.

[**SOURCE:** Amended at 9 Ok Reg 2337, eff 6-25-92; Amended in Rule Making 980000033, eff 7-1-99]

165:10-15-14. Enhanced oil recovery project allowables

(a) **Effective date of allowable.** The allowable for an enhanced oil recovery project shall be effective on the date operations commenced or the date specified by order of the Commission authorizing the project, whichever is later, provided the operator has complied with the provisions of this Section and other rules governing allowables. In situations where the operator fails to comply, the allowable shall become effective the date the operator complies with this Section and other rules governing allowables.

(b) **Qualification for enhanced oil recovery allowable.** For any project to qualify for an enhanced oil recovery allowable, an order of the Commission authorizing the project must be obtained.

(c) **Allowable for enhanced oil recovery project.** The allowable for an enhanced oil recovery project shall be on a project basis and shall be the capacity of the project to produce.

(d) **Wells on a project producing from another reservoir.** Oil wells within the boundaries of a project which do not produce from the project shall not be permitted to produce any portion of the allowable of such enhanced oil recovery project. The oil produced by non-project wells shall be separately produced, measured, and reported.

165:10-15-15. Production tests and reports for enhanced oil recovery projects

(a) Within 30 days of commencement of any enhanced oil recovery project, the operator shall file with the Conservation Division an inventory of all the wells located within the boundaries of the project completed in the approved common source of supply showing the name of the project and the new OTC Production Unit Number (including merge number) and the following for each well:

(1) Previous OTC Production Unit Number.
(2) API Number.
(3) Well Name and Number.
(4) Legal location, including quarter quarter quarter quarter section.
(5) Current status (producer, injector, observation, or temporarily abandoned).

The inventory shall also include the current daily (24 hour) production and injection rates for the project.

(b) The operator shall notify the Conservation Division in writing within 30 days of the completion of any new well or the change in status of any existing well in the project.

(c) Until the operator submits the required test results for any enhanced oil recovery project as provided in subsection (a), no allowable shall be assigned to the project. If said test results are filed late, then the allowable shall be effective the first day of the following month after the Conservation Division accepts the tests.

(d) All initial tests shall be conducted as set forth in subsection (a).

(e) Annual testing shall not be required except as provided in OAC 165:10-1-6.

[**SOURCE:** Amended in Rule Making 980000033, eff 7-1-99]

165:10-15-16. Excessive water exempt oil project allowables

(a) **Effective date of allowables.** The allowable for an excessive water exempt oil project shall be on a well or a project basis and shall be effective when the Conservation Division receives and accepts the production test of, Form 1013, unless otherwise specified by order of the Commission.

(b) **Qualification for excessive water exempt oil project.** For any project or well to qualify for excessive water exempt allowable, an order of the Commission authorizing the well or project must be obtained.

(c) **Allowable for excessive water exempt oil project.** The allowable for a well or project which has received a special excessive water exempt allowable shall be the capacity of the well or project to produce without causing preventable waste unless otherwise adjusted by the Director of Conservation. The production from a well which has received a special excessive water exempt allowable under this Section shall be separately produced, measured, and accounted for to the Commission from the oil produced from the remainder of the lease.

165:10-15-17. Production tests and reports for excessive water exempt oil projects

(a) The operator of each individual well with an excessive water exempt allowable shall file an initial production test, in duplicate, on Form 1013 with the Conservation Division. Each individual well shall be tested for seven consecutive days, and the amount of oil and the amount of water produced each day shall be reported on Form 1013. With respect to the initial test, the operator shall give twenty-four (24) hour notice of the opportunity to witness said test to the Conservation Division and the offset operator(s) producing from the same formation, but no waiver or signature of Conservation Division personnel is required on Form 1013.
(b) Each individual well shall be given an initial allowable equal to the unallocated per-well basis allowable until the production test has been performed with the results reported to the Conservation Division on Form 1013. The allowable shall be effective for a period not longer than 30 days from completion of the well. No further allowable shall be assigned to the well until compliance with this subsection.
(c) Until the operator submits the required test results for any excessive water exempt well or project, as provided in subsection (a), no allowable shall be assigned to the well or project. If said test results are filed late, the allowable shall be effective the first day of the following month after the Conservation Division accepts the test.
(d) All initial tests shall be conducted as set forth in (a) of this Subsection.
(e) Annual testing shall not be required except as provided in OAC 165:10-1-6.

[**SOURCE:** Amended in Rule Making 980000033, eff 7-1-99]

165:10-15-18. Production tests and reports for reservoir dewatering oil spacing units

(a) **Effective date for oil allowable.** To establish the commencement date of an allowable for an oil well in a reservoir dewatering oil spacing unit, the operator shall file Forms 1002A and 1013, in lieu of the Form 1029A, with the Commission according to OAC 165:10-13-3 within thirty (30) days after the completion date of the well. The allowable will commence on the date of first production.
(b) **Qualification for reservoir dewatering unit.** Proof of fifty percent (50%) water saturation presented at the time of a hearing to establish dewatering oil spacing may entail calculations from logs or core data from wells within the common source of supply covered by the application or an analogous common source of supply, or an actual production test from a well in the common source of supply covered by the application. To qualify for the reservoir dewatering spacing unit allowable provided on Appendix J, the Form 1013 must provide data that verifies that the water-oil ratio is greater than 1:1. If the water-oil ratio is less than 1:1, then the oil allowable shall be the appropriate allowable for the depth of the top of the formation and the maximum acreage provided in Appendix A.
(c) **Allowable rate not provided for in Appendix J.** To establish an allowable other than that specified in Appendix J, the operator shall file a Form 1030 with the Commission to adjust the allowable.
(d) **Record of annual production rates.** The operator shall maintain production records on an annual basis. Operators shall make these records available to the Conservation Division staff upon the request of the Manager of the Technical Department. Annual testing shall not be required except as provided in OAC 165:10-1-6.

[**SOURCE:** Amended in Rule Making 200100009, eff 7-1-02]

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SUBCHAPTER 17. GAS WELL OPERATIONS AND PERMITTED PRODUCTION

Section

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165:10-17-1. Gas production from gas pools [RESERVED]

165:10-17-2. Classification of gas pools

(a) **Types of gas pools.** Each gas pool shall be classified by the Commission into one of the following categories:

(1) Allocated Gas Pool.

(2) Special Allocated Gas Pool.

(3) Unallocated Gas Pool.

(b) **Treatment of gas well in an oil pool.** If a well in an oil pool is classified as a gas well for allowable purposes, the well shall be treated as if it were in an unallocated gas pool, unless the well is subject to pool rules which establish allowables by volumetric withdrawal.

(c) **Allocated gas wells.**

(1) **Classification of pool by order.** Upon application, notice, and hearing, the Commission may issue an order establishing allowables for gas wells in a pool by the allocated gas pool rules in 165:10-17-8.

(2) **Status of an oil well reclassified as a gas well.** If a well classified as an oil well in an allocated gas pool is reclassified as a gas well for allowable purposes, the well shall be subject to allocated gas pool rules.

(3) **Termination of allocated status.** Each allocated gas well shall be subject to allocated gas pool rules until:

(A) The Commission establishes special allocated gas pool rules for the common source of supply.

(B) The well is reclassified as an oil well for allowable purposes.

(C) The Commission issues an order reclassifying the well as an unallocated gas well.

(D) The well becomes the only gas well in the pool.

(E) The well is abandoned.

(d) **Special allocated gas pools.** Each gas pool for which special pool allocation rules (field rules) are or have been established by the Commission shall be classified as a special allocated gas pool. Each gas well in a special allocated gas pool shall be referred to as a special allocated gas well for allowable purposes.

(e) **Unallocated gas pools.** Each gas pool not classified as an allocated gas pool or as a special allocated gas pool shall be classified as an unallocated gas pool. Each gas well in an unallocated gas pool shall be referred to as an unallocated gas well for allowable purposes.

165:10-17-3. Effective date of allowables

A gas well shall be assigned an allowable as of the date it is connected into a pipeline and the first delivery is made if the Notice of Intention to Drill (Form 1000) is valid, the Completion Report (Form 1002A) is filed with attachments, if required, and all required tests are run within 30 days from the date of first sales and are filed within 45 days of the date of first sales, and special reports have been filed with the Conservation Division.

[**SOURCE:** Amended in Rule Making 980000033, eff 7-1-99]

165:10-17-4. Standard gas measurement law

Sections 471 through 477, inclusive, of Title 52, Oklahoma Statutes Annotated, cited as the "Standard Gas Measurement Law", are hereby adopted as rules of the Commission as fully as if set out verbatim herein.

165:10-17-5. Meters and recorders

(a) **Requirement of a gas meter and recorder.**

(1) For allowable, allocation or custody transfer purposes, each well producing natural gas other than a shut-in gas well shall have a gas meter and recorder for the gathering line; provided, if two or more wells share a single allowable, a single meter and recorder may be used to measure gas production, unless a special order of the Commission or either 165:10-13-9 or 165:10-3-39 require allocation of gas production on a per well basis.

(2) For purposes of (1) of this subsection, the term "recorder" refers to a circular gas chart recorder or other type of recording device which has been mutually agreed upon by the gas seller and the gas purchaser.

(3) For purposes of (1) of this subsection, an offsite recorder shall be permitted provided:

(A) There is compliance with the requirements of (2) of this subsection.

(B) The recording device is made available for inspection by the Conservation Division to determine that the recorder is functioning properly.

(4) Offsite recordation under (1) and (3) of this subsection shall be treated as wellsite metering for purposes of the reporting requirements of 165:10-1-47.

(5) Use of electronic gas measurement and recording devices that meet industry standards of (b)(2) of this Section are permitted for allowable, allocation, custody transfer, and well testing.

(b) **Standards for meters and recorders.**

(1) Each meter and recorder shall be properly constructed, maintained, repaired, and operated to continually and accurately register the quantity of gas produced from the well into a gathering line.

(2) The meter and recorder shall be installed, used, and operated according to the natural gas industry standards and guidelines promulgated by the American Gas Association, the American Petroleum Institute, and the Gas Processors Association, in effect at the time of installation of the meter and recorder. If there are conflicting standards, then the most current American Petroleum Institute standard shall apply.

(c) **Prohibited meter bypasses.** For each meter measuring production at the wellsite, use of piping to bypass the meter is prohibited. Gas meters with internal bypasses are permitted.

(d) **Reporting of estimated volume if the meter or recorder fails.**

(1) **Seventy-two hours to repair equipment.** If a meter or recorder at the wellsite malfunctions, then the malfunctioning equipment shall be repaired within 72 hours after discovery of the malfunction.

(2) **Reporting of estimated volumes while the meter or recorder is down.** If the well continues to produce gas while the meter or recorder is malfunctioning or being repaired, estimated gas volumes shall be reported to the Conservation Division for purposes of 165:10-1-47.

[**Source:** Amended at 12 Ok Reg 2017, 7-1-95]

165:10-17-6. General well testing requirements

(a) All single-point and multi-point potential tests shall be calculated for all gas wells in a uniform manner with respect to the following:

(1) The potential shall be the calculated wellhead absolute open flow potential of the well determined by obtaining a static column wellhead flowing pressure and shall indicate the capacity of the well to produce against zero psia at the wellhead.

(2) All pressures used in test calculations shall be corrected to pounds per square inch absolute, using 14.4 psia as the average barometric pressure.

(3) The static column wellhead pressure, either measured or calculated as reported in the potential test, shall be no more than 90 percent of the wellhead shut-in pressure. If data cannot be obtained in accordance with the foregoing provisions, an assumed static column wellhead pressure of 90

percent of the wellhead shut-in pressure shall be used to calculate the results of the test. This paragraph supersedes any contrary provision in special pool rules.

(b) The operator of a well shall be responsible for testing the well and submitting the test results to the Conservation Division. The results of a potential test shall be filed with the Conservation Division on Form 1016. If the operator wishes to obtain a copy of the approved Form 1016, he shall enclose with the original form a self-addressed stamped envelope and one additional copy of the test and/or form. The Conservation Division shall acknowledge such requests within 15 days, stating either the date of acceptance of the test results or rerunning the original test if it has been rejected. If any order or rule of the Conservation Division requires witnessing of a test, the operator of the well shall be responsible for securing the presence of an authorized Conservation Division representative to witness the test and sign the Form 1016 for the test.

(c) Unless otherwise prescribed by special pool rules, field testing procedure shall be performed in accordance with the procedures set out in Oklahoma Corporation Commission Manual of Back-Pressure Testing of Gas Wells, Parts I and II, utilizing the specified tables in the Interstate Oil and Gas Compact Commission Manual of Back-Pressure Testing. A gas turbine meter may be used in lieu of an orifice meter for flow measurements in gas well testing.

(d) The initial test for all gas wells shall be run into the pipeline within 30 days and test results filed within 45 days after the date of first sales of gas. Any test filed after the 45 day limit will not be made effective until the first of the month following the date of acceptance of the test. With regard to initial tests for special allocated gas wells, the operator of the well shall provide twenty-four (24) hours notice to the Conservation Division of its intent to run an initial test in order to give the Conservation Division the opportunity to witness said test, but in no case shall the operator be precluded from performing said test and filing the results as provided for in subsection (b). Initial tests for special allocated gas wells need not be witnessed, nor signatures obtained, if witnessed, in order for the Conservation Division to assign an allowable to said well. Initial tests for unallocated gas wells with calculated open flow of less than two million cubic feet per day are exempt from witnessing by Conservation Division personnel under 165:10-17-7(b)(1).

(e) The annual test for all gas wells shall be run into a pipeline in accordance with this Section or applicable pool rules. Any annual test for a well in a special allocated pool, filed late shall not be made effective until the first of the month following the date of acceptance of the test.

(f) Wells in allocated pools shall be tested in accordance with the requirements for wells in unallocated pools, unless superseded by specific field rules. Form 1016 shall be used to report shut-in pressure tests on wells in allocated and special allocated pools, except for the Guymon-Hugoton Pool #182 which shall use a form 1017 Deliverability Gas Test.

[**SOURCE:** Amended in Rule Making 980000033, eff 7-1-99]

165:10-17-7. Well tests

(a) **Wells in special allocated pools.**

(1) An initial test shall be filed for each newly completed gas well in each special allocated pool. The well shall be tested into a pipeline no later than 30 days after the date of the first sale of gas. Test procedures shall be those specified in the applicable pool rules subject to the uniform requirements of 165:10-17-6.

(2) An annual test shall be filed in accordance with the requirements of the applicable pool rules, subject to the following provisions specific to the Guymon-Hugoton special allocated pool.

(3) **Wells in the Guymon-Hugoton special allocated pool.**

(A) The Conservation Division staff will not be required to witness any well test on any well in the Guymon-Hugoton special allocated gas pool unless requested to do so by an offset operator. Operators have a right to witness any well test on any well offsetting said operator's well in the pool. Operators of offsetting wells will be given sufficient prior notice of testing to allow for a representative to be present to witness testing, and will be provided access to the designated witness throughout testing.

(B) Wells in the Guymon-Hugoton special allocated gas pool which are not capable of producing 450 Mcf/day will be exempt from biannual deliverability tests. Operators shall have the right to elect to receive the minimum allowable by deciding not to conduct well deliverability tests on any such wells in the pool. No well shall be exempt from the annual wellhead shut-in pressure test requirements. For the purpose of the annual wellhead shut-in pressure test, the shut-in pressure shall be measured after the well has been shut-in for approximately 48 hours. In no case shall the well have been shut-in for less than 44 hours at the time the shut-in pressure is taken.

(b) **Wells in unallocated pools.**

(1) **Testing of newly completed wells.**

(A) An initial test shall be submitted to the Conservation Division for each newly completed gas well in an unallocated gas pool under 165:10-17-2. The well shall be tested into a pipeline no later than 30 days after the date of first sale of gas into a pipeline. The flow period for the initial test shall be 24 hours. It shall not be necessary for the operator to submit the initial flow potential test for an unallocated well with a calculated open flow of less than 2,000,000 cubic feet per day, only the wellhead shut-in pressure taken for a minimum of 24 hours for the well is required, unless requested by the Commission. All tests and initial shut-in pressures shall be submitted to the Conservation Division on Form 1016 and, at the operator's discretion, in digital magnetic form in a format prescribed by the Commission. The form shall contain complete and accurate information.

(B) If said initial test is taken between the first day of January and the thirty-first day of July of the calendar year, the test shall be used for allowable purposes for the calendar year unless the operator later submits a retest which is accepted by the Conservation Division.

(C) The well shall also be tested during the annual test period between the first day of May and the thirty-first day of October, but no sooner than three months after the initial test. Said test shall be used for the annual test to determine permitted production for the following calendar year unless the well is later retested.

(D) If the test used for the following year cannot be submitted during the annual test period, the Conservation Division may grant administratively a written extension of time up to 30 days beyond the thirty-first day of October for running the test.

(2) **Annual test period for other wells.** An annual potential test shall be run on each gas well in each unallocated pool between May 1, and November 30, and must be accepted by the Commission no later than December 15, except for wells exempt under (4) of this subsection. The annual potential test shall be effective January 1 of the succeeding calendar year (annual accounting period) unless superseded by a later test. The Director of Conservation may require additional tests at any time. Retests become effective the first day of the month following acceptance of the test by the Conservation Division.

(3) **One-point tests.** The potential test required for each gas well in each unallocated pool shall use the one-point back pressure method and an assumed flow characteristic of 0.85 shall be used in establishing the wellhead absolute open flow. The test shall be governed by the requirements of OAC 165:10-17-6.

(4) **Minimum well exemption from annual tests.** Each gas well in each unallocated pool having a tested potential of 2,000,000 cubic feet of gas per day, or less, shall thereafter be exempt from the annual potential test, and the operator of the well shall report annually the results of an annual wellhead shut-in pressure test taken for a minimum of 24 hours on Machine Accounting Form 1007A and, at the operator's discretion, in digital magnetic form in a format prescribed by the Commission unless the Director of

Conservation waives in writing the pressure test requirement. Machine Accounting Form 1007A, when received by the operator, shall be used to report shut-in pressure tests and gas sales from the previous calendar year on wells in unallocated pools. Wellhead shut-in pressure just for minimum wells may be taken any time during the year, but must be taken at least six months after the test submitted for the prior year.

(5) **Retests.** Retests may be run at any time and shall become effective the first day of the month following acceptance of the test by the Conservation Division. Retests submitted during the unallocated gas well testing period of May 1, through October 31, will also be classified as annual-status tests to establish the allowable for the following year.

(6) **Minimum compliance.** Each operator shall be responsible for conducting and submitting the required potential tests on the applicable form and for the annual reporting of all required information on Machine Accounting Form 1007A and, at the operator's discretion, in digital magnetic form in a format prescribed by the Commission. All submitted tests and 1007A forms must contain complete and accurate information. Permitted production rates will be granted only to those wells which meet this requirement and all other rules or orders of the Commission.

[**SOURCE:** Amended in Rule Making 97000002, eff 7-1-97; Amended in Rule Making 97000011, eff 7-1-98; Amended in Rule Making 980000033, eff 7-1-99]

165:10-17-8. Allocated pools

(a) The current monthly allowable for each allocated pool shall be equal to the total production from the pool during the current month.

(b) The current allowable for each capable drilling and spacing unit within the pool shall be that proportion of the pool allowable that the acreage of the drilling and spacing unit bears to the total developed acreage in the pool, adjusted in accordance with any order of the Commission imposing an allowable adjustment. The current allowable for each limited drilling and spacing unit shall be equal to the current production from the unit. A unit shall be deemed limited when its underage is cancelled under this Section until it thereafter produces a current allowable for any one month.

(c) Accrued underage shall be carried forward as a cumulative credit by adding it to the unit's current allowable until the underage has been produced. If the unit's cumulative underage exceeds six times the allowable assigned to it for the preceding January, all of the underage will be cancelled, the unit shall be classified as "limited", and the unit shall not thereafter accumulate underage until such time as the unit produces a current allowable for any one month. All cancelled underage shall be distributed to the capable drilling and spacing units within the pool in the proportion that the acreage of each unit bears to the total capable acreage in the pool, adjusted in accordance with any order of the Commission imposing an allowable adjustment. A capable unit shall be any nonlimited unit. Cancelled underage may be reinstated administratively by the Director of Conservation to any capable unit in an overproduced status within six months after cancellation by application on Form 1010.

(d) Accrued overage shall be carried forward as a cumulative charge against the unit by subtracting it from the unit's current allowable until the overage has been made up. If the cumulative overage exceeds six times the current allowable assigned for the preceding January, the Director of Conservation shall notify the operator in writing, and the unit shall thereafter be permitted to produce not more than 25 percent of its current allowable until all of the overage in excess of six times the well's current allowable for the preceding January has been made up. In the event the operator fails to limit production as herein provided, the well shall be ordered shut-in by the Commission upon application of the Director of Conservation and after notice and hearing.

(e) If a unit did not have a current allowable assigned to it on a full month's basis for the preceding January, the first current allowable assigned to the unit on a full month's basis shall be used as reference for the purpose of limiting underage and overage.

165:10-17-9. Special allocated gas pools

(a) **Scope.** This Section applies to special allocated gas pools except any special allocated gas pool with allowables based upon volumetric withdrawals.

(b) **Minimum unit allowable of 150 mcf/d.** For all special allocated gas pools except the West Cheyenne Upper Morrow, Purvis Chert, Guymon-Hugoton, Custer City N. Hunton, Sharon W. Morrow, Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro, the minimum allowable for a drilling and spacing unit in the pool shall be 150 MCF/D regardless of the amount of any location exception penalty charged against a unit well. For purposes of this Section, the net minimum allowable shall be the gross minimum allowable adjusted for overage or underage according to this Section.

(c) **Minimum unit allowable of 450 mcf/d for the Guymon-Hugoton pool.**

(1) For the Guymon-Hugoton Special Allocated Gas Pool, minimum allowables shall be determined as follows: The minimum allowable shall be the lesser of 450 mcf/d or the drilling and spacing unit's capability. Capability shall be defined as the average of the highest three (3) of the last twelve (12) months of production. A drilling and spacing unit receiving a minimum allowable shall not accrue underage. The minimum allowables under this Section shall not affect the calculation of capable well allowables. The field monthly allowable shall be equal to total nominations and not adjusted for underage or overage.

(2) The deliverability standard pressure (DSP) to be used in the application of special allocated rules (field rules) shall be defined as 25 pounds less than the average shut-in wellhead pressure of the pool.

(3) The Corporation Commission shall calculate and publish reports of allowable and production quarterly.

(d) Minimum unit allowable of 2,000 mcf/d for the Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro Pools. For the Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro Pools (Pool Nos. 456, 457 and 458) located in Latimer and LeFlore Counties, Oklahoma, the minimum allowable for a drilling and spacing unit in each pool shall be 2,000 mcf/d. For purposes of this Section, the net minimum allowable shall be the gross minimum allowable adjusted for overage or underage according to this Section.

(e) **Double minimum allowable of 300 mcf/d.**

(1) **Compressor and application required.** For all special allocated gas pools except the West Cheyenne Upper Morrow, Purvis Chert, Guymon-Hugoton, Custer City N. Hunton, Sharon W. Morrow, Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro, if a drilling and spacing unit has a minimum allowable under (b) of this Section, the operator of a well in the drilling and spacing unit may obtain for the unit a double minimum allowable regardless of any location penalty against a well by installing a compressor on a unit well and applying for a double minimum allowable under (2) of this subsection.

(2) **Request for administrative approval.** To apply for a double minimum allowable, the operator shall submit to the Manager of Production Allowables for the Conservation Division a letter requesting a double minimum allowable and stating the factual basis for the request and the legal description of the well with the compressor.

(f) **Basic allowable.**

(1) **Use of basic allowable for determining overage and underage.** For purposes of determining the amount of overage or underage accrued by a well or drilling and spacing unit, the Conservation Division shall establish on a yearly basis a status factor known as the basic allowable.

(2) **Apportionment of basic allowable.**

(A) **Increased density unit without apportionment of the allowable.** If neither OAC 165:10-13-9 nor an order of the Commission require specific allocation of the unit allowable to each unit well, overage and underage shall be carried on a unit basis.

(B) **Increased density unit with ratable allowables.** If either OAC 165:10-13-9 or an order of the Commission require specific allocation of the unit allowable to each unit well, overage and underage shall be carried on a per well basis. For purposes of computing overage and underage, the basic allowable shall be apportioned to each unit well using the formula for determining each well's ratable allowables for the applicable month under (3) of this subsection. The term "ratable allowables" refers to a well's share of the unit allowable under the formula apportioning the allowable amongst the unit wells.

(3) **Computation of the basic allowable.** Except as provided in (C) of this paragraph for basic allowable changes, the basic allowable for the calendar year shall be computed as follows:

(A) **For all pools except the Red Oak Pools.** For all pools except the Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro, the basic allowable shall equal the drilling and spacing unit's January allowable for the calendar year.

(B) **For the Red Oak Pools.** For the Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro, the basic allowable shall equal the drilling and spacing unit's March allowable for the calendar year.

(C) **Changes in the basic allowable.**

(i) **Test exempt minimum allowable.** If a drilling and spacing unit receives test exempt minimum allowable status as provided in this Section, then the basic allowable shall be a minimum allowable.

(ii) **Test exempt double minimum allowable.** If a drilling and spacing unit receives a test exempt double minimum allowable as provided in this Section, then the basic allowable for the unit shall be a double minimum allowable.

(iii) **Retests.** If the well operator submits to the Conservation Division a retest which is approved by the Conservation Division, then the Conservation Division shall recompute the basic allowable using the retest. Retests are permitted at any time and become effective the first day of the month after acceptance by the Conservation Division.

(g) **Determination of overage and underage.**

(1) **Overage.**

(A) **Drilling and spacing unit without ratable allowables.** If no well in a drilling and spacing unit is subject to a ratable allowable, the current monthly allowable shall be compared with the second prior month's unit production. Production in excess of the current monthly allowable is overage. Aside from any adjustment to the pool allowable required by pool rules, overage shall not reduce any subsequent monthly allowable until accumulated overage exceeds the applicable overage limit under (h) of this Section.

(B) **Drilling and spacing unit subject to ratable allowables.** If any well in a drilling and spacing unit is subject to a ratable allowable, the current monthly ratable allowable for the well shall be compared with the second prior month's production from the well. Production in excess of the ratable allowable is overage. Aside from any adjustment to the pool allowable required by pool rules, the well's overage shall not reduce any subsequent monthly ratable allowable until accumulated overage exceeds the well's overage limit under (h) of this Section.

(2) **Underage.**

(A) **Drilling and spacing unit without ratable allowable.** If no well in a drilling and spacing unit is subject to a ratable allowable under OAC 165:10-13-9, the current monthly allowable for the unit shall be compared with the second prior month's unit production. If production is less than the allowable, the difference between the production and the unit allowable is underage. Aside from any adjustment to the pool allowable required by pool rules, only reinstated cancelled underage under (k) of this Section shall increase any subsequent monthly allowable.

(B) **Drilling and spacing unit with ratable allowables.** In a drilling and spacing unit with ratable allowables, the current monthly ratable allowable for a well shall be compared with the second prior month's production from the well. If production was less than the current monthly ratable allowable, the difference between the production and the ratable allowable is underage. Aside from any adjustment to the pool allowable required by pool rules, only reinstated cancelled underage under (k) of this Section shall increase any subsequent monthly ratable allowable for the well.

(h) **Overage limits.**

(1) **For all pools Except the Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro.** For all pools except the Red Oak Fanshawe, Red Oak Red Oak, and the Red Oak Spiro, the overage limit is six times:

(A) The basic allowable for the drilling and spacing unit, if the overage carried on a unit basis; or

(B) The well's share of the basic allowable for the drilling and spacing unit, if the well receives a ratable allowable.

(2) **For the Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro Pools.** For the Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro Pools, the overage limit is 168 times:

(A) The basic allowable for the drilling and spacing unit, if the overage is carried on a unit basis; or

(B) The well's share of the basic allowable for the drilling and spacing unit, if the well receives a ratable allowable.

(3) **Mandatory curtailment for excessive overage.**

(A) **Single well drilling and spacing unit.** If accumulated overage from a single well drilling and spacing unit exceeds the applicable overage limit, production from the unit shall be curtailed to 25 percent of the monthly allowable until accumulated overage is reduced below the overage limit.

(B) **Multiple well unit without ratable allowables.** In a multiple well drilling and spacing unit without ratable allowables, if accumulated overage for the unit exceeds the applicable overage limit, the unit production shall be curtailed to 25 percent of its monthly allowable until the accumulated overage is reduced below the overage limit.

(C) **Multiple well unit with a ratable allowable.** In a multiple well drilling and spacing unit with one or more wells subject to a ratable allowable, if the accumulated overage for a well exceeds its overage limit, production from the well shall be curtailed to 25 percent of its monthly ratable allowable until the well's accumulated overage is reduced below its overage limit.

(i) **Underage limits.**

(1) **For the Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro Pools.** For the Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro Pools (Pool Nos. 456, 457 and 458) located in Latimer and LeFlore Counties, Oklahoma, the underage limit is three times the status factor for:

(A) The drilling and spacing unit,

(i) If the unit has only one well, or

(ii) If the unit has multiple wells but no unit well has a ratable allowable; or

(B) The well, if a well has a ratable allowable.

(2) **For all other special allocated gas pools subject to this Section.** For all other special allocated gas pools subject to the Section, the underage limit is six times the status factor for:

(A) The drilling and spacing unit, if the status factor is determined on a unit basis; or

(B) The well, if the well is subject to a ratable allowable.

(j) **Cancellation of underage.**

(1) **Underage in excess of the underage limit.** If accumulated underage exceeds the applicable underage limit, the accumulated underage shall be cancelled.

(2) **Subsequent underage.** After cancellation, underage shall not accrue until after:

(A) The drilling and spacing unit produces a current monthly allowable, if the unit wells share a unit allowable; or

(B) A well with a ratable allowable produces a current monthly ratable allowable.

(k) **Reinstatement of cancelled underage.**

(1) The operator may apply for reinstatement of cancelled underage by:

(A) An application for administrative approval on Form 1010, if filed within six months after cancellation of underage; or

(B) Application, notice, and hearing under OAC 165:5-7-1.

(2) Reinstated cancelled underage shall be available to increase the monthly allowable or ratable allowable for up to one year without cancellation. If reinstated underage is cancelled, the operator may reapply under (1) of this subsection.

(3) For the Guymon-Hugoton special allocated gas pool, the operator of any drilling and spacing unit in such pool which unit has accumulated cancelled underage credited thereto on the records of the Commission prior to July 1, 1998 shall have until January 1, 2000 to file an application with the Commission pursuant to OAC 165:5-7-1 for the reinstatement of such accumulated cancelled underage as credited to such unit prior to July 1, 1998. Upon the filing of such an application, the cause seeking reinstatement of such accumulated cancelled underage shall be diligently prosecuted. In such proceeding for the reinstatement of such accumulated cancelled underage credited to such drilling and spacing unit prior to July 1, 1998, the Commission shall determine the portion of such accumulated cancelled underage which is proper and valid under the special pool allocation rules (field rules) applicable to the Guymon-Hugoton special allocated gas pool and shall reinstate only such portion that is determined to be proper and valid under such special pool allocation rules (field rules). If an application for reinstatement of any such accumulated cancelled underage credited to a drilling and spacing unit on the records of the Commission prior to July 1, 1998 is not filed with the Commission on or before January 1, 2000, such accumulated cancelled underage shall be permanently deleted from the records of the Commission and shall not thereafter be able to be reinstated or used for any other purpose under the special pool allocation rules (field rules) applicable to the Guymon-Hugoton special allocated gas pool.

(l) **Effect of reinstatement of underage on pool allowables.** If cancelled underage has been distributed among the capable wells in the pool, reinstated underage shall not be deducted for the allowables of the capable wells which received distributed cancelled underage.

(m) **Test exempt status.**

(1) **No allowable without test.** For all pools except West Cheyenne Upper Morrow and Purvis Chert, no allowable shall be assigned unless:

(A) **Single well drilling and spacing unit.** The operator submits the required test or the unit has test exempt status under this Section.

(B) **Multiple well drilling and spacing unit.** In a multiple well drilling and spacing unit, the operator of at least one well in the unit submits the required test in accordance with applicable pool rules or the unit is granted test exempt status under this Section.

(2) **Automatic test exempt status.**

(A) **For the West Cheyenne Upper Morrow and Purvis Chert Pool.** For the West Cheyenne Upper Morrow and Purvis Chert, a drilling and spacing unit shall have test exempt status as follows:

(i) **Single well drilling and spacing unit.** In a single well drilling and spacing, the well operator does not submit either an initial or an annual test.

(ii) **Multiple well drilling and spacing unit.** In a multiple well drilling and spacing unit, none of the well operators in the unit submit either an initial or annual test. A test exempt drilling and spacing unit on the West Cheyenne Upper Morrow and Purvis Chert Pools shall have a minimum allowable under the applicable orders establishing and modifying pool rules as opposed to (b) of this Section.

(3) **Test exempt status upon requests for all other pools.** For all other pools except Guymon-Hugoton a drilling and spacing unit shall be test exempt upon written request to the Conservation Division if the potential for the unit does not exceed:

(A) The applicable minimum allowable under this Section.

(B) A double minimum allowable, if the Conservation Division has granted a double minimum to the unit.

(4) **Termination of requested test exempt status.**

(A) **Automatic termination.** Requested test exempt status shall terminate upon:

(i) **Submission of a retest.** Submission of a retest showing that the well has a potential in excess of a test exempt allowable, or;

(ii) **Overproduction.**

(I) **Single well drilling and spacing unit.** If gas production from a single well drilling and spacing unit exceeds a test exempt allowable during any month while the well has test exempt status, the unit shall lose test exempt status beginning with next month following the month with overproduction.

(II) **Multiple well drilling and spacing unit.** If total gas production from a multiple well drilling and spacing unit exceeds the minimum allowable during any month while the unit has test exempt status, the unit shall lose test exempt status beginning with the next month following the month with overproduction.

(B) **Reinstatement of test exempt status after automatic termination.** After termination of test exempt status for overproduction, the Conservation Division shall not reinstate test exempt status until:

(i) The operator requests test exempt status; and

(ii) The allowable year during which overproduction occurred expires.

[**SOURCE:** Amended in Rule Making 970000011, eff 7-1-98; Amended in Rule Making 980000033, eff 7-1-99; Amended in Rule Making 200100006, eff 7-1-01; Amended in Rule Making 200400006, eff 7-1-04]

165:10-17-10. Unallocated pools [RESERVED]

165:10-17-11. Maximum permitted rates of production for unallocated gas wells

(a) **Scope.**

(1) This Section shall apply to each gas well in unallocated status except as otherwise provided by Commission order. The Commission may establish different production rates by:

(A) Location exception order.

(B) Establishment of pool rules for the common source of supply.

(C) Other order adjusting gas production from the well.

(2) For purposes of this Section, the term "well" shall include any drilling and spacing unit with multiple unallocated gas wells, which do not receive separate maximum permitted rates of production by Commission order.

(3) For the purposes of this Section, the term "allowable formula" shall mean the formula used by the Commission for the determination of the daily rates for capable and minimum wells.

(4) For purposes of this Section, the term "capable well" shall refer to those unallocated gas wells having a wellhead absolute flow potential of 2000 mcf/d or greater. All other wells are minimum wells.

(5) For purposes of this Section, the term "daily natural flow" means the wellhead absolute open flow potential determined in the manner described in OAC 165:10-17-6 and OAC 165:10-17-7.

(b) **Commission authority and responsibility.** Production shall be governed by the provisions of 52 O.S. Section 29. Pursuant to said statute, the Commission has the power and authority to adjust allowables to meet reasonable market demand. The Commission, upon its own application, after notice and hearing, shall establish allowables which may be greater or lesser than those set forth in 52 O.S. Section 29.

(c) **Procedure.**

(1) Allowables for wells other than those provided in subsections (a), (e), (f), and (g) of this Section shall be determined pursuant to a proration hearing held at least semiannually for the proration periods of April through September and October through March. The Commission may hold additional proration hearings at shorter intervals if necessary. At least 15 days prior to scheduled semiannual hearings, the Commission shall publish

in a newspaper of general circulation in Oklahoma County, the proposed allowable formula for the next proration period. The semiannual proration hearings shall be held at least 30 days prior to the proration period for which the allowable is being determined. Such hearing shall be for the purpose of gathering comments and hearing testimony from all interested parties concerning the determination of reasonable market demand for the next proration period. As a guideline, but not to the exclusion of any other information that the Commission deems pertinent, the following may be considered by the Commission in determining reasonable market demand and corresponding allowables:

(A) Production from prior years.

(B) Production from the most recent proration period.

(C) Wellhead open flow potentials.

(D) New wells, recompletions, temporarily abandoned wells and plugged wells.

(E) Gas which is available but is not being produced at the present time.

(F) Changes in existing gas markets, forecasts, and new markets for Oklahoma gas.

(G) State-wide gas production and the portion thereof attributable to unallocated gas wells.

(H) Overproduction and underproduction from the preceding proration period.

(2) After a proration hearing, the Commission shall publish in a newspaper of general circulation in Oklahoma County, the allowable formula, no later than 15 days prior to the proration period for which the allowable formula is determined.

(d) **Emergency allowables.**

(1) When the Commission determines that an emergency gas supply situation exists, the Commission may establish an emergency allowable. The emergency allowable shall provide for the protection of correlative rights including those relating to minimum wells and penalized wells.

(2) The Commission may extend or change the emergency allowable for as long as an emergency exists. However, any authorized extension of the emergency allowable shall be by order after notice and hearing.

(e) **Exceptions.** Upon application, notice, and hearing, the Commission may establish a different allowable for good cause shown.

(f) **Exclusion for hardship and distressed wells.** The allowable established under this Section shall not limit rates established by special order for those wells classified as hardship or distressed wells.

(g) **Discovery gas well.**

(1) For thirty (30) months from the date of first production, a discovery gas well, as defined in this subsection, subject to the provisions of this Section, shall have a production allowable which shall be the greater of one thousand three hundred (1,300) mcf/d or sixty-five percent (65%) of the absolute open flow (AOF) as specified by the Corporation Commission. Such discovery well allowable shall not be available for any discovery gas well wherein two (2) or more separate common sources of supply are commingled and one (1) common source of supply would not qualify a new gas well as a discovery gas well, as defined in this Section.

(2) Drilling and spacing units which are downspaced after June 1, 1997, shall not qualify for the discovery gas well allowable.

(3) For purposes of this subsection, "discovery gas well" shall mean a new gas well, which is not an off-pattern well, is the first well completed in a common source of supply within a drilling and spacing unit and is at least one (1) mile from all existing gas wells which are completed in the same common source of supply. In the absence of spacing, a discovery well shall be the first well in the governmental section completed in a common source of supply, provided that the discovery gas well shall not be drilled closer than one thousand three hundred twenty (1,320) feet from the boundaries of the governmental section and is at least one (1) mile from all existing gas wells which are completed in the same common source of supply.

(h) **Minimum compliance.**

(1) The Conservation Division shall monitor well production at least annually. The allowable for a well shall be based on the product of the number of days in the proration period, multiplied by the applicable allowable formula, provided that said product shall be reduced for overproduction as provided by this Section or by any penalty or limitation on production imposed by applicable Commission order.
(2) Any overproduction existing at the end of the calendar year shall be applied against the allowable for the next calendar year. Furthermore, the overproduced well shall be required to make up overproduction within the first six months of the next calendar year. If the overproduction is not made up within that time period, the flow rate shall not exceed ten percent of the then current allowable until the overproduction is made up.

[**Source:** Amended at 9 Ok Reg 3969, eff 8-28-92 (emergency); Amended at 10 Ok Reg 1275, eff 9-25-92 (emergency); Amended at 10 Ok Reg 1579, eff 5-13-93; Amended in Rule Making 97000002, eff 7-1-97; Amended in Rule Making 980000011, eff 7-1-98; Amended in Rule Making 200200017, eff 7-1-02]

165:10-17-12. New proposed well classification for the priority schedule
(a) Any common purchaser as defined in 52 O.S. 1981, Section 240 shall purchase all the gas which may be offered for sale and which may reasonably be reached by its trunk lines or gathering lines, without discrimination in favor of one producer as against another or in favor of any one source of supply as against another, except as authorized by the Commission under (b) of this Section.
(b) In the interest of the prevention of waste and protection of correlative rights, the following priority schedule shall be implemented by any first purchaser of gas whenever the permitted production from all wells in any common source of supply in its system in this State, including gas which is processed, is in excess of that purchaser's reasonable market demand; provided, however, if the first purchaser does not contractually control wellhead production, the first taker of gas shall be responsible for implementation of the following priority schedule.
(1) Priority One - Hardship and distressed wells.
(2) Priority Two - Enhanced recovery wells.
(3) Priority Three - Wells producing casinghead gas and associated gas.
(c) With respect to all gas not identified in (b) of this Section, the collective market demand of multiple common purchasers on each pipeline system for natural gas production from each well and each common source of supply in this state shall be deemed adequate to meet statutory purchasing requirements unless the Commission, upon its own motion or upon verified application by any interested party and after notice and hearing, as hereinafter provided, shall determine that differing obligations shall be imposed upon any common purchaser in order to protect correlative rights, the interest of the public or otherwise meet the requirements of applicable law.
(d) When permitted production of gas from all Priority 1, 2, and 3 wells from which a purchaser or taker is required to take exceeds the market demand of said purchaser or taker, all reductions in gas purchases or takes from wells in each priority shall be ratable. All production from the lower priority wells shall be shut-in before production from any well in the next higher priority is curtailed.
(e) Any well which meets the definition of more than one priority shall be assigned the higher priority.
(f) When there is more than one purchaser or taker involved in the taking of gas from a well into any purchaser's system, all purchasers and takers within that system shall be responsible for compliance with this Section.
(g) Upon a verified application of the Director of the Conservation Division or any other person, the Commission, after notice and hearing, may determine if gas has been ratably purchased or taken from a common source of supply on a system-wide basis in accordance with this Section without avoidable waste and

with equitable participation in production and markets by all operators and other interested parties.
(h) First purchasers or takers of gas produced from Priority 1, 2, or 3 wells, who anticipate curtailing production from such wells, shall file by the twentieth day of each month nominations of requirements for gas to be purchased and/or used by them during the following month (Form 1004B). Nominations shall be made according to priorities established in (b) of this Section. Curtailments of production and acceptance of deliveries of gas shall be performed in accordance with (a) and (b) of this Section.
(i) Any interested party may file an application requesting that the Commission, for good cause shown, authorize limited deviation from the general priority schedule provided under (b) of this Section. The Commission, on its own motion, may initiate a review of the continued need for such a limited deviation. After notice and hearing, the Commission may authorize limited deviation upon finding that the same is necessary in order to prevent waste, protect correlative rights, and is otherwise required by the public interest or authorized by law.

[**Source:** Amended at 12 Ok Reg 2045, eff 7-1-95]

165:10-17-13. Use of gas for carbon black
Gas may not be used for the manufacture of carbon black or similar products predominately carbon, except as specifically authorized by the Commission after notice and hearing.

165:10-17-14. Waste of tail gas at gasoline plants
The duty, obligation, and jurisdiction of the Commission to prevent waste of tail gas where an additional market is available shall not be circumvented by any exclusive provisions in private contracts between the owners and the purchasers of tail gas.

165:10-17-15. Gas removed from storage
The rules relating to gas production from pools shall not apply to gas being removed from storage except and unless waste is involved.

165:10-17-16. Reports
A calendar year shall constitute the accounting period for each unallocated gas well. At the end of each calendar year, the Conservation Division will mail an original and one copy of Machine Accounting Form 1007A (Unallocated Gas Well Survey) to the operator, and the operator shall complete and file the original form with the Conservation Division on or before the following February 15th and retain the copy for his own use.

[**Source:** Amended in Rule Making 200200017, eff 7-1-02]

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SUBCHAPTER 19. NATURAL GAS POLICY ACT DETERMINATION [REVOKED]

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165:10-19-1. Definitions [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2401, eff 7-1-96]

165:10-19-2. Applications for NGPA determination [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2401, eff 7-1-96]

165:10-19-3. Application for additional well in existing proration unit [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2401, eff 7-1-96]

165:10-19-4. Notice of application; service of notice [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2401, eff 7-1-96]

165:10-19-5. Procedures for protest, administrative consideration, and hearing [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2401, eff 7-1-96]

165:10-19-6. Stripper well determination [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2401, eff 7-1-96]

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SUBCHAPTER 21. APPLICATIONS FOR TAX EXEMPTIONS

PART 1. TERTIARY RECOVERY PROJECT [REVOKED]

PART 2. ENHANCED RECOVERY PROJECT [REVOKED]

PART 3. HORIZONTALLY DRILLED PRODUCTION WELLS [REVOKED]

PART 4. DELETERIOUS SUBSTANCES [REVOKED]

PART 6. PRODUCTION ENHANCEMENT PROJECTS

PART 7. RE-ESTABLISHMENT OF PRODUCTION FROM AN INACTIVE WELL

PART 8. DEEP WELLS

PART 9. NEW DISCOVERY WELLS

PART 11. HORIZONTALLY DRILLED PRODUCING WELLS

PART 13. INCREMENTAL PRODUCTION FROM ENHANCED RECOVERY PROJECTS

PART 14. PRODUCTION OF OIL, GAS OR OIL AND GAS FROM ANY WELL LOCATED WITHIN

BOUNDARIES OF A THREE-DIMENSIONAL SEISMIC SHOOT

PART 15. GENERAL PROVISIONS

PART 17. SALES TAX EXEMPTION FOR ELECTRICITY AND ASSOCIATED DELIVERY AND TRANSMISSION SERVICES SOLD FOR OPERATION OF RESERVOIR DEWATERING PROJECT AND/OR UNIT

SUBCHAPTER 21. APPLICATIONS FOR TAX EXEMPTIONS

PART 1. TERTIARY RECOVERY PROJECT [REVOKED]

165:10-21-1. Tertiary recovery project certification [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2933, eff 7-11-96]

PART 2. ENHANCED RECOVERY PROJECT [REVOKED]

165:10-21-2. Gross production tax exemption for enhanced recovery project [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2933, eff 7-11-96]

PART 3. HORIZONTALLY DRILLED PRODUCTION WELLS [REVOKED]

165:10-21-3. Qualification and application for exemption from the levy of gross production tax on horizontally drilled production wells [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2933, eff 7-11-96]

PART 4. DELETERIOUS SUBSTANCES

165:10-21-4. Recycling, reuse, and ultimate destruction of deleterious substances [REVOKED**]**

[SOURCE: Revoked in rule making 200000009, eff 5-11-01]

PART 6. PRODUCTION ENHANCEMENT PROJECTS

165:10-21-21. General

Exemption from the levy of gross production tax on the incremental production which results from a production enhancement project with a project beginning date on or after July 1, 1994, and prior to July 1, 2006 shall be determined according to the provisions of this Part, which have been jointly adopted by the Oklahoma Corporation Commission and Oklahoma Tax Commission pursuant to 68 O.S. Section 1001(M)(1).

[SOURCE: Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Amended at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01, Amended in Rule Making 200400006, eff 7-1-04]

165:10-21-22. Definitions

The following words and terms, when used in this Part, shall have the following meaning, unless the context clearly indicates otherwise:

"Base production" means the average monthly amount of production for the twelve-month (12) period immediately prior to the commencement of the project or the average monthly amount of production for the twelve-month period immediately prior to the commencement of the project less the monthly rate of production decline for the project for each month beginning one hundred eighty (180) days prior to the commencement of the project. The monthly rate of production decline shall be equal to the average extrapolated monthly decline rate for the twelve-month period immediately prior to the commencement of the project based on the production history of the well. If the well or wells covered by the application had production for less than the full twelve-month period prior to the filing of the application for the production enhancement project, the base production shall be the average monthly production for the months during that period that the well or wells produced.

"Effective date" means the project beginning date for the production enhancement project.

"Exemption period" means a period of twenty-eight (28) months from the date of first sale after completion of the production enhancement project.

"Incremental production" means the amount of crude oil, natural gas or other hydrocarbons which are produced as a result of the production enhancement project in excess of the base production.

"Production enhancement project" means: for production enhancement projects having a project beginning date prior to July 1, 1997, any workover as defined in this Section, recompletion as defined in this Section, or fracturing of a producing well; for production enhancement projects having a project beginning date on or after July 1, 1997, and prior to July 1, 2006, "production enhancement project" means any workover as defined in this Section, recompletion as defined in this Section, reentry of plugged and abandoned wellbores, or addition of well or field compression.

"Recompletion" means: for production enhancement projects having a project beginning date prior to July 1, 1997, any downhole operation in an existing oil or gas well that is conducted to establish production of oil or gas from any geological interval not currently completed or producing in such existing oil or gas well; for production enhancement projects having a project beginning date on or after July 1, 1997, and prior to July 1, 2006, "recompletion" means any downhole operation in an existing oil or gas well that is conducted to establish production of oil or gas from any geologic interval not currently completed or producing in such existing oil or gas well within the same or a different geologic formation.

"Workover" means any downhole operation in an existing oil or gas well that is designed to sustain, restore or increase the production rate or ultimate recovery in a geologic interval currently completed or producing in said existing oil or gas well. For production enhancement projects having a project beginning date prior to July 1, 1997, "workover" includes, but is not limited to, acidizing, reperforating, fracture treating, sand/paraffin removal, casing repair, squeeze cementing, or setting bridge plugs to isolate water productive zones from oil or gas productive zones, or any combination thereof. For production enhancement projects having a project beginning date on or after July 1, 1997, and prior to July 1, 2006, "workover" includes, but is not limited to, the following: acidizing; reperforating; fracture treating; sand/paraffin/scale removal or other wellbore cleanouts; casing repair; squeeze cementing; installation of compression on a well or group of wells or artificial lifts on oil and/or gas wells, including plunger lifts, rod pumps, submersible pumps and coiled tubing velocity strings; downsizing existing tubing to reduce well loading; downhole commingling; bacteria treatments; upgrading the size of pumping unit equipment; setting bridge plugs to isolate water production zones; or any combination thereof. "Workover" shall not mean the routine maintenance, routine repair, or like-for-like replacement of downhole equipment such as rods, pumps, tubing, packers, or other mechanical devices.

[SOURCE: Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Amended at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 97000025, eff 7-1-98; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200400006, eff 7-1-04]

165:10-21-23. Qualification procedure

The well operator or one of the working interest owners in the well, on behalf of the well operator and the other owners of the well, shall apply for qualification of the production enhancement project and incremental production, at the Oklahoma Corporation Commission on OCC Form 1534.

(1) OCC Form 1534 shall be completed in its entirety, and together with supporting documentation, shall be submitted to the Technical Services Department of the Conservation Division of the Oklahoma Corporation Commission for review.
(2) If the Department approves the application, an order of the Oklahoma Corporation Commission shall be issued, and a copy of the order shall be forwarded to the operator.
(3) If the application is denied or refused, or approval is delayed beyond sixty (60) days, the applicant may seek review by application, notice and hearing.

[SOURCE: Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Amended at 13 Ok Reg 2933, eff 7-11-96]

165:10-21-24. Rebates - Refund procedure
(a) **Request to Oklahoma Tax Commission for a tax refund.** If the Oklahoma Corporation Commission grants the application, the operator or one of the working interest owners in the well, on behalf of the well operator and the other owners of the well, shall make its request for refund by letter to the Audit Division, Oklahoma Tax Commission. Such letter request shall state the reason for refund and the amount claimed and must be accompanied by the following:
(1) A Corporation Commission order certifying the well as production enhanced.
(2) A Copy of OCC Form 1534 submitted to the Corporation Commission.
(3) A properly completed OTC Form 328 Gross Production 841/495 Refund Report.
(4) If the refund request is filed by any person other than the party named in the Oklahoma Corporation Commission order, a notarized affidavit, signed by the party named in the order must be filed, authorizing the applicant to apply for the refund.
(b) **No time limitation on rebate for prior periods; claim limitation after July 1, 2003.** Approval of a "Production Incentive" for production periods prior to July 1, 2003 shall not be time-barred by either the date of certification or the date of filing a claim for refund of the rebate of gross production tax. Effective July 1, 2003, claims for rebate filed with the Oklahoma Tax Commission shall be subject to a time limitation pursuant to Title 68 O.S., Section 1001(L).
(c) **Method of appeal.** If the refund is denied, the applicant may file an appeal under the provisions of Title 68, Sections 227 and 228 of the Oklahoma Statutes.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04]

PART 7. RE-ESTABLISHMENT OF PRODUCTION FROM AN INACTIVE WELL

165:10-21-35. General
Exemption from the levy of gross production tax on the re-establishment of production from an inactive well shall be determined according to the provisions of this Part, which have been jointly adopted by the Oklahoma Corporation Commission and Oklahoma Tax Commission pursuant to 68 O.S. Section 1001(M)(1).

[SOURCE: Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Amended at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01]

165:10-21-36. Definitions

The following words and terms, when used in this Part, shall have the following meaning, unless the context clearly indicates otherwise:

"Effective date" means the date on which the reestablishment of production has occurred.

"Exemption period" means a period of twenty-eight (28) months from the date upon which production from an inactive well is reestablished.

"Inactive well" means a well which may be defined under one (1) of the following three (3) categories:

(A) A well which after July 1, 1997 experiences mechanical failure or loss of mechanical integrity, as defined by the Corporation Commission, including but not limited to, casing leaks, collapse of casing or loss of equipment in a wellbore, or any similar event which causes cessation of production, shall be considered an inactive well. For use within this sub-paragraph "mechanical failure" means a well which experiences mechanical failure or loss of mechanical integrity because of, but not limited to, casing leaks, collapse of casing or loss of equipment in a wellbore, or any similar event which results in a workover of the well and cessation of production as evidenced by the use of a workover rig or other mechanical device being placed over the well to repair the well or equipment.

(B) A well on which work to reestablish production commenced on or after July 1, 1997, and on or before June 30, 2006, that has not produced oil, gas or oil and gas for a period of not less than one (1) year as evidenced by the appropriate forms on file with the Oklahoma Corporation Commission reflecting the well.

(C) A well on which work to reestablish production commenced on or after July 1, 1994, and on or before June 30, 1997, that has not produced oil, gas or oil and gas for a period of not less than two (2) years as evidenced by the appropriate forms on file with the Oklahoma Corporation Commission reflecting the well's status.

[**SOURCE:** Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Amended in Rule Making 97000025, eff 7-1-98; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200400006, eff 7-1-04]

165:10-21-37. Qualification procedure

The well operator or one of the working interest owners, on behalf of the well operator and the other owners of the well, shall apply for qualification of the well and production at the Oklahoma Corporation Commission on OCC Form 1534.

(1) OCC Form 1534 shall be completed in its entirety, and together with supporting documentation, shall be submitted to the Technical Services Department of the Conservation Division of the Oklahoma Corporation Commission for review.

(2) If the Department approves the application, an order of the Oklahoma Corporation Commission shall be issued, and a copy shall be forwarded to the operator.

(3) If the application is denied or refused, or approval is delayed beyond sixty (60) days, the applicant may seek review by application, notice and hearing.

[SOURCE: Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Amended at 13 Ok Reg 2933, eff 7-11-96]

165:10-21-38. Rebates - Refund procedure

(a) **Request to Oklahoma Tax Commission for a tax refund.** If the Oklahoma Corporation Commission grants the application, the operator or one of the working interest owners in the well, on behalf of the well operator and the other owners of the well, shall make its request for refund by letter to the

Audit Division, Oklahoma Tax Commission. Such letter request shall state the reason for refund and the amount claimed and must be accompanied by the following:

(1) A Corporation Commission order certifying the well as an inactive well for which production has been reestablished.

(2) A copy of OCC Form 1534 submitted to the Corporation Commission.

(3) A copy of an approved OTC Form 320C that shows the date of the re-establishment of production of oil and/or gas.

(4) A properly completed OTC Form 328 Gross Production 841/495 Refund Report.

(5) If the refund request is filed by any person other than the party named in the Oklahoma Corporation Commission order, a notarized affidavit, signed by the party named in the order must be filed, authorizing the applicant to apply for the refund.

(b) **No time limitation on rebate for prior periods; claim limitation after July 1, 2003.** Approval of a "Reestablished Incentive" for production periods prior to July 1, 2003 shall not be time-barred by either the date of certification or the date of filing a claim for refund of gross production tax. Effective July 1, 2003, claims for rebate filed with the Oklahoma Tax Commission shall be subject to a time limitation pursuant to Title 68 O.S., Section 1001(L).

(c) **Method of appeal.** If the refund is denied, the applicant may file an appeal under the provisions of Title 68, Sections 227 and 228 of the Oklahoma Statutes.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04]

PART 8. DEEP WELLS

165:10-21-45. General

(a) **General provisions.** Exemption from the levy of gross production tax on the production of gas, oil, or gas and oil from wells certified as being "Deep Wells" set out in 68 O.S. §.1001(H).shall be determined according to the provisions of this Part, which have been jointly adopted by the Oklahoma Corporation Commission and the Oklahoma Tax Commission pursuant to 68 O.S. § 1001(M)(1).

(b) **Definitions.** For purposes of qualifying for the exemption, **"depth"** means the length of the maximum continuous string of drill pipe utilized between the drill bit face and the drilling rig's kelly bushing.

(c) **Exemption for wells spudded between July 1, 1994, and June 30, 2000, to a depth of fifteen thousand (15,000) feet or greater.** Deep wells spudded between July 1, 1994, and June 30, 2000, and drilled to a depth of fifteen thousand (15,000) feet or greater shall be exempt from the gross production tax, beginning from the date of first sale, for a period of twenty-eight (28) months.

(d) **Exemption for wells spudded between July 1, 1997, and June 30, 2006, to a depth of twelve thousand five hundred (12,500) feet.** Deep wells spudded between July 1, 1997, and June 30, 2006, and drilled to a depth of twelve thousand five hundred (12,500) feet or greater shall be exempt from the gross production tax, beginning from the date of first sale, for a period of twenty-eight (28) months.

(e) **Exemption for wells spudded between July 1, 2002, and June 30, 2006.** Deep wells spudded between July 1, 2002, and June 30, 2006, shall be eligible for an exemption from the gross production tax which shall begin from the date of first sale, and vary as to duration in relation to the depth of the well.

(1) **12,500 to 14,999 feet.** The duration of the exemption for wells drilled to this depth is twenty-eight (28) months.

(2) **15,000 to 17,499 feet.** The duration of the exemption for wells drilled to this depth is forty-eight (48) months.

(3) **17,500 feet or greater.** The duration of the exemption for wells drilled to this depth is sixty (60) months.

[SOURCE: Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Amended at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 970000025, eff 7-1-98; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04]

165:10-21-46. Definitions [REVOKED]

[SOURCE: Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Amended at 13 Ok Reg 2933, eff 7-11-96; Revoked in Rule Making 97000025, eff 7-1-98]

165:10-21-47. Qualification procedure

The well operator or one of the working interest owners, on behalf of the well operator and the other owners of the well, shall apply for qualification of the well at the Oklahoma Corporation Commission on OCC Form 1534.

(1) OCC Form 1534 shall be completed in its entirety, and together with supporting documentation, shall be submitted to the Technical Services Department of the Conservation Division of the Oklahoma Corporation Commission for review.

(2) If the Department approves the application, an order of the Oklahoma Corporation Commission shall be issued, and a copy shall be forwarded to the operator.

(3) If the application is denied or refused, or approval is delayed beyond sixty (60) days, the applicant may seek review by application, notice and hearing.

[SOURCE: Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Amended at 13 Ok Reg 2933, eff 7-11-96]

165:10-21-47.1. Rebates-Refund procedure

(a) **Request to Oklahoma Tax Commission for a tax refund.** If the Oklahoma Corporation Commission grants the application, the operator or one of the working interest owners in the well, on behalf of the well operator and the other owners of the well, shall make its request for refund by letter to the Audit Division, Oklahoma Tax Commission. Such letter request shall state the reason for refund and the amount claimed and must be accompanied by the following:

(1) A Corporation Commission order certifying the well as a well spudded within the applicable time periods and drilled to the prescribed depths provided in OAC 165:10-21-45.

(2) A copy of OCC Form 1534 submitted to the Corporation Commission.

(3) A copy of an approved OTC Form 320A that shows date of first sale of production.

(4) A properly completed OTC Form 328 Gross Production 841/495 Refund Report.

(5) If the refund request is filed by any person other than the party named in the Oklahoma Corporation Commission order, a notarized affidavit, signed by the party named in the order must be filed, authorizing the applicant to apply for the refund.

(b) **No time limitation on rebate for prior periods; claim limitation after July 1, 2003.** Approval of a "Deep Well Incentive" for production periods prior to July 1, 2003 shall not be time-barred by either the date of certification or the date of filing a claim for refund of the rebate of gross production tax. Effective July 1, 2003, claims for rebate filed with the Oklahoma Tax Commission shall be subject to a time limitation pursuant to Title 68 O.S., Section 1001(L).

(c) **Method of appeal.** If the refund is denied, the applicant may file an appeal under the provisions of Title 68, Sections 227 and 228 of the Oklahoma Statutes.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04]

165:10-21-48. Audit requirements [REVOKED]

[SOURCE: Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Revoked in Rule Making 200300001, eff 7-1-03]

165:10-21-49. Certificate of investment to be filed by the operator [REVOKED**]**

[SOURCE: Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Revoked at 13 Ok Reg 2933, eff 7-11-96]

PART 9. NEW DISCOVERY WELLS

165:10-21-55. General

(a) Exemption from the levy of gross production tax on the production of gas, oil, or gas and oil from wells spudded or reentered between July 1, 1995 and July 1, 2006, which qualify as a new discovery well pursuant to Title 68, Section 1001(I), shall be determined according to the provisions of this Part, which have been jointly adopted by the Oklahoma Corporation Commission and the Oklahoma Tax Commission pursuant to Title 68, Section 1001(M)(1).

(b) **"New discovery"** means production of oil, gas or oil and gas from:

(1) A well spudded or reentered prior to July 1, 1997, which discovers crude oil in paying quantities and is located more than one mile from the nearest oil well producing from the same interval.

(2) A well, spudded or reentered on or after July 1, 1997, and prior to July 1, 2006, which discovers crude oil in paying quantities and is located more than one mile from the nearest oil well producing from the same interval of the same formation.

(3) A well, spudded or reentered prior to July 1, 1997, which discovers crude oil in paying quantities beneath current production in a deeper producing formation located more than one mile from the nearest oil well producing from the same deeper interval.

(4) A well, spudded or reentered on or after July 1, 1997, and prior to July 1, 2006, which discovers crude oil in paying quantities beneath current production in a deeper producing interval located more than one mile from the nearest oil well producing from the same deeper interval.

(5) A well, spudded or reentered, prior to July 1, 1997, which discovers natural gas in paying quantities and is located more than two miles from the nearest gas well producing from the same producing interval.

(6) A well, spudded or reentered, on or after July 1, 1997, and prior to July 1, 2006, which discovers natural gas in paying quantities and is located more than two miles from the nearest gas well producing from the same producing interval.

(7) A well, spudded or reentered, prior to July 1, 1997, which discovers natural gas in paying quantities beneath current production in a deeper producing interval that is more than two miles from the nearest gas well producing from the same deeper interval.

(8) A well, spudded or reentered, on or after July 1, 1997, and prior to July 1, 2006, which discovers natural gas in paying quantities beneath current production in a deeper producing interval that is more than two

miles from the nearest gas well producing from the same deeper producing interval.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 97000025, eff 7-1-98; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200400006, eff 7-1-04]

165:10-21-56. Definitions

The following words and terms, when used in this Part, shall have the following meaning, unless the context clearly indicates otherwise:

"Effective date" means the date the well was spudded or the beginning date for a re-entered well.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 97000025, eff 7-1-98]

165:10-21-57. Qualification procedure

The well operator or one of the working interest owners, on behalf of the well operator and the other owners of the well, shall apply for qualification of the well at the Oklahoma Corporation Commission on OCC Form 1534.

(1) OCC Form 1534 shall be completed in its entirety, and together with supporting documentation, shall be submitted to the Technical Services Department of the Oklahoma Corporation Commission for review.

(2) If the Department approves the application, an order of the Oklahoma Corporation Commission shall be issued, and a copy shall be forwarded to the operator.

(3) If the application is denied or refused, or approval is delayed beyond sixty (60) days, the applicant may seek review by application, notice and hearing.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96]

165:10-21-58. Rebates - Refund procedure

(a) **Request to Oklahoma Tax Commission for a tax refund.** If the Oklahoma Corporation Commission grants the application, the operator or one of the working interest owners in the well, on behalf of the well operator and the other owners of the well, shall make its request for refund by letter to the Audit Division, Oklahoma Tax Commission. Such letter request shall state the reason for refund and the amount claimed and must be accompanied by the following:

(1) A Corporation Commission order certifying the well as a new discovery well spudded or re-entered between July 1, 1995 and June 30, 2006.

(2) A copy of OCC Form 1534 submitted to the Corporation Commission.

(3) A copy of an approved OTC Form 320A that shows date of first sale of production.

(4) A properly completed OTC Form 328 Gross Production 841/495 Refund Report.

(5) If the refund request is filed by any person other than the party named in the Oklahoma Corporation Commission order, a notarized affidavit, signed by the party named in the order must be filed, authorizing the applicant to apply for the refund.

(b) **No time limitation on rebate for prior periods; claim limitation after July 1, 2003.** Approval of a "New Discovery Incentive" for production periods prior to July 1, 2003 shall not be time-barred by either the date of certification or the date of filing a claim for refund of the rebate of gross production tax. Effective July 1, 2003, claims for rebate filed with the Oklahoma Tax Commission shall be subject to a time limitation pursuant to Title 68 O.S., Section 1001(L).

(c) **Method of appeal.** If the refund is denied, the applicant may file an appeal under the provisions of Title 68, Sections 227 and 228 of the Oklahoma Statutes.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04]

165:10-21-59. Audit requirements [REVOKED]

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Revoked in Rule Making 200300001, eff 7-1-03]

PART 11. HORIZONTALLY DRILLED PRODUCING WELLS

165:10-21-65. General

Exemption from the levy of Gross Production Tax on horizontally drilled producing wells set out in 68 O.S. § 1001(E) shall be determined according to the provisions of this Part, which have been jointly adopted by the Oklahoma Corporation Commission and the Oklahoma Tax Commission pursuant to law. [See: 68 O.S. §1001(M)(1)]

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03]

165:10-21-66. Definitions

In addition to terms defined in 165:10-1-2, the following words and terms, when used in this Part, shall have the following meaning, unless the context clearly indicates otherwise:

"Angle of deviation" means that angle in which a wellbore may deviate from the vertical.

"Date of completion of a gas well" means the date that gas is capable of being delivered to a pipeline purchaser.

"Date of completion of an oil well" means the date that the well first produces into the lease tanks through permanent well head equipment.

"Effective date" means that the first production must have commenced after July 1, 1995 and before July 1, 2006.

"Horizontal displacement" means that distance drilled into the pay zone of a formation at an angle exceeding seventy (70) degrees.

"Horizontally drilled payout" means the point at which gross working interest revenue from the horizontally drilled well equals the cost of drilling and completing such well.

"Horizontally drilled well" means an oil, gas, or oil and gas well drilled or completed in a manner which encounters and subsequently produces from a geological formation at an angle in excess of seventy (70) degrees from the vertical and which laterally penetrates a minimum of one hundred and fifty (150) feet into the pay zone of the formation.

"True vertical depth" means that depth measured from the surface perpendicular to the surface.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 97000025, eff 7-1-98; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200400006, eff 7-1-04]

165:10-21-67. Qualification procedure

The well operator or one of the working interest owners in the well, on behalf of the well operator and the other owners of the well, shall apply for qualification of the production from horizontally drilled wells, at the Oklahoma Corporation Commission on OCC Form 1534.

(1) OCC Form 1534 shall be completed in its entirety, and together with supporting documentation, shall be submitted to the Technical Services Department of the Conservation Division of the Oklahoma Corporation Commission for review.

(2) If the Department approves the application, an order of the Oklahoma Corporation Commission shall be issued, and a copy of the order shall be forwarded to the operator.

(3) If the application is denied or refused, or approval is delayed beyond sixty (60) days, the applicant may seek review by application, notice and hearing.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96]

165:10-21-68. Rebates - Refund procedure

(a) **Request to Oklahoma Tax Commission for a tax refund.** If the Commission grants the application, the well operator or one of the working interest owners in the well, on behalf of the well operator and the other owners of the well, shall make its request for refund by letter to the Audit Division, Oklahoma Tax Commission. Such letter request shall state the reason for refund and the amount claimed and must be accompanied by the following:

(1) A Corporation Commission order certifying the well as a horizontally drilled well.

(2) A copy of OCC Form 1534 submitted to the Corporation Commission.

(3) A copy of an approved OTC Form 320A that shows the date of initial production.

(4) A properly completed OTC Form 328 Gross Production 841/495 Refund Report.

(5) If the refund request is filed by any person other than the party named in the Oklahoma Corporation Commission order, a notarized affidavit, signed by the party named in the order must be filed, authorizing the applicant to apply for the refund.

(b) **No time limitation on rebate for prior periods; claim limitation after July 1, 2003.** Approval of a "Horizontal Drilling Incentive" for production periods prior to July 1, 2003 shall not be time-barred by either the date of certification or the date of filing a claim for refund of the rebate of gross production tax. Effective July 1, 2003, claims for rebate filed with the Oklahoma Tax Commission shall be subject to a time limitation pursuant to Title 68 O.S., Section 1001(L).

(c) **Method of appeal.** If the refund is denied, the applicant may file an appeal under the provisions of Title 68, Sections 227 and 228 of the Oklahoma Statutes.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04]

165:10-21-69. Time periods for exemption from gross production tax levied on horizontally drilled producing wells

(a) **General provisions.** The exemption for horizontally drilled wells qualified pursuant to this Part shall be determined from the project beginning date until project payback is achieved, and are limited in duration to the time periods set out in this Section.

(b) **Twenty-four (24) month exemptions.** For production described in this subsection, duration of the exemption may not exceed a period of twenty-four

(24) months commencing with the date of initial production from the horizontally drilled well.

(1) **Production prior to July 1, 1994.** Any incremental production which results from a horizontally drilled well producing prior to July 1, 1994.

(2) **Production prior to July 1, 2002, which commenced after July 1, 1995.** Any horizontally drilled well producing prior to July 1, 2002, which production commenced after July 1, 1995.

(c) **Forty-eight (48) month exemption.** For a horizontally drilled well producing prior to July 1, 2006, which production commenced after July 1, 2002, the duration of the exemption may not exceed a period of forty-eight (48) months commencing with the date of initial production from the horizontally drilled well. [See: 68 O.S. Supp. 2002, Section 1001(E)(1)]

[SOURCE: Added in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04]

PART 13. INCREMENTAL PRODUCTION FROM ENHANCED RECOVERY PROJECTS

165:10-21-75. General

Exemption from the levy of gross production tax on the incremental production of oil or other liquid hydrocarbons attributable to the working interest owners of an enhanced recovery project and property shall be determined according to the provisions of this Part.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01]

165:10-21-76. Definitions

The following words and terms, when used in this Part, shall have the following meaning, unless the context clearly indicates otherwise:

"Base production amount" means the average monthly amount of productions for the twelve (12) month period immediately prior to the project beginning date minus the monthly rate of production decline for the project or property for each month beginning one hundred eighty (180) days prior to the project beginning date.

"Completion date" means the date a well is first capable of being used for the injection of liquids, gases or other matter, or is capable of producing crude oil or other liquid hydrocarbons through permanent wellhead equipment.

"Enhanced recovery project costs" means the incremental project costs that are allowed as payback factors in determining the exemptions from the levy of gross production tax of project incremental production.

"Existing tertiary recovery project" means, for purposes of the exemption described in 68 O.S. Section 1001(D)(1), a tertiary recovery project whose beginning date is prior to October 16, 1987.

"Incremental production" means the amount of crude oil or other liquid hydrocarbons which are produced during an approved enhanced oil recovery operation and which are in excess of the base production amount of crude oil or other liquid hydrocarbons.

"Incremental working interest revenue" means the gross value of the incremental production, less the royalty interest therein.

"Monthly rate of production decline" means a rate equal to the average extrapolated monthly decline rate for the twelve (12) month period immediately prior to the project beginning date as determined by the Commission, based on the production history of the field, its current status, and sound reservoir engineering principles.

"New enhanced recovery project" means, for purposes of the exemption described in 68 O.S. Section 1001(D)(1), a secondary or tertiary recovery project whose beginning date is on or after October 16, 1987.

"Project beginning date" means the date on which the injection of liquids, gas or other matter begins on an enhanced recovery project.

"Project payback or payout" means that point at which the incremental working interest revenue from the enhanced recovery project equals the enhanced project costs.

"Secondary recovery properties" means secondary recovery properties approved or having an initial project beginning date on or after July 1, 2000 and before July 1, 2006, such that any incremental production attributable to the working interest which results from such secondary recovery property shall be exempt from the gross production tax levied pursuant to 68 O.S. Section 1001 for a period not to exceed five (5) years from the initial project beginning date or for a period ending upon the termination of the secondary recovery process, whichever occurs first. [Applicant may omit payback report for such secondary recovery properties.]

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04]

165:10-21-77. Qualification procedure

The provisions of this Section establish criteria for determining if an operator of an enhanced recovery project or property has met the required conditions to qualify the incremental production from such project or property for the exemption from the Gross Production Tax. [**See:** 68 O.S. §1001]

(1) **Application to Oklahoma Corporation Commission; determination; order.** An operator seeking an exemption of incremental production from the gross production tax shall make application to the Oklahoma Corporation Commission, as provided in OAC 165:5-7-14, for a determination that such project or property qualifies, a determination of the starting date, and of the base production amount.

(A) If the application is administratively approved, an order of the Oklahoma Corporation Commission shall be issued.

(B) To obtain the tax exemption, the operator shall forward a copy of the Oklahoma Corporation Commission order to the Oklahoma Tax Commission, together with any other data required by that agency.

(2) **Tax Commission approval of exemption.** An operator desiring an exemption from the gross production tax shall make application by letter to the Audit Division, Oklahoma Tax Commission. Such application shall be accompanied by:

(A) Corporation Commission Order approving such application and containing a determination of the project beginning date, base production amount and project payback.

(B) The ratio of working interest/royalty interest in the well. Only the incremental production attributable to the working interest owners shall be exempted from the gross production tax. For purposes of this exemption, overriding royalty shall be included in working interest.

(C) A schedule of production, by month, of the gross amounts of crude oil or other liquid hydrocarbons produced, and the gross values thereof, from the project beginning date until the date application is made to the Tax Commission.

(D) OTC Form 320A, 320C, and 320U, as are necessary, to set up the OTC Production Units, to request merge numbers, and to show the entity who will remit taxes.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01]

165:10-21-78. Recovery of costs allowed as payback factors

(a) **Enhanced recovery project, project beginning date between October 17, 1987 and June 30, 1990.** For any enhanced recovery project with a project beginning date between October 17, 1987, and June 30 1990, allowed enhanced recovery costs shall include only incremental capital costs and incremental operating expenses associated with enhanced recovery operations.

(b) **Enhanced recovery project, project beginning date between July 1, 1990 and June 30, 1993.** For any enhanced recovery project with a project beginning date between July 1, 1990, and June 30, 1993, allowable enhanced recovery project costs shall be limited to the incremental capital costs of project start up, including the cost of completing any well necessary to the project and of converting any existing well to handle secondary or tertiary injection of liquids, gas or other matter. With respect to completing or converting a well, no expenditure after completion or conversion for enhanced recovery purposes shall be included.
(c) **Secondary recovery project, project beginning date on or after July 1, 1993 and before July 1, 2000.** For any secondary recovery project with a project beginning date on or after July 1, 1993, and before July 1, 2000, allowed enhanced recovery project costs shall include only incremental capital costs and fifty percent (50%) of incremental operating expenses, provided however that the period for project payback shall not exceed a period of ten (10) years from the project beginning date.
(d) **Tertiary enhanced recovery project, project beginning date on or after July 1, 1993 and before July 1, 2006.** For any tertiary enhanced recovery project with a project beginning date on or after July 1, 1993, and before July 1, 2006, allowable enhanced recovery project costs shall include only incremental capital costs and incremental operating expenses, excluding administrative expenses. The capital expenses of pipelines constructed to transport carbon dioxide to a tertiary recovery project shall not be included in determining project payback. The period for project payback shall not exceed ten (10) years from the project beginning date.
(e) **Excluded costs.** The cost of tank batteries, meters, pipelines or other external equipment shall not be included in allowable enhanced recovery project costs. Allowable costs shall be determined using generally accepted accounting principles such as outlined in the "Council of Petroleum Accountants Society (COPAS) - Accounting Procedure Form for Joint Operations" and "COPAS Bulletin No. 16", or subsequent revisions thereto.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 97000025, eff 7-1-98; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04]

165:10-21-79. Responsibility for filing and payment of taxes
(a) **Responsibility for reporting; reporting; forms required.** The operator of a qualifying project will have primary responsibility for filing OTC Form 300-R-7-81, Gross Production Tax Monthly Tax Report, and for remitting gross production and petroleum excise taxes on project production controlled by the operator. Working interest owners who take-in-kind will be responsible for filing Gross production Monthly Tax Reports, unless the take-in-kind owner has made an agreement with his purchaser or the operator to report and remit on his behalf. A take-in-kind interest owner must submit, through the project operator, a Form 320, showing the disposition of his share of production. Purchasers may report taxes on project production with the approval of the Tax Commission, provided whenever there are multiple purchasers from a project, each reporting purchaser must report his allocated share of production, incremental production, and any exempt interest. All persons remitting taxes must comply with Tax Commission security requirements.
(b) **Valuation of incremental production.** When an operator or a single purchaser files the gross production tax reports and remits taxes, the incremental production will be valued at the volume-weighted average price per barrel of all crude oil or other liquid hydrocarbons produced from the project during the month. When multiple purchasers file the gross production tax reports and remit taxes, the incremental production will be valued at the volume-weighted average price per barrel purchased for the month, by each purchaser individually.
(c) **Method of computing production, base production amount and incremental production.**

(1) Frac oil recovered must be excluded as a Code 07 exemption. Frac oil will not be counted as part of the project base production amount, nor as incremental production.
(2) Incremental production will be deducted next as a Code 11 exemption.
(3) Exempt interests will be deducted next, in order of exemption code, as a decimal equivalent of the amount and value of production remaining after subtraction of the frac oil and incremental production.

(d) Well operators are advised to contact the Oklahoma Tax Commission concerning required annual reporting.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96]

165:10-21-80. Expiration of exemption for incremental production

For secondary recovery projects approved prior to July 1, 2000, and tertiary recovery projects approved prior to July 1, 2006, once the gross working revenue equals the enhanced recovery project cost, the exemption of incremental production shall end and the Oklahoma Tax Commission shall resume collection of the Gross Production Tax thereon.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200400006, eff 7-1-04]

PART 14. PRODUCTION OF OIL, GAS OR OIL AND GAS FROM ANY WELL LOCATED WITHIN BOUNDARIES OF A THREE-DIMENSIONAL SEISMIC SHOOT

165:10-21-82. General

Exemption from the levy of gross production tax on the production of oil, gas or oil and gas from a well, drilling of which is commenced on or after July 1, 2000, and prior to July 1, 2006, located within the boundaries of a three-dimensional seismic shoot and drilled based on three-dimensional seismic technology, shall be determined according to the provisions of this Part.

[SOURCE: Added in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200400006, eff 7-1-04]

165:10-21-82.1. Definitions

The following words and terms, when used in this Part, shall have the following meaning, unless the context clearly indicates otherwise:

"Three-dimensional seismic shoot" means any three-dimensional geophysical or seismic exploration activity conducted in the field for the purpose of drilling for and producing oil, gas or oil and gas from geological formations, intervals and/or common sources of supply.

"Three-dimensional seismic technology" means any three-dimensional geophysical or seismic equipment or instruments, data processing equipment, and/or data utilized to evaluate geological formations, intervals and/or common sources of supply in connection with a three-dimensional seismic shoot.

[SOURCE: Added in Rule Making 200000009, eff 5-11-01]

165:10-21-82.2. Qualification procedure

(a) **Applicable wells.** The provisions of this Section establish criteria for determining if an operator producing oil, gas or oil and gas from a well, drilling of which is commenced on or after July 1, 2000, and prior to July 1, 2006, located within the boundaries of a three-dimensional seismic shoot and drilled based on three-dimensional seismic technology, has met the required conditions to qualify the production from such a well for the exemption from the Gross Production Tax. [See: 68 O.S. §1001(J)]

(b) **Application to Oklahoma Corporation Commission; determination; order.** An operator seeking an exemption of the gross production tax on production from a well located within the boundaries of a three-dimensional seismic shoot and drilled based on such technology, shall make application to the Oklahoma Corporation Commission on a Form 1534 for a determination that the well qualifies for such exemption, as provided in 68 O.S. 2000 Supp. §1001(J).

(1) If the application is administratively approved, an order of the Oklahoma Corporation Commission shall be issued.

(2) To obtain the tax exemption, the operator shall forward a copy of the Oklahoma Corporation Commission order to the Oklahoma Tax Commission, together with any other data required by that agency pursuant to OAC 165:10-21-82.3.

(3) Any data, maps and other information submitted with the Form 1534 for determination that a well qualifies for the exemption provided in this paragraph shall be held as confidential information by the Conservation Division and/or Commission, and upon approval through issuance of a Commission order, shall be returned to the applicant or destroyed.

[SOURCE: Added in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04]

165:10-21-82.3. Rebates - Refund procedure

(a) **Request to Oklahoma Tax Commission for a tax refund.** If the Commission grants the application, the well operator or one of the working interest owners in the well, on behalf of the well operator and the other owners of the well, shall make its request for refund by letter to the Audit Division, Oklahoma Tax Commission. Such letter request shall state the reason for refund and the amount claimed and must be accompanied by the following:

(1) Corporation Commission order approving such application and containing a determination that the well meets the criteria of the statute insofar that its drilling was commenced on or after July 1, 2000, and prior to July 1, 2006, that it is located within the boundaries of a three-dimensional seismic shoot and was drilled based on such technology, and indicating whether the seismic shoot was shot either prior to or on or after July 1, 2000.

(2) A schedule of production, by month, of the gross amounts of oil, gas or oil and gas produced, and the gross values thereof, from the date of first sale until the date application is made to the Tax Commission.

(3) OTC Form 320A, 320C, and 320U, as are necessary, to set up the OTC Production Units, to request merge numbers, and to show the entity who will remit taxes.

(4) If the refund request is filed by any person other than the party named in the Oklahoma Corporation Commission order, a notarized affidavit, signed by the party named in the order must be filed, authorizing the applicant to apply for the refund.

(b) **No time limitation on rebate for prior periods; claim limitation after July 1, 2003.** Approval of a "Three-Dimensional Incentive" for production periods prior to July 1, 2003 shall not be time-barred by either the date of certification or the date of filing a claim for refund of the rebate of gross production tax. Effective July 1, 2003, claims for rebate filed with the Oklahoma Tax Commission shall be subject to a time limitation pursuant to Title 68 O.S., Section 1001(L).

(c) **Method of appeal.** If the refund is denied, the applicant may file an appeal under the provisions of Title 68, Sections 227 and 228 of the Oklahoma Statutes.

[SOURCE: Added in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04]

165:10-21-82.4. Time periods for exemption from gross production tax levied on oil, gas or oil and gas production from a well located within boundaries of three-dimensional seismic shoot

The exemption from gross production tax levied on oil, gas or oil and gas production from a well qualified pursuant to this Section shall be applied as follows:

(1) **Eighteen (18) month exemption.** For a well where the seismic shoot was shot prior to July 1, 2000, the well shall be exempt from the gross production tax levied from the date of first sales for a period of eighteen (18) months.

(2) **Twenty-eight (28) month exemption.** For a well where the seismic shoot was shot on or after July 1, 2000, the well shall be exempt from the gross production tax levied from the date of first sales for a period of twenty-eight (28) months.

[SOURCE: Added in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03]

PART 15. GENERAL PROVISIONS

165:10-21-85. Election of exemption

(a) **Election of exemptions generally.** Persons entitled to exemption based upon production from qualifying oil, gas, or oil and gas wells shall be entitled only to the exemption granted pursuant to:

(1) Incremental production from enhanced recovery projects, as authorized by 68 O.S. Supp. 2000 §1001(D) and Part 13 of this Subchapter; **or,**

(2) Horizontally drilled production wells, as authorized by 68 O.S. Supp. 2000 §1001(E) and Part 11 of this Subchapter; **or,**

(3) Reestablished production from inactive wells, as authorized by 68 O.S. Supp. 2000 §1001(F) and Part 7 of this Subchapter; **or,**

(4) Production enhancement projects, as authorized by 68 O.S. Supp. 2000 §1001(G) and Part 6 of this Subchapter; **or,**

(5) Production from deep wells, as authorized by 68 O.S. Supp. 2000 §1001(H) and Part 8 of this Subchapter; **or,**

(6) Production from new discovery wells, as authorized by 68 O.S. Supp. 2000 §1001(I) and Part 9 of this Subchapter; **or,**

(7) Production from wells located within the boundaries of three-dimensional seismic shoot, as authorized by 68 O.S. §1001(J) and Part 14 of this Subchapter.

(b) **Special provision.** Expiration of an exemption available for production from a qualifying well pursuant to one of Subsections (a)(2) through (a)(6) of this Section does not prohibit any person from qualifying for the exemption provided for in Subsection (a)(1).

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01]

PART 17. SALES TAX EXEMPTION FOR ELECTRICITY AND ASSOCIATED DELIVERY AND TRANSMISSION SERVICES SOLD FOR OPERATION OF RESERVOIR DEWATERING PROJECT AND/OR UNIT

165:10-21-90. General

(a) **Scope.** This Part deals with the classification by the Oklahoma Corporation Commission (Corporation Commission or Commission) of a reservoir dewatering project and/or unit for the purpose of an exemption, beginning January 1, 2004, from sales taxes levied on electricity and associated delivery and transmission services sold to an oil and gas operator for reservoir dewatering projects and associated operations commencing on or after July 1, 2003, as provided in 68

O.S. 2002 Supp., §1357(28).
(b) **Distinction from designation as reservoir dewatering oil spacing unit or other spacing application.** The classification of an area and reservoir(s) as a "reservoir dewatering project" and/or a "reservoir dewatering unit" pursuant to this Part shall be separate and distinct from the designation of a reservoir dewatering oil spacing unit for oil allowable purposes pursuant to OAC 165:10-15-18. Corporation Commission approval of an area and reservoir(s) for the instant sales tax exemption shall be made by application under this Part and not as a result of a spacing application filed for oil allowable purposes under OAC 165:10-15-1 and OAC 165:10-15-18, a spacing application filed for gas allowable purposes under OAC 165:10-17-2 through 10-17-16, a spacing application filed for horizontal drilling purposes under OAC 165:10-3-28, or any spacing application filed under OAC 165:10-1-22.
(c) **Reservoir Dewatering Projects for Oil Production.** Any reservoir that is the subject of an application pursuant to this Part, which produces predominantly oil, shall be evaluated to determine the initial water-to-oil ratio is equal to or greater than five-to-one (5-to-1).
(d) **Reservoir Dewatering Projects for Gas Production.** Any reservoir that is the subject of an application pursuant to this Part, which produces predominantly gas, shall be evaluated to determine the initial five-to-one (5-to-1) water-to-oil ratio using a gas conversion factor of one (1) barrel of oil converted to an MCF of natural gas based on an initial natural gas formation volume factor, BTU or price calculation or conversion accepted by the Conservation Division.

[**SOURCE:** Added in Rule Making 200300001, eff 7-1-03]

165:10-21-91. Definitions

The following words and terms, when used in this Part, shall have the following meaning, unless the context clearly indicates otherwise:

"Reservoir dewatering project" means an oil or gas production project covering a specified area and reservoir(s), which utilizes water recovery and disposal technology to increase water production in the initial phase of reservoir development, with the primary purpose of increasing oil or gas production from the reservoir(s) as a result of the dewatering process. For the purpose of qualification for the sales tax exemption pursuant to this Part, the definition of reservoir dewatering project shall require the proof that the reservoir's initial water-to-oil ratio is greater than or equal to five-to-one (5-to-1), or is greater than or equal to the appropriate gas-to-water ratio calculated using the gas conversion factor outlined in OAC 165:10-21-90(d). This definition shall not include enhanced recovery projects or secondary recovery properties, which are subject to gross production tax exemptions pursuant to 68 O.S. Section 1001 and Part 13 of this Subchapter, OAC 165:10-21-75 through 10-21-80.

"Reservoir dewatering unit" means an area and reservoir(s) designated a reservoir dewatering project where a reservoir dewatering process is conducted as defined in this Part.

[**SOURCE:** Added in Rule Making 200300001, eff 7-1-03]

165:10-21-92. Qualification procedure

(a) **Applicable operations.** The provisions of this Section establish criteria for determining if an area and reservoir(s) can be classified a reservoir dewatering project and/or a reservoir dewatering unit, beginning January 1, 2004, for the purpose of an exemption from sales taxes levied on electricity and associated delivery and transmission services sold to an oil and gas operator for a reservoir dewatering project and associated operations commencing on or after July 1, 2003.

(b) **Application to the Oklahoma Corporation Commission.** An oil and gas operator seeking the classification of an area and reservoir(s) as a reservoir dewatering project and/or reservoir dewatering unit pursuant to this Part shall file an application with the Corporation Commission on a Form 1535 for a determination that the project and/or unit qualifies for the exemption, as provided in 68 O.S. 2002 Supp., §1357(28). The operator shall attach to the Form 1535 a copy of the following information:

(1) A production test or other appropriate data showing the initial water-to-oil ratio is greater than or equal to five-to-one (5-to-1) or is greater than or equal to the appropriate gas-to-water ratio calculated using the gas conversion factor outlined in OAC 165:10-21-90(d). For this purpose, a Corporation Commission Form 1013 may be filed with the sales tax exemption application to demonstrate the initial 5-to-1 water-to-oil ratio for the reservoir.

(2) Geological structure and isopach maps for the applicable reservoir showing its geological characteristics; and any additional engineering and geological data or information deemed necessary by the Conservation Division to evaluate the application.

(3) A schematic diagram of the electrical grid and dewatering and water disposal equipment associated with the reservoir dewatering project covered by the application.

(c) **Administrative approval, determination and order.**

(1) If the application is administratively approved, an order of the Oklahoma Corporation Commission shall be issued.

(2) To obtain the tax exemption, the operator should contact the Director's Office, Taxpayer Assistance Division, Oklahoma Tax Commission, 2501 N. Lincoln Blvd., Oklahoma City, Ok. 73194.

(3) Any data, maps and other information submitted with the Form 1535 for determination that an area and reservoir qualify for the exemption provided in this Part shall be held as confidential information by the Conservation Division and/or Corporation Commission, and upon approval through issuance of a Commission order, shall be returned to the applicant or destroyed.

[**SOURCE:** Added in Rule Making 200300001, eff 7-1-03]

SUBCHAPTER 23. RATABLE SHARING OF REVENUE [REVOKED]

Section

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165:10-23-1. Definitions (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-2. General provisions for all interest owners in a well producing natural gas or casinghead gas (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-3. Revenue sharing in contract entered into on or after January 1, 1984; market by operator (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-4. Revenue sharing in contract entered into prior to May 3, 1983 (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-5. Revenue sharing in contract entered into on or after May 3, 1983, but prior to January 1, 1984 (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-6. Gas statements of production (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-7. Expiration of a gas contract (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-8. Special circumstances; parties selling under a joint operating agreement (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-9. Payments on production (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-10. Administrative expense (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-11. Commencement of an action (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-12. Other rights and remedies (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165-10-23-13. Crude oil (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-14. Liability (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-15. Severability (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

SUBCHAPTER 24. MARKET SHARING

Section

[**Authority:** 52 O.S. 1992, Section 581.1 et seq.]

[**Source:** Codified 6-25-93]

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165:10-24-1. Scope

(a) This Subchapter implements the Natural Gas Market Sharing Act of 1992, codified at 52 O.S. Section 581, et seq.

(b) This Subchapter establishes a procedure whereby an owner in a well may compel the well operator or other designated marketer to either sell gas on the owner's behalf or find a market for that owner's gas.

(c) This Subchapter shall apply to the sale of natural gas from a well except for:

(1) any sale under a gas contract for more than one year, entered into before January 1, 1985 (including any successor, replacement or roll-over contract entered into before January 1, 1990) provided that any participating mineral owners who were sharing in a contract on January 1, 1992, and continue to share in such a contract on September 1, 1992, are subject to this Subchapter;

(2) any sale under a contract which provides for:

(A) an initial term of more than three years; and

(B) a guarantee or warranty of delivery of fixed volumes without limitation on specified wells or reserves; and

(C) delivery of such volumes;

(3) any sale of natural gas liquids extracted by mechanical processing of the natural gas stream for removal of liquid components other than methane.

(d) Nothing in this Subchapter shall change the obligation of a first purchaser of production under an existing gas contract unless otherwise agreed to by the parties.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93; Amended at 11 Ok Reg 3699, eff 7-11-94]

165:10-24-2. Definitions

The following words or terms, when used in this Subchapter, shall have the following meaning, unless the context clearly indicates otherwise:

"Designated marketer" means the operator of the well or a producing owner substituted for the operator as provided in 165:10-24-5.

"Electing owner" means any owner who elects to produce and market its share of production pursuant to the provisions of this Subchapter.

"Nonexempt sales" means those gas sales which are subject to the provisions of this Subchapter and do not qualify for exemptions as set forth in 165:10-24-1(c) and 165:10-24-3(b).

"Overproduced owner" means an owner who has produced and sold a volume of gas in excess of his working interest percentage of cumulative sales from a well.

"Owner" means a person or persons who own a working interest in a well.

"Producing owner" means an owner who produces and sells gas from a well for its own account.

"Working interest" means the interest in a well, calculated prior to deduction for royalty, overriding royalty and other non-cost bearing interests burdening production, entitling the owner thereof to drill for and produce oil and gas, including the interest of a participating mineral owner to the extent set forth in Section 87.1 of Title 52 of the Oklahoma Statutes.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-24-3. Election to market share

(a) An owner eligible to market share as to a particular well, may elect to market share as to such well by sending written notice to the designated marketer for the well.

(b) An owner may not elect to market share as to a particular well if as to such well:

(1) said owner is subject to a balancing agreement (or other written agreement expressly providing for gas balancing or the taking, sharing, marketing of gas); or

(2) the term has yet to expire for a gas contract, where the owner terminated the contract for value received; or

(3) said owner terminated market sharing within the previous 12 months; or

(4) said owner is currently over-produced; or

(5) the designated marketer is relieved from the duty to market share pursuant to 165:10-24-4(g) or 165:10-24-4(i) and (j).

(c) An election to market share shall be effective on the first day of the month following 60 days from receipt of the election by the designated marketer.

(d) The well operator shall serve as the designated marketer until appointment of a substitute.

(e) An owner may terminate his election by sending writing notice to the designated marketer. Notice of termination is effective on the first day of the month following 60 days after receipt of the notice.

(f) Copies of all market sharing elections and notices shall be sent to the well operator, if said operator is not the designated marketer.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-24-4. Duties and accounting

(a) The designated marketer shall find an independent, non-affiliated purchaser for the electing owner's gas, or the designated marketer shall produce and sell said gas for the account of the electing owner.

(b) During market sharing, the designated marketer shall have the right to produce and sell and electing owner's gas, without further notice and consent except in those cases where the designated marketer has secured an independent non-affiliated purchaser for the gas production of such electing owner.

(c) If the designated marketer produces and sells the electing owner's gas for the account of the electing owner, the designated marketer shall account to the electing owner at the average price, weighted by volume, received by the marketer for all of the designated marketer's non-exempt sales from the well for that month, less post production cost and expenses required to render the gas marketable and to sell and deliver the gas to market, and net of all reasonable marketing costs, expenses and administrative fees. Volumetric allocation between the designated marketer and the electing owner shall be in proportion to their working interests in the well, with one exception. If the owner's proportionate production interest is different from his working interest, the proportionate production interest shall be used.

(d) Disbursement of gas sales proceeds shall be subject to the Production Revenue Standards Act of 1992 (52 O.S. Section 570.1, et seq.).

(e) The designated marketer shall not be considered as a fiduciary to any electing owner or to any owner with an interest burdening the electing owner's interest. The designated marketer shall not be liable for losses absent bad faith, gross negligence or willful misconduct.

(f) Market sharing according to this Subchapter shall not confer any contract rights to an electing owner or his assigns, either directly or as third party beneficiaries.

(g) For a gas contract with a term in excess of one year, the designated marketer may require an electing owner to either agree in writing to be bound by the contract terms or forego market sharing under that contract. Absent a confidentiality provision in said gas contract, the designated marketer shall send a copy of the gas contract to each electing owner.

(1) After receipt of the contract, the electing owner shall have 30 days in which to:

(A) send written consent to the contract terms, or

(B) provide a written termination of market sharing or

(C) elect a new designated marketer.

(2) If the electing owner fails to so respond, his election to market share shall be deemed terminated.

(h) If the designated marketer ceases to sell gas from the well and therefore has no sales, the designated marketer:

(1) may:

(A) notify the electing owners in writing that it has no sales and that the electing owners must elect a new designated marketer, or

(B) locate a non-affiliated purchaser for the electing owners.

(2) shall not be responsible for sharing sales with electing owners as it has no sales. If such a designated marketer again begins to produce and market gas from the well, then the electing owners may re-elect it as designated marketer.

(i) If the designated marketer provides the electing owner with a sales contract with a gas purchaser, the designated marketer shall be relieved of the duty to market share with the electing owner to the extent that the terms of said contract provide for the purchase of the electing owner's share of each withdrawal from the well during the contract period, provided:

(1) The designated marketer is not an affiliate of the gas purchaser: said term "affiliate" being defined at 18 O.S. Section 1148A(2); and

(2) The contract is of a type and with terms generally offered at the time to other producers for gas production from wells in the common source of supply; and

(3) If the designated marketer operates and controls a gathering line to the well, it does not prohibit access to downstream transportation or impose unjust or discriminatory gathering fees or tariffs upon the electing owner; and

(4) Before discontinuing market sharing if it had begun, the designated marketer provides the electing owner with at least thirty days in which to accept or reject the offer for said contract.

(j) In so far as the exemption established by subsection (i) of this Section, if the designated marketer fulfills each of the foregoing conditions, it shall be relieved from the duty to market share with the electing owner for a time period hereafter described as the "exemption period", calculated as follows:

(1) If the electing owner enters into said contract with said purchaser, then the exemption period shall be the duration of the contract as originally offered to the electing owner or the duration of the contract as entered into by the electing owner, whichever is greater;

(2) If the electing owner fails to enter into said contract for any reason, then the exemption period shall be the duration of the contract period as initially offered to the electing owner or twelve months, whichever is less.

(k) During the exemption period as determined in subsection (j) of this Section, failure to enter into said contract shall not be grounds for election or appointment of an additional designated marketer to market share with the electing owner with respect to volumes of gas which would have been purchased if the electing owner had entered into the said contract as initially offered to the electing owner.

(l) Upon request, the designated marketer or electing owner shall provide the first purchaser of production with information concerning the election to market share and the electing owner's share of monthly production.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-24-5. Replacement of the designated marketer

A new designated marketer may be appointed by a majority vote of the remaining market sharing owners. If an electing owner does not agree to the terms of a gas contract with a term greater than one year, the electing owner may elect a new designated marketer unless said election is prohibited by 165:10-24-4(i) and (j). Otherwise, substitution of the designated marketer shall occur not more than once every twelve months.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-24-6. Fees

(a) The designated marketer may charge each electing owner with an administrative fee for marketing the electing owner's share of production. Said fee shall be assessed monthly on a per-well basis. It shall be based on a formula described in this Section subject to annual adjustments as provided below. Said formula consists of 2.5% of the electing owner's monthly share of proceeds, but not less than twenty dollars nor more than seventy-five dollars, unless application of the annual adjustment factor provides a different maximum amount. The maximum amount of the fee permitted by this Section shall be adjusted as of the first day of May each year following May 1, 1993. The annual adjustment shall be computed by multiplying the rate currently in use by the percentage of increase or decrease in the annual overhead adjustment factor established by the Council of Petroleum Accountants Societies at its annual spring meeting for purposes of adjusting the combined fixed-rate overhead charges against joint operations in a well.
(b) If the designated marketer produces and sells gas for the account of the electing owner, the designated marketer may charge the electing owner or deduct said fee from the electing owner's share of the undistributed proceeds of production.
(c) Administrative fees under this Section shall be in addition to and separate from any and all post-production costs and expenses, including but not limited to reasonable marketing costs and expenses which may also be deducted from the proceeds payable to eligible electing owners.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

SUBCHAPTER 25. ESCROWED ACCOUNTS FOR POOLED MONIES

Section

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165:10-25-1. Definitions

The following words or terms, when used in this Subchapter, shall have the following meaning, unless the context clearly indicates otherwise:

"Escrow account" means an account established in a financial institution and held in the name of the holder and an escrow agent wherein each owner is federally insured to One Hundred Thousand Dollars ($100,000.00).

"Financial institution" means a federally or state chartered bank, savings and loan, or credit union.

"Holder" means any person in possession of royalties, bonus payments, or other monies directed to be paid under a Commission pooling order and which cannot be paid because the persons entitled thereto are unknown or cannot be located.

"Owner" means the last known record titleholder of a mineral interest which is subject to a Commission pooling order.

"Person" means any individual, partnership, joint stock associations, trust, cooperative, unincorporated association, or corporation.

165:10-25-2. Escrow account required

(a) Each pooling order which pools interest of unknown or unlocated owners shall contain language substantially similar to the following: "If any payment of bonus, royalty payments, or other payments due and owing under this order cannot be made because the person entitled thereto cannot be located or is unknown, then said bonus, royalty payments or other payments shall be paid into an escrow account in a financial institution within ninety (90) days after this order and shall not be commingled with any funds of the applicant or operator. Provided however, that the Commission shall retain jurisdiction to grant to financially solid and stable holders an exception to the requirement that such funds be paid into an escrow account with a financial institution and permit such holder to escrow such funds within such holder's organization. Responsibility for filing reports with the Commission as required by law and Commission rule as to bonus, royalty or other payments escrowed hereunder shall be with the applicable holder. Such escrowed funds shall be held for the exclusive use of, and the sole benefit of, the person entitled thereto. It shall be the responsibility of the operator to notify all other holders of this provision and of the Commission rules regarding unclaimed monies under pooling orders".

(b) Each pooling order issuing upon an application filed on or after July 1, 1984, shall contain, in addition to the foregoing language, an attached exhibit listing all parties or interests which are unknown or cannot be located, together with each party's last known address, if available.

165:10-25-3. Escrow account requirements

(a) Monies which are directed to be paid under a Commission pooling order and which cannot be paid because the persons entitled thereto are unknown or cannot be located shall be placed into escrow accounts in a financial institution. The holder shall choose the institution. The holder and the financial institution may make such arrangements as are necessary and appropriate for the establishment of the account. Service charges, fees, and costs may be deducted from any interest generated by the monies but in no event shall such charges, fees, and costs be deducted from the principal. Any financially solid and stable holder may apply to the Commission for an exception to the requirement to place monies into escrow accounts in a financial institution. The granting of an exception shall be within the sole discretion of the Commission and may only be granted upon the filing of a proper application therefor pursuant to notice given to the Manager of the Mineral Owners Escrow Account by mail at least ten days prior to the hearing and by publication one time at least 15 days prior to the hearing in a newspaper of general circulation in Oklahoma County and in a newspaper of general circulation in the county where the holder's principal

office in the state is located. The granting of an exception shall not exempt the holder from any other requirements set forth in this Subchapter.
(b) Only one account need be established by each holder. If only one account is established, a record shall be make of deposits and withdrawals for each person for whom monies are being held. Either the holder or the financial institution may keep the deposit/withdrawal record.
(c) An application for an exception under (a) of this Section shall state that the holder has proof by the holder's annual financial statement that it is a solid and stable holder. The holder must introduce its annual financial statement into evidence in the cause and the order, if one is issued, shall show that the annual financial statement was in fact introduced into evidence and considered by the Administrative Law Judge in making the determination to grant holder's request for an exemption under (a) of this Section, and holder shall submit a current financial statement on an annual basis thereafter.
(d) Withdrawals from such escrow account by the holder may only be made for the following purposes:
(1) To pay the rightful recipient of the monies upon presentation of a proper claim.
(2) To submit and pay to the Commission the principal of all monies placed in escrow pursuant to 165:10-25-6.
(3) To correct an overpayment or other mistake made in the distribution of monies by the holder.

[**SOURCE:** Amended at 9 Ok Reg 2337, eff 6-25-92]

165:10-25-4. Payment to owner

The holder shall have a designated officer or employee to whom claims upon the escrow account may be made. The holder shall promptly pay the appropriate sum to any person showing the holder sufficient proof of ownership and proof of identity as may be determined in good faith by the holder. The holder shall report any payments made on his annual report to the Commission.

165:10-25-5. Reports to the Commission

Each holder shall submit a report for persons who cannot be located or are unknown and for whom monies are being held in escrow no later than 30 days after such holder's annual reporting date. Each holder's initial report shall be filed no later than one year and 30 days after the date of the issuance of the first pooling order subject to this Subchapter. Such reports shall be filed each year that any monies are held in escrow, until the well is plugged.

165:10-25-6. Payment to the Commission

(a) No later than 30 days after the annual reporting date of each year, the holder shall submit to the Commission the principal of all monies placed in escrow accruing under the orders issued during the first year, and all subsequent years where the sum exceeds $100.00 for any one person.
(b) If the holder has placed in escrow less than $100.00 for any one person, the holder may follow the procedures for deposit, or maintain the funds in escrow. If the amount accumulates to over $100.00 for any one person after any annual reporting date, it shall be submitted to the Commission on the next annual reporting date.
(c) Payments shall be tendered to the Finance Office of the Commission. Payments shall be made by cashier's check, certified check, or money order made payable to the "Oklahoma Corporation Commission".

165:10-25-7. Affidavit of compliance

In addition to the Plugging Record (Form 1003) and Completion Report (Form 1002A) required under 165:10-11-7, the operator shall file a compliance affidavit. No plugging bond shall be released until after the compliance affidavit is filed.

165:10-25-8. Forms

The Commission may issue appropriate forms to implement the provisions of this Subchapter.

165:10-25-9. Release from liability

Any holder who pays or delivers monies to the Commission required to be paid under this Subchapter shall be relieved of all liability for the monies so paid or delivered for any claim which then exists or thereafter may arise or be made in respect to such monies.

165:10-25-10. Construction

This Subchapter shall not be construed as limiting the Commission's authority to grant an exception to any rule in this Subchapter, unless precluded by law.

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SUBCHAPTER 27. PRODUCTION REVENUE STANDARDS

Section

[**Authority**: 52 O.S. 1992, Section 570.13 et seq.]

[**Source**: Codified 6-25-93]

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165:10-27-1. Scope

This Subchapter implements the Production Revenue Standards Act of 1992, codified at 52 O.S. Section 570.1, et seq. It shall apply to all producing wells as set forth in the Production Revenue Standards Act of 1992. However, Sections 165:10-27-4 through 165:10-27-10 shall not apply to any well which is a part of a compulsory enhanced recovery project, or where royalty remittance is otherwise regulated by written agreement among all owners in the well. This Subchapter is intended to supplement and clarify as needed the language in the statutes.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-27-2. Effective date [Revoked]

[**Source:** Added at 10 OK Reg 2601, eff 6-25-93; Revoked at 11 Ok Reg 3699, eff 7-11-94]

165:10-27-3. Definitions

The following words or terms, when used in this Subchapter, shall have the following meaning, unless the context clearly indicates otherwise.

"Owner" means a person or governmental entity with a legal interest in the mineral acreage under a well which entitles that person or entity to oil or gas production or the proceeds or revenues therefrom.

"Produce", **"producing"** and **"production"** mean the physical act of severance of oil and gas from a well by an owner and includes but is not limited to the sale or other disposition thereof.

"Producing owner" means an owner entitled to produce who during a given month produces oil or gas for its own account or the account of subsequently created interests as they burden its interest.

"Proportionate production interest" means that interest in production which a working interest owner is entitled to produce in order to adjust for shifting of royalty burdens among working interest owners under the royalty provisions of 52 O.S. Sections 570.1, et seq., and is equal to the quotient of:

(A) the sum of a working interest owner's net revenue interest plus the net revenue interests of any subsequently created interests as they burden such owner's working interest,

(B) divided by the remainder of one (1) less the royalty share.

"Proportionate royalty share" means the percentage of the royalty share owned by a royalty interest owner calculated by dividing such owner's royalty interest in a well by the royalty share.

"Royalty interest" means the entirety of the percentage interest in production or proceeds therefrom:

(A) reserved or granted by a mineral interest owner exclusive of any interest defined as a working interest or a subsequently created interest, or

(B) otherwise provided or ascribed to a mineral interest owner by statute, rule, order or operation of law.

"Royalty interest in a well" means an owner's royalty interest multiplied by the quotient of:

(A) the gross mineral acres under the well attributable to such interest, divided by

(B) the total mineral acres under the well.

"Royalty proceeds" means the share of proceeds or other revenue derived from or attributable to any production of oil and gas attributable to the royalty share, but shall not include payments of bonus, delay rentals, shut-in royalties or any additional royalty payable to the Commissioners of the Land Office or other governmental entity, pursuant to and valued according to the terms of its oil and gas lease, which is calculated separately from the royalty portion of actual proceeds from the sale of oil or gas.

"Royalty share" means the percentage of the well equal to the sum of all royalty interests in the well.

"Share of production" means the monthly entitlement to produce belonging to a producing owner.

"Shipper" means any entity who contracts with a transporter to move gas through the transporter's system.

"Subsequently created interest" means any interest carved from a working interest other than a royalty interest. In addition to the royalty interest contained in a lease, a non-participatory interest created by a working interest owner for the benefit of a mineral interest owner in excess of a one-eighth (1/8) royalty interest may, by separate agreement other than the oil and gas lease, be a subsequently created interest and thereby not be communitized under the terms of the Production Revenue Standards Act only if there is clear and unambiguous language expressing that intent in the creating document. The additional royalty payable to the Commissioners of the Land Office or other governmental entity pursuant to and valued according to the terms of its oil and gas lease, which is calculated separately from the sale of oil or gas, shall also be a subsequently created interest and thereby shall not be communitized under 52 O.S. Section 570.1, et seq.

"Well" means an oil or gas well, and shall include:

(A) a well having uniform ownership as to all producing zones, or

(B) a drilling and spacing unit having uniform ownership wherein multiple wells producing gas are commonly metered, and

(C) each separately metered producing zone within a single wellbore wherein ownership varies by zone.

"Working interest" means the interest in a well entitling the owner thereof to drill for an produce oil and gas, including but not limited to the interest of a participating mineral owner to the extent set forth in Section 87.1 of Title 52 of the Oklahoma Statutes.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93; Amended at 11 Ok Reg 3699, eff 7-11-94]

165:10-27-4. Well operator records

Each well operator shall establish or cause to be established records showing the production allocations and payments to each interest owner in the well. For purposes of such records, the working interest owners shall provide the well operator with accounting and remittance information as required by statute. At a minimum, the required information shall consist of the name, address, interest amount and tax identification number of each royalty owner along with payment status. Each working interest owner shall provide said information in writing within 60 days of receipt of a written information request from the well operator. Updated information shall be provided by a working interest owner within 60 days after receipt of notice of a change.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93; Amended at 11 Ok Reg 3699, eff 7-11-94]

165:10-27-5. Pre-sale nominations

(a) Any producing owner marketing production separately from the well operator shall send pre-production nominations to the well operator for his withdrawals. A nomination shall be due five business days prior to the month in which the nomination is to be effective, but earlier if required by the first purchaser or transporter. The nomination shall consist of the name of the first purchaser or shipper, shipper contract number and the volumes of gas nominated for production for such producing owner's account.

(b) Nothing in this Section shall supersede or limit the operator's right to control gas nominations and allocations under a joint operating agreement, separate balancing agreement or Commission order.

(c) The owner of the gas meter shall confirm all nominations with the operator of the well no later than the last business day prior to the month in which production occurs.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93; Amended at 11 Ok Reg 3699, eff 7-11-94]

165:10-27-6. Entitlement

Each producing owner in a well shall be entitled to produce each month his proportionate production interest subject to balancing restrictions created by statute, rule, agreement or operation of law.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-27-7. Post-sale reports

(a) Within sixty days after the end of the month of production, each producing owner shall report and account to the operator of the well, the identity of the first purchaser or shipper of the gas and information specified in 165:10-27-13.
(b) Within fifteen days after the end of the month of production, each owner of a gas meter taking gas solely from a gathering system shall provide upon first request by the owner of such gathering system and thereafter, the gross volume of gas measured by such meter both in MCF and British Thermal Unit equivalent.
(c) Within twenty days after the end of the month of production, each owner of a gas meter shall provide or cause to be provided in writing to the operator of the well, the gross volume of gas measured by such meter, both in MCF and British Thermal Unit equivalent, and the volume of gas allocated at the meter to each first purchaser or shipper and each contracted producing owner that sold gas to the owner of the gas meter. Each meter owner shall, within the same time period, furnish each first purchaser or shipper the volume of gas allocated at the meter to that first purchaser or shipper. However, if the gas processing plant operator is performing the allocations, then within ten days after the end of the month of production, the owner of the pipeline residue gas meter shall provide, upon first request by the processing plant operator and thereafter, the volume in MCF and British Thermal Unit equivalent measured through its meter as required by the gas processing plant operator for its allocations under this subsection.
(d) As an alternative to supplying the operator with information in the manner prescribed by subsections (b) and (c) of this Section, the owner of a gas meter who has a contract with one or more producing owners, covering all of the gas flowing through its meter, may furnish monthly volume statements to the operator of the well, provided said owner of the gas meter has previously furnished the operator with names of the producing owners and the decimal interest owned by each such producing owner or owners or any method other than by decimal interest then in effect for allocating gas among the producing owners. After adopting alternative reporting under this subsection, the owner of the gas meter shall be required to supply the operator of the well with any change to the name of a producing owner, the decimal interest by a producing owner or the method, other than by decimal interest, for allocating gas among the producing owners: such change to reported by the owner of the gas meter to the operator of the well within thirty days after the owner of the gas meter receives notice of such change.
(e) Within thirty-five days after the end of the month of production, each first purchaser or shipper of gas from a gas meter shall furnish or cause to be furnished to the operator of the well, a volume allocation statement showing the volume of gas purchased from or shipper for each contracted producing owner. Within thirty days after making any retroactive gas volume adjustment for such well, the first purchaser or shipper shall furnish notice of such retroactive gas volume adjustment to the operator of the well.
(f) Any person subject to multiple reporting requirements under this Section shall not be required to re-report the same information to the operator if such

information has been previously provided by such person in a different report. Such person may consolidate the required information into a single report to the operator; provided, however, that all such reporting must comply with the applicable statutory time periods for the type of information being communicated to the operator.
(g) Any first purchaser, shipper or owner of a gas meter that does not provide the information required of it by this Section shall be subject to having its takes from the well suspended by the operator of the well pursuant to 165:10-27-8.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93; Amended at 11 Ok Reg 3699, 7-11-94]

165:10-27-8. Operator's option to confirm zero volume of gas sales because of noncompliance
(a) If a producing owner fails to timely provide the operator of the well with any of the information required by 165:10-27-4 and 165:10-27-7, or if the owner of a gas meter, first purchaser or shipper of gas fails to timely provide the operator of the well with any of the information required of it by 165:10-27-7 for the transfer, transportation, delivery or sale of gas by a producing owner, the operator of the well shall have the right, but not the obligation, to confirm zero volume of gas sales for such producing owner, and to make available for nomination and sale to other producing owners in the well, then in compliance with said Sections, all of such producing owner's share of production for the next subsequent calendar month and for each and every month thereafter of noncompliance. If the operator elects to make such producing owner's share of production available for nomination and sale, the operator shall immediately notify such producing owner by certified mail and inform such producing owner that such producing owner shall no longer have the right to nominate any volume of gas, until the next production month following the date of compliance, unless the operator of the well agrees to an earlier date. Such notice shall contain the lease or well identification, legal description, production months of noncompliance, a brief description of the noncompliance, and a provision stating that the operator is confirming zero volume of gas sales for such producing owner. The operator shall than immediately notify each producing owner then in compliance with the aforesaid Sections and inform said producing owner about additional gas volumes available for nomination and sale. In regard to the producing owner for which the operator has confirmed zero gas sales, the operator shall also immediately notify in writing such producing owner's first purchaser or shipper, and the owner of the gas meter, and such notice shall report that such producing owner does not have the right to nominate and sell or transport any volume of gas, until the next production month following compliance, unless the operator of the well agrees to an earlier date. Such notice shall also contain the lease or well identification, legal description, a brief description of the noncompliance, and the production months of noncompliance.
(b) As soon as a noncomplying party is in compliance, but no sooner than the next production month unless otherwise agreed to, the operator of the well shall give the affected producing owner the opportunity to nominate and sell gas subject to existing agreements or by common practice within the oil and gas industry.
(c) The first purchaser or shipper and the owner of the gas meter shall be entitled to rely on and shall incorporate on a prospective basis any nomination or allocation changes pursuant to such notification from the operator under this Section. Changes pursuant to such notification may be made on a retroactive basis if so agreed to by the operator, owner of the meter, the first purchaser or shipper.
(d) The remedies provided for in this Section shall not preclude any party from pursuing the remedies available to it through the district courts, as provided by existing law, including the right of offset.
(e) All elections and notices given pursuant to the provisions of this Subchapter shall become effective as of the first day of the month following the

end of any time period specified in the Production Revenue Standards Act as last amended, 52 O.S. Section 570.1, et seq.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93; Amended at 11 Ok Reg 3699, eff 7-11-94]

165:10-27-9. Designated payor for royalty distributions

(a) For royalty distributions, the well operator shall serve as payor for all proceeds of production, absent appointment of a substitute payor and/or election of a working interest owner to distribute royalties attributable to that working interest owner's sales.

(b) A substitute payor may be appointed by Commission order or by the owners owning a majority in interest of the working interest in the well. A substitute payor so appointed shall assume the rights and duties of the well operator concerning assessment of fees, royalty record maintenance and disbursement of royalties. A surety bond of $50,000 shall be required if the substitute payor is not a working interest owner, a first purchaser of production from the well, a bank or a trust company. Such bond shall be posted with the Surety Department of the Conservation Division before receipt of sales proceeds by the substitute payor. Any such bond shall be drafted so as to compensate royalty owners if the substitute payor defaults on his disbursement obligation.

(c) A producing owner may elect to distribute royalties from his sales subject to the following conditions:

(1) the producing owner shall provide 60 days written notice to the operator before starting or stopping the alternative procedure;

(2) the producing owner shall assume liability for its errors;

(3) the producing owner shall report payment information to the well operator within 30 days after each disbursement;

(4) the producing owner cannot re-start the alternative procedure within 12 months after terminating it.

(d) For good cause shown, the Commission may cancel a producing owner's election to separately distribute royalty. Cancellation shall occur only by order after application, notice and hearing.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-27-10. Administrative fees

(a) This Section prescribes fees which may be charged by the operator of a gas producing well or substitute payor, for administrative expenses generated by the Production Revenue Standards Act.

(b) Fees shall be assessed on a per-well basis against the cost-bearing working interests in a well according to respective gross working interest. They shall not be assessed against either royalty interests or non-cost bearing working interests in the well.

(c) A one-time implementation fee shall cover any cost associated with establishing or modifying the well operator's record keeping for the well, and it shall apply to any existing gas producing well with a date of first production occurring before September 1, 1992. If operations are transferred to a different operator after assessment of the one-time implementation fee, the successor operator may not assess another implementation fee against the working interests in the well.

(d) Should any working interest owner in a well producing gas fail to fully and timely comply with the requirements of 165:10-27-4, the well operator or substitute payor shall have the right to charge against said non-complying working interest owner a late fee of two hundred-fifty dollars per affected well.

(e) An annual maintenance fee shall cover any cost associated with record keeping, issuance of gas balancing statements and any election of a producing owner regarding separate distribution of royalty proceeds. Maintenance fees shall be calculated on an annual basis using the first day of May as the

anniversary date. Such fees may be prorated and billed on a monthly basis at the well operator's discretion. If a well has a date of first production after the first day of May of the calendar year, the annual maintenance fee shall be prorated based on the remaining number of months before the next anniversary date on the first day of May.
(f) No working interest owner other than the well operator shall be entitled to assess either an implementation fee or a maintenance fee.
(g) The rates for implementation fees and annual maintenance fees shall be based on the appropriate table values found in Appendix G to this Chapter, subject to annual adjustments as provided below. The appropriate table value shall be determined from a matrix using the number of working interest owners or royalty owners in a well. The table value shall be adjusted as of the first day of May each year following May 1, 1993. The annual adjustment shall be computed by multiplying the rate currently in use by the percentage of increase or decrease in the annual overhead adjustment factor established by the Council of Petroleum Accountants Societies at its annual spring meeting for purposes of adjusting the combined fixed-rate overhead charges against joint operations in a well.
(h) Any fee assessed under this Section may be billed or deducted from the working interest owner's share of undistributed proceeds of production.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-27-11. Balancing of royalty accounts
(a) In the event of a production imbalance among royalty owners in a well, the affected working interest owners may adopt a royalty payment method to balance the royalty accounts, provided it is used only to extent necessary to balance the cumulative accounts of the royalty owners, and prior notice of the plan is sent to the affected royalty owners and to the well operator along with any ongoing information necessary for said operator to discharge its duties.
(b) Nothing in this Section shall impair any balancing rights arising by contract or law.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-27-12. Record keeping
Any record required by this Subchapter shall be maintained for a period of at least five years. Upon reasonable request, the well operator or substitute payor shall make available to a royalty owner for confidential inspection a record of receipts and payment of proceeds to said royalty owner, as well as copies of information furnished to the well operator pursuant to the Production Revenue Standards Act.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-27-13. Check stub information
(a) With each royalty payment, the following information shall be provided:
(1) lease or well identification;
(2) month and year of sales included in the payment;
(3) total barrels or MCF attributed to such payment;
(4) price per barrel or MCF, including British Thermal Unit adjustment of gas sold;
(5) gross production and severance taxes attributable to said interest;
(6 net value of total sales attributed to such payment after deduction of gross production and severance taxes;
(7) owner's interest in the well expressed as a decimal;
(8) owner's share of the total value of sales attributed to such payment before any deductions;

(9) owner's share of the sales value attributed to such payment less owner's share of the production and severance taxes.

(b) Upon payee's request, the payor shall provide a list of any other deduction from such payment.

(c) All revenue decimals shall be calculated to at least six decimal places.

(d) Gas volumes shall be measured according to 52 O.S. Section 474.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

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APPENDIX A. ALLOCATED WELL ALLOWABLE TABLE*

The depth in feet from the surface of the ground to the top of the pay in the discovery oil well in each such pool will be the assumed average producing depth thereof.

AVERAGE DEPTH OF POOL/FEET**	ACREAGE 10 or less	20	40	80	160
To-3000		30	45	57	
3001-3200		31	45	57	
3201-3400		32	46	58	
3401-3600		33	47	59	
3601-3800		34	48	60	
3801-4000		35	49	61	
4001-4200		36	49	61	71
4201-4400		37	50	62	73
4401-4600		38	51	63	75
4601-4800		39	52	64	77
4801-5000		40	53	65	79
5001-5200		41	54	67	82
5201-5400		42	55	69	85
5401-5600		43	56	71	88
5601-5800		45	58	73	91
5801-6000		47	60	75	94
6001-6200		49	62	77	97
6201-6400		51	64	79	100
6401-6600		53	66	82	103
6601-6800		55	68	85	107
6801-7000		57	70	88	110
7001-7200		59	72	90	113
7201-7400		61	74	92	116
7401-7600		63	76	95	119
7601-7800		65	78	98	122
7801-8000		67	80	101	126
8001-8200		69	83	104	130
8201-8400		71	86	107	134
8401-8600		73	89	111	139

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	A C R E A G E				
AVERAGE DEPTH OF POOL/FEET**	**10 or less**	**20**	**40**	**80**	**160**
8601-8800	75	92	115	144	
8801-9000	77	95	119	149	
9001-9200	79	98	123	154	
9201-9400	81	101	127	159	
9401-9600	84	105	131	164	
9601-9800	87	109	136	170	
9801-10000	90	113	141	176	
10001-10200	95	119	148	185	333
10201-10400	100	125	156	195	351
10401-10600	105	131	164	205	369
10601-10800	110	137	172	215	387
10801-11000	115	144	180	225	405
11001-11200	122	153	190	239	431
11201-11400	129	162	202	254	458
11401-11600	137	171	214	269	485
11601-11800	145	181	226	284	512
11801-12000	153	191	239	299	539
12001-12200	163	203	254	318	573
12201-12400	173	215	269	338	609
12401-12600	183	228	285	358	645
12601-12800	193	241	301	378	681
12801-13000	203	254	317	398	717
13001-13200	213	266	333	416	749
13201-13400	223	278	349	436	785
13401-13600	233	290	365	455	819
13601-13800	243	303	380	475	855
13801-14000	253	316	395	494	890
14001-14200	263	328	410	514	926
14201-14400	273	340	426	534	962
14401-14600	283	353	441	554	998

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	A C R E A G E				
AVERAGE DEPTH OF POOL/FEET**	**10 or less**	**20**	**40**	**80**	**160**
14601-14800	293	366	457	573	1032
14801-15000	303	379	473	593	1068

***** Allowables currently are established at 200 percent of market demand. To determine the allowable for any well, the number in the appropriate column of the chart in the appendix must be doubled (multiplied by 2). The minimum allocated well is therefore 60 BOPD (from the 10 acre column, depth to 3,000 feet, 30 BOPD times 2) (Market Demand).

****** The average producing depth of the pool is assumed to be the depth in feet from the surface of the ground to the top of pay in the discovery well in that pool.

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APPENDIX B. DISCOVERY WELL ALLOWABLE TABLE
(100 percent of market demand)

DEPTH*	BARRELS PER DAY	DAYS AFTER DISCOVERY
0-1000	100	365
1001-1200	105	391
1201-1400	110	416
1401-1600	115	442
1601-1800	120	467
1801-2000	125	493
2001-2200	130	518
2201-2400	135	545
2401-2600	140	569
2601-2800	145	596
2801-3000	150	621
3001-3200	155	647
3201-3400	160	672
3401-3600	165	698
3601-3800	170	723
3801-4000	175	749
4001-4200	180	774
4201-4400	185	800
4401-4600	190	825
4601-4800	195	851
4801-5000	200	876
5001-5200	205	910
5201-5400	210	942
5401-5600	215	975
5601-5800	225	1007
5801-6000	235	1041
6001-6200	245	1073
6201-6400	255	1107
6401-6600	265	1139
6601-6800	275	1172
6801-7000	285	1205
7001-7200	295	1245
7201-7400	305	1285
7401-7600	315	1326
7601-7800	325	1365

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DEPTH*	BARRELS PER DAY	DAYS AFTER DISCOVERY
7801-8000	335	1406
8001-8200	345	1445
8201-8400	355	1486
8401-8600	365	1526
8601-8800	375	1567
8801-9000	385	1606
9001-9200	395	1650
9201-9400	405	1694
9401-9600	420	1737
9601-9800	435	1781
9801-10000	450	1825
10001-10200	475	1837
10201-10400	500	1847
10401-10600	525	1859
10601-10800	550	1869
10801-11000	575	1880
11001-11200	610	1888
11201-11400	645	1895
11401-11600	685	1902
11601-11800	725	1910
11801-12000	765	1917
12001-12200	815	1917
12201-12400	865	1917
12401-12600	915	1917
12601-12800	965	1917
12801-13000	1015	1917
13001-13200	1065	1917
13201-13400	1115	1917
13401-13600	1165	1917
13601-13800	1215	1917

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DEPTH*	**BARRELS PER DAY**	**DAYS AFTER DISCOVERY**
13801-14000	1265	1917
14001-14200	1315	1917
14201-14400	1365	1917
14401-14600	1415	1917
14601-14800	1465	1917
14801-15000	1515	1917

***** The depth of the discovery pool well is assumed to be the depth in feet from the surface of the ground to the top of the pay in the initial discovery well.

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APPENDIX C: TABLE HD

RECOMMENDED ALLOWABLE ON HORIZONTAL OIL WELLS
BASED ON DEPTH AND ACREAGE

UNIT SIZE	TRUE VERTICAL DEPTH	REQUIRED HORIZONTAL COMPONENT	BBLS/DAY ALLOWABLE	BONUS BBL/DAY PER FT. OF LATERAL
10 acre	0-4000'	150' - 467'	70	.2
20 acre	0-4000'	468' - 1044'	98	.2
40 acre	0-4000'	933' - 1400'	122	.2
80 acre	0-4000'	1401' - 2087'	244	.2
160 acre	0-4000'	1866' - 2800'	488	.2
320 acre	0-4000'	2801' - 4174'	976	.2
640 acre	0-4000'	3733' and over	1952	.2
10 acre	4001-8000'	150' - 467'	134	.3
20 acre	4001-8000'	468' - 1044'	160	.3
40 acre	4001-8000'	933' - 1400'	202	.3
80 acre	4001-8000'	1401' - 2087'	252	.3
160 acre	4001-8000'	1866' - 2800'	504	.3
320 acre	4001-8000'	2801' - 4174'	1008	.3
640 acre	4001-8000'	3733' and over	2016	.3
10 acre	8001-12000'	150' - 467'	306	.4
20 acre	8001-12000'	468' - 1044'	382	.4
40 acre	8001-12000'	933' - 1400'	478	.4
80 acre	8001-12000'	1401' - 2087'	598	.4
160 acre	8001-12000'	1866' - 2800'	1078	.4
320 acre	8001-12000'	2801' - 4174'	2156	.4
640 acre	8001-12000'	3733' and over	4312	.4

All oil produced and marketed during the drilling and completion operations shall be charged against the allowable assigned to the well upon completion. Effective date of the allowable shall be the date of first production.

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APPENDIX D. LIST OF NGPA FORMS [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2401, eff 7-1-96]

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APPENDIX E. SCHEDULE A FINES [REVOKED]

[**Source:** Revoked in Rule Making 200200017, eff 7-1-02]

APPENDIX E. SCHEDULE A FINES [NEW]

RULE	VIOLATION	FINE
165:10-3-1	Failure to obtain permit (Form 1000) to drill, re-enter, deepen or recomplete.	$1,000
165:10-3-3	Failure to report surface casing failure.	$1,000
165:10-3-4	Failure to set sufficient surface casing or circulate cement.	$5,000
165:10-3-4	Failure to run and cement surface well marker.	$1,000
165:10-5-2	Failure to obtain permit for injection or disposal well.	$5,000
165:10-5-13	Failure to obtain permit for annular injection of drilling fluids.	$2,500
165:10-7-14	Failure to obtain approval to drill deep anode groundbed.	$1,000
165:10-7-16	Failure to obtain permit for construction of off-site pit.	$1,000
165:10-7-16	Illegal discharge from noncommercial pit.	$2,000
165:10-7-17	Failure to obtain permit to discharge produced water to surface.	$1,000
165:10-7-19	Failure to obtain permit for one-time land application of water-based fluids from tanks/ earthen pits.	$2,000
165:10-7-26	Failure to obtain permit for a one-time land application of contaminated soils or petroleum hydrocarbon-based drill cuttings.	$2,000
165:10-7-27	Failure to obtain permit to apply waste oil, waste oil residue, or crude oil contaminated soil to lease roads, pipeline service roads, tank farm roads, well locations and production sites.	$2,000
165:10-7-29	Failure to obtain permit for a one-time application of freshwater-based drill cuttings to private access areas, well locations and production sites.	$2,000
165:10-9-1	Failure to obtain permit for construction and use of commercial pit.	$5,000
165:10-9-1	Illegal discharge from a commercial pit.	$5,000
165:10-11-1	Failure to acquire license to pull pipe and plug wells.	$2,500

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165:10-11-4	Failure to obtain plugging instructions and notify district office of time well is to be plugged.	$1,000

[**Source:** New in Rule Making 200200017, eff 7-1-02]

APPENDIX F. SCHEDULE B FINES [REVOKED]

[**Source:** Revoked in Rule Making 200200017, eff 7-1-02]

APPENDIX F. SCHEDULE B FINES [NEW]

RULE	VIOLATION	FINE
165:10-1-10	Failure to maintain current surety.	$500
165:10-3-4	Failure to protect treatable water or file for alternate casing procedure.	$2,500
165:10-3-17	Failure to remove trash, debris and junk from well site.	Up to $1,000
165:10-3-17	Failure to post lease sign or OTC number.	$50 per well/$500 per lease
165:10-3-25	Failure to file completion report, Form 1002A.	$250
165:10-3-26	Failure to submit required electric logs.	$250
165:10-3-35	Failure to obtain order for multiple completion.	$500
165:10-3-39	Failure to obtain order for commingling.	$500
165:10-5-6	Failure to conduct/perform mandatory initial mechanical integrity test within rule timeframe.	$500
165:10-5-6	Failure to perform subsequent mechanical integrity test.	$500
165:10-5-7	Failure to file fluid injection report, Form 1012.	$500
165:10-5-7	Failure to report loss of mechanical integrity on well.	$1,500
165:10-7-5	Failure to report non-permitted discharge.	$500
165:10-7-16	Failure to comply with any closure requirement for noncommercial pit.	$1,000
165:10-9-1	Failure to close commercial pit as required by rule.	$1,000
165:10-11-3	Failure to plug well in rule timeframe.	$1,000
165:10-11-7	Failure to file plugging and cementing report as required by rule.	$500

[**Source:** New in Rule Making 200200017, eff 7-1-02]

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APPENDIX G.

IMPLEMENTATION FEES (ONE - TIME)

No. of RIOs*	No. of Working Interest Owners 2-10	11-20	21+
2-30	$350	$500	$650
31-100	$500	$500	$650
100+	$650	$650	$650

MAINTENANCE FEES (ANNUAL)

No. of RIOs*	No. of Working Interest Owners 2-10	11-20	21+
2-30	$200	$325	$450
31-100	$325	$325	$450
100+	$450	$450	$450

* RIO = Royalty Interest Owners

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

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APPENDIX H. CALCULATIONS

PROCEDURE FOR CALCULATING LOADING RATE OF TOTAL SOLUBLE SALTS (TSS)

__________ ppm TSS in soil[1] X 2 = __________ lbs/ac TSS in soil

6,000 lbs/ac TSS - ________________ lbs/ac TSS in soil = Maximum TSS (lbs/ac) to be applied ____________

Maximum TSS (lbs/ac) ________ ÷ (________ ppm TSS in pit materials[1] X .000001) = Maximum lbs/ac of pit materials to be applied _________

Maximum lbs/ac ________ ÷ ________ lbs/bbl = Maximum bbls/ac _______

PROCEDURE FOR CALCULATING LOADING RATE OF HEAVY METALS AND OIL AND GREASE

OCC Standard for the parameter _______ lbs/ac ÷ (_______ ppm in pit materials X .000001) = Maximum lbs/ac of pit materials to be applied _________

Maximum lbs/ac _______ ÷ _______ lbs/bbl = Maximum bbls/ac ________

PROCEDURE FOR CALCULATING MAXIMUM DRY WEIGHT

Weight of drilling mud[2] ______ lbs/gal x 42 = ______ lbs/bbl

200,000 lbs ÷ ______ lbs/bbl = Maximum bbls/acre ______

PROCEDURE FOR CALCULATING VOLUME OF PIT CONTENTS

$$V = \frac{(W_t \times L_t) + (W_b \times L_b)}{2} \times D \times .1781$$

Where, V = volume

W_t = width of pit in feet at top of pit contents.

L_t = length of pit in feet at top of pit contents.

W_b = width of pit in feet at bottom of pit.

L_b = length of pit in feet at bottom of pit.

D = depth in feet of pit contents to be soil farmed.

[1]Electrical Conductivity (EC expressed in micromhos/cm) may be used to estimate TSS: EC x 0.64 = ppm TSS.

[2]Based on laboratory analysis of Dry Weight.

[**Source:** Added at 12 Ok Reg 2017, 7-1-95]

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APPENDIX I. SOIL LOADING FORMULAS

TOTAL DISSOLVED SOLIDS

EC of receiving soil ______ micromhos/cm x 0.64 = ______ ppm TDS. TDS in receiving soil ________ ppm x 2 = _______ lbs/ac TDS in receiving soil.

6,000 lbs/ac TDS* - _______ lbs/ac TDS in receiving soil = Maximum TDS (lbs/ac) to be applied _______.

EC of materials to be applied ________ micromhos/cm x 0.64 = _______ ppm TDS.

Maximum TDS (lbs/ac) to be applied _______ ÷ (TDS of materials to be applied ________ ppm x .000001) = Maximum weight of materials to be applied _______ lbs/ac.

FOR LIQUID MATERIALS:

Maximum weight of materials to be applied _______ lbs/ac ÷ (sample weight _______ lbs/gal** x 42) = Maximum loading _______ bbls/ac.

Total volume of materials to be applied _______ bbls ÷ Maximum loading ________ bbls/ac = Minimum acres required ________.

FOR SOLID MATERIALS:

Maximum weight of materials to be applied ________ lbs/ac ÷ (sample weight _______ lbs/gal** x 202) = Maximum loading ________ cu yds/ac.

Total volume of materials to be applied _________ cu yds ÷ Maximum loading ______ cu yds/ac = Minimum acres required _______.

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CHLORIDES

Cl in receiving soil _________ ppm x 2 = _________ lbs/ac Cl in receiving soil.

3500 lbs/ac Cl – ________ lbs/ac Cl in receiving soil = Maximum Cl (lbs/ac) to be applied _________.

Maximum Cl (lbs/ac) to be applied _________ ÷ (Cl of materials to be applied _________ ppm x .000001) = Maximum weight of materials to be applied _________ lbs/ac.

Maximum weight of materials to be applied _________ lbs/ac ÷ (sample weight _________ lbs/gal** x 202) = Maximum loading _________ cu yds/ac.

Total volume of materials to be applied _________ cu yds ÷ Maximum loading _________ cu yds/ac = Minimum acres required _________.

OIL AND GREASE[1]

40,000 lbs/ac O&G* ÷ (O&G of materials to be applied _________ ppm x .000001) = Maximum weight of materials to be applied ________ lbs/ac.

FOR LIQUID MATERIALS:

Maximum weight of materials to be applied ________ lbs/ac ÷ (sample weight __________ lbs/gal** x 42) = Maximum loading ________ bbls/ac.

Total volume of materials to be applied ________ bbls ÷ Maximum loading _________ bbls/ac = Minimum acres required _________.

Maximum bbls/ac ÷ 4.809 = Maximum cu yds/ac _________.

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FOR SOLID MATERIALS:

Maximum weight of materials to be applied _________ lbs/ac ÷ (sample weight _________ lbs/gal** x 202) = Maximum loading _________ cu yds/ac.

Total volume of materials to be applied ________ cu yds ÷ Maximum loading ________ cu yds/ac = Minimum acres required ________.

DRY WEIGHT

Wet weight of drilling mud**_________ lbs/gal x _________ % Dry weight = _________ lbs/gal Dry weight.

_________lbs/gal Dry weight x 202 = _________ lbs/cu yd.

200,000 lbs/ac Dry weight ÷ _________ lbs/cu yd = Maximum cu yds/ac _________.

Total volume of materials to be applied _________ cu yds ÷ Maximum cu yds/ac _________ = Minimum acres required _________.

*Soil loading standards are based upon standards set forth in "Diagnosis and Improvement of Saline and Alkaline Soils," U.S. Agriculture Handbook 60. Pub. U.S. Salinity Laboratory, Riverdale, California, 1954; Moseley, H.R., "Summary and Analysis of API Onshore Drilling Mud and Produced Water Environmental Studies," 1983, American Petroleum Institute Bulletin D-19.

**Based on actual weight of composite sample of materials.

[1] GRO or DRO may be substituted for oil and grease

[**SOURCE:** Added at 12 Ok Reg 2039, 7-1-95; Amended in Rule Making 97000002, eff 7-1-97

APPENDIX J. DEWATERING OIL ALLOWABLE TABLE

(100 percent of market demand)

Depth*	**Barrels Per Day**
To-3000	200
3001-4000	400
4001-5000	600
5001-6000	800
6001-7000	1000
7001-8000	1100
8001-9000	1200
9001-10000	1300
10001-	1400

* The depth in feet from the surface of the ground to the top of the producing formation in the oil well.

[**SOURCE:** Added in Rule Making 200100009, eff 7-1-02]

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Appendix E – Texas Regulatory Summary (General)

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Texas Administrative Code

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.1	**Organization Report; Retention of Records; Notice Requirements**

(a) Filing requirements.

(1) Except as provided under subsection (d) of this section, no organization, including any person, firm, partnership, joint stock association, corporation, or other organization, domestic or foreign, operating wholly or partially within this state, acting as principal or agent for another, for the purpose of performing operations within the jurisdiction of the commission shall perform such operations without having on file with the commission an approved organization report and financial security as required by Texas Natural Resources Code §§91.103-91.1091. Operations within the jurisdiction of the commission include, but are not limited to, the following:

(A) drilling, operating, or producing any oil, gas, geothermal resource, brine mining injection, fluid injection, or oil and gas waste disposal well;

(B) transporting, reclaiming, treating, processing, or refining crude oil, gas and products, or geothermal resources and associated minerals;

(C) discharging, storing, handling, transporting, reclaiming, or disposing of oil and gas waste, including hauling salt water for hire by any method other than pipeline;

(D) operating gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance or repressurizing plants, or recycling plants;

(E) recovering skim oil from a salt water disposal site;

(F) nominating crude oil;

(G) operating a directional survey company;

(H) cleaning a reserve pit;

(I) operating a pipeline;

(J) operating as a cementer approved for plugging wells; or

(K) operating an underground hydrocarbon or natural gas storage facility.

(2) The Commission shall notify organizations that perform operations not included in paragraph (1)(A)-(K) of this subsection of any additional activities subject to the jurisdiction of the Commission which require the filing of the organization report. Such notification shall make the provisions of this section applicable to such activities.

(3) Each organization performing activities subject to the jurisdiction of the Commission shall maintain a current organization report with the Commission until all duties, obligations, and liabilities incurred

pursuant to Commission rules, the Natural Resources Code, Titles 3 (Subtitles A, B, C, and Chapter 111 of Subtitle D) and 5, and the Water Code, Chapters 27 and 29, are fulfilled.

(4) The organization report shall contain the following information:

(A) the name, street address, mailing address, telephone number, and emergency after-hours telephone number of the organization;

(B) the plan of the business organization;

(C) for each officer, director, general partner, owner of more than 25% ownership interest, or trustee (hereinafter controlling entity) of the organization:

(i) that entity's or individual's full legal name, the name(s) under which such entity or individual conducts business in the State of Texas, and all assumed names;

(ii) the following:

(I) if the entity is an individual, his or her social security number. Any individual who does not have a valid social security number shall submit, at that person's option, either his or her valid driver's license or Texas State Identification number;

(II) if the entity is not an individual, the name and, at that person's option, either the valid driver's license, social security, or Texas Identification number of each officer, director, or other person, who, under Texas Natural Resources Code, §91.114, holds a position of ownership or control of the organization, or an active P-5 number for that entity. All controlling entities connected to an organization which are not individuals shall provide the identification of the individuals in ownership or control of those entities.

(iii) a street address different than that of the organization; and

(iv) if different from the mailing address of the organization, a mailing address;

(D) if a foreign or nonresident organization, the name and street address of a resident agent.

(E) the name of any non-employee agent that the organization authorizes to act for the organization in signing Oil and Gas Division certificates of compliance which initially designate the operator or change the designation of the operator. Organizations may designate non-employee agents to execute subsequent organization reports. That designation shall be authorized by the organization and not by a non-employee agent.

(5) Any organization may designate a resident agent with a street address different than that of the organization in place of submitting the street addresses of the three (if applicable) primary controlling entities of the organization. Any foreign or nonresident organization identified in paragraph (1) of this subsection shall designate and maintain a resident agent upon whom may be served any process, notice, or demand required or permitted by law to be served upon such entity by or on behalf of the Commission. Failure of such organization to designate and maintain a resident agent shall render the organization report invalid. (Reference Order Number 20-60,617, effective January 1, 1971.)

(6) Failure by any organization identified in paragraph (1) of this subsection to answer any subpoena, commission to take deposition, or directive to appear at a hearing served upon such organization by or on behalf of the Commission shall render the organization report invalid.

(7) An organization shall refile an organization report annually according to the schedule assigned by the

commission. Prior to the filing date, the commission shall mail notification and information to each organization for update of the organization report file. An organization shall file an amended organization report within 15 days after a change in any information required to be reported in the organization report. Only address changes may be made by letter.

(8) The commission shall meet any requirement under statute or commission rule for an order to be sent or notice to be given by the commission to an organization by mailing the item to the organization's mailing address shown on the most recently filed organization report or the most recently filed letter notification of change of address. Notices sent by regular first-class mail shall be presumed to have been received if, upon arrival of the deadline for any response to the notice, the wrapper containing the notice has not been returned to the commission. Any commission action or proceeding for which notice is required shall go forward on the basis of the notice provided under this subsection, whether or not actual notice has been received. Service of notices and orders sent by certified mail is effective upon:

(A) acceptance of the item by any person at the address;

(B) initial failure to claim or refusal to accept the item by any person at the address prior to its eventual return to the commission by the United States Postal Service; or

(C) return of the item to the commission by the United States Postal Service bearing a notation such as "addressee unknown," "no forwarding address," "forwarding order expired," or any similar notation indicating that the organization's mailing address shown on the most recently filed organization report or address change notification letter is incorrect.

(9) An organization may also designate to the commission in writing a specified address for all commission correspondence relating to a particular district. If designated by an operator, this specified address shall be used in lieu of the organization address for any notices, other than hearing notices, pertaining to that district.

(10) The commission may return, unapproved, to the organization address an organization report which is submitted to the commission not fully completed according to the report's written instructions and not timely corrected. In the event that the commission returns an organization report, all submitted financial assurances shall remain non-refundable. If an organization report approved by the commission is found to contain information that was materially false at the time it was submitted for approval, the commission may suspend or revoke the organization report after notice and opportunity for hearing.

(b) Record requirements. All entities who perform operations which are within the jurisdiction of the commission shall keep books showing accurate records of the drilling, redrilling, or deepening of wells, the volumes of crude oil on hand at the end of each month, the volumes of oil, gas, and geothermal resources produced and disposed of, together with records of such information on leases or property sold or transferred, and other information as required by commission rules and regulations in connection with the performance of such operations, which books shall be kept open for the inspection of the commission or its representatives, and shall report such information as required by the commission to do so.

(c) Time frame. All organizations shall keep copies of records, forms, and documents which are required to be filed with the commission, along with the supporting documents referred to in subsection (b) of this section, for a period of three years, or longer if required by another commission rule, and any such copies may be disposed of at the discretion of such entities after the original records, forms, and documents have been on file with the commission for the required period, except that particular documents shall be retained beyond the required period and until the resolution of pending commission regulatory enforcement proceedings if the documents contain information material to the determination of any issues therein. All records, forms, and documents required to be filed with the commission shall be filed in the same name, exactly as it appears on the organization report.

(d) Issuance of permits to organizations without active organization reports.

(1) Notwithstanding contrary provisions of this section, the commission or its delegate may issue a permit to an organization or individual that does not have an active organization report or does not ordinarily conduct oil and gas activities when the issuance of such a permit is determined to be necessary to implement a compliance schedule, or to remedy circumstances or a violation of a commission rule, order, license, permit, or certificate of compliance relating to safety or the prevention of pollution. For permits issued under this subsection, the commission may impose special conditions or terms not found in like permits issued pursuant to other commission rules. Any organization or individual who requests such a permit shall file an organization report and any other required forms for record-keeping purposes only. The report or form shall contain all information ordinarily required to be submitted to the commission.

(2) This section shall not limit the commission's authority to plug or to replug wells or to clean up pollution or unpermitted discharges of oil and gas waste.

(e) Each organization required to file an organization report under subsection (a) of this section or an affiliate of such an organization that performs operations within the jurisdiction of the Commission that files for federal bankruptcy protection shall provide written notice to the Commission of that action not later than the 30th day after the date the organization or the affiliate files for bankruptcy protection by submitting the notice to the Enforcement Section of the Office of General Counsel. All bankruptcy-related notices sent to the Commission shall be submitted in writing to that section. For the purpose of this section, affiliate means an organization that is effectively controlled by another.

(f) Organization reports shall not be approved unless the organization has complied with the state registration requirements of the Secretary of State and the taxation requirements of the Comptroller of Public Accounts. A tax dispute with the Comptroller of Public Accounts shall not be a basis for disapproving an organization report.

Source Note: The provisions of this §3.1 adopted to be effective January 1, 1976; amended to be effective January 1, 1981, 5 TexReg 4990; amended to be effective February 22, 1986, 11 TexReg 701; amended to be effective December 7, 1987, 12 TexReg 4411; amended to be effective July 22, 1991, 16 TexReg 3767; amended to be effective July 1, 1992, 17 TexReg 4173; amended to be effective May 22, 2000, 25 TexReg 4512; amended to be effective January 11, 2004, 29 TexReg 359

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.103	**Certification for Severance Tax Exemption for Casinghead Gas Previously Vented or Flared**

(a) Purpose. The purpose of this section is to provide a procedure by which an operator may obtain commission certification that the operator markets gas that was previously released into the air for 12 months or more pursuant to §3.32 of this title (relating to Gas Well Gas and Casinghead Gas Shall Be Used for Legal Purposes). Certification under this section is voluntary.

(b) Definitions. The following terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise:

(1) Oil lease--A commission-designated oil lease to which the commission has assigned an identifying number as listed on the monthly oil proration schedule at the time an application is filed under this rule.

(2) Oil well--A wellbore completed in a commission-designated field and assigned to an oil lease as listed on the monthly oil proration schedule at the time an application for certification is filed under this rule.

(c) Eligibility. An operator shall be eligible to receive the tax exemption on marketed casinghead gas for the life of an oil well or oil lease as listed on the oil proration schedule at the time an application for certification is filed under this rule if:

(1) the operator previously released the casinghead gas from an oil well or oil lease into the air for 12 months or more pursuant to §3.32 of this title; and

(2) the operator marketed the gas no earlier than June 1, 1997, in accordance with §3.32 of this title.

(d) Certification.

(1) An operator may apply for commission certification on the appropriate form. The completed form shall be accompanied by information necessary to establish:

(A) prior release into the air of casinghead gas for 12 months or more during a period of 13 consecutive months pursuant to §3.32 of this title; and

(B) such gas has generated taxable proceeds subject to the severance tax as a result of being marketed on or after September 1, 1997.

(2) The director of the commissions's Oil and Gas Division, or the director's delegate, may administratively approve or deny a request for certification.

(3) If the director of the commission's Oil and Gas Division or the director's delegate denies the request, the operator may request a hearing by filing such a request in writing within 15 days after the postmarked date of the notice of the administrative denial.

(4) If the operator fails to appear at the hearing without good cause, the request for certification shall be dismissed.

(5) Filings and correspondence concerning the application for certification shall be addressed to the Railroad Commission, P.O. Box 12967, Austin, Texas 78711-2967, Attention: Permitting/Production Services Section.

(e) Application to the Comptroller. After the commission issues the certification provided for in subsection (d) of this section, the operator may apply to the Comptroller of Public Accounts to receive the tax exemption.

(f) Termination of Authorization to Release Gas. On the date the commission issues the certification provided for in subsection (d) of this section, either by administrative action or by commission order, the volume of casinghead gas authorized to be released into the air as an exception obtained pursuant to §3.32(h) of this title shall be reduced to the volume of casinghead gas not subject to the certification. If all of the volume of casinghead gas authorized to be released under an exception is certified for purposes of the tax exemption, the exception shall no longer apply, and shall automatically terminate as of the date of certification.

Source Note: The provisions of this §3.103 adopted to be effective August 4, 1998, 23 TexReg 7770.

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TITLE 16	ECONOMIC REGULATION
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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.102	**Tax Reduction for Incremental Production**

(a) Purpose. The purpose of this section is to provide a procedure by which an operator can obtain a 50% severance tax reduction for five years on the incremental oil and casinghead gas production from a qualifying lease.

(b) Definitions. The following terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise:

(1) Oil lease--A commission-designated oil lease to which the commission has assigned an identifying number.

(2) Production--Barrels of oil (including barrels of gas liquids reported as production monthly on the appropriate form) plus casinghead gas, where six thousand cubic feet of gas is the equivalent of one barrel of oil, expressed in barrels of oil equivalent (BOE).

(3) Baseline production--An oil lease's average BOE monthly production during the four highest months of production in the time period from January 1, 1996, through December 31, 1996.

(4) Incremental production--Production from a qualifying lease in excess of baseline production.

(5) Incremental production technique--

(A) any secondary or tertiary production enhancement technique;

(B) any primary production enhancement technique that an operator certifies required an expenditure of at least $5,000 to cause increased production.

(6) Qualifying lease--A lease is a qualifying lease provided that:

(A) the commission has designated the lease as an oil lease and has assigned to it an identifying number;

(B) production from the lease, measured by dividing the sum of lease production during the four-month period used to compute the baseline production by the sum of the number of well-days during the same four-month period, is no more than seven barrels of oil equivalent per day per well, excluding gas flared pursuant to the rules of the commission; and

(C) after the operator performs an incremental production technique, the lease shows incremental production for four of five consecutive months on or after September 1, 1997, and before December 31, 1998.

(7) Incremental ratio--The amount of a qualifying lease's average monthly incremental production during the four-month period used to meet the definition of a qualifying lease divided by its average monthly total production during the same four-month period.

(8) Qualified incremental production--A qualifying lease's total monthly production multiplied by the

incremental ratio.

(9) Well-day--One well producing hydrocarbons for one day.

(c) Qualification for the tax reduction. An operator of a qualifying lease is entitled to a 50% tax reduction on that lease's qualified incremental production for five years provided that:

(1) The operator of a qualifying lease applies to the commission for a determination of an incremental ratio before February 11, 1999;

(2) The commission certifies an incremental ratio;

(3) The operator provides to the state comptroller the certified incremental ratio; and

(4) The operator applies to the state comptroller for the tax relief provided by this section not later than one year after the date the commission certifies the incremental ratio for a qualifying lease.

(d) Request for hearing. If the request for certification of an incremental ratio is denied administratively, or if the operator does not agree with the administrative determination of the amount of the incremental ratio, the applicant may request a hearing. The request for a hearing must be filed within 20 days after the date on which notice of the administrative decision is mailed to the operator. The commission shall provide notice of the hearing to the applicant and to any other affected person named by the applicant. After hearing, the examiner shall recommend final action by the commission.

Source Note: The provisions of this §3.102 adopted to be effective June 23, 1998, 23 TexReg 6437.

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PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.101	**Certification for Severance Tax Exemption or Reduction for Gas Produced From High-Cost Gas Wells**

(a) Purpose. This section specifies the procedure by which an operator can obtain a Railroad Commission of Texas certification that natural gas from a particular gas well qualifies as high-cost natural gas under the Texas Tax Code, Chapter 201, Subchapter B, §201.057(a)(2)(A) and that such gas is exempt from or eligible for a reduction of the severance tax imposed by the Texas Tax Code, Chapter 201.

(b) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Commission--The Railroad Commission of Texas.

(2) Completion--The act of making a well capable of producing gas from a particular commission designated or new field.

(3) Completion date--The date on which a well is first made capable of producing oil or gas from a particular commission-designated or new field, as shown on the completion report filed by the operator with the commission.

(4) Comptroller--The Comptroller of Public Accounts of the State of Texas.

(5) Data-point well--A well that has been tested and/or produced in the proposed tight gas formation; and, from the test results or other data, applicant provides a measured or calculated in situ permeability and/or a measured or calculated pre-stimulation stabilized flow rate against atmospheric pressure.

(6) Director--The director of the Oil and Gas Division or the director's delegate. Any authority given to the director in this section is also retained by the commission. Any action taken by the director pursuant to this section is subject to review by the commission.

(7) High-cost gas--Natural gas which the commission finds to be:

(A) produced from any gas well, if production is from a completion which is located at a depth of more than 15,000 feet;

(B) produced from geopressured brine;

(C) occluded natural gas produced from coal seams;

(D) produced from Devonian shale; or

(E) produced from designated tight formations or produced as a result of production enhancement work.

(8) Operator--The person responsible for the actual physical operation of a gas well.

(9) Spud date--The date of commencement of drilling operations, as shown on commission records.

(c) Applicability.

(1) A severance tax exemption is available for high-cost gas produced from a well that is spudded or completed between May 24, 1989, and September 1, 1996. Eligible high-cost gas shall be exempt from the tax imposed by the Texas Tax Code, Chapter 201, during the period from September 1, 1991, through August 31, 2001.

(2) A severance tax reduction is available for high-cost gas produced from a well that is spudded or completed after August 31, 1996. Eligible high-cost gas shall be entitled to a reduction of the tax imposed

by the Texas Tax Code, Chapter 201, for the first 120 consecutive calendar months beginning on the first day of production or until the cumulative value of the tax reduction equals 50% of the drilling and completion costs incurred for the well, whichever occurs first. The amount of tax reduction is determined pursuant to the Texas Tax Code, §201.057(c). If the application for certification is submitted to the Commission after January 1, 2004, the total allowable credit for taxes paid for reporting periods before the date the application is filed may not exceed the total tax paid on the gas that otherwise qualified for the exemption or tax reduction and that was produced during the 24 consecutive calendar months immediately preceding the month in which the application for certification under this section was filed with the Commission.

(3) The plug back or deepening of an existing wellbore qualifies as a completion under this section. When the plug back or deepening is completed prior to September 1, 1996, the gas produced may qualify for a tax exemption. When the plug back or deepening is completed after August 31, 1996, the gas produced may qualify for a tax reduction. The plug back or deepening qualifies as a completion if:

(A) it is the initial completion in a commission-designated or newly discovered field that has not been previously produced from that wellbore; or

(B) the operator can demonstrate that the strata between the former completion and the new completion contain a minimum of 20 vertical feet of impermeable strata; or

(C) the operator submits the results of bottom hole pressure surveys, gas analyses or other methods or calculations comparing the new completion with previous completions in the wellbore that were in existence prior to May 24, 1989. The application shall include an explanation of the engineering principles, calculations, and reasoning to show that the gas to be produced from the applied-for completion could not have been produced from any completion in existence prior to May 24, 1989.

(4) If the operator determines that a gas well previously certified as producing high-cost gas no longer produces high-cost gas or if the operator takes any action or discovers any information that affects the eligibility of gas for an exemption or tax reduction under Texas Tax Code, §201.057, the operator shall notify the Commission in writing within 30 days after such an event occurs.

(5) If the Commission determines that a gas well previously certified as producing high-cost gas no longer produces high-cost gas or if the commission takes any action or discovers any information that affects the eligibility of gas for an exemption or tax reduction under Texas Tax Code, §201.057, the Commission shall notify within 48 hours, in writing, the comptroller and the operator.

(d) Application procedure.

(1) An application for a state severance tax exemption or tax reduction for a gas well may be made only by the operator of that well. The operator shall file one copy of the required application form, one copy of the required attachments specified in subsection (e)(1)-(6) of this section and any additional information deemed necessary by the Commission to clarify, explain and support the required attachments. Submission of legible copies of required attachments shall comply if the application includes a statement, signed by the operator, that the attachments are true and correct copies of the documents originally filed with the Commission. However, the Commission may require an operator to file certified copies of required attachments or other documents from Commission files if necessary for a certification.

(2) Filings and correspondence on high-cost gas state severance tax applications shall be addressed to the Railroad Commission of Texas, P.O. Box 12967, Austin, Texas 78711-2967, Attention: High-Cost Gas Severance Tax Section. No filings may be made at the district offices.

(e) Application requirements for individual well certifications. To qualify for the severance tax exemption or tax reduction, the operator shall prove that the gas produced is high-cost gas by providing the following information:

(1) Applications for wells producing deep high-cost gas shall include:

(A) the completed applicable commission form; and

(B) copies of all Gas Well Back Pressure Test, Completion or Recompletion Reports and Logs ever filed on the subject well.

(2) Applications for wells producing geopressured brine shall include:

(A) the completed applicable commission form;

(B) copies of all Gas Well Back Pressure Test, Completion or Recompletion Reports and Logs ever filed on the subject well;

(C) a bottom-hole pressure test report and other information establishing the initial reservoir pressure gradient; and

(D) evidence to establish that, before production, the gas from the well was in solution in a brine aquifer with at least 10,000 parts of dissolved solids per million parts of water.

(3) Applications for wells producing coal seam gas shall include:

(A) the completed applicable commission form;

(B) copies of all Gas Well Back Pressure Test, Completion or Recompletion Reports and Logs ever filed on the subject well if the gas is produced through a wellbore, or a detailed description of the production process if the gas is not produced through a wellbore;

(C) a radioactivity, electric or other log which will define the coal seams or, if such logs are not reasonably available, a detailed lithologic description of the gas-producing interval; and

(D) evidence to establish that the natural gas was produced from coal seams.

(4) Applications for wells producing Devonian shale gas shall include:

(A) the completed applicable commission form;

(B) copies of all Gas Well Back Pressure Test, Completion or Recompletion Reports and Logs ever filed on the subject well;

(C) an environmentally corrected, calibrated gamma ray log with values greater than 100 API units over the Devonian age stratigraphic section, or a gamma ray log with superimposed indications of the shale base line and the gamma ray index of 0.7 over this section or, if the gamma ray log is not reasonably available, a driller's log or similar report indicating the general characteristics of the strata penetrated and the corresponding depths at which they are encountered throughout the Devonian age stratigraphic section;

(D) information which calculates the percentage of footage of the producing interval which is not Devonian shale as indicated by the gamma ray log, driller's log, or similar report;

(E) information which demonstrates that the percentage of potentially disqualifying nonshale footage for the stratigraphic section selected is equal to or less than 5.0% of the Devonian stratigraphic age interval; and

(F) reference to a standard stratigraphic chart or text establishing that the producing interval is a shale of Devonian age.

(5) Applications for wells producing designated tight formation gas shall include:

(A) the completed applicable commission form;

(B) copies of all Gas Well Back Pressure Test, Completion or Recompletion Reports and Logs ever filed on the subject well;

(C) specific reference to the commission docket number assigned to the applicable designated tight formation area certification along with a copy of the map with the subject well location shown, which outlines the designated tight formation area approved by the commission.

(6) Applications for wells producing production enhancement gas shall include:

(A) the completed applicable commission form;

(B) copies of all Gas Well Back Pressure Test, Completion or Recompletion Reports and Logs ever filed on the subject well;

(C) a description of the production enhancement work that has been performed on the well, including the dates the work was commenced and completed, or that will be performed on the well;

(D) an itemized statement of costs incurred in performing the production enhancement work, including copies of invoices and bills for such work, or, if the work has not yet been completed, estimates of such costs;

(E) a statement estimating, for a five-year test period beginning from the month in which the application is filed, the increase in gas production resulting from the application of production enhancement work;

(F) calculations showing that the projected increase in revenue does not exceed 200% of the §103 price;

(G) the renegotiated price;

(H) a copy of that portion of the sales contract that authorizes collection of the renegotiated price; and

(I) the properly executed statement under oath made by the purchaser of natural gas which states that there is a reasonable basis for the statements and estimates made by the applicant.

(f) Application requirements for tight formation area certifications.

(1) If justification for an individual well application is based on a tight formation certification and the well is not located within a geographical area that has been previously certified as a designated tight formation area or the well is not completed in a formation interval that has been previously certified as a designated tight formation by the Federal Energy Regulatory Commission under the Natural Gas Policy Act or by the Railroad Commission of Texas, the operator shall first apply for a tight formation area designation.

(2) An applicant requesting a tight formation area designation shall submit a written request to the High-Cost Gas Severance Tax Section, at the address given in subsection (d)(2) of this section, for a

certification that a named formation or a specific portion thereof is a tight formation. The applicant shall supply a list of the names and addresses of all affected persons. For purposes of this subsection, "affected persons" means all operators of all wells listed on the current proration schedule for the applicable field or fields located within the proposed designated area. The applicant shall mail or deliver a copy of the prescribed, completed notice of application form to all affected persons, and if required, shall publish the notice of application in accordance with §1.46 of this title (relating to Notice by Publication in Oil and Gas and Surface Mining and Reclamation Nonrulemaking Proceedings), as found in the Commission's General Rules of Practice and Procedure (16 Texas Administrative Code Chapter 1). Notice of application forms may be obtained by contacting the Railroad Commission of Texas, P.O. Box 12967, Austin, Texas 78711-2967, Attention: High-Cost Severance Tax Section. Before Cont'd...

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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.100	**Seismic Holes and Core Holes**

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Seismic hole--Any hole drilled for the purpose of securing geophysical information to be used in the exploration or development of oil, gas, geothermal, or other mineral resources.

(2) Core hole--Any hole drilled for the purpose of securing geological information to be used in the exploration or development of oil, gas, geothermal, or other mineral resources, except coal or uranium. For regulations governing coal exploratory wells, see Chapter 12 of this title (relating to Coal Mining Regulations), and for regulations governing uranium exploratory wells, see Chapter 11, Subchapter C of this title (relating to Surface Mining and Reclamation Division, Substantive Rules--Uranium Mining).

(3) Project area--The geographic area in which an exploratory survey involving one or more seismic holes or core holes is carried out.

(4) Protection depth--Depth or depths at which usable quality water must be protected or isolated, as determined by the Texas Commission on Environmental Quality (TCEQ) or its successor agencies.

(5) Operator--The person who contracts for the services of a seismic crew or core hole drilling contractor or, if the seismic survey or core hole testing is not performed on a contract basis, but is performed by an exploration and production company or by a geophysical contractor for speculative purposes, the person who drills the seismic holes or core holes.

(6) Commission--The Railroad Commission of Texas or its authorized representative.

(b) Exemption. Any seismic hole or core hole drilled to a depth of 20 feet or less is not subject to the requirements of this section.

(c) Determination of protection depth. Before drilling any seismic hole or core hole in a project area, an operator shall obtain a letter from the TCEQ stating the protection depth or depths in the project area.

(d) Drilling permits.

(1) Holes that do not penetrate any protection depth. A seismic hole or core hole that does not penetrate any protection depth does not require a drilling permit.

(2) Holes that penetrate any protection depth. A seismic hole or core hole that penetrates any protection depth requires a drilling permit to satisfy the requirements for exploratory wells described in §3.5(g) of this title (relating to Application To Drill, Deepen, Reenter, or Plug Back) (Statewide Rule 5).

(e) Plugging.

(1) Holes that do not penetrate any protection depth. A seismic hole or core hole that does not penetrate any protection depth must be plugged in accordance with subparagraph (A) or (B) of this paragraph. Seismic

holes must be plugged after the hole is loaded with explosives. Core holes must be plugged immediately after completion of coring the hole.

(A) The operator shall adequately plug the hole by filling it from total depth to a depth of no more than 16 feet below the surface with drill cuttings and/or bentonite. Immediately above the drill cuttings and/or bentonite, the operator shall place a bentonite plug no less than 10 feet in length. A plastic cap imprinted with the name of the operator shall be set above the bentonite plug no less than three feet below the surface. The remainder of the hole shall be filled with drill cuttings or native soil. All precautions should be taken to prevent bentonite from bridging over.

(B) Alternative plugging procedures and materials may be utilized when the operator has demonstrated to the commission's satisfaction that the alternatives will protect usable quality water.

(2) Holes that penetrate any protection depth. A seismic hole or core hole that penetrates any protection depth must be plugged in accordance with the requirements of §3.14 of this title (relating to Plugging) (Statewide Rule 14) and a plastic cap imprinted with the name of the operator shall be set in the hole no less than three feet below the surface.

(f) Physical requirements for bentonite plugging materials. Bentonite materials used to plug seismic or core holes shall be derived from naturally occurring, untreated, high swelling sodium bentonite that is composed of at least 85% montmorillonite clay and that meets the International Association of Geophysical Contractors (IAGC) recommended geophysical industry standard dated January 24, 1992, for the physical characteristics of bentonite used in seismic shot hole plugging.

(g) Reporting.

(1) Holes that do not penetrate any protection depth. Within 30 days of plugging the last hole in the project area, the operator shall submit a letter to the commission stating that each seismic hole or core hole in the project area has been plugged in accordance with subsection (e)(1) of this section. The letter must include the plugging date for each hole and the name and address of the operator. A plat of the project area identifying seismic or core hole locations, counties, survey lines, scale, and northerly direction must be attached. A United States Geological Survey map of the project area with hole locations marked will satisfy the plat requirement. In addition, a letter from the TCEQ stating the protection depth or depths must be attached.

(2) Holes that penetrate any protection depth. For any seismic or core hole that penetrates any protection depth, a plugging record shall be filed in accordance with §3.14 of this title (relating to Plugging) (Statewide Rule 14).

Source Note: The provisions of this §3.100 adopted to be effective September 1, 1992, 17 TexReg 5283; amended to be effective August 25, 2003, 28 TexReg 6816

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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.99	**Cathodic Protection Wells**

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Cathodic protection well--Any well drilled for the purpose of installing one or more anodes to prevent corrosion of a facility associated with the production of oil, gas, or geothermal resources, such as a well casing, storage and separation facility, or pipeline.

(2) Project area--The geographic area in which a related group of cathodic protection wells is drilled.

(3) Protection depth--Depth or depths at which usable quality water must be protected or isolated, as determined by the Texas Commission on Environmental Quality (TCEQ) or its successor agencies.

(4) Commission--The Railroad Commission of Texas or its authorized representative.

(b) Exemption. Any cathodic protection well that is drilled to a depth of 30 feet or less is not subject to the requirements of this section.

(c) Determination of protection depth. Before drilling any cathodic protection well, an operator shall obtain a letter from the TCEQ stating the protection depth or depths.

(d) Drilling permits.

(1) Wells that do not penetrate any protection depth. A cathodic protection well that does not penetrate any protection depth does not require a drilling permit.

(2) Wells that penetrate any protection depth. A cathodic protection well that penetrates any protection depth must be drilled in accordance with the requirements of §3.5(g) of this title (relating to Application To Drill, Deepen, Reenter, or Plug Back) (Statewide Rule 5).

(e) Completion.

(1) Timing. A cathodic protection well must be completed as soon as possible after it is drilled.

(2) Wells that do not penetrate any protection depth. A cathodic protection well that does not penetrate any protection depth must be completed in accordance with subparagraph (A) or (B) of this paragraph.

(A) The operator must place at least a 10-foot cement or bentonite plug at the top of the well. The top of the plug shall be no less than three feet below the surface, and the remainder of the hole between the top of the plug and the surface shall be filled with drill cuttings or native soil.

(B) Alternative completion procedures and materials may be utilized when the operator has demonstrated to the commission's satisfaction that the alternatives will protect usable quality water.

(3) Wells that penetrate any protection depth. A cathodic protection well that penetrates any protection

depth must be completed in accordance with subparagraph (A) or (B) of this paragraph.

(A) The operator must either set and cement casing to the deepest protection depth penetrated or center a 100-foot cement plug across each protection depth penetrated and must place at least a 10-foot cement or bentonite plug at the top of the well. The top of the plug shall be no less than three feet below the surface, and the remainder of the hole between the top of the plug and the surface shall be filled with drill cuttings or native soil.

(B) Alternative completion procedures and materials may be utilized when the operator has demonstrated to the commission's satisfaction that the alternatives will protect usable quality water.

(f) Physical requirements for bentonite plugging materials. Bentonite materials used to plug cathodic protection wells shall be derived from naturally occurring, untreated, high swelling sodium bentonite that is composed of at least 85% montmorillonite clay and that meets the International Association of Geophysical Contractors (IAGC) recommended geophysical industry standard dated January 24, 1992, for the physical characteristics of bentonite used in seismic shot hole plugging.

(g) Reporting. Within 30 days of completion of the last well in a project area, the operator shall submit a letter to the commission stating that each cathodic protection well in the project area has been completed in accordance with subsection (e) of this section. The letter must include the completion date for each well, the name and address of the operator, and the drilling permit and API numbers of the well, if applicable. A plat of the project area identifying cathodic protection well locations, counties, survey lines, scale, and northerly direction must be attached. In addition, a letter from the TCEQ stating the protection depth or depths must be attached.

(h) Abandonment. Upon abandonment of a cathodic protection well, any wires or vent pipe must be cut off at the top of the 10-foot surface plug, and the vent pipe must be securely capped or plugged.

Source Note: The provisions of this §3.99 adopted to be effective July 21, 1992, 17 TexReg 4877; amended to be effective August 25, 2003, 28 TexReg 6816

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.98	**Standards for Management of Hazardous Oil and Gas Waste**

(a) Purpose. The purpose of this section is to establish standards for management of hazardous oil and gas waste.

(b) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Activities associated with the exploration, development, and production of oil or gas or geothermal resources--Activities associated with:

(A) the drilling of exploratory wells, oil wells, gas wells, or geothermal resource wells;

(B) the production of oil, gas, or geothermal resources, including:

(i) activities associated with the drilling of injection water source wells that penetrate the base of usable quality water;

(ii) activities associated with the drilling of cathodic protection holes associated with the cathodic protection of wells and pipelines subject to the jurisdiction of the commission to regulate the production of oil, gas, or geothermal resources;

(iii) activities associated with natural gas or natural gas liquids processing plants or reservoir pressure maintenance or repressurizing plants;

(iv) activities associated with any underground natural gas storage facility, provided the terms "natural gas" and "storage facility" shall have the meanings set out in Texas Natural Resources Code, §91.173;

(v) activities associated with any underground hydrocarbon storage facility, provided the terms "hydrocarbons" and "underground hydrocarbon storage facility" shall have the meanings set out in Texas Natural Resources Code, §91.201; and

(vi) activities associated with the storage, handling, reclamation, gathering, transportation, or distribution of oil or gas prior to the refining of such oil or prior to the use of such gas in any manufacturing process or as a residential or industrial fuel;

(C) the operation, abandonment, and proper plugging of wells subject to the jurisdiction of the commission to regulate the exploration, development, and production of oil or gas or geothermal resources; and

(D) the discharge, storage, handling, transportation, reclamation, or disposal of waste or any other substance or material associated with any activity listed in subparagraphs (A) - (C) of this paragraph.

(2) Administrator--The administrator of the United States Environmental Protection Agency, or the administrator's designee.

(3) Authorized facility--Either:

(A) an authorized recycling or reclamation facility; or

(B) an authorized treatment, storage, or disposal facility.

(4) Authorized recycling or reclamation facility--A facility permitted in accordance with the requirements of 40 CFR, Parts 270 and 124 or Part 271, if required, at which hazardous waste that is to be recycled or reclaimed is managed and whose owner or operator is subject to regulation under:

(A) 40 CFR, §261.6(c) or an equivalent state program (concerning facilities that recycle recyclable materials); or

(B) 40 CFR, Part 266, Subparts C (concerning recyclable materials used in a manner constituting disposal), F (concerning recyclable materials used for precious metal recovery), or G (concerning spent lead-acid batteries being reclaimed), or an equivalent state program.

(5) Authorized representative--The person responsible for the overall operation of all or any part of a facility or generation site.

(6) Authorized treatment, storage, or disposal facility--A facility at which hazardous waste is treated, stored, or disposed of that:

(A) has received either:

(i) a permit (or interim status) in accordance with the requirements of 40 CFR, Parts 270 and 124 (EPA permit); or

(ii) a permit (or interim status) from a state authorized in accordance with 40 CFR, Part 271; and

(B) is authorized under applicable state or federal law to treat, store, or dispose of that type of hazardous waste. If a hazardous oil and gas waste is destined to a facility in an authorized state that has not yet obtained authorization from the EPA to regulate that particular hazardous waste, then the designated facility must be a facility allowed by the receiving state to accept such waste and the facility must have a permit issued by the EPA to manage that waste.

(7) Centralized Waste Collection Facility or CWCF--A facility that meets the requirements of subsection (m)(3) of this section.

(8) Certification--A statement of professional opinion based upon knowledge and belief.

(9) CFR--Code of Federal Regulations.

(10) CESQG--A conditionally exempt small quantity generator, as described in subsection (f)(1) of this section (relating to generator classification and accumulation time).

(11) Commission--The Railroad Commission of Texas or its designee.

(12) Container--Any portable device in which material is stored, transported, treated, disposed of, or otherwise handled.

(13) Contaminated media--Soil, debris, residues, waste, surface waters, ground waters, or other materials containing hazardous oil and gas waste as a result of a discharge or clean-up of a discharge.

(14) Department of Transportation or DOT--The United States Department of Transportation.

(15) Designated facility--An authorized facility that has been designated on the manifest by the generator pursuant to the provisions of subsection (o)(1) of this section (relating to general manifest requirements).

(16) Discharge or hazardous waste discharge--The accidental or intentional spilling, leaking, pumping, pouring, emitting, emptying, or dumping of hazardous waste into or on any land or water.

(17) Disposal--The discharge, deposit, injection, dumping, spilling, leaking, or placing of any hazardous waste into or on any land or water so that such waste or any constituent thereof may enter the environment or be emitted into the air or discharged into any waters, including ground waters.

(18) Disposal facility--A facility or part of a facility at which hazardous waste is intentionally placed into or on any land or water, and at which waste will remain after closure.

(19) Elementary neutralization unit--A device consisting of a tank, tank system, container, transport vehicle, or vessel that is used for neutralizing wastes that are hazardous wastes:

(A) only because they exhibit the characteristic of corrosivity under the test referred to in subsection (e)(1)(D)(ii) of this section (relating to characteristically hazardous wastes); or

(B) they are identified in subsection (e)(1)(D)(i) of this section (relating to listed hazardous wastes) only because they exhibit the corrosivity characteristic.

(20) Empty container--A container or an inner liner removed from a container that has held any hazardous waste and that meets the requirements of 40 CFR, §261.7(b).

(21) Environmental Protection Agency or EPA--The United States Environmental Protection Agency.

(22) EPA Acknowledgment of Consent--The cable sent to the EPA from the United States Embassy in a receiving country that acknowledges the written consent of the receiving country to accept the hazardous waste and describes the terms and conditions of the receiving country's consent to the shipment.

(23) EPA hazardous waste number--The number assigned by the EPA to each hazardous waste listed in 40 CFR, Part 261, Subpart D, and to each characteristic identified in 40 CFR, Part 261, Subpart C.

(24) EPA identification number or EPA ID Number--The number assigned by the EPA to each hazardous waste generator, transporter, and treatment, storage, or disposal facility.

(25) EPA Form 8700-12--The EPA form that must be completed and delivered to the commission in order to obtain an EPA ID number.

(26) Executive director of the TCEQ--The executive director of the TCEQ or the executive director's designee.

(27) Facility--All contiguous land, including structures, other appurtenances, and improvements on the land, used for recycling, reclaiming, treating, storing, or disposing of hazardous waste. A facility may consist of several treatment, storage, or disposal operational units (e.g., one or more landfills, surface impoundments, or combinations thereof).

(28) Generate--To produce hazardous oil and gas waste or to engage in any activity (such as importing) that first causes a hazardous oil and gas waste to become subject to regulation under this section.

(29) Generation site--

(A) Excluding sites addressed in subparagraphs (B) (relating to pipelines) and (C) (relating to gas plants) of this paragraph, any of the following operational units that are owned or operated by one person and other sites at which hazardous oil and gas waste is generated or where actions first cause a hazardous oil and gas waste to become subject to regulation, including but not limited to:

(i) all oil and gas wells that produce to one set of storage or treatment vessels, such as a tank battery, the storage or treatment vessels, associated flowlines, and related land surface;

(ii) an injection or disposal site, that is not part of a generation site described in subparagraph (A)(i) of this paragraph, its related injection or disposal wells, associated injection lines, and related land surface;

(iii) an offshore platform; or

(iv) any other site, including all structures, appurtenances, or other improvements associated with that site that are geographically contiguous, but which may be divided by public or private right-of-way, provided the entrance and exit between the properties is at a cross-roads intersection, and access is by crossing as opposed to going along, the right-of-way.

(B) In the case of a pipeline system (other than a field flowline or injection line system), an equipment station (such as a pump station, breakout station, or compressor station) or any other location along a pipeline (such as a drip pot, pigging station, or rupture), together with any and all structures, other appurtenances, and improvements:

(i) that are geographically contiguous with or are physically related to an equipment station or other location described in this paragraph, but excluding any pipeline that connects two or more such stations or locations;

(ii) that are owned or operated by one person; and

(iii) at which hazardous oil and gas waste is produced or where actions first cause a hazardous oil and gas waste to become subject to regulation.

(C) A natural gas treatment or processing plant or a natural gas liquids processing plant.

(30) Generator--Any person, by generation site, whose act or process produces hazardous oil and gas waste or whose act first causes a hazardous oil and gas waste to become subject to regulation under this section, or such person's authorized representative.

(31) Geothermal energy and associated resources Geothermal energy and associated resources as defined in Texas Natural Resources Code, §141.003(4).

(32) Hazardous oil and gas waste--Any oil and gas waste determined to be hazardous under the provisions of subsection (e) of this section (relating to hazardous waste determination).

(33) Hazardous oil and gas waste constituent--A hazardous waste constituent of hazardous oil and gas waste.

(34) Hazardous waste--A hazardous waste, as defined in 40 CFR, §261.3, including a hazardous oil and gas waste.

(35) Hazardous waste constituent--A constituent that caused the administrator to list a hazardous waste in

40 CFR, Part 261, Subpart D, or a constituent listed in table 1 of 40 CFR, §261.24.

(36) International shipment--The transportation of hazardous oil and gas waste into or out of the jurisdiction of the United States.

(37) Land disposal--The placement in or on the land, except as otherwise provided in 40 CFR, Part 268, including placement in a landfill, surface impoundment, waste pile, injection well, land treatment facility, salt dome formation, salt bed formation, or underground mine or cave, or placement in a concrete vault or bunker intended for disposal purposes.

(38) LQG--A large quantity generator, as described in subsection (f)(3) of this section (relating to generator classification and accumulation time).

(39) Management--The systematic control of the collection, source separation, storage, transportation, processing, treatment, recovery, and disposal of hazardous waste.

(40) Manifest--The shipping document required pursuant to the provisions of subsection (o) of this section (relating to manifests).

(41) Manifest document number--The 12-digit identification number assigned to a generator by the EPA, plus a unique five-digit document number assigned to the manifest by the generator, or preprinted on the manifest, for recording and reporting purposes.

(42) Oil and gas waste--Waste generated in connection with activities associated with the exploration, development, and production of oil or gas or geothermal resources, or the solution mining of brine. Until delegation of authority under RCRA to the commission by EPA, the term "oil and gas waste" shall exclude hazardous waste arising out of or incidental to activities associated with natural gas treatment or natural gas liquids processing plants and reservoir pressure maintenance or repressurizing plants.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.97	**Underground Storage of Gas in Salt Formations**

(a) Definitions. The following terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Affected person--A person who, as a result of actions proposed in an application for a storage facility permit or amendment or modification of an existing storage facility permit, has suffered or may suffer actual injury or economic damage other than as a member of the general public.

(2) Cavern--The storage space created in a salt formation by solution mining.

(3) Commission--The Railroad Commission of Texas.

(4) Emergency shutdown valve--A valve that automatically closes to isolate a gas storage well from surface piping in the event of specified conditions that, if uncontrolled, may cause an emergency.

(5) Fresh water--Water having bacteriological, physical, and chemical properties that make it suitable and feasible for beneficial use for any lawful purpose. For purposes of this section, brine associated with the creation, operation, and maintenance of an underground gas storage facility is not considered fresh water.

(6) Gas storage well or storage well--A well used for the injection or withdrawal of natural gas or any other gaseous substance into or out of an underground gas storage facility.

(7) Leak detector--A device capable of detecting by chemical or physical means the presence of hydrocarbon vapor or the escape of vapor through a small opening.

(8) Operator--The person recognized by the commission as being responsible for the physical operation of an underground gas storage facility, or such person's authorized representative.

(9) Owner--The person recognized by the commission as owning all or part of an underground gas storage facility, or such person's authorized representative.

(10) Person--A natural person, corporation, organization, government, governmental subdivision or agency, business trust, estate, trust, partnership, association, or any other legal entity.

(11) Pollution--Alteration of the physical, chemical, or biological quality of, or the contamination of, water that makes it harmful, detrimental, or injurious to humans, animal life, vegetation, or property, or to public health, safety, or welfare, or impairs the usefulness or the public enjoyment of the water for any lawful or reasonable purpose.

(12) Underground gas storage facility or storage facility--A facility used for the storage of natural gas or any other gaseous substance in an underground salt formation, including surface and subsurface rights, appurtenances, and improvements necessary for the operation of the facility.

(b) Permit required.

(1) General. No person may create, operate, or maintain an underground gas storage facility without obtaining a permit from the commission. A permit issued by the commission for such activities before the effective date of this section shall continue in effect until revoked, modified, or suspended by the commission, or until it expires according to its terms. The provisions of this section apply to permits to conduct gas storage operations issued prior to the effective date of this section, except as otherwise specifically provided.

(2) Conflict with other requirements. If a provision of this section conflicts with any provision or term of a commission order, field rule, or permit, the provision of such order, field rule, or permit shall control.

(c) Application.

(1) Information required. An application for a permit to create, operate, or maintain an underground gas storage facility shall be filed with the commission by the owner or operator, or the proposed owner or operator, on the prescribed form. The application shall contain the information necessary to demonstrate compliance with applicable state laws and commission regulations.

(2) Permit amendment. An application for amendment of an existing underground gas storage facility permit shall be filed with the commission:

(A) prior to any planned enlargement of a cavern in excess of the permitted cavern capacity by solution mining;

(B) when required in accordance with paragraph (3) of this subsection;

(C) prior to the drilling of any additional storage wells;

(D) prior to an increase in the maximum operating pressure above the permitted pressure; or

(E) any time that conditions at the storage facility deviate materially from the conditions specified in the permit or permit application.

(3) Increase in capacity. The owner or operator of a storage facility shall notify the commission if information indicates that the capacity of a cavern exceeds the permitted cavern capacity by 20% or more. Such notification shall be made in writing to the commission within 10 days of the date that the owner or operator of the storage facility knows or has reason to know that the cavern capacity exceeds the permitted capacity by 20% or more. The notification shall include a description of the information that indicates that the permitted cavern capacity has been exceeded, and an estimate of the current cavern capacity. Upon receipt of such information, the commission or its designee may take any one or more of the following actions:

(A) require the permittee to comply with a compliance schedule that lists measures to be taken to ensure that conditions at the storage facility do not pose a danger to life or property, and that no waste of gas, uncontrolled escape of gas, or pollution of fresh water occurs;

(B) require the permittee to file an application to amend the underground gas storage facility permit;

(C) modify, cancel, or suspend the permit as provided in subsection (f) of this section; or

(D) take enforcement action.

(d) Standards for underground storage zone.

(1) Impermeable salt formation. An underground gas storage facility may be created, operated, or maintained only in an impermeable salt formation in a manner that will prevent waste of the stored gases, uncontrolled escape of gases, pollution of fresh water, and danger to life or property. This section does not authorize storage of liquid or liquefied hydrocarbons in an underground salt formation. A permit under §3.95 of this title (relating to Underground Storage of Liquid or Liquefied Hydrocarbons in Salt Formations) is required to convert from storage of natural gas to storage of liquid or liquefied hydrocarbons in an underground salt formation.

(2) Fresh water strata. The applicant must submit with the application a letter from the Texas Commission on Environmental Quality or its successor agencies stating the depth to which fresh water strata occur at each storage facility.

(e) Notice and hearing.

(1) Notice requirements. Such notice shall be given no later than the date the application is mailed to or filed with the commission. The applicant shall give notice of an application for a permit to create, operate, or maintain an underground gas storage facility, or to amend an existing storage facility permit, by mailing or delivering a copy of the application form to:

(A) the surface owner of the tract where the storage facility is located or is proposed to be located;

(B) the surface owner of each tract adjoining the tract where the storage facility is located or is proposed to be located;

(C) each oil, gas, or salt leaseholder, other than the applicant, of the tract on which the storage facility is located or is proposed to be located;

(D) each oil, gas, or salt leaseholder of any tract adjoining the tract on which the storage facility is located or is proposed to be located;

(E) the county clerk of the county or counties where the storage facility is located or is proposed to be located; and

(F) if the storage facility is located or is proposed to be located within city limits, the city clerk or other appropriate city official.

(2) Publication of notice. Notice of the application, in a form approved by the commission or its designee, shall be published by the applicant once a week for three consecutive weeks in a newspaper of general circulation in the county where the storage facility is or is proposed to be located. The applicant shall file proof of publication prior to any hearing on the application or administrative approval of the application.

(3) Notice by publication. The applicant shall make diligent efforts to ascertain the name and address of each person identified under paragraph (1)(A) - (D) of this subsection. The exercise of diligent efforts to ascertain names and addresses of such persons shall require an examination of the county records here the facility is located and an investigation of any other information of which the applicant has actual knowledge. If, after diligent efforts, the applicant has been unable to ascertain the name and address of one or more persons required to be notified under paragraph (1)(A) - (D) of this subsection, the notice requirements for those persons are satisfied by the publication of the notice of application as required in paragraph (2) of this subsection. The applicant must submit an affidavit to the commission specifying the efforts that were taken to identify each person whose name and/or address could not be ascertained.

(4) Hearing required for new permits. A permit application for a new underground gas storage facility will

be considered for approval only after notice and hearing. The commission will give notice of the hearing to all affected persons, local governments, and other persons who express, in writing, an interest in the application. After hearing, the examiner shall recommend a final action by the commission.

(5) Hearing on permit amendments.

(A) An application for an amendment to an existing storage facility permit may be approved administratively if the commission receives no protest from a person notified pursuant to paragraph (1) of this subsection or from any other affected person.

(B) If the commission receives a protest from a person notified pursuant to paragraph (1) of this subsection or from any other affected person within 15 days of the date of receipt of the application by the commission, or of the date of the third publication, whichever is later, or if the commission determines that a hearing is in the public interest, then the applicant will be notified that the application cannot be approved administratively. The commission will schedule a hearing on the application upon written request of the applicant. The commission will give notice of the hearing to all affected persons, local governments, and other persons who express, in writing, an interest in the application. After hearing, the examiner shall recommend a final action by the commission.

(C) If the application is administratively denied, a hearing will be scheduled upon written request of the applicant. After hearing, the examiner shall recommend a final action by the commission.

(f) Modification, cancellation, or suspension of a permit.

(1) General. Any permit may be modified, suspended, or canceled after notice and opportunity for hearing if:

(A) a material change in conditions has occurred in the operation, maintenance, or construction of the storage facility, or there are material deviations from the information originally furnished to the commission. A change in conditions at a facility that does not affect the safe operation of the facility or the ability of the facility to operate without causing waste of hydrocarbons or pollution is not considered to be material;

(B) pollution of fresh water is likely as a result of continued operation of the storage facility;

(C) there are material violations of the terms and provisions of the permit or commission regulations;

(D) the applicant has misrepresented any material facts during the permit issuance process; or

(E) injected fluids are escaping or are likely to escape from the storage facility.

(2) Imminent danger. Notwithstanding the provisions of paragraph (1) of this subsection, in the event of an emergency that presents an imminent danger to life or property, or where waste of hydrocarbons, uncontrolled escape of hydrocarbons, or pollution of fresh water is imminent, the commission or its designee may immediately suspend a storage facility permit until a final order is issued pursuant to a hearing, if any, conducted in accordance with the provisions of paragraph (1) of this subsection. All operations at the facility shall cease upon suspension of a permit under this paragraph.

(g) Transfer of permit. A storage facility permit may not be transferred without the prior approval of the commission, or its designee. Until such transfer is approved by the commission or its designee, the proposed transferee may not conduct any activities authorized by the permit. The following procedure shall be followed when requesting approval for transfer of a permit.

(1) Request. Prior to transferring either ownership or operation of a storage facility, the permittee shall file

with the commission a request for transfer of the permit. Such a request may not be filed unless a completed Form P-4, signed by both the permittee and the proposed transferee, has been filed with the commission.

(2) Approval. The commission, or its designee, shall approve the transfer of a storage facility permit, provided:

(A) the proposed transferee is not the subject of any unsatisfied commission enforcement order at the time of the request for permit transfer; and

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.96	**Underground Storage of Gas in Productive or Depleted Reservoirs**

(a) Definitions. The following terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Affected person--A person who, as a result of actions proposed an application for an underground gas storage project permit or an amendment or modification of an existing underground gas storage project permit, has suffered or may suffer actual injury or economic damage other than as a member of the general public.

(2) Commission--The Railroad Commission of Texas.

(3) Fresh water--Water having bacteriological, physical, and chemical properties that make it suitable and feasible for beneficial use for any lawful purpose.

(4) Leak detector--A device capable of detecting by chemical or physical means the presence of hydrocarbon vapor or the escape of vapor through a small opening.

(5) Gas storage or underground gas storage--Storage of natural gas or other gaseous material in a productive or depleted reservoir, exclusive of gas injection for enhanced recovery.

(6) Gas storage project--All surface and subsurface rights, appurtenances, and improvements necessary for conducting underground gas storage operations in a gas storage reservoir.

(7) Gas storage well or storage well--A well used to inject or withdraw natural gas or other gaseous material stored in a productive or depleted reservoir, exclusive of a well used to inject gas for enhanced recovery.

(8) Operator--The person recognized by the commission as being responsible for the physical operation of a gas storage project, or such person's authorized representative.

(9) Person--A natural person, corporation, organization, government, governmental subdivision or agency, business trust, estate, trust, partnership, association, or any other legal entity.

(10) Pollution--Alteration of the physical, chemical, or biological quality of, or the contamination of, water that makes it harmful, detrimental, or injurious to humans, animal life, vegetation, or property, or to public health, safety, or welfare, or impairs the usefulness or the public enjoyment of the water for any lawful or reasonable purpose.

(11) Productive or depleted reservoir--A subsurface sand, stratum, or formation that is productive of, or has previously produced, oil, gas, or geothermal resources.

(b) Permit required.

(1) General. No person may operate a gas storage project without obtaining a permit from the commission.

A permit issued by the commission for operation of a gas storage project before the effective date of this section shall continue in effect until revoked, modified, or suspended by the commission, or until it expires according to its terms. The provisions of this section apply to gas storage projects permitted prior to the effective date of this section, except as otherwise specifically provided.

(2) Conflict with other requirements. If a provision of this section conflicts with any provision or term of a commission order, field rule, or permit, the provision of such order, field rule, or permit shall control.

(c) Application. An application to operate a gas storage project shall be filed with the commission by the owner or operator or proposed owner or operator. The application shall include the following:

(1) compliance with safety requirements--information demonstrating compliance with the provisions of subsection (i) of this section;

(2) request for reservoir designation--a request for designation of a productive or depleted reservoir as a gas storage reservoir, supported by the following:

(A) information demonstrating that the reservoir is suitable for gas storage; and

(B) information demonstrating the amount of recoverable native gas remaining in the reservoir;

(3) compliance with standards for injection wells--information demonstrating compliance with the provisions of subsections (j), (k), and (l) of this section for each gas injection well. The requirements of this paragraph do not apply to wells used for gas withdrawal only;

(4) water protection letter--a letter from the Texas Commission on Environmental Quality or its successor agencies stating the depth to which fresh water strata occur in the project area;

(5) public interest--a request that the commission issue an order containing the findings described in the Texas Natural Resources Code, §91.174(a), if such an order is desired by the applicant;

(6) fees--the fees required under §3.78 of this title (relating to Fees and Financial Security Requirements) for each gas storage well in the storage project that will be used for injection.

(d) Permit amendment. An application for amendment of an existing gas storage project permit shall be filed with the commission as specified in paragraphs (1)-(4) of this subsection.

(1) Expansion of reservoir. An application for permit amendment shall be filed prior to expanding the areal extent of the gas storage reservoir.

(2) Increase in pressure. An application for permit amendment shall be filed prior to increasing the gas storage reservoir pressure above the maximum permitted pressure.

(3) Adding storage wells. An application for permit amendment shall be filed prior to adding additional gas storage wells to the project.

(4) Material deviation. An application for permit amendment shall be filed at any time that conditions at the storage project deviate materially from the conditions specified in the permit or permit application.

(e) Standards for storage reservoir. A gas storage project shall be operated only in a productive or depleted reservoir in a manner that will prevent waste of oil, gas, or geothermal resources, uncontrolled escape of gases, pollution of fresh water, and danger to life or property.

(f) Notice and hearing.

(1) Notice requirements. By no later than the date the application is mailed to or filed with the commission, the applicant shall give notice of an application for a permit to operate a gas storage project, or to amend an existing storage project permit, by mailing or delivering a copy of the application to:

(A) each mineral interest owner, other than the applicant, of the proposed gas storage reservoir;

(B) each leaseholder of minerals lying above or below the proposed gas storage reservoir;

(C) each leaseholder of minerals offsetting the proposed gas storage reservoir;

(D) each owner or leaseholder of any portion of the surface overlying the proposed gas storage reservoir;

(E) the clerk of the county or counties where the proposed gas storage reservoir is located; and

(F) the city clerk or other appropriate city official where the proposed gas storage reservoir is located within city limits.

(2) Publication of notice. Notice of the application for an original or amended gas storage project permit, in a form approved by the commission or its designee, shall be published by the applicant once a week for three consecutive weeks in a newspaper of general circulation in the county where the gas storage project is located. The applicant shall file proof of publication of the notice prior to any hearing on the application or administrative approval.

(3) Notice by publication. The applicant shall make diligent efforts to ascertain the name and address of each person identified under paragraph (1)(A)-(D) of this subsection. The exercise of diligent efforts to ascertain the names and addresses of such persons shall require an examination of county records where the facility is located and an investigation of any other information of which the applicant has actual knowledge. If, after diligent efforts, the applicant has been unable to ascertain the name and address of one or more persons required to be notified under paragraph (1)(A)-(D) of this subsection, the notice requirements for those persons are satisfied by the publication of the notice of application as required in paragraph (2) of this subsection. The applicant must submit an affidavit to the commission specifying the efforts that were taken to identify each person whose name and/or address could not be ascertained.

(4) Hearing required for new permits. An application for a new gas storage project permit will be considered for approval only after notice and hearing. The commission will give notice of the hearing to all affected persons, local governments, and other persons who express, in writing, an interest in the application. After hearing, the examiner shall recommend a final action by the commission.

(5) Hearing on permit amendments.

(A) If the commission receives a protest regarding an application for amendment of a gas storage project permit from a person notified pursuant to paragraph (1) of this subsection or from any other affected person within 15 days of the date of receipt of the application by the commission, or of the date of the third publication, whichever is later, or if the commission or its designee determines that a hearing is in the public interest, then the applicant will be notified that the application for amendment cannot be administratively approved. The commission will schedule a hearing on the application upon request of the applicant. The commission will give notice of the hearing to all affected persons, local governments, and other persons who express, in writing, an interest in the application. After hearing, the examiner shall recommend a final action by the commission.

(B) If the commission receives no protest regarding an application for amendment of a gas storage project permit from a person notified pursuant to paragraph (1) of this subsection or from any other affected person, the application may be approved administratively.

(C) If the application for amendment of a gas storage project permit is administratively denied, a hearing will be scheduled upon written request of the applicant. After hearing, the examiner shall recommend a final action by the commission.

(g) Modification, cancellation, or suspension of a permit.

(1) General. A permit may be modified, suspended, or canceled after notice and opportunity for hearing under any of the following circumstances:

(A) a material change in conditions has occurred in the operation of the gas storage project, or there are material deviations from the information originally furnished to the commission. A change in conditions at a facility that does not affect the safe operation of the facility or the ability of the facility to operate without causing waste of hydrocarbons or pollution is not considered to be material;

(B) fresh water is likely to be polluted as a result of the continued operation of the gas storage project;

(C) there are material violations of the terms and provisions of the permit or of applicable commission orders or regulations;

(D) the applicant has misrepresented material facts during the permit issuance process; or

(E) injected fluids are escaping or are likely to escape from the storage project.

(2) Imminent danger. Notwithstanding the provisions of paragraph (1) of this subsection, in the event of an emergency that presents an imminent danger to life or property, or where waste of hydrocarbons, uncontrolled escape of hydrocarbons, or pollution of fresh water is imminent, the commission or its designee may immediately suspend a permit for underground gas storage until a final order is issued pursuant to a hearing, if any, conducted in accordance with the provisions of paragraph (1) of this subsection. All underground gas storage operations shall cease upon suspension of a permit under this paragraph.

(h) Transfer of permit. A gas storage project permit may be transferred from one operator to another operator if both of the following requirements are met.

(1) Notice. Written notice of intended permit transfer is submitted to the commission at least 15 days prior to the date the transfer takes place.

(2) No objection. The commission or its designee does not notify the present permit holder of an objection to the transfer prior to the transfer date stated in the notification in paragraph (1) of this subsection.

(i) Safety requirements for gas storage projects.

(1) Leak detectors.

(A) Within two years of the effective date of this section, leak detectors shall be installed and in operation at each gas storage well that is located 100 yards or less from a residence, commercial establishment, church, school, or small, well-defined outside area, and at each structurally enclosed compressor site. For purposes of this section, the term "small, well-defined outside area" means an area such as a playground, recreation area, outdoor theater, or other place of public assembly that is occupied by 20 or more persons on at least five days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive.

(B) Each leak detector required under this paragraph shall be tested twice each calendar year at intervals not to exceed 7-1/2 months and, when defective, repaired or replaced within 10 days.

(2) Warning systems. Within two years of the effective date of this section, all leak detectors required in paragraph (1) of this subsection shall be integrated with warning systems that are audible and visible in the control room and at any remote control center. The circuitry shall be designed so that failure of a detector or pressure monitor to function will activate the warning.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.95	**Underground Storage of Liquid or Liquefied Hydrocarbons in Salt Formations**

(a) Definitions. The following terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Affected person--A person who, as a result of actions proposed in an application for a storage facility permit or for amendment or modification of an existing storage facility permit, has suffered or may suffer actual injury or economic damage other than as a member of the general public.

(2) Brine string--The uncemented tubing through which highly saline water flows into or out of a hydrocarbon storage well during hydrocarbon withdrawal or injection operations.

(3) Cavern--The storage space created in a salt formation by solution mining.

(4) Commission--The Railroad Commission of Texas.

(5) Emergency shutdown valve--A valve that automatically closes to isolate a hydrocarbon storage well from surface piping in the event of specified conditions that, if uncontrolled, may cause an emergency.

(6) Fire detector--A device capable of detecting the presence of a flame or the heat from a fire.

(7) Fresh water--Water having bacteriological, physical, and chemical properties that make it suitable and feasible for beneficial use for any lawful purpose. For purposes of this section, brine associated with the creation, operation, and maintenance of an underground hydrocarbon storage facility is not considered fresh water.

(8) Hydrocarbon storage well or storage well--A well used for the injection or withdrawal of liquid or liquefied hydrocarbons into or out of an underground hydrocarbon storage facility.

(9) Leak detector--A device capable of detecting by chemical or physical means the presence of hydrocarbon vapor or the escape of vapor through a small opening.

(10) Liquid or liquefied hydrocarbons--Crude oil and products, derivatives, or by-products of oil or gas that are:

(A) liquid under standard conditions of temperature and pressure;

(B) liquefied under the temperatures and pressures at which they are stored; or

(C) stored under conditions that necessitate the use of displacement fluids to withdraw them from storage.

(11) Operator--The person recognized by the commission as being responsible for the physical operation of an underground hydrocarbon storage facility, or such person's authorized representative.

(12) Owner--The person recognized by the commission as owning all or part of a storage facility, or such

person's authorized representative.

(13) Person--A natural person, corporation, organization, government, governmental subdivision or agency, business trust, estate, trust, partnership, association, or any other legal entity.

(14) Pollution--Alteration of the physical, chemical, or biological quality of, or the contamination of, water that makes it harmful, detrimental, or injurious to humans, animal life, vegetation, or property, or to public health, safety, or welfare, or impairs the usefulness or the public enjoyment of the water for any lawful or reasonable purpose.

(15) Process or transfer area--Any area at an underground hydrocarbon storage facility where hydrocarbons are physically altered by equipment, including dehydrators, compressors, and pumps, or where hydrocarbons are transferred to or from trucks, rail cars, or pipelines.

(16) Underground hydrocarbon storage facility or storage facility--A facility used for the storage of liquid or liquefied hydrocarbons in an underground salt formation, including surface and subsurface rights, appurtenances, and improvements necessary for the operation of the facility.

(b) Permit required.

(1) General. No person may create, operate, or maintain an underground hydrocarbon storage facility without obtaining a permit from the commission. A permit issued by the commission for such activities before the effective date of this section shall continue in effect until revoked, modified, or suspended by the commission, or until it expires by its terms. The provisions of this section apply to permits for underground hydrocarbon storage facility operations issued prior to the effective date of this section, except as specifically provided in this section.

(2) Conflict with other requirements. If a provision of this section conflicts with any provision or term of a commission order, field rule, or permit, the provision of such order, field rule, or permit shall control.

(c) Application.

(1) Information required. An application for a permit to create, operate, or maintain an underground hydrocarbon storage facility shall be filed with the commission by the owner or operator, or proposed owner or operator, on the prescribed form. The application shall contain the information necessary to demonstrate compliance with the applicable state laws and commission regulations.

(2) Permit amendment. An application for amendment of an existing underground hydrocarbon storage facility permit shall be filed with the commission:

(A) prior to any planned enlargement of a cavern in excess of the permitted cavern capacity by solution mining;

(B) when required in accordance with paragraph (3) of this subsection;

(C) prior to the drilling of any additional hydrocarbon storage wells;

(D) prior to any increase in the volume of liquid or liquefied hydrocarbons stored in the cavern in excess of the permitted storage volume; or

(E) any time that conditions at the storage facility deviate materially from conditions specified in the permit or the permit application.

(3) Increase in capacity. The owner or operator of a storage facility shall notify the commission if information indicates that the capacity of a cavern exceeds the permitted cavern capacity by 20% or more. Such notification shall be made in writing to the commission within 10 days of the date that the owner or operator knows or has reason to know that the cavern capacity exceeds the permitted capacity by 20% or more. The notification shall include a description of the information that indicates that the permitted cavern capacity has been exceeded, and an estimate of the current cavern capacity. Upon receipt of such information, the commission or its designee may take any one or more of the following actions:

(A) require the permittee to comply with a compliance schedule that lists measures to be taken to ensure that conditions at the storage facility do not pose a danger to life or property, and that no waste of hydrocarbons, uncontrolled escape of hydrocarbons, or pollution of fresh water occurs;

(B) require the permittee to file an application to amend the underground hydrocarbon storage facility permit;

(C) modify, cancel, or suspend the permit as provided in subsection (f) of this section; or

(D) take enforcement action.

(4) Related activities. An application for a permit to dispose of saltwater or other oil and gas waste arising out of or incidental to the creation, operation, or maintenance of an underground hydrocarbon storage facility shall be filed in accordance with applicable commission requirements.

(d) Standards for underground storage zone.

(1) Impermeable salt formation. An underground hydrocarbon storage facility may be created, operated, or maintained only in an impermeable salt formation in a manner that will prevent waste of the stored hydrocarbons, uncontrolled escape of hydrocarbons, pollution of fresh water, and danger to life or property. Natural gas storage operations are not authorized under the provisions of this section. A permit under §3.97 of this title (relating to Underground Storage of Gas in Salt Formations) is required to convert from storage of liquid or liquefied hydrocarbons to storage of natural gas in an underground salt formation.

(2) Fresh water strata. The applicant must submit with the application a letter from the Texas Commission on Environmental Quality or its successor agencies stating the depth to which fresh water strata occur at each storage facility.

(e) Notice and hearing.

(1) Notice requirements. Such notice shall be given no later than the date the application is mailed to or filed with the commission. The applicant shall give notice of an application for a permit to create, operate, or maintain an underground hydrocarbon storage facility, or to amend an existing storage facility permit, by mailing or delivering a copy of the application form to:

(A) the surface owner of the tract where the storage facility is located or is proposed to be located;

(B) the surface owner of each tract adjoining the tract where the storage facility is located or is proposed to be located;

(C) each oil, gas, or salt leaseholder, other than the applicant, of the tract on which the storage facility is located or is proposed to be located;

(D) each oil, gas, or salt leaseholder of any tract adjoining the tract on which the storage facility is located or is proposed to be located;

(E) the county clerk of the county where the storage facility is located or is proposed to be located; and

(F) if the storage facility is located or proposed to be located within city limits, the city clerk or other appropriate city official.

(2) Publication of notice. Notice of the application, in a form approved by the commission or its designee, shall be published by the applicant once a week for three consecutive weeks in a newspaper of general circulation in the county or counties where the facility is or is proposed to be located. The applicant shall file proof of publication prior to any hearing on the application or administrative approval of the application.

(3) Notice by publication. The applicant shall make diligent efforts to ascertain the name and address of each person identified under paragraph (1)(A) - (D) of this subsection. The exercise of diligent efforts to ascertain the names and addresses of such persons shall require an examination of the county records where the facility is located and an investigation of any other information of which the applicant has actual knowledge. If, after diligent efforts, the applicant has been unable to ascertain the name and address of one or more persons required to be notified under paragraph (1)(A) - (D) of this subsection, the notice requirements for those persons are satisfied by the publication of the notice of application as required in paragraph (2) of this subsection. The applicant must submit an affidavit to the commission specifying the efforts that were taken to identify each person whose name and/or address could not be ascertained.

(4) Hearing required for new permits. A permit application for a new underground hydrocarbon storage facility will be considered for approval only after notice and hearing. The commission will give notice of the hearing to all affected persons, local governments, and other persons who express, in writing, an interest in the application. After hearing, the examiner shall recommend a final action by the commission.

(5) Hearing on permit amendments.

(A) An application for an amendment to an existing storage facility permit may be approved administratively if the commission receives no protest from a person notified pursuant to the provisions of paragraph (1) of this subsection, or from any other affected person.

(B) If the commission receives a protest from a person notified pursuant to paragraph (1) of this subsection or from any other affected person within 15 days of the date of receipt of the application by the commission, or of the date of the third publication, whichever is later, or if the commission determines that a hearing is in the public interest, then the applicant will be notified that the application cannot be approved administratively. The commission will schedule a hearing on the application upon written request of the applicant. The commission will give notice of the hearing to all affected persons, local governments, and other persons who express, in writing, an interest in the application. After hearing, the examiner shall recommend a final action by the commission.

(C) If the application is administratively denied, a hearing will be scheduled upon written request of the applicant. After hearing, the examiner shall recommend a final action by the commission.

(f) Modification, cancellation, or suspension of a permit.

(1) General. Any permit may be modified, suspended, or canceled after notice and opportunity for hearing if:

(A) a material change in conditions has occurred in the operation, maintenance, or construction of the storage facility, or there are material deviations from the information originally furnished to the commission. A change in conditions at a facility that does not affect the safe operation of the facility or the ability of the facility to operate without causing waste of hydrocarbons or pollution is not considered to be material;

(B) fresh water is likely to be polluted as a result of continued operation of the facility;

(C) there are material violations of the terms and provisions of the permit or commission regulations;

(D) the applicant has misrepresented any material facts during the permit issuance process; or

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.93	**Water Quality Certification Definitions**

(a) The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) 401 certification--A certification issued by the commission, under the authority of the Federal Clean Water Act, §401, that a federal permit that may result in a discharge to waters of the United States is consistent with applicable state and federal water quality laws and regulations.

(2) Commission--The Railroad Commission of Texas or its designee.

(3) Department of the Army permits--Individual or general permits or letters of permission issued by the U.S. Army Corps of Engineers under the authority of the Federal Clean Water Act, §404, or the Rivers and Harbors Act of 1899, §9 and §10, United States Code, Title 33, §402 and §403.

(4) District engineer--The U.S. Army Corps of Engineers representative responsible for administering and enforcing federal laws and regulations, including processing and issuance of permits, under the jurisdiction of the U.S. Army Corps of Engineers.

(5) Federal Clean Water Act--United States Code, Title 33, Chapter 26.

(6) NPDES permit--A permit issued by the regional administrator under the authority of the Federal Clean Water Act, §402, Title 33, United States Code, §1342. NPDES permits can either be individual or general permits.

(7) Permitting agency--Any agency of the federal government to which application is made for any permit to conduct an activity that may result in any discharge into waters of the United States.

(8) Person--A natural person, corporation, organization, government or governmental subdivision or agency, business trust, estate, trust, partnership, association, or any other legal entity.

(9) Pollutant--Any constituent that contaminates or alters the physical, thermal, chemical, or biological quality of water so as to be harmful, detrimental, or injurious to humans, animal life, vegetation, or property or to the public health, safety, or welfare, or that impairs the usefulness or the public enjoyment of the water for any lawful purpose.

(10) Regional administrator--The administrator of the United States Environmental Protection Agency, Region 6.

(11) Water quality standards--Texas Surface Water Quality Standards, Title 30, Texas Administrative Code, Chapter 307.

(12) Waters of the United States--Interstate waters, the territorial seas, and waters that would or could affect interstate commerce, including tributaries of such waters and adjacent wetlands, as defined in Title 33, Code of Federal Regulations, Part 328.

(b) Certification Required. No person may conduct any activity subject to the jurisdiction of the commission pursuant to a Department of the Army permit or an NPDES permit if the activity may result in a discharge into waters of the United States within the boundaries of the State of Texas, unless the commission has first issued a certification or waiver of certification under this section.

(c) Request for Certification. The regional administrator, district engineer, or the permit applicant may submit a request for certification to the commission.

(1) Request by Applicant. If the permit applicant requests certification, the applicant shall submit to the commission:

(A) a copy of the completed permit application and any amendments thereto;

(B) a list on a map or on a separate sheet attached to a map of the names and addresses of owners of tracts of land adjacent to the site where the proposed activity would occur and, where the activity may result in a discharge to watercourse other than the Gulf of Mexico or a bay, the owners of each waterfront tract between the potential discharge point and 1/2 mile downstream of the potential discharge point, except for those waterfront tracts within the corporate limits of an incorporated city, town, or village;

(C) a request for certification; and

(D) for Department of the Army permits in the coastal zone, as described in 31 TAC §503.1 (Coastal Management Program Boundary), a description of the acreage proposed to be filled, if any.

(2) Request by EPA or the Corps. Except as provided in subsection (d)(1) of this section, a request for certification submitted by the regional administrator or the district engineer shall contain the information specified in this paragraph:

(A) a copy of the public notice;

(B) a request for certification;

(C) for NPDES permits, a copy of the draft permit, if available; and

(D) for Department of the Army permits in the coastal zone, as described in 31 TAC §503.1 (Coastal Management Program Boundary), a description of the acreage proposed to be filled, if any.

(3) Request for Additional Information. Where the commission believes more information is required to accomplish review of a request for certification, the commission shall notify the applicant or the permitting agency and request such information. In response to such a notification from the commission, the applicant or the permitting agency shall submit such materials as the commission finds necessary for review of the request for certification. Except as otherwise provided, such information shall be provided within ten days of issuance of a request for additional information by the commission.

(d) Notice of Request for Certification.

(1) Joint Notice. Notice of a request for certification shall be made using a joint mailed notice issued by the U.S. Army Corps of Engineers or the U.S. Environmental Protection Agency after agreements with those agencies have been reached regarding the content of the notice and the persons entitled to notice in Texas. When a joint notice is issued by either the U.S. Army Corps of Engineers or the U.S. Environmental Protection Agency, the requirements of subsection (c) (2) of this section do not apply.

(2) Notice by Applicant. If a joint notice is not used as provided in paragraph (1) of this subsection, the

applicant must mail notice of the request for certification on or before the date the request for certification is filed with the commission. Such notice shall include the information required in paragraph (3) of this subsection. The applicant shall provide notice by first class mail to:

(A) the owners of land adjacent to the tract upon which the activity is proposed to take place, and where the activity may result in a discharge to a watercourse other than the Gulf of Mexico or a bay, the surface owners of each waterfront tract between the potential discharge point and 1/2 mile downstream of the potential discharge point, excluding owners of those waterfront tracts within the corporate limits of an incorporated city, town, or village;

(B) the mayor and health authorities of any city or town in which the proposed activity will be located or that is within 1/2 mile downstream of the potential discharge;

(C) the county judge and health authorities of any county in which the proposed activity will be located or that is within 1/2 mile downstream of the potential discharge;

(D) the Texas Commission on Environmental Quality (TCEQ) or its successor agencies;

(E) the Texas Parks and Wildlife Department;

(F) the U.S. Environmental Protection Agency, Region 6;

(G) the U.S. Fish and Wildlife Service; and

(H) for a proposed activity within the coastal management program boundary as defined under Title 31, Texas Administrative Code §503.1 (Coastal Management Program Boundary), the Secretary of the Coastal Coordination Council.

(3) Contents of Notice. Any notice provided as required in paragraph (2) of this subsection shall contain:

(A) the applicant's name and mailing address, together with the name and mailing address of the party conducting the activity, if different from the applicant;

(B) a brief written description of the activity;

(C) a statement that the applicant is seeking certification from the commission under the Federal Clean Water Act, §401;

(D) a statement that any comments concerning the request for certification may be submitted in writing to the assistant Director of Environmental Services, Railroad Commission, 1701 North Congress Avenue, P.O. Box 12967, Austin, Texas 78711-2967, on or before the deadline for submission of written public comments, which, absent special circumstances, shall be at least 30 days after the date notice is mailed; and

(E) a statement that a copy of the permit application is available for review in the office of the federal permitting agency.

(4) Emergency Actions. When the division engineer for the U.S. Army Corps of Engineers authorizes emergency procedures and it is in the public interest to provide a certification in less than 30 days, the commission may waive the notice and hearing requirements under this section and issue a final determination. For emergency actions within the coastal zone, as described in 31 TAC §503.1 (Coastal Management Program Boundary), the commission may only issue a final determination if the emergency action is consistent with the provisions of 31 TAC §501.14(j)(7) (Policies for Specific Activities and Coastal Natural Resource Areas).

(e) Public Comments.

(1) Written Comments. The commission shall consider all comments related to the water quality impacts of the proposed activity that are submitted to the commission in writing prior to the deadline for submission of comments.

(2) Public Meetings. The commission shall hold a meeting to receive public comment on a request for certification if the commission finds that such a meeting is in the public interest. If the commission holds a meeting to receive public comment on a request for certification, the commission shall notify the applicant by first class mail not less than ten days before the date set for the public meeting that a meeting to receive public comment will be held on the request for certification. The commission will also provide notice by first-class mail or by personal service to all of the persons identified under subsection (d)(2) of this section and the federal permitting agency at least ten days prior to the public meeting. The notice of public meeting shall identify the federal permit application; the date, time, place, and nature of the public meeting; the legal authority and jurisdiction under which the public meeting is to be held; the applicant's proposed action; the requirements for submitting written comments; the method for obtaining additional information; and such other information as the commission deems necessary. The notice to the federal permitting agency shall also estimate the additional time necessary to consider the request for certification and shall state that the commission is not waiving certification.

(f) Commission Review of Requests for Certification. After expiration of the time for receipt of public comments, the commission shall determine whether the proposed activity for which a request for certification has been received will result in any discharge into waters of the United States within the boundaries of the State of Texas, and if so, whether the proposed activity will comply with all applicable water quality requirements. Applicable water quality requirements include, but are not limited to, state water quality standards, and any other applicable water quality requirements. For an activity within the boundary of the Texas Coastal Management Program (CMP), applicable state water quality requirements include the enforceable goals and policies of the CMP, Title 31, Texas Administrative Code, Chapter 501.

(g) Final Action.

(1) Issuance of Final Determination. A final determination on a request for certification of an NPDES or Department of the Army permit shall be issued by the commission within 15 days from the close of the public comment period, unless the regional administrator or the district engineer, in consultation with the commission, finds that unusual circumstances require a longer time. If the commission does not act upon the request for certification within 15 days from the close of the public comment period or within a longer time granted by the regional administrator or the district engineer, the commission will be deemed to have waived certification. Notwithstanding any contrary provisions of this paragraph, in unusual circumstances the commission may elect to delay acting upon a request for certification of an NPDES permit until after a review of the draft permit.

(2) Notification of Final Determination. The commission shall notify the applicant, the regional administrator or district engineer, and any person so requesting of its final determination. Such final determination shall waive, grant, grant conditionally or deny certification. The notification of a final determination shall be in writing and shall include:

(A) the name and address of the applicant;

(B) a statement of conditions that are necessary to ensure compliance with the applicable water quality requirements;

(C) when the state certifies a draft permit instead of a permit application, any condition required to ensure compliance with applicable water quality requirements shall be identified, citing the federal or state law references upon which that condition is based. Failure by the commission to provide such a citation waives its right to certify with respect to that condition;

(D) for NPDES permits, a statement of the extent to which each condition of the draft permit can be made less stringent without the concurrence of the commission; and

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.91	**Cleanup of Soil Contaminated by a Crude Oil Spill**

(a) Terms. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Free oil--The crude oil that has not been absorbed by the soil and is accessible for removal.

(2) Sensitive areas--These areas are defined by the presence of factors, whether one or more, that make an area vulnerable to pollution from crude oil spills. Factors that are characteristic of sensitive areas include the presence of shallow groundwater or pathways for communication with deeper groundwater; proximity to surface water, including lakes, rivers, streams, dry or flowing creeks, irrigation canals, stock tanks, and wetlands; proximity to natural wildlife refuges or parks; or proximity to commercial or residential areas.

(3) Hydrocarbon condensate--The light hydrocarbon liquids produced in association with natural gas.

(b) Scope. These cleanup standards and procedures apply to the cleanup of soil in non-sensitive areas contaminated by crude oil spills from activities associated with the exploration, development, and production, including transportation, of oil or gas or geothermal resources as defined in §3.8(a)(30) of this title (relating to Water Protection). For the purposes of this section, crude oil does not include hydrocarbon condensate. These standards and procedures do not apply to hydrocarbon condensate spills, crude oil spills in sensitive areas, or crude oil spills that occurred prior to the effective date of this section. Cleanup requirements for hydrocarbon condensate spills and crude oil spills in sensitive areas will be determined on a case-by-case basis. Cleanup requirements for crude oil contamination that occurred wholly or partially prior to the effective date of this section will also be determined on a case-by-case basis. Where cleanup requirements are to be determined on a case-by-case basis, the operator must consult with the appropriate district office on proper cleanup standards and methods, reporting requirements, or other special procedures.

(c) Requirements for cleanup.

(1) Removal of free oil. To minimize the depth of oil penetration, all free oil must be removed immediately for reclamation or disposal.

(2) Delineation. Once all free oil has been removed, the area of contamination must be immediately delineated, both vertically and horizontally. For purposes of this paragraph, the area of contamination means the affected area with more than 1.0% by weight total petroleum hydrocarbons.

(3) Excavation. At a minimum, all soil containing over 1.0% by weight total petroleum hydrocarbons must be brought to the surface for disposal or remediation.

(4) Prevention of stormwater contamination. To prevent stormwater contamination, soil excavated from the spill site containing over 5.0% by weight total petroleum hydrocarbons must immediately be:

(A) mixed in place to 5.0% by weight or less total petroleum hydrocarbons; or

(B) removed to an approved disposal site; or

(C) removed to a secure interim storage location for future remediation or disposal. The secure interim storage location may be on site or off site. The storage location must be designed to prevent pollution from contaminated stormwater runoff. Placing oily soil on plastic and covering it with plastic is one acceptable means to prevent stormwater contamination; however, other methods may be used if adequate to prevent pollution from stormwater runoff.

(d) Remediation of soil.

(1) Final cleanup level. A final cleanup level of 1.0% by weight total petroleum hydrocarbons must be

achieved as soon as technically feasible, but not later than one year after the spill incident. The operator may select any technically sound method that achieves the final result.

(2) Requirements for bioremediation. If on-site bioremediation or enhanced bioremediation is chosen as the remediation method, the soil to be bioremediated must be mixed with ambient or other soil to achieve a uniform mixture that is no more than 18 inches in depth and that contains no more than 5.0% by weight total petroleum hydrocarbons.

(e) Reporting requirements.

(1) Crude oil spills over five barrels. For each spill exceeding five barrels of crude oil, the responsible operator must comply with the notification and reporting requirements of §3.20 of this title (relating to Notification of Fire Breaks, Leaks, or Blow-outs) and submit a report on a Form H-8 to the appropriate district office. The following information must be included:

(A) area (square feet), maximum depth (feet), and volume (cubic yards) of soil contaminated with greater than 1.0% by weight total petroleum hydrocarbons;

(B) a signed statement that all soil containing over 1.0% by weight total petroleum hydrocarbons was brought to the surface for remediation or disposal;

(C) a signed statement that all soil containing over 5.0% by weight total petroleum hydrocarbons has been mixed in place to 5.0% by weight or less total petroleum hydrocarbons or has been removed to an approved disposal site or to a secure interim storage location;

(D) a detailed description of the disposal or remediation method used or planned to be used for cleanup of the site;

(E) the estimated date of completion of site cleanup.

(2) Crude oil spills over 25 barrels. For each spill exceeding 25 barrels of crude oil, in addition to the report required in paragraph (1) of this subsection, the operator must submit to the appropriate district office a final report upon completion of the cleanup of the site. Analyses of samples representative of the spill site must be submitted to verify that the final cleanup concentration has been achieved.

(3) Crude oil spills of five barrels or less. Spills into the soil of five barrels or less of crude oil must be remediated to these standards, but are not required to be reported to the commission. All spills of crude oil into water must be reported to the commission.

(f) Alternatives. Alternatives to the standards and procedures of this section may be approved by the commission for good cause, such as new technology, if the operator has demonstrated to the commission's satisfaction that the alternatives provide equal or greater protection of the environment. A proposed alternative must be submitted in writing and approved by the commission.

Source Note: The provisions of this §3.91 adopted to be effective November 1, 1993, 18 TexReg 6835.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.86	**Horizontal Drainhole Wells**

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Correlative interval--The depth interval designated by the field rules, by new field designation, or, where a correlative interval has not been designated by the commission, by other evidence submitted by the operator showing the producing interval for the field in which the horizontal drainhole is completed.

(2) Horizontal drainhole--That portion of the wellbore drilled in the correlative interval, between the penetration point and the terminus.

(3) Horizontal drainhole displacement--The calculated horizontal displacement of the horizontal drainhole from the penetration point to the terminus.

(4) Horizontal drainhole well--Any well that is developed with one or more horizontal drainholes having a horizontal drainhole displacement of at least 100 feet.

(5) Penetration point--The point where the drainhole penetrates the top of the correlative interval.

(6) Terminus--The farthest point required to be surveyed along the horizontal drainhole from the penetration point and within the correlative interval.

(b) Drainhole spacing.

(1) No point on a horizontal drainhole shall be drilled nearer than 1,200 feet (horizontal displacement), or other between-well spacing requirement under applicable rules for the field, to any point along any other horizontal drainhole in another well, or to any other well completed or drilling in the same field on the same lease, pooled unit, or unitized tract.

(2) No point on a horizontal drainhole shall be drilled nearer than 467 feet, or other lease-line spacing requirement under applicable rules for the field, from any property line, lease line, or subdivision line.

(3) All wells developed with horizontal drainholes shall otherwise comply with Statewide Rule 37, §3.37 of this title (relating to Statewide Spacing Rule), or other applicable spacing rules.

(c) Well densities. All wells developed with horizontal drainholes shall comply with Statewide Rule 38, §3.38 of this title (relating to Well Densities) or other applicable density rules.

(d) Proration and drilling units.

(1) Acreage may be assigned to each horizontal drainhole well for the purpose of allocating allowable oil or gas production up to the amount specified by applicable rules for a proration unit for a vertical well plus the additional acreage assignment as provided in this paragraph.

Attached Graphic

(2) Assignment of acreage to proration and drilling units for horizontal drainhole wells must be done in accordance with Statewide Rule 40, §3.40 of this title (relating to Assignment of Acreage to Pooled Development and Proration Units).

(3) All proration and drilling units shall consist of continuous and contiguous acreage and proration units shall consist of acreage that can be reasonably considered to be productive of oil or gas.

(4) All points on the horizontal drainhole must be within the proration and drilling unit.

(5) The maximum daily allowable for a horizontal drainhole well shall be determined by multiplying the applicable allowable for a vertical well in the field with a proration unit containing the maximum acreage authorized by the applicable rules for the field, exclusive of tolerance acreage, by a fraction:

(A) the numerator of which is the acreage assigned to the horizontal drainhole well for proration purposes; and

(B) the denominator of which is the maximum acreage authorized by the applicable field rules for proration purposes, exclusive of tolerance acreage. The daily oil allowable shall be adjusted in accordance with Statewide Rule 49(a), §3.49(a) of this title (relating to Gas-Oil Ratio), when applicable.

(6) The maximum diagonal for each proration unit containing a horizontal drainhole well shall be the horizontal drainhole displacement of the longest horizontal drainhole for the well plus:

(A) 2,100 feet for fields that are regulated under statewide rules; or

(B) the maximum diagonal allowed for fields where the special field rules specify a maximum diagonal.

(e) Multiple drainholes allowed.

(1) A single well may be developed with more than one horizontal drainhole originating from a single vertical wellbore.

(2) A horizontal drainhole well developed with more than one horizontal drainhole shall be treated as a single well.

(3) The horizontal drainhole displacement used for calculating additional acreage assignment for a well completed with multiple horizontal drainholes shall be the horizontal drainhole displacement of the longest horizontal drainhole plus the projection of any other horizontal drainhole on a line that extends in a 180 degree direction from the longest horizontal drainhole.

(f) Drilling applications and required reports.

(1) Application. Any intent to develop a new or existing well with horizontal drainholes must be indicated on the application to drill. An application for a permit to drill a horizontal drainhole shall include the fees required by Statewide Rule 78, §3.78 of this title (relating to Fees and Financial Security Requirements), and shall be certified by a person acquainted with the facts, stating that all information in the application is true and complete to the best of that person's knowledge.

(2) Drilling unit plat. The application to drill a horizontal drainhole shall be accompanied by a plat.

(A) In addition to the plat requirements provided for in §3.5 of this title (relating to Application to Drill, Deepen, Reenter, or Plug Back) (Statewide Rule 5), the plat shall include:

(i) the lease, pooled unit, or unitized tract, showing the acreage assigned to the drilling unit for the proposed well and the acreage assigned to the drilling units for all current applied for, permitted, or completed oil, gas, or oil and gas wells on the lease, pooled unit, or unitized tract;

(ii) the surface location of the proposed horizontal drainhole well, and the proposed path, penetration points, and terminus locations of all drainholes;

(iii) two perpendicular lines from the nearest point on the lease line, pooled unit line, or any unleased interest in a tract of the pooled unit, depicting the distance(s) to:

(I) the penetration point(s); and

(II) the terminus location(s);

(iv) perpendicular lines providing the distance in feet from the two nearest non-parallel survey lines to the terminus location(s);

(v) a line providing the distance in feet from the closest point along the horizontal course(s) of the drainhole(s) to the nearest point on the lease line, pooled unit line, or unitized tract line. If there is an unleased interest in a tract of the pooled unit that is nearer than the pooled unit line, the nearest point on that unleased tract boundary shall be used; and

(vi) lines from the nearest oil, gas, or oil and gas well, applied for, permitted or completed in the same lease or pooled unit and in the same field and reservoir depicting the distance to:

(I) the penetration point(s);

(II) the closest point along the horizontal course(s) of the drainhole(s); and

(III) the terminus location(s).

(B) An amended drilling permit application and plat shall be filed after completion of the horizontal drainhole well if the commission determines that the drainhole as drilled is not reasonable with respect to the drainhole represented on the plat filed with the drilling permit application.

(3) Directional survey. A directional survey from the surface to the farthest point drilled on the horizontal drainhole shall be required for all horizontal drainholes. The directional survey and accompanying reports shall be conducted and filed in accordance with Statewide Rules 11 and 12, §3.11 and §3.12 of this title (relating to Inclination and Directional Surveys Required and Directional Survey Company Report). No allowable shall be assigned to any horizontal drainhole well until a directional survey and survey plat has been filed with and accepted by the commission.

(4) Proration unit plat. The required proration unit plat must depict the lease, pooled unit, or unitized tract, showing the acreage assigned to the proration unit for the horizontal drainhole well, the acreage assigned to the proration units for all wells on the lease, pooled unit, or unitized tact, and the path, penetration point, and terminus of all drainholes. No allowable shall be assigned to any horizontal drainhole well until the proration unit plat has been filed with and accepted by the commission.

(g) Exceptions and procedure for obtaining exceptions.

(1) The commission may grant exceptions to this section in order to prevent waste, prevent confiscation, or to protect correlative rights.

(2) If a permit to drill a horizontal drainhole requires an exception to this section, the notice and opportunity for hearing procedures for obtaining exceptions to the density provisions prescribed in Statewide Rule 38, §3.38 of this title (relating to Well Densities), shall be followed as set forth in Statewide Rule 38(h), §3.38(h) of this title (relating to Well Densities).

(3) For notice purposes, the commission presumes that for each adjacent tract and each tract nearer to any point along the proposed or existing horizontal drainhole than the prescribed minimum lease-line spacing distance, affected persons include:

(A) the designated operator;

(B) all lessees of record for tracts that have no designated operator; and

(C) all owners of record of unleased mineral interests.

Source Note: The provisions of this §3.86 adopted to be effective June 1, 1990, 15 TexReg 2635; amended to be effective July 10, 2000, 25 TexReg 6487; amended to be effective June 11, 2001, 26 TexReg 4088; amended to be effective September 1, 2004, 29 TexReg 8271

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.85	**Manifest To Accompany Each Transport of Liquid Hydrocarbons by Vehicle**

(a) The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Cargo manifest--One or more documents that together contain the information required by subsection (c) of this section. That part of a manifest which contains information unique to the particular transport being described (such as date and time of removal) must be part of a book, tablet, or series, wherein the documents are sequentially numbered.

(2) Commission--The Railroad Commission of Texas.

(3) Facility--Any place used to store, process, refine, reclaim, dispose of, or treat liquid hydrocarbons.

(4) Lease--A well producing oil, gas, or oil and gas, and any group of contiguous wells producing oil, gas, or oil and gas of any number operated as a producing unit.

(5) Liquid hydrocarbons--Unrefined oil or condensate, and refined oil or condensate to be blended with unrefined liquid hydrocarbons.

(6) Oil tanker vehicle--A motor vehicle licensed for highway use on a public highway or used on a public highway:

(A) that is equipped with, carrying, pulling, or otherwise transporting an assembly, compartment, tank, or other container that is used for transporting, hauling, or delivering liquids; and

(B) that is being used to transport liquid hydrocarbons on a public highway.

(7) Public highway--A way or place of whatever nature open to the use of the public as a matter of right for the purpose of vehicular travel, even if the way or place is temporarily closed for the purpose of construction, maintenance, or repair.

(8) Transporter--Each gatherer, storer, or other handler of liquid hydrocarbons who moves or transports those liquid hydrocarbons by truck or other motor vehicle, provided however, that the provisions of this rule do not apply to:

(A) common carriers as defined in the Natural Resources Code, Chapter 111; or

(B) the movement of salt water, brine, sludge, drilling mud, or other liquid or semiliquid material if the commission has authorized the entity to move such material and such material contains less than 7.0% liquid hydrocarbon, by volume, or if not authorized by the commission, the movement is not for hire and the material moved does not contain more than 7.0% liquid hydrocarbons by volume.

(b) A cargo manifest must be carried in each oil tanker vehicle transporting liquid hydrocarbons on a public highway in this state and must be presented on request for inspection as provided by subsection (f) of this section.

(c) For each load of liquid hydrocarbons loaded onto and transported by an oil tanker vehicle, the cargo manifest must include:

(1) an identification of the lease or facility from which the liquid hydrocarbons were removed, which must include:

(A) the lease or facility name; and

(B) the name of the operator of the lease or facility;

(2) the total quantity of liquid hydrocarbons removed from the lease or facility and loaded onto the oil tanker vehicle; provided that for purposes of indicating quantity on the copy of the manifest left with the lease operator, top and bottom gauges will suffice. On the other copies, an estimate in barrels must be included;

(3) the date and hour when the liquid hydrocarbons were removed from the lease or facility and loaded onto the oil tanker vehicle;

(4) the identity of the transporter which must include;

(A) the company or individual transporter's name and address;

(B) the oil tanker vehicle driver's name; and

(C) a unique number for the oil tanker vehicle that for a truck tractor and semitrailer type oil tanker vehicle must include unique vehicle numbers for both truck tractor and semitrailer; and

(5) the intended point of destination for the liquid hydrocarbons, including the name of the receiving facility.

(d) Copy of manifest to be left at the lease.

(1) A copy of the cargo manifest must be left at the lease or facility from which the liquid hydrocarbons were removed or delivered to the lease or facility operator, his agent, or his representative.

(2) The requirements of this section may be met by leaving a separate document at the lease or facility from which the liquid hydrocarbons were removed or by delivering to the lease or facility operator a separate document that includes information required under subsection (c)(1)-(3) and (4)(A) and (B) this section.

(3) If more than one load of liquid hydrocarbons is removed from a single tank or other container of liquid hydrocarbons within a period of 24 consecutive hours, subsection (c)(2) and (3) of this section may be met for purposes of this section by a separate document that includes:

(A) the total quantity of liquid hydrocarbons removed;

(B) the date and hour the first load was removed; and

(C) the date and hour the last load was removed.

(4) If the operator of a facility requires that a transporter leave at the facility or deliver to the operator a

document other than the transporter's cargo manifest, a transporter may meet the requirements of this section by leaving those specified documents at an agreed location or delivering the document to the operator.

(e) After the delivery of all liquid hydrocarbons in an oil tanker vehicle is completed, the cargo manifest must be maintained in the records of the transporter for a period of not less than two years from the date the liquid hydrocarbons are removed from the oil tanker vehicle.

(f) Upon request from a commission agent or other law enforcement official the transporter must produce the cargo manifest for inspection immediately, whether it is on an oil tanker vehicle or in the records of the transporter. Copies of cargo manifests must be filed with the commission, upon request from the commission.

(g) Companies or individuals who do not have organization reports (Form P-5) on file with the Railroad Commission, as required by §3.1 of this title (relating to Organization Report; Retention of Records; Notice Requirement (commonly referred to as Statewide Rule 1)), may not issue cargo manifests.

(h) Every truck or other vehicle covered by this section shall bear on both sides thereof the name of the company or individual responsible for such transportation, the number of the vehicle, and the number of the certificate or permit authorizing the service. In the case of vehicles not for hire, this number shall be the company's organizational report (P-5) number. The identifying signs shall be printed in letters not less than two inches in height, in sharp color contrast to the background, and shall be plainly legible for a distance of at least 50 feet.

Source Note: The provisions of this §3.85 adopted to be effective August 25, 2003, 28 TexReg 6816

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.84	**Gas Shortage Emergency Response**

(a) The purpose of this section is to provide a means for a producer or purchaser to increase production and takes from wells in a field in response to an increase in demand caused by unforeseen events. This section outlines the commission's mechanisms for both determining that a gas shortage emergency exists, and responding to a gas shortage emergency.

(b) The commission may, after notice and hearing, determine that a gas shortage emergency exists or has existed. The commission may also determine the duration of the emergency at such hearing. The commission shall issue notice when it has determined that a gas shortage emergency exists, or has existed, and when it determines the gas shortage emergency has ended or will end. In determining whether a gas shortage emergency exists or has existed, the commission shall consider any relevant information, including, but not limited to, the following:

(1) notification from gas storage facilities that they are attaining maximum gas withdrawal rates;

(2) notification from a gas utility, distributor, transporter, producer or purchaser that gas shortages have occurred or are anticipated; and

(3) weather data.

(c) Upon the commission's finding that a gas shortage emergency exists, or has existed, producers or purchasers shall be authorized to meet the increased demand for the duration of the gas shortage emergency as determined by the commission regardless of a well's assigned allowable or allowable status.

(d) If inequities occur as a result of production authorized by subsection (c) of this section, an adjustment shall be made at the hearing in which production reported for the month of the gas shortage emergency is considered in setting future allowables. Such adjustment shall include the assignment of additional allowable to adequately protect correlative rights. The commission may determine the maximum amount of the supplemental allowable by multiplying the number of days of the gas shortage emergency period by the difference between the well's capability (as defined in §3.31 of this title (relating to Gas Reservoirs and Gas Well Allowable)) and the assigned allowable.

Source Note: The provisions of this §3.84 adopted to be effective September 13, 1994, 19 TexReg 6853; amended to be effective November 24, 2004, 29 TexReg 10728

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.83	**Tax Exemption for Two-Year Inactive Wells and Three-Year Inactive Wells**

(a) Purpose. The purpose of this section is to provide a procedure by which an operator can obtain commission certification of a wellbore as a two-year inactive well or three-year inactive well in order to qualify for the tax exemptions provided for in the Tax Code, §§201.053, 202.052, and 202.056.

(b) Definitions.

(1) Two-year inactive well--A well that has not produced any hydrocarbons in more than one calendar month in the two years prior to the date of certification by the Commission under this section.

(2) Three-year inactive well--A well that has not produced any hydrocarbons in more than one calendar month in the three years prior to the date of certification by the commission under this section.

(3) Eligible well--Wells eligible under this section include those that:

(A) were previous producing or injection wells that have not been plugged or abandoned; or

(B) have been plugged and abandoned; or

(C) are active injection wells.

(4) Well--A wellbore with single or multiple completions.

(c) Certification. The commission or its delegate may certify a well as a two-year inactive well or a three-year inactive well. If the commission or its delegate declines to certify a well administratively, the operator affected by this action may request a hearing.

(d) Revocation of Certification. Certification of a two-year inactive well or a three-year inactive well may be revoked by the commission for cause which includes, but is not limited to, receipt of information by the commission that a certified well produced hydrocarbons in more than one calendar month in the applicable two or three years prior to certification, or if production from other wells is credited to the two-year inactive well or the three-year inactive well, or if a certified well is reported to the commission to be capable of production but is not capable of production. The Comptroller of Public Accounts will be notified of any revocation.

(e) Certified Wells.

(1) Three-year inactive wells. The commission may not certify a three-year inactive well under this section after February 29, 1996. Prior to applying to the Comptroller of Public Accounts for the tax incentives listed in subsection (a) of this section, the operator of a three-year inactive certified well shall file with the commission a test report showing productive capability for the well. Production is presumed to begin on this well test date. The certification remains with the well in the event of a change of operator or ownership.

(2) Two-year inactive wells. The commission may not designate a two-year inactive well under this section

after February 28, 2010. An application for two-year inactive well certification shall be made during the period of September 1, 1997, through August 31, 2009, to qualify for the tax exemption. Certification will be issued upon the filing of a test report showing the well's capability and an approval of application for certification. Production is presumed to begin on the well test date as reported on the appropriate report. The certification shall remain with the well in the event of a change of operator or ownership.

Source Note: The provisions of this §3.83 adopted to be effective November 23, 1993, 18 TexReg 8195; amended to be effective January 10, 1996, 20 TexReg 11119; amended to be effective July 21, 1998, 23 TexReg 7363; amended to be effective September 10, 2001, 26 TexReg 6869

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.81	**Brine Mining Injection Wells**

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Affected person--A person who, as a result of the activity sought to be permitted, has suffered or may suffer actual injury or economic damage other than as a member of the general public.

(2) Brine mining facility or facility--The brine mining injection well, and the pits, tanks, fresh water wells, pumps, and other structures and equipment that are or will be used in conjunction with the brine mining injection well.

(3) Brine mining injection well--A well used to inject fluid for the purpose of extracting brine by the solution of a subsurface salt formation. The term "brine mining injection well" does not include a well used to inject fluid for the purpose of leaching a cavern for the underground storage of hydrocarbons or the disposal of waste, or a well used to inject fluid for the purpose of extracting sulphur by the thermofluid mining process.

(4) Commission--The Railroad Commission of Texas.

(5) Director--The director of the Oil and Gas Division or a staff delegate designated in writing by the director of the Oil and Gas Division or the commission.

(6) Existing brine mining injection well--A brine mining injection well in which injection operations began prior to the effective date of this section.

(7) Fresh water--Water having bacteriological, physical, and chemical properties that make it suitable and feasible for beneficial use for any lawful purpose.

(8) New brine mining injection well--A brine mining injection well in which injection operations begin on or after the effective date of this section.

(9) Permit--A written authorization issued by the commission under this section for the operation of a brine mining injection well.

(10) Person--A natural person, corporation, organization, government or governmental subdivision or agency, business trust, estate, trust partnership, association, or any other legal entity.

(11) Pollution--The alteration of the physical, chemical, or biological quality of, or the contamination of, water that makes it harmful, detrimental, or injurious to humans, animal life, vegetation or property or to public health, safety, or welfare, or impairs the usefulness or the public enjoyment of the water for any lawful purpose.

(b) Prohibitions.

(1) Unauthorized injection. No person may operate a brine mining injection well without obtaining a

permit from the commission under this section. No person may begin constructing a new brine mining injection well until the commission has issued a permit to operate the well under this section and a permit to drill, deepen, plug back, or reenter the well under §3.5 of this title (relating to Application to Drill, Deepen, Reenter, or Plug Back) (Statewide Rule 5).

(2) Fluid migration. No person may operate a brine mining injection well in a manner that allow fluids to escape from the permitted injection zone. If fluids are migrating from the permitted injection zone, the operator shall immediately cease injection operations.

(3) Falsifying documents and tampering with gauges. No person may knowingly make any false statement, representation, or certification in any application, report, record, or other document submitted or required to be maintained under this section or under any permit issued pursuant to this section, or falsify, tamper with, or knowingly render inaccurate any monitoring device or method required to be maintained under this section or under any permit issued pursuant to this section.

(c) Standards for permit issuance. A permit may be issued only if the commission determines that the operation of the brine mining injection well will not result in the pollution of fresh water. All permits issued under this section will contain the conditions required by subsections (f) and (g) of this section, and all other conditions reasonably necessary to prevent the pollution of fresh water.

(d) Permit application.

(1) Duty to apply. Any person who operates or proposes to operate a brine mining injection well shall file a permit application with the commission in Austin within the time provided in paragraph (2) of this subsection. The applicant shall mail or deliver a copy of the application to the appropriate district office on the same day the application is mailed or delivered to the commission in Austin. A permit application will be considered filed with the commission on the date it is received by the commission in Austin.

(2) Time to apply.

(A) Any person who proposes to operate a new brine mining injection well shall file a permit application at least 180 days before the date on which injection is to begin, unless a later date has been authorized by the director.

(B) Any person who is operating an existing brine injection well shall file a permit application within 90 days of the effective date of this section.

(C) Any person who has obtained a permit under this section and who wishes to continue to operate the brine mining injection well after the permit expires shall file an application for new permit at least 180 days before the existing permit expires, unless a later date has been authorized by the director.

(3) Who applies. When a brine mining facility is owned by one person but is operated by another person, it is the operator's duty to file an application for a permit.

(4) Application requirements for all applicants. All applicants shall submit the following information, using application forms supplied by the commission:

(A) name, mailing address, and location of the brine mining facility for which the application is submitted;

(B) the operator's name, mailing address, telephone number, and status as federal, state, private, public, or other entity, and a statement indicating whether the operator is the owner of the facility;

(C) the proposed uses for the brine mined at the facility;

(D) a listing of all permits or construction approvals for the facility received or applied for under federal or state environmental programs;

(E) a topographic map, or other map if the topographic map is unavailable, extending one mile beyond the property boundaries of the facility, depicting the facility and those springs, other surface water bodies, drinking water wells, and other wells listed in public records or otherwise known to the applicant within 1/4 mile of the facility property boundary;

(F) a plat showing the oil and gas operators of the tract on which the facility is located and the tracts adjacent to the tract on which the facility is located. On the plat or on a separate sheet attached to the plat, the applicant shall list the names and addresses of the oil and gas operators;

(G) a plat showing the surface ownership of the tract on which the facility is located and the tracts adjacent to the tract on which the facility is located. On the plat or on a separate sheet attached to the plat, the applicant shall list the names and addresses of the surface owners, as determined from the current county tax rolls or other reliable sources, and shall identify the source of the list. If the director determines that, after diligent efforts, the applicant has been unable to ascertain the name and address of one or more surface owners, the director may waive the requirements of this subparagraph with respect to those surface owners;

(H) a map with surveys marked showing the type, location, and depth of all wells of public record within a 1/4 mile radius of the brine mining injection well that penetrate the salt formation. The applicant shall attach the following information to the map:

(i) a tabulation of the wells showing the dates the wells were drilled and the present status of the wells; and

(ii) plugging records for plugged and abandoned wells and completion records for other wells;

(I) a letter from the Texas Commission on Environmental Quality stating the depth to which fresh water strata should be protected;

(J) a complete electric log of the brine mining injection well or a nearby well. On the log, the applicant shall identify the geologic formations between the land surface and the top of the salt formation and the depths at which they occur;

(K) a drawing of the surface and subsurface construction details of the brine mining injection well;

(L) the proposed maximum daily injection rate and maximum injection pressure;

(M) the proposed injection procedure;

(N) the proposed mechanical integrity testing procedure;

(O) the source of mining water to be used at the facility. If the source is groundwater, the following information must be included:

(i) the groundwater formation name;

(ii) an depth of the groundwater formation; and

(iii) an analysis of the groundwater;

(P) the direction of the hydraulic gradient in the area; and

(Q) the proposed groundwater monitoring plan, or an alternate plan for assuring that fluids are not escaping from the permitted injection zone.

(5) Additional information. The applicant shall submit any other information required on the application form supplied by the commission. In addition to the information reported on the application form, the applicant shall submit, at the director's request, any other information the commission may reasonably require to assess the brine mining injection well and to determine whether to issue a permit.

(e) Signatories to applications and reports.

(1) Applications. All applications shall be signed as follows:

(A) for a corporation, by a responsible corporate officer. A responsible corporate officer means a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy-making or decision-making functions for the corporation; or

(B) for a partnership or sole proprietorship, by a general partner or the proprietor, respectively.

(2) Reports. All reports required by permits and other information requested by the commission shall be signed by a person described in paragraph (1) of this subsection or by a duly authorized representative of that person. A person is a duly authorized representative only if:

(A) the authorization is made in writing by a person described in paragraph (1) of this subsection;

(B) the authorization specifies an individual or position having responsibility for the overall operation of the regulated facility; and

(C) the authorization is submitted to the commission before or together with any report of information signed by the authorized representative.

(3) Certification. Any person signing a document under paragraph (1) or (2) of this subsection shall make the following certification: "I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gathered and evaluated the information submitted. Based on my inquiry of the person or persons who manage the system, or who are directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information."

(f) Conditions applicable to all permits. The conditions specified in this subsection apply to all permits.

(1) Duty to comply. The operator shall comply with all conditions of the permit. Any permit noncompliance is grounds for enforcement action, for permit termination, revocation and reissuance, or modification, or for denial of a permit renewal application.

(2) Duty to reapply. If the operator wishes to continue a permitted activity after the expiration date of the permit, the operator shall apply for and obtain a new permit.

(3) Need to halt or reduce activity not a defense. It is not a defense for an operator in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit.

(4) Duty to mitigate. The operator shall take all reasonable steps to minimize and correct any adverse effect on the environment resulting from noncompliance with the permit.

(5) Proper operation and maintenance. The operator shall at all times properly operate and maintain all facilities and systems of treatment and control, and related appurtenances, that are installed or used by the operator to achieve compliance with the conditions of the permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up and auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of the permit.

(6) Permit actions. The permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the operator for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance does not stay any permit condition.

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TITLE 16	ECONOMIC REGULATION
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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.80	**Commission Oil and Gas Forms, Applications, and Filing Requirements**

(a) Forms. Forms required to be filed at the Commission shall be those prescribed by the Commission as listed in Table 1 of this subsection. A complete set of all Commission forms listed on Table 1 required to be filed at the Commission shall be kept by the Commission secretary and posted on the Commission's web site. Notice of any new or amended forms shall be issued by the Commission. For any required or discretionary filing, an organization may either file the prescribed form on paper or use any electronic filing process in accordance with subsections (e) or (f) of this section, as applicable. The Commission may at its discretion accept an earlier version of a prescribed form, provided that it contains all required information and meets the requirements of subsection (e)(3) of this section.

Attached Graphic

(b) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Commission--The Railroad Commission of Texas.

(2) Electronic filing process--An electronic transmission to the Commission in a prescribed form and/or format authorized by the Commission and completed in accordance with Commission instructions.

(3) Form--A printed or typed paper document or electronic submission, including any necessary instructions, with blank spaces for insertion of required or requested specific information.

(4) Organization--Any person, firm, partnership, joint stock association, corporation, or other organization, domestic or foreign, operating wholly or partially within this state, acting as principal or agent for another, for the purpose of performing operations within the jurisdiction of the Commission.

(5) Position of ownership or control--A person holds a position of ownership or control in an organization if the person is:

(A) an officer or director of the organization;

(B) a general partner of the organization;

(C) the owner of an organization which is a sole proprietorship;

(D) the owner of more than a 25 percent ownership interest in the organization; or

(E) the designated trustee of the organization.

(6) Violation--Non-compliance with a statute, Commission rule, order, license, permit, or certificate relating to safety or the prevention or control of pollution.

(c) Organization eligibility. The Commission may not accept an organization report or an application for a permit, or approve a certificate of compliance if:

(1) the organization that submitted the report, application, or certificate violated a statute or Commission rule, order, license, certificate, or permit that relates to safety or the prevention or control of pollution; or

(2) any person who holds a position of ownership or control in the organization has, within the seven years preceding the date on which the report, application, or certificate is filed, held a position of ownership or control in another organization, and during that period of ownership or control the other organization violated a statute or Commission rule, order, license, permit, or certificate that relates to safety or the prevention or control of pollution.

(d) Violations. An organization has committed a violation if there is either a Commission order against an organization finding that the organization has committed a violation and all appeals have been exhausted or an agreed order entered into by the Commission and an organization relating to an alleged violation, and:

(1) the conditions that constituted the violation or alleged violation have not been corrected;

(2) all administrative, civil and criminal penalties, if any, relating to the violation or agreed settlement relating to an alleged violation have not been paid; or

(3) all reimbursements of costs and expenses, if any, assessed by the Commission relating to the violation or to the alleged violation have not been collected.

(e) Authorization and standards for electronic filing.

(1) An organization may file electronically any form listed on Table 1 for which the Commission has provided an electronic version, provided that the organization pays all required filing fees and complies with all requirements, including but not limited to security procedures, for electronic filing.

(2) The Commission deems an organization that files electronically or on whose behalf is filed electronically any form, as of the time of filing, to have knowledge of and to be responsible for the information filed on the form, pursuant to the statutory requirements, restrictions, and standards found in and pertaining to:

(A) Texas Natural Resources Code, Title 3 (oil and gas well drilling, production, and plugging);

(B) Texas Natural Resources Code, Title 5 (geothermal resources);

(C) Texas Natural Resources Code, Title 11 (hazardous liquids storage);

(D) Texas Utilities Code, Chapter 121, Subchapter I (sour gas pipeline facilities);

(E) Texas Water Code, §26.131 (discharge permits);

(F) Texas Water Code, Chapter 27 (class II injection and disposal wells and class III brine mining wells);

(G) Texas Water Code, Chapter 29 (oil and gas waste haulers);

(H) Texas Health and Safety Code, §401.415 (oil and gas naturally occurring radioactive material (NORM) waste); and

(I) Texas Administrative Code, Title 16, Chapter 3 (Oil and Gas Division) and Chapter 4 (Environmental Protection).

(3) All forms that an organization submits or that are submitted on behalf of an organization shall be transmitted in the manner prescribed by the Commission that is compatible with its software, equipment, and facilities.

(4) The Commission may provide notice electronically to an organization of, and may provide an organization the ability to confirm electronically, the Commission's receipt of a form submitted electronically by or on behalf of that organization.

(5) The Commission deems that the signature of an organization's authorized representative appears on each form submitted electronically by or on behalf of the organization, as if this signature actually appears, as of the time the form is submitted electronically to the Commission.

(6) The Commission holds each organization responsible, under the penalties prescribed in Texas Natural Resources Code, §91.143, for all forms, information, or data that an organization files or that are filed on its behalf. The Commission charges each organization with the obligation to review and correct, if necessary, all forms or data that an organization files or that are filed on its behalf.

(f) Other electronic transmissions. The Commission may at its discretion accept other documents or data electronically transmitted.

Source Note: The provisions of this §3.80 adopted to be effective June 11, 2001, 26 TexReg 4088; amended to be effective April 12, 2004, 29 TexReg 3612; amended to be effective July 12, 2004, 29 TexReg 6633; amended to be effective October 11, 2004, 29 TexReg 9533

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.79	**Definitions**

The following words and terms, when used in this chapter, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Adjacent estuarine zones--This term embraces the area inland from the coast line of Texas and is comprised of the bays, inlets, and estuaries along the gulf coast.

(2) By-product--Any element found in a geothermal formation which when brought to the surface is not used in geothermal heat or pressure inducing energy generation.

(3) Casinghead gas--Any gas or vapor, or both, indigenous to an oil stratum and produced from such stratum with oil.

(4) Commission--The Railroad Commission of Texas.

(5) Common reservoir--Any oil, gas, or geothermal resources field or part thereof which comprises and includes any area which is underlaid, or which from geological or other scientific data or experiments or from drilling operations or other evidence appears to be underlaid by a common pool or accumulation of oil, gas, or geothermal resources.

(6) Cubic foot of gas or standard cubic foot of gas--The volume of gas contained in one cubic foot of space at a standard pressure base and at a standard temperature base. The standard pressure base shall be 14.65 pounds per square inch absolute, and the standard temperature base shall be 60 degrees Fahrenheit. Whenever the conditions of pressure and temperature differ from the standard in this definition, conversion of the volume from these conditions to the standard conditions shall be made in accordance with the ideal gas laws, corrected for deviation.

(7) District office--The commission-designated office for the geographic area in which the property or act subject to regulation is located or arises.

(8) Dry gas--Any natural gas produced from a stratum that does not produce crude petroleum oil.

(9) Exploratory well--Any well drilled for the purpose of securing geological or geophysical information to be used in the exploration or development of oil, gas, geothermal, or other mineral resources, except coal and uranium, and includes what is commonly referred to in the industry as "slim hole tests," "core hole tests," or "seismic holes." For regulations governing coal exploratory wells, see Chapter 12 of this title (relating to Coal Mining Regulations), and for regulations governing uranium exploratory wells, see Chapter 11, Subchapter C of this title (relating to Surface Mining and Reclamation Division, Substantive Rules--Uranium Mining).

(10) Gas lift--Gas lift by the use of gas not in solution with oil produced.

(11) Gas well--Any well:

(A) which produces natural gas not associated or blended with crude petroleum oil at the time of production;

(B) which produces more than 100,000 cubic feet of natural gas to each barrel of crude petroleum oil from the same producing horizon; or

(C) which produces natural gas from a formation or producing horizon productive of gas only encountered in a wellbore through which crude petroleum oil also is produced through the inside of another string of casing or tubing. A well which produces hydrocarbon liquids, a part of which is formed by a condensation from a gas phase and a part of which is crude petroleum oil, shall be classified as a gas well unless there is produced one barrel or more of crude petroleum oil per 100,000 cubic feet of natural gas; and that the term "crude petroleum oil" shall not be construed to mean any liquid hydrocarbon mixture or portion thereof which is not in the liquid phase in the reservoir, removed from the reservoir in such liquid phase, and obtained at the surface as such.

(12) Gatherer--Includes any pipeline, truck, motor vehicle, boat, barge, or person authorized to gather or accept oil, gas, or geothermal resources from lease production or lease storage.

(13) Geothermal energy and associated resources--

(A) All products of geothermal processes, embracing indigenous steam, hot water and hot brines, and geopressured water;

(B) Steam and other gases, hot water and hot brines resulting from water, gas, or other fluids artificially introduced into geothermal formations;

(C) Heat or other associated energy found in geothermal formations;

(D) Any by-product derived from them.

(14) Geothermal resource well--A well drilled within the established limits of a designated geothermal field.

(A) A geopressured geothermal well must be completed within a geopressured aquifer.

(B) A geopressured aquifer is a water-bearing zone with a pressure gradient in excess of 0.5 pounds per square inch per foot and a temperature gradient in excess of 1.6 degrees Fahrenheit per 100 feet of depth.

(15) Marginal well--Any oil well which is incapable of producing its maximum capacity of oil except by pumping, gas lift, or other means of artificial lift, and which well so equipped is capable, under normal unrestricted operating conditions, of producing such daily quantities of oil as herein set out, as would be damaged, or result in a loss of production ultimately recoverable, or cause the premature abandonment of same, if its maximum daily production were artificially curtailed. The following described wells shall be deemed "marginal wells" in this state.

(A) Any oil well incapable of producing its maximum daily capacity of oil except by pumping, gas lift, or other means of artificial lift, within this state and having a maximum daily capacity for production of 10 barrels or less, averaged over the preceding 10 consecutive days of stabilized production, producing from a depth of 2,000 feet or less.

(B) Any oil well incapable of producing its maximum daily capacity of oil except by pumping, gas lift, or other means of artificial lift, within this state and having a maximum daily capacity for production of 20 barrels or less, averaged over the preceding 10 consecutive days of stabilized production, producing from a horizon deeper than 2,000 feet and less in depth than 4,000 feet.

(C) Any oil well incapable of producing its maximum daily capacity of oil except by pumping, gas lift, or other means of artificial lift, within this state and having a maximum daily capacity for production of 25 barrels or less, averaged over the preceding 10 consecutive days of stabilized production, producing from a horizon deeper than 4,000 feet and less in depth than 6,000 feet.

(D) Any oil well incapable of producing its maximum daily capacity of oil except by pumping, gas lift, or other means of artificial lift, within this state and having a maximum daily capacity for production of 30 barrels or less, averaged over the preceding 10 consecutive days of stabilized production, producing from a horizon deeper than 6,000 feet and less in depth than 8,000 feet.

(E) Any oil well incapable of producing its maximum daily capacity of oil except by pumping, gas lift, or other means of artificial lift, within this state and having a maximum daily capacity for production of 35 barrels or less, averaged over the preceding 10 consecutive days of stabilized production, producing from a horizon deeper than 8,000 feet. (Reference Order Number 20-59,200, effective May 1, 1969.)

(16) Natural gas or gas--These terms shall have the same meaning, as used in the rules, regulations, or forms of the commission.

(17) Natural gasoline--Gasoline manufactured from casinghead gas or from any natural gas.

(18) Oil well--Any well which produces one barrel or more crude petroleum oil to each 100,000 cubic feet of natural gas.

(19) Operator--A person, acting for himself or as an agent for others and designated to the commission as the one who has the primary responsibility for complying with its rules and regulations in any and all acts subject to the jurisdiction of the commission.

(20) Person--Any natural person, corporation, association, partnership, receiver, trustee, guardian, executor, administrator, and a fiduciary or representative of any kind.

(21) Product--Includes refined crude oil, crude tops, topped crude, processed crude petroleum, residue from crude petroleum, cracking stock, uncracked fuel oil, fuel oil, treated crude oil, residuum, casinghead gasoline, natural gas gasoline, gas oil, naphtha, distillate, gasoline, kerosene, benzine, wash oil, waste oil, blended gasoline, lubricating oil, blends or mixtures of petroleum, and/or any and all liquid products or by-products derived from crude petroleum oil or gas, whether hereinabove enumerated or not.

(22) Sour gas--Any natural gas containing more than 1 1/2 grains of hydrogen sulphide per 100 cubic feet or more than 30 grains of total sulphur per 100 cubic feet, or gas which in its natural state is found by the commission to be unfit for use in generating light or fuel for domestic purposes.

(23) Sweet gas--All natural gas except sour gas and casinghead gas.

(24) Texas offshore--This term embraces the area in the Gulf of Mexico seaward of the coast line of Texas comprised of:

(A) the three league area confirmed to the State of Texas by the Submerged Land Act (43 United States Code §§1301-1315); and

(B) the area seaward of such three league area owned by the United States.

(25) Transportation or to transport--The movement of any crude petroleum oil or products of crude

petroleum oil or the products of either from any receptacle in which any such crude petroleum or products of crude petroleum oil or the products of either has been stored to any other receptacle by any means or method whatsoever, including the movement by any pipeline, railway, truck, motor vehicle, barge, boat, or railway tank car. It is the purpose of this definition to include the movement or transportation of crude petroleum oil and products of crude petroleum oil and the products of either by any means whatsoever from any receptacle containing the same to any other receptacle anywhere within or from the State of Texas, regardless of whether or not possession or control or ownership change.

(26) Transporter or transporting agency--Includes any common carrier by pipeline, railway, truck, motor vehicle, boat, or barge, and/or any person transporting oil or a product by pipeline, railway, truck, motor vehicle, boat, or barge.

Source Note: The provisions of this §3.79 adopted to be effective August 25, 2003, 28 TexReg 6816

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.78	**Fees and Financial Security Requirements**

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise:

(1) Violation--Noncompliance with a Commission rule, order, license, permit, or certificate relating to safety or the prevention or control of pollution.

(2) Outstanding violation--A violation for which:

(A) either:

(i) a Commission order finding a violation has been entered and all appeals have been exhausted; or

(ii) an agreed order between the Commission and the organization relating to a violation has been entered; and

(B) one or more of the following conditions still exist:

(i) the conditions that constituted the violation have not been corrected;

(ii) all administrative, civil, and criminal penalties, if any, relating to the violation of such Commission rules, orders, licenses, permits, or certificates have not been paid; or

(iii) all reimbursements of any costs and expenses assessed by the Commission relating to the violation of such Commission rules, orders, licenses, permits, or certificates have not been paid.

(3) Commercial facility--A facility whose owner or operator receives compensation from others for the storage, reclamation, treatment, or disposal of oil field fluids or oil and gas wastes that are wholly or partially trucked or hauled to the facility and whose primary business purpose is to provide these services for compensation if:

(A) the facility is permitted under §3.8 of this title (relating to Water Protection);

(B) the facility is permitted under §3.57 of this title (relating to Reclaiming Tank Bottoms, Other Hydrocarbon Wastes, and Other Waste Materials);

(C) the facility is permitted under §3.9 of this title (relating to Disposal Wells) and a collecting pit permitted under §3.8 is located at the facility; or

(D) the facility is permitted under §3.46 of this title (relating to Fluid Injection into Productive Reservoirs) and a collecting pit permitted under §3.8 is located at the facility.

(4) Financial security--An individual performance bond, blanket performance bond, letter of credit, or cash deposit filed with the Commission.

(5) Bay well--Any well under the jurisdiction of the Commission for which the surface location is either:

(A) located in or on a lake, river, stream, canal, estuary, bayou, or other inland navigable waters of the state and which requires plugging by means other than conventional land-based methods, including, but not limited to, use of a barge, use of a boat, dredging, or building a causeway or other access road to bring in the necessary equipment to plug the well; or,

(B) located on state lands seaward of the mean high tide line of the Gulf of Mexico in water of a depth at mean high tide of not more than 100 feet that is sheltered from the direct action of the open seas of the Gulf of Mexico.

(6) Land well--Any well subject to Commission jurisdiction for which the surface location is not in or on inland or coastal waters.

(7) Offshore well--Any well subject to Commission jurisdiction for which the surface location is on state lands in or on the Gulf of Mexico, that is not a bay well.

(8) Officers and owners--Any persons owning or controlling an organization including officers, directors, general partners, sole proprietors, owners of more than 25% ownership interest, any trustee of an organization, and any person determined by a final judgment or final administrative order to have exercised control over the organization.

(9) Letter of credit--An irrevocable letter of credit issued:

(A) on a Commission-approved form;

(B) by and drawn on a third party bank authorized under state or federal law to do business in Texas; and

(C) renewed and continued in effect until the conditions of the letter of credit have been met or its release is approved by the Commission or its authorized delegate.

(10) Bond--A surety instrument issued:

(A) on a Commission-approved form;

(B) by and drawn on a third party corporate surety authorized under state law to issue surety bonds in Texas; and

(C) renewed and continued in effect until the conditions of the bond have been met or its release is approved by the Commission or its authorized delegate.

(11) Director--The director of the Commission's Oil and Gas Division or the director's delegate.

(b) Filing fees. The following filing fees are required to be paid to the Railroad Commission.

(1) With each application or materially amended application for a permit to drill, deepen, plug back, or reenter a well, the applicant shall submit to the Commission a nonrefundable fee of:

(A) $200 if the proposed total depth of the well is 2,000 feet or less;

(B) $225 if the proposed total depth of the well is greater than 2,000 feet but less than or equal to 4,000 feet;

(C) $250 if the proposed total depth of the well is greater than 4,000 feet but less than or equal to 9,000 feet; or

(D) $300 if the proposed total depth of the well is greater than 9,000 feet.

(2) An application for a permit to drill, deepen, plug back, or reenter a well will be considered materially amended if the amendment is made for a purpose other than:

(A) to add omitted required information;

(B) to correct typographical errors; or

(C) to correct clerical errors.

(3) An applicant shall submit an additional nonrefundable fee of $150 when requesting that the Commission expedite the application for a permit to drill, deepen, plug back, or reenter a well.

(4) With each individual application for an exception to any rule or rules in this chapter, the applicant shall submit to the Commission a nonrefundable fee of $150, except as provided in paragraph (5) of this subsection.

(5) With each application for an exception to any rule or rules in this chapter that includes an exception to §3.37 of this title (relating to Statewide Spacing Rule) (Statewide Rule 37) or §3.38 of this title (relating to Well Densities) (Statewide Rule 38), the applicant shall submit a nonrefundable fee of $200.

(6) With each application for an oil and gas waste disposal well permit, the applicant shall submit to the Commission a nonrefundable fee of $100 per well.

(7) With each application for a fluid injection well permit, the applicant shall submit to the Commission a nonrefundable fee of $200 per well. Fluid injection well means any well used to inject fluid or gas into the ground in connection with the exploration or production of oil or gas other than an oil and gas waste disposal well.

(8) With each application for a permit to discharge to surface water other than a permit for a discharge that meets national pollutant discharge elimination system (NPDES) requirements for agricultural or wildlife use, the applicant shall submit to the Commission a nonrefundable fee of $300.

(9) If a certificate of compliance for an oil lease or gas well has been canceled for violation of one or more Commission rules, the operator shall submit to the Commission a nonrefundable fee of $300 for each severance or seal order issued for the well or lease before the Commission may reissue the certificate pursuant to §3.58 of this title (relating to Oil, Gas, or Geothermal Resource Producer's Reports) (Statewide Rule 58).

(10) With each application for issuance, renewal, or material amendment of an oil and gas waste hauler's permit, the applicant shall submit to the Commission a nonrefundable fee of $100.

(11) With each Natural Gas Policy Act (15 United States Code §§3301-3432) application, the applicant shall submit to the Commission a nonrefundable fee of $150.

(12) Hazardous waste generation fee. A person who generates hazardous oil and gas waste, as that term is defined in §3.98 of this title (relating to Standards for Management of Hazardous Oil and Gas Waste), shall pay to the Commission the fees specified in §3.98(z).

(13) A check or money order for any of the aforementioned fees shall be made payable to the Railroad Commission of Texas. If the check accompanying an application is not honored upon presentment, the permit issued on the basis of that application, the allowable assigned, the exception to a statewide rule granted on the basis of the application, the certificate of compliance reissued, or the Natural Gas Policy Act category determination made on the basis of the application may be suspended or revoked.

(14) If an operator submits a check that is not honored on presentment, the operator shall, for a period of 24 months after the check was presented, submit any payments in the form of a credit card, cashier's check, or cash.

(c) Organization Report Fee. An organization report required by Texas Natural Resources Code, §91.142, shall be accompanied by a fee as follows:

(1) for an operator of:

(A) not more than 25 wells, $300;

(B) more than 25 but not more than 100 wells, $500; or

(C) more than 100 wells, $1,000;

(2) for an operator of one or more natural gas pipelines, $225;

(3) for an operator of one or more of the following service activities: pollution cleanup contractor; directional surveying; approved cementer for plugging wells; or physically moving or storing crude or condensate, $300;

(4) for an operator of one or more liquids pipelines, $625;

(5) for an operator of all other service activities or facilities, $500;

(6) for an operator with multiple activities, a total fee equal to the sum of the separate fees applicable to each category of service activity, facility, pipeline, or number of wells operated shall be submitted, provided that the total fee for an operator of wells shall not exceed $1,125; and

(7) for an entity not currently performing operations under the jurisdiction of the Commission, $300.

(d) Financial security.

(1) Except for those operators exempted under subsection (g)(7) of this section, any person, including any firm, partnership, joint stock association, corporation, or other organization, required by Texas Natural Resources Code, §91.142, to file an organization report with the Commission must also file financial security in one of the following forms:

(A) an individual performance bond;

(B) a blanket performance bond; or

(C) a letter of credit or cash deposit in the same amount as required for an individual performance bond or blanket performance bond.

(2) An unbonded operator that has a current and active organization report and filed a nonrefundable annual fee as its financial security prior to September 1, 2004, may continue to perform operations subject to

the Commission's jurisdiction with such financial security until the first date after September 1, 2004, for annual renewal of the operator's organization report, at which time the operator shall file financial security as required by subsection (g) of this section.

(e) Forms for financial security. Operators shall submit bonds and letters of credit on forms prescribed by the Commission.

(f) Filing deadlines for financial security. Operators shall submit required financial security at the time of filing an initial organization report or upon yearly renewal, or as otherwise required under this section.

(g) Amount of financial security. An operator required to file financial security under subsection (d) of this section shall file financial security described in this subsection.

(1) Types and amounts of financial security required.

(A) A person operating one or more wells may file an individual performance bond, letter of credit, or cash deposit in an amount equal to the sum of $2.00 for each foot of total well depth for each well operated.

(B) A person operating one or more wells may file a blanket bond, letter of credit, or cash deposit to cover all wells for which a bond, letter of credit, or cash deposit is required in an amount equal to the sum of the base amount determined by the total number of wells operated. A person performing multiple operations shall be required to file only one blanket bond, letter of credit, or cash deposit unless the person is operating a commercial facility, in which case the person also shall comply with the financial security requirements of subsection (l) of this section. The financial security amount shall be at least the base amount determined by the total number of wells operated or $25,000, whichever is greater. The base amount is determined as follows:

(i) The base amount for a person operating 10 or fewer wells or performs other operations shall be $25,000.

(ii) The base amount for a person operating more than 10 but fewer than 100 wells shall be $50,000.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.76	**Commission Approval of Plats for Mineral Development**

(a) The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Minerals--Oil and/or gas.

(2) Operations site--A surface area of two or more acres that an owner of a possessory mineral interest may use to explore for and produce minerals, which is located in whole or in part within a qualified subdivision, and designated on the subdivision plat.

(3) Possessory mineral interest--A mineral interest that includes the right to use the land surface for exploration and production of minerals.

(4) Qualified subdivision--A tract of land not more than 640 acres:

(A) that is located in a county having a population in excess of 400,000, or in a county having a population in excess of 140,000 that borders a county having a population in excess of 400,000 or located on a barrier island;

(B) that has been subdivided in a manner authorized by law by the surface owners for residential, commercial, or industrial use; and

(C) that contains an operations site for each separate 80 acres within the 640-acre tract and provisions for road and pipeline easements to allow use of the operations sites.

(5) Barrier island--An island bordering on the Gulf of Mexico and entirely surrounded by water.

(b) As provided in subsections (e) and (f) of this section, the surface owners of a parcel of land may restrict use of the surface by the possessory mineral owners if the tract is a qualified subdivision and if a plat of the subdivision has been approved by the Railroad Commission after notice and hearing and filed with the clerk of the county in which the qualified subdivision is to be located.

(c) An application for a hearing under this section must be made in writing and mailed or delivered to the director of the Oil and Gas Division. The application must include:

(1) a jurisdictional statement setting out the facts stated in subsection (a)(4)(A) and (B) of this section;

(2) a statement that the applicant has authority to represent and represents all surface owners of land contained in the proposed qualified subdivision;

(3) the names and addresses of all owners of possessory mineral interests and all mineral lessors of land contained in the proposed qualified subdivision;

(4) a plat of the proposed subdivision showing each proposed 80-acre tract with its operations site, road easements, and pipeline easements and a legible copy thereof no larger than 8 1/2 inches by 11 inches;

(5) a concise description of mineral development in the area, including the number of oil and/or gas wells within 2.5 miles of the boundary of the proposed qualified subdivision and the depths at which each well is completed;

(6) a list of all the Railroad Commission designated oil and/or gas fields, if any, which underlie the proposed qualified subdivision; including the spacing and density requirements. If no Railroad Commission designated fields underlie the qualified subdivision, the application should so state.

(d) The Railroad Commission shall, on proper notice to the applicant and owners of possessory mineral interests and mineral lessors of land contained in the proposed qualified subdivision, hold a hearing on the application to determine the adequacy of the number and location of operations sites and road and pipeline easements. At the hearing on the application, evidence may be presented by the applicant and the owners of possessory mineral interests and mineral lessors. The applicant must carry the burden of proof. After considering the evidence, the commission may approve, reject, or amend the application to ensure that the mineral resources of the subdivision may be fully and effectively developed.

(e) An owner of a possessory mineral interest within a Railroad Commission approved qualified subdivision may use only the surface contained in designated operations sites for exploration, development, and production of minerals and only the designated easements as necessary to adequately use the operations sites.

(f) The owner of the possessory mineral interest may drill wells or extend well bores from an operations site or from a site outside of the qualified subdivision to bottomhole locations vertically beneath the surface of parts of the qualified subdivision other than the operation sites. Such drilling is subject to other applicable commission rules and regulations, and is permissible only to the extent that the operations do not unreasonably interfere with the use of the surface of the qualified subdivision outside the operations site.

(g) Subsections (e) and (f) of this section cease to apply to a subdivision if, by the third anniversary of the date on which the order of the commission becomes final:

(1) the surface owner has not commenced actual construction of roads or utilities within the qualified subdivision; and

(2) a lot within the qualified subdivision has not been sold to a third party.

(h) All or any portion of a qualified subdivision may be amended, replatted, or abandoned by the surface owner. An amendment or replat, however, may not alter, diminish, or impair the usefulness of an operations site or appurtenant road or pipeline easement unless the amendment or replat is approved by the commission. Railroad Commission approval of a replat or amendment may be administratively granted by the director of the Oil and Gas Division, or his delegate, upon submission of items required in subsection (c) of this section and after notice and opportunity for hearing has been afforded to all possessory mineral interest owners and mineral lessors of land contained within the original and/or replatted or amended qualified subdivision.

Source Note: The provisions of this §3.76 adopted to be effective July 10, 2000, 25 TexReg 6487

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TITLE 16	ECONOMIC REGULATION
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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.73	**Pipeline Connection; Cancellation of Certificate of Compliance; Severance**

(a) No pipeline shall be connected with any oil, gas, or geothermal resources well until the operator of the well provides the pipeline operator with a certificate from the Commission that the rules in this title have been complied with. This section shall not prevent a temporary connection with any well in order to take care of production and prevent waste until the operator has a reasonable time, not to exceed 30 days from the date of such connection, within which to obtain such certificate. For purposes of this section, the term "Commission" means the Railroad Commission of Texas, the Director of the Oil and Gas Division, or the Director's delegate.

(b) No pipeline operator shall physically disconnect its facilities from or cease providing pipeline services to any well or lease without first obtaining:

(1) written consent of the well or lease operator for the proposed disconnect or termination; or

(2) written permission from the Commission. This section does not apply to temporary suspensions of service authorized under other rules in this title or attributable to maintenance, safety, or product quality issues.

(c) If the pipeline operator is unable to obtain the written consent of the well or lease operator to physically disconnect from or cease providing service to the well or lease, or the well or lease operator objects to the proposed physical disconnect or termination of service, and the pipeline operator still desires to physically disconnect from or cease providing service to the well or lease, the pipeline operator shall file an application with the Commission requesting permission to physically disconnect its facilities from or cease providing service to the well or lease. An affected well or lease operator may object to physical disconnection or cessation of service and file a complaint with the Commission under this subsection.

(1) The pipeline operator shall file its application with the Commission at least 30 days prior to the date on which the pipeline operator desires to make the physical disconnection or cease providing service. On the same date as the pipeline operator files its application with the Commission, the pipeline operator shall send a copy of the application to the operator of the well or lease affected by the application by certified mail, return receipt requested. The application shall identify the well operator and pipeline operator, identify each lease or well involved, and provide sufficient information to allow the Commission to make a determination pursuant to subsection (c)(4).

(2) If the operator of the well or lease does not file with the Commission a written objection to the application within 28 days following the filing of the application, the Commission shall administratively approve or deny the application and shall notify the pipeline operator and the well or lease operator of the decision by certified mail, return receipt requested. Following such notification, either party shall have 21 days to file a written request for hearing. If neither party files a timely request for hearing, the administrative approval or denial shall be deemed final.

(3) If either party files a timely request for hearing, the Commission shall refer the application to the Office of General Counsel docket services to be set for hearing within 60 days following the date of referral.

(4) In determining whether or not to approve a request to physically disconnect from or cease providing service to a well or lease, the Commission may consider relevant factors, including but not limited to:

(A) operational integrity of the pipeline facilities;

(B) operational integrity of the equipment on the well or lease;

(C) cost of continued operation of the physical connection or service;

(D) risk to public safety, human health and the environment;

(E) availability of alternative transportation;

(F) protection of correlative rights; and

(G) prevention of waste.

(d) The Commission may shut in and seal any well, and cancel any certificate of compliance if it appears that the operator of a well has violated or is violating, in connection with the operation of the well, any statutes, rules in this title, permits, or orders of the Commission. Upon receipt of information that indicates operations are being conducted in violation of statutes, rules in this title, or a Commission permit or order, the Commission shall send a notice letter to the operator directing the operator to correct the violation. The letter shall state the facts or conduct alleged to warrant the shut-in and sealing of the well, and cancellation of the certificate of compliance. The letter shall give the operator an opportunity to show compliance with the statutes, rules in this title, or Commission permits or orders. The letter shall be sent by registered or certified mail, and shall indicate the time within which compliance shall be demonstrated or achieved. The time period allowed for the operator to achieve compliance shall not be less than 10 days from the date the notice letter is sent.

(e) Within the time period set out in the notice letter, the operator shall either demonstrate compliance or correct the violation, and notify the Commission of its action.

(f) If the violation is not corrected within the time period set out in the notice letter, the Commission may shut in and seal the well, and cancel the certificate of compliance.

(g) If a certificate of compliance has been cancelled, the Commission may not issue a new certificate of compliance until the owner or operator of the property covered by the certificate of compliance submits to the Commission a reissuance fee as required by §3.78 of this title (relating to Fees and Financial Security Requirements) (Statewide Rule 78); and

(1) the property covered by the certificate is brought into compliance with the statutes, rules in this title, and Commission permits and orders; or

(2) the Commission determines that there are just and equitable grounds for reissuing the certificate.

(h) Pursuant to Texas Natural Resources Code, §85.165, upon notice from the Commission to any operator of a pipeline or other carrier connected to any oil, gas, or geothermal resource well that the certificate of compliance applicable to the well has been cancelled by the Commission, the operator of the pipeline or other carrier shall disconnect from or suspend service to the well and shall not transport any oil or gas produced from that well until a new certificate of compliance has been issued by the Commission. Pursuant to Texas Natural Resources Code, §85.3855, failure to comply with this subsection may subject a person to a penalty of up to $10,000 per violation.

(i) Pursuant to Texas Natural Resources Code, §85.166, upon notice from the Commission that a certificate of compliance as to any oil, gas, or geothermal resource well has been cancelled as provided in this section, the operator of such well shall not produce oil, gas, or geothermal resources from that well until a new certificate of compliance with respect to the well has been issued by the Commission as provided in this section. Pursuant to Texas Natural Resources Code, §85.3855, failure to comply with this subsection may subject a person to a penalty of up to $10,000 per violation.

(j) The provisions of this section shall be cumulative of other Commission actions and procedures relating to violations of state statutes or Commission permits, rules, and orders, including the authority of the Commission to immediately shut in a well or lease, or to direct the operator to shut in a well or lease, when an emergency exists due to pollution or an imminent threat of harm to people or property.

Source Note: The provisions of this §3.73 adopted to be effective October 28, 2003, 28 TexReg 9241; amended to be effective September 1, 2004, 29 TexReg 8271

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PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.72	**Obtaining Pipeline Connections**

(a) A common carrier pipeline transporting crude oil in Texas, upon application for connection and offer of crude oil by a producer or persons owning unconnected lease batteries, shall connect such lease batteries in the following instances:

(1) when such request is made for connection of lease batteries in the general area served by a common carrier, which is an affiliate or subsidiary of a common purchaser, as defined in the Texas Natural Resources Code, §111.081; and

(2) within individual fields, when any common carrier possesses the only pipeline serving such field or common reservoir and request is made for connection of an unconnected lease battery in the field, provided, that for just cause a common carrier pipeline may apply for an exception. If proper application has been made for such connection and the common carrier pipeline refuses to connect the unconnected lease battery, a complaint for failure to connect may be filed with the commission by the person seeking the connection. The complaining person may allege discrimination or noncompliance with the provisions of this subsection or the appropriate section(s) of the Texas Natural Resources Code.

(b) Whether the matter comes to the commission either as an application for exception by the pipeline or on a complaint for failure to connect, at least 10 days' notice shall be given to all interested parties, after which the hearing shall be held. At the hearing, the commission may require and consider, among other factors, evidence relating to ability of the pipeline carrier to transport the quality of oil, the market or lack of market for the proffered oil, and the period required to return the capital investment for the connection. It is not its intention to limit, nor does the commission herein limit, the consideration by it of any facts with respect to a claim of violation of, or of any facts that may constitute a cause of action for violation of, any of the provisions of Texas Natural Resources Code, §§11.001-11.136, whether enumerated in this section or not.

Source Note: The provisions of this §3.72 adopted to be effective August 25, 2003, 28 TexReg 6816

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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.71	**Pipeline Tariffs**

Every person owning, operating, or managing any pipeline, or any part of any pipeline, for the gathering, receiving, loading, transporting, storing, or delivering of crude petroleum as a common carrier shall be subject to and governed by the following provisions. Common carriers specified in this section shall be referred to as "pipelines," and the owners or shippers of crude petroleum by pipelines shall be referred to as "shippers."

(1) All marketable oil to be received for transportation. By the term "marketable oil" is meant any crude petroleum adapted for refining or fuel purposes, properly settled and containing not more than 2.0% of basic sediment, water, or other impurities above a point six inches below the pipeline connection with the tank. Pipelines shall receive for transportation all such "marketable oil" tendered; but no pipeline shall be required to receive for shipment from any one person an amount exceeding 3,000 barrels of petroleum in any one day; and, if the oil tendered for transportation differs materially in character from that usually produced in the field and being transported therefrom by the pipeline, then it shall be transported under such terms as the shipper and the owner of the pipeline may agree or the commission may require.

(2) Basic sediment, how determined--temperature. In determining the amount of sediment, water, or other impurities, a pipeline is authorized to make a test of the oil offered for transportation from an average sample from each such tank, by the use of centrifugal machine, or by the use of any other appliance agreed upon by the pipeline and the shipper. The same method of ascertaining the amount of the sediment, water, or other impurities shall be used in the delivery as in the receipt of oil. A pipeline shall not be required to receive for transportation, nor shall consignee be required to accept as a delivery, any oil of a higher temperature than 90 degrees Fahrenheit, except that during the summer oil shall be received at any atmospheric temperature, and may be delivered at like temperature. Consignee shall have the same right to test the oil upon delivery at destination that the pipeline has to test before receiving from the shipper.

(3) "Barrel" defined. For the purpose of these sections, a "barrel" of crude petroleum is declared to be 42 gallons of 231 cubic inches per gallon at 60 degrees Fahrenheit.

(4) Oil involved in litigation, etc.--indemnity against loss. When any oil offered for transportation is involved in litigation, or the ownership is in dispute, or when the oil appears to be encumbered by lien or charge of any kind, the pipeline may require of shippers an indemnity bond to protect it against all loss.

(5) Storage. Each pipeline shall provide, without additional charge, sufficient storage, such as is incident and necessary to the transportation of oil, including storage at destination or so near thereto as to be available for prompt delivery to destination point, for five days from the date of order of delivery at destination.

(6) Identity of oil, maintenance of oil. A pipeline may deliver to consignee either the identical oil received for transportation, subject to such consequences of mixing with other oil as are incident to the usual pipeline transportation, or it may make delivery from its common stock at destination; provided, if this last be done, the delivery shall be of substantially like kind and market value.

(7) Minimum quantity to be received. A pipeline shall not be required to receive less than one tank car-load of oil when oil is offered for loading into tank cars at destination of the pipeline. When oil is offered for transportation for other than tank car delivery, a pipeline shall not be required to receive less than 500 barrels.

(8) Gathering charges. Tariffs to be filed by a pipeline shall specify separately the charges for gathering of the oil, for transportation, and for delivery.

(9) Measuring, testing, and deductions (reference Special Order Number 20-63,098 effective June 18, 1973).

(A) Except as provided in subparagraph (B) of this paragraph, all crude oil tendered to a pipeline shall be gauged and tested by a representative of the pipeline prior to its receipt by the pipeline. The shipper may be present or represented at the gauging or testing. Quantities shall be computed from correctly compiled tank tables showing 100% of the full capacity of the tanks.

(B) As an alternative to the method of measurement provided in subparagraph (A) of this paragraph, crude oil and condensate may be measured and tested, before transfer of custody to the initial transporter, by:

(i) lease automatic custody transfer (LACT) equipment, provided such equipment is installed and operated in accordance with the latest revision of American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 6.1, or;

(ii) any device or method, approved by the commission or its delegate, which yields accurate measurements of crude oil or condensate.

(C) Adjustments to the quantities determined by the methods described in subparagraphs (A) or (B) of this paragraph shall be made for temperature from the nearest whole number degree to the basis of 60 degrees Fahrenheit and to the nearest 5/10 API degree gravity in accordance with the volume correction Tables 5A and 6A contained in API Standard 2540, American Society for Testing Materials 01250, Institute of Petroleum 200, first edition, August 1980. A pipeline may deduct the basic sediment, water, and other impurities as shown by the centrifugal or other test agreed upon by the shipper and pipeline; and 1.0% for evaporation and loss during transportation. The net balance shall be the quantity deliverable by the pipeline. In allowing the deductions, it is not the intention of the commission to affect any tax or royalty obligations imposed by the laws of Texas on any producer or shipper of crude oil.

(D) A transfer of custody of crude between transporters is subject to measurement as agreed upon by the transporters.

(10) Delivery and demurrage. Each pipeline shall transport oil with reasonable diligence, considering the quality of the oil, the distance of transportation, and other material elements, but at any time after receipt of a consignment of oil, upon 24 hours' notice to the consignee, may offer oil for delivery from its common stock at the point of destination, conformable to paragraph (6) of this section, at a rate not exceeding 10,000 barrels per day of 24 hours. Computation of time of storage (as provided for in paragraph (5) of this section) shall begin at the expiration of such notice. At the expiration of the time allowed in paragraph (5) of this section for storage at destination, a pipeline may assess a demurrage charge on oil offered for delivery and remaining undelivered, at a rate for the first 10 days of $.001 per barrel; and thereafter at a rate of $.0075 per barrel, for each day of 24 hours or fractional part thereof.

(11) Unpaid charges, lien for and sale to cover. A pipeline shall have a lien on all oil to cover charges for transportation, including demurrage, and it may withhold delivery of oil until the charges are paid. If the

charges shall remain unpaid for more than five days after notice of readiness to deliver, the pipeline may sell the oil at public auction at the general office of the pipeline on any day not a legal holiday. The date for the sale shall be not less than 48 hours after publication of notice in a daily newspaper of general circulation published in the city where the general office of the pipeline is located. The notice shall give the time and place of the sale, and the quantity of the oil to be sold. From the proceeds of the sale, the pipeline may deduct all charges lawfully accruing, including demurrage, and all expenses of the sale. The net balance shall be paid to the person lawfully entitled thereto.

(12) Notice of claim. Notice of claims for loss, damage, or delay in connection with the shipment of oil must be made in writing to the pipeline within 91 days after the damage, loss, or delay occurred. If the claim is for failure to make delivery, the claim must be made within 91 days after a reasonable time for delivery has elapsed.

(13) Telephone-telegraph line--shipper to use. If a pipeline maintains a private telegraph or telephone line, a shipper may use it without extra charge, for messages incident to shipments. However, a pipeline shall not be held liable for failure to deliver any messages away from its office or for delay in transmission or for interruption of service.

(14) Contracts of transportation. When a consignment of oil is accepted, the pipeline shall give the shipper a run ticket, and shall give the shipper a statement that shows the amount of oil received for transportation, the points of origin and destination, corrections made for temperature, deductions made for impurities, and the rate for such transportation.

(15) Shipper's tanks, etc.--inspection. When a shipment of oil has been offered for transportation the pipeline shall have the right to go upon the premises where the oil is produced or stored, and have access to any and all tanks or storage receptacles for the purpose of making any examination, inspection, or test authorized by this section.

(16) Offers in excess of facilities. If oil is offered to any pipeline for transportation in excess of the amount that can be immediately transported, the transportation furnished by the pipeline shall be apportioned among all shippers in proportion to the amounts offered by each; but no offer for transportation shall be considered beyond the amount which the person requesting the shipment then has ready for shipment by the pipeline. The pipeline shall be considered as a shipper of oil produced or purchased by itself and held for shipment through its line, and its oil shall be entitled to participate in such apportionate.

(17) Interchange of tonnage. Pipelines shall provide the necessary connections and facilities for the exchange of tonnage at every locality reached by two or more pipelines, when the commission finds that a necessity exists for connection, and under such regulations as said commission may determine in each case.

(18) Receipt and delivery--necessary facilities for. Each pipeline shall install and maintain facilities for the receipt and delivery of marketable crude petroleum of shippers at any point on its line if the commission finds that a necessity exists therefor, and under regulations by the commission.

(19) Reports of loss from fires, lightning, and leakage.

(A) Each pipeline shall immediately notify the commission district office, electronically or by telephone, of each fire that occurs at any oil tank owned or controlled by the pipeline, or of any tank struck by lightning. Each pipeline shall in like manner report each break or leak in any of its tanks or pipelines from which more than five barrels escape. Each pipeline shall file the required information with the commission in accordance with the appropriate commission form within 30 days from the date of the spill or leak.

(B) No risk of fire, storm, flood, or act of God, and no risk resulting from riots, insurrection, rebellion, war, or act of the public enemy, or from quarantine or authority of law or any order, requisition or necessity of the government of the United States in time of war, shall be borne by a pipeline, nor shall any liability accrue to it from any damage thereby occasioned. If loss of any crude oil from any such causes occurs after the oil has been received for transportation, and before it has been delivered to the consignee, the shipper shall bear a loss in such proportion as the amount of his shipment is to all of the oil held in transportation by the pipeline at the time of such loss, and the shipper shall be entitled to have delivered only such portion of his shipment as may remain after a deduction of his due proportion of such loss, but in such event the shipper shall be required to pay charges only on the quantity of oil delivered. This section shall not apply if the loss occurs because of negligence of the pipeline.

(C) Common carrier pipelines shall mail (return receipt requested) or hand deliver to landowners (persons who have legal title to the property in question) and residents (persons whose mailing address is the property in question) of land upon which a spill or leak has occurred, all spill or leak reports required by the commission for that particular spill or leak within 30 days of filing the required reports with the commission. Registration with the commission by landowners and residents for the purpose of receiving spill or leak reports shall be required every five years, with renewal registration starting January 1, 1999. If a landowner or resident is not registered with the commission, the common carrier is not required to furnish such reports to the resident or landowner.

(20) Printing and posting. Each pipeline shall have paragraphs (1)-(19) of this section printed on its tariff sheets, and shall post the printed sections in a prominent place in its various offices for the inspection of the shipping public. Each pipeline shall post and publish only such rules and regulations as may be adopted by the commission as general rules or such special rules as may be adopted for any particular field.

(21) Immediately upon the publication of its tariffs, and each subsequent amendment thereof, each pipeline is requested to file one copy with the commission.

(22) Records.

(A) Each person operating crude oil gathering, transportation, or storage facilities in the state must maintain daily records of the quantities of all crude oil moved from each oil field in the state, and such records shall also show separately for each field to whom delivery is made, and the quantities so delivered.

(B) The information contained in the records thus required to be kept must be reported to the commission by the gatherers, transporters, and handlers at such times and in such manner as may be required by the commission.

Source Note: The provisions of this §3.71 adopted to be effective August 25, 2003, 28 TexReg 6816

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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.70	**Pipeline Permits Required**

(a) No pipeline or gathering system, whether a common carrier or not, shall be used to transport oil, gas, or geothermal resources from any tract of land within this state without a permit from the commission. Application for the permit shall be made upon the required form, and the permit will be granted if the commission is satisfied from such application and the evidence in support thereof, and its own investigation, that the proposed line is, or will be, so laid, equipped, and managed, as to reduce to a minimum the possibility of waste, and will be operated in accordance with the conservation laws and conservation rules and regulations of the commission.

(b) The permit, if granted, shall be revocable at any time after hearing held after 10 days' notice, if the commission finds that the line is so unsafe, or so improperly equipped, or so managed, as likely to result in waste. If the commission finds the line is in such condition as to cause waste, five days' written notice shall be given to the operating company to correct the condition before notice of hearing for revocation of the permit is given. A permit may also be revoked after 10 days' notice and hearing, if the commission finds that the operator of the line, in its operation thereof, is willfully violating or contributing to the violation of the laws of Texas regulating the production, transportation, processing, refining, treating, and/or marketing of crude oil or geothermal resources, or any of the laws of the state to conserve the oil, gas, or geothermal resources, or any rule or regulation of the commission enacted under such laws.

Source Note: The provisions of this §3.70 adopted to be effective August 25, 2003, 28 TexReg 6816

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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.63	**Carbon Black Plant Permits Required**

(a) Each operator of a carbon black plant shall make application for a permit to operate the plant, using the appropriate form.

(b) No person shall operate a plant for the burning of natural gas in the manufacture of carbon black without a permit authorizing the operation of the plant.

(c) Each 12 months the commission, on application, may grant a permit to each of the operators of carbon black plants for a period of 12 months.

Source Note: The provisions of this §3.63 adopted to be effective January 1, 1976.

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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.62	**Cycling Plant Control and Reports**

(a) The operator of each cycling plant shall use tanks for measuring the crude oil, condensate, or other liquid hydrocarbons taken into or extracted by the cycling plant.

(b) The operator of each cycling plant shall meter the following separately:

(1) all gas taken into the plant from statutory gas wells;

(2) all casinghead gas taken into the cycling plant;

(3) all gas used for plant fuel;

(4) all gas taken by pipe lines or for domestic or commercial uses;

(5) all gas, including flash vapors, vented directly or indirectly to the air.

(c) Gas used for lifting water by jetting, or used in turbines and subsequently vented to the air or burned in a flare, shall be accurately metered and reported by the operator as vented on the appropriate form.

(d) No cycling plant shall be permitted to vent any gas taken into the plant from statutory gas wells; however, the venting of a volume of flash vapors not to exceed 2.0% of the volume of gas taken into said plant shall be considered to be compliance.

(e) No gas shall be used for plant operation that is not burned in boilers, heaters, or internal combustion engines in a reasonably efficient manner, and no raw gas or residue gas shall be used for plant fuel if any flash vapors are being vented or flared.

(f) No cycling plant shall be operated without a certificate of compliance. The appropriate form submitted to the commission and approved by it shall be in effect for a period of 12 months, but may be renewed for one or more periods of 12 months. The certificate of compliance shall be revoked if an inspection reveals noncompliance.

Source Note: The provisions of this §3.62 adopted to be effective January 1, 1976.

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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.61	**Refinery and Gasoline Plants**

(a) The operator of each refinery in the state shall use tanks for measuring the crude oil and products taken into the refinery and the finished products of the refinery.

(b) No refinery or gasoline plant shall be operated without a certificate of compliance on a form supplied by the commission and approved by it, which shall be in effect for a period of 12 months, but may be renewed for one or more additional 12-month period. The operator must equip the plant with tanks and proper metering facilities.

(c) Measuring facilities for the accurate measurement of the volume of each type of gas taken into a natural gasoline plant shall be installed and used by the operator of the gasoline plant. Meters must be provided and used for measuring separately the dry sweet natural gas, the dry sour natural gas, casinghead gas, and refinery vapors taken into each plant. Accurate meters must be installed and used in each gasoline plant in which is processed dry gas (as distinguished from casinghead gas) so that all disposals of residue gas from such natural gasoline plant are accurately accounted for. Adequate devices should likewise be installed and used in each gasoline plant at which casinghead gas exclusively, or casinghead gas and refinery vapors only are processed, for the purpose of making approximate estimates of the volume of residue gas produced from such plant; such devices may consist either of meters, pilot tubes, pressure recording gauges, or manometers, through which measurements may be made from which reasonably accurate estimates of volume can be made.

(d) Measuring natural gasoline.

(1) Adequate tanks or meters of standard or approved types must be provided for measuring accurately all finished products of natural gasoline plants.

(2) The operator of each natural gasoline plant shall meter separately the volume of dry sweet natural gas, dry sour natural gas, casinghead gas, and refinery vapors that are taken into each natural gasoline plant.

(3) The operator of each natural gasoline plant in which dry natural gas (as distinguished from casinghead gas) is processed shall use metering facilities so that all disposition of residue gas from such natural gasoline plants are accurately accounted for. The operator of each natural gasoline plant in which casinghead gas exclusively, or casinghead gas and refinery vapors only, are processed shall install and use measuring devices, consisting either of meters, pitot tubes, pressure recording gauges, or manometers, with which measurements may be made of the residue gas disposition from the plant.

(4) The operator of each natural gasoline plant shall provide and use tanks or meters of standard or approved type for measuring each finished product of the plant.

Source Note: The provisions of this §3.61 adopted to be effective January 1, 1976.

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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.60	**Refinery Reports**

On or before the 15th day of each calendar month, the operator of each refinery, processing plant, blending plant or treating plant, and/or other plant situated within the state that processes or manufactures a product, except those gas processing plants for which another form is required by §3.54(a) of this title (relating to Gas Reports Required), shall file with the commission a report covering the operations of the refinery or plant during the preceding month. The report must contain the data and information required to be reported on the form.

Source Note: The provisions of this §3.60 adopted to be effective January 1, 1976.

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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.59	**Oil and Gas Transporter's Reports**

(a) General. The commission may, from time to time, require oil and gas pipeline companies to make reports to the commission showing wells connected with their lines during any month, the amount of production taken therefrom, names of parties from whom oil and gas are purchased, and the amount of oil or gas purchased therefrom.

(b) Daily report. The commission may, in case of overproduction or for any other reason which it deems urgent, require oil and gas pipe line companies to furnish daily reports of the amount of oil or gas purchased or taken from different wells or parties.

(c) Weekly stock report. Rescinded by Order Number 20-57,970, effective 11-16-67.

(d) Monthly transportation and storage report.

(1) Each gatherer, transporter, storer, and/or handler of crude oil or products, or both, shall file with the commission on or before the last day of each calendar month a report showing the required information concerning the transportation operations of such gatherer, transporter, or storer for the next preceding month. Such form is incorporated in and made a part of this section.

(2) The original of the report, covering all of the operations of the gatherer, transporter, storer, and/or handler of crude oil or products, or both, shall be filed in the Austin office of the commission. One copy of the report shall be filed in each district office in which the gatherer, transporter, storer, and/or handler of crude oil or products, or both, operates, but may include only the information pertaining to the operations in that district in which it is filed.

(3) The written instructions appearing on said form are incorporated in and made a part of this section, and all of the data and information on the form shall be reported and arranged on the form as required by the form.

(4) No gatherer, transporter, storer, and/or handler of crude oil shall remove crude oil from any property unless such property is identified by a sign posted in compliance with §3.3(3) of this title (relating to Identification of Properties, Wells, and Tanks).

(5) The provisions of this section shall not apply to the operator of any refinery, processing plant, blending plant, or treating plant to which §3.60 of this title (relating to Refinery Reports) applies if the operator has filed the required form.

(e) Annual report.

(1) Each common carrier pipeline shall make and file with the commission, at its Austin office, an annual report for each calendar year. The report must show the names of the officers, directors, and stockholders, and the residence of each; the amount of capital stock and bonded indebtedness outstanding; the results of financial operations; the sources of revenue; and the expenditures, assets and liabilities, and statistical data of oil transported; and such other information as may be deemed pertinent by the commission concerning

the carrier's transactions in the performance of services under its charter provisions relative to the transportation of crude petroleum in the State of Texas.

(2) The annual report must be made to the commission on the form prescribed and furnished by the commission; and must be returned complete, under oath, within 30 days after the receipt of the forms from the commission.

(3) For all purposes applicable under these rules and regulations the "Classification of Investment for Pipe Lines, Pipe Line Operating Revenues, and Pipe Line Operating Expenses" prescribed by the Interstate Commerce Commission and effective on January 1, 1915, is adopted and made a part of these rules for the use of all common carrier pipelines subject to the provisions of that act of the legislature, being Chapter 30 of the Regular Session of the 35th Legislature, State of Texas.

Source Note: The provisions of this §3.59 adopted to be effective January 1, 1976.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.58	**Oil, Gas, or Geothermal Resource Operator's Reports**

(a) Certificate of Compliance and transportation authority.

(1) Each operator who seeks to operate wells related to crude oil, natural gas, or geothermal resources shall file with the commission's Austin office a commission form P-4 (certificate of compliance and transportation authority) for each property on which the wells are located certifying that the operator has complied with the conservation laws and the oil, gas, and geothermal resources conservation orders, rules, and regulations of the commission in respect to the property. The Commission form P-4 establishes the operator of an oil lease, gas well, or other well; certifies responsibility for regulatory compliance, including plugging wells in accordance with §3.14 of this title (relating to plugging); and identifies gatherers, purchasers, and purchasers' commission-assigned system codes authorized for each well or lease. Operators shall file form P-4 for new oil leases, gas wells, or other wells; recompletions; reclassifications of wells from oil to gas or gas to oil; consolidation, unitization or subdivision of oil leases; or change of gatherer, gas purchaser, gas purchaser system code, operator, field name or lease name. When an operator files a form P-4, the oil and gas division shall review the form for completeness and accuracy. Except as otherwise authorized by the Commission, a transporter (whether the operator or someone else) shall not transport the oil, gas, or geothermal resources from such property until the Commission has approved the certificate of compliance and transportation authority. No certificate of compliance designating or changing the designation of an operator will be approved that is signed, either as transferor or transferee, by a non-employee agent of the organization unless the organization has filed with the commission, on its organization report, the name of the non-employee agent it has authorized to sign such certificates of compliance on its behalf.

(2) An approved certificate of compliance and transportation authority shall bind the operator until another operator files a subsequent certificate and the Commission has approved the subsequent certificate and transferred the property on commission records to the subsequent operator.

(3) The appropriate district office or the Austin office may grant temporary authority for an operator to use a transporter not authorized for a particular property in order to take care of production and prevent waste. The operator shall secure such temporary authority in writing from the appropriate district office or the Austin office before the oil or condensate is moved. In an emergency situation the operator may secure such temporary authority verbally but shall notify the district office in writing within 10 days after the oil or condensate is moved. An emergency situation exists when oil or condensate must be moved off a lease because it poses an imminent threat to the public health and safety, or when the threat of waste is imminent. The operator shall also furnish copies of such authorization or notification to the regular transporter and to the temporary transporter.

(4) If an applicant wishes to assume operator status for a property, but is unable to obtain the signature of the previous operator on the certificate of compliance and transportation authority, the applicant shall file with the oil and gas division in Austin a completed form P-4 signed by a designated officer or agent of the applicant, along with an explanatory letter and legal documentation of the applicant's right to operate the property. Prior to approval of such an application, the office of the general counsel will notify the last known operator of record, if such operator's address is available, affording such operator an opportunity to protest.

(b) Monthly producer's report (oil, natural gas and geothermal resources). For each calendar month, each operator who is a producer of crude oil, natural gas or geothermal resources shall file with the commission a report for each of the operator's producing properties. Operators shall file such reports on commission form P-1 (producer's monthly report of oil wells), commission form P-2 (producer's monthly report of gas wells), or commission form GT-2 (producer's monthly report of geothermal wells). These commission forms report monthly production and disposition of oil and casinghead gas (form P-1), gas well gas and condensate (form P-2) and geothermal resources (form GT-2). On or before the last day of the month subsequent to the period of the report, the operator shall file an original and one copy of each such form, the original to be filed in the

Austin office, and one copy with the transporter taking the oil, gas or geothermal resources from the property.

(c) Recovered load oil.

(1) The operator of each lease from which load oil is recovered shall file the original and one copy of commission form P-3 (authority to transport recovered load or frac oil) with the district office, and another copy with the transporter prior to running the load oil. Form P-3 requires a producer to report the quantity of recovered load or frac oil to be transported from a particular lease and to identify the transporter. The form P-3 (authority to transport recovered load or frac oil) filed by the operator shall be the authority for the transporter to run the quantity of recovered load or frac oil stated in the form.

(2) The provisions of this subsection apply only to oil that has been obtained from a source other than the lease on which it is used. "Recovered load oil or frac oil," as that term is used herein, is any oil or liquid hydrocarbons used in any operation in an oil or gas well, and which has been recovered as a merchantable product.

(d) Subdivision and consolidation of oil leases.

(1) An operator seeking to subdivide or consolidate existing oil leases shall file and obtain approval of a commission form P-4 (certificate of compliance and transportation authority) and a commission form P-6 (request for permission to subdivide or consolidate oil lease(s)). Form P-6 identifies the leases to be subdivided or consolidated as well as the resulting leases. Two plats shall be filed with form P-6, one showing the boundaries of the lease(s) before and one showing the boundaries of the lease(s) after the subdivision or consolidation.

(2) An operator seeking to subdivide an existing oil lease that it operates or to assume operatorship of fewer than all of the wells on an oil lease shall file and obtain approval of a commission form P-4 (certificate of compliance and transportation authority) and a commission form P-6 (request for permission to subdivide or consolidate oil lease(s)). A request to subdivide an oil lease may be approved administratively if the commission staff determines that approval of the request will not cause waste, harm correlative rights, or result in the circumvention of commission rules.

(3) An operator seeking to consolidate two or more existing oil leases that it operates shall file and obtain approval of a commission form P-4 (certificate of compliance and transportation authority) and a commission form P-6 (request for permission to subdivide or consolidate oil lease(s)). A request to consolidate two or more oil leases may be approved administratively if the commission staff determines that approval of the request will not cause waste, harm correlative rights, or result in the circumvention of commission rules and:

(A) the mineral and royalty ownership of the leases proposed for consolidation is identical in all respects;

(B) the operator has obtained a surface commingling exception permit pursuant to §3.26 of this title (relating to separating devices, tanks, and surface commingling of oil) that authorizes commingling of production from all of the leases proposed for consolidation ; or

(C) the operator has filed and obtained approval of a valid commission form P-12 (certificate of pooling authority) authorizing pooling of all of the leases proposed for consolidation.

Source Note: The provisions of this §3.58 adopted to be effective January 1, 1976; amended to be effective February 23, 1979, 4 TexReg 436; amended to be effective May 9, 1988, 13 TexReg 2026; amended to be effective May 22, 2000, 25 TexReg 4512; amended to be effective May 12, 2002, 27 TexReg 3756

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PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.57	**Reclaiming Tank Bottoms, Other Hydrocarbon Wastes, and Other Waste Materials**

(a) Applicability. This section is applicable to reclamation of tank bottoms and other hydrocarbon wastes generated through activities associated with the exploration, development, and production (including transportation) of crude oil and other waste materials containing oil, as those activities are defined in §3.8(a)(30) of this title (relating to Water Protection). The provisions of this section shall not apply where tank bottoms or other hydrocarbon-bearing materials are recycled or processed on-site by the owner/custodian and are returned to a tank or vessel at the same lease or facility. This section is not applicable to the practice of recycling or reusing drilling mud, except as to those hydrocarbons recovered from such mud recycling and sent to a permitted reclamation plant.

(b) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Tank bottoms--A mixture of crude oil or lease condensate, water, and other substances that is concentrated at the bottom of producing lease tanks and pipeline storage tanks (commonly referred to as basic sediment and water or BS&W).

(2) Other hydrocarbon wastes--Oily waste materials, other than tank bottoms, which have been generated in connection with activities associated with the exploration, development, and production of oil or gas or geothermal resources, as those activities are defined in §3.8(a)(30) of this title (relating to Water Protection). The term "other hydrocarbon wastes" includes, but is not limited to, pit hydrocarbons, skim oil, spillage, and leakage of crude oil or condensate from producing lease or pipeline storage tanks, and crude oil or condensate associated with pipeline ruptures and other spills.

(3) Authorized person--A tank bottoms cleaner or transporter that is under contract for disposition of untreated tank bottoms or other hydrocarbon wastes to a person who has obtained a permit to operate a reclamation plant.

(4) Affected person--A person who has suffered or will suffer actual injury or economic damage other than as a member of the general public and includes surface owners of property on which a reclamation plant is located and surface owners of adjoining properties.

(5) Director--The director of the Oil and Gas Division or a staff delegate designated in writing by the director of the Oil and Gas Division or the commission.

(c) Permitting process.

(1) Removal of tank bottoms or other hydrocarbon wastes from any producing lease tank, pipeline storage tank, or other production facility, for reclaiming by any person, is prohibited unless such person has either obtained a permit to operate a reclamation plant, or is an authorized person. Applicants for a reclamation plant operating permit shall file the appropriate form with the commission in Austin.

(2) The applicant shall give notice by mailing or delivering a copy of the application to the county clerk of

the county where the reclamation plant is to be located, and to the city clerk or other appropriate city official of any city where the reclamation plant is located within the corporate limits of the city, on or before the date the application is mailed to or filed with the commission.

(3) In order to give notice to other local governments and interested or affected persons, notice of the application shall be published once by the applicant in a newspaper of general circulation for the county where the reclamation plant is to be located, in a form approved by the commission. Publication shall occur on or before the date the application is mailed to or filed with the commission. The applicant shall file with the commission in Austin proof of publication prior to the hearing or administrative approval.

(4) If a protest from an affected person or local government is made to the commission within 15 days of receipt of the application or of publication, or if the commission determines that a hearing is in the public interest, then a hearing will be held on the application after the commission provides notice of hearing to all affected persons, local governments, or other persons who express an interest in writing in the application.

(5) If no protest from an affected person or local government is received by the commission within the allotted time, the director may administratively approve the application. If the director denies administrative approval, the applicant shall have a right to a hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(6) Applicants must demonstrate they are familiar with commission rules and have the proper facilities to comply with the rules.

(7) Except as provided in subparagraphs (A) and (B) of this paragraph, a permit to operate a reclamation plant shall remain in effect until canceled at the request of the operator. Existing permits subject to annual renewal may be renewed so as to remain in effect until canceled. Such renewal shall be subject to the requirements of paragraph (10) of this subsection. A reclamation plant permit may be canceled by the commission after notice and opportunity for hearing, if:

(A) the permitted facility has been inactive for 12 months; or

(B) there has been a violation, or a violation is threatened, of any provision of the permit, the conservation laws of the state, or rules or orders of the commission.

(8) If the operator objects to the cancellation, the operator must file, within 15 days of the date shown on the notice, a written objection and request for a hearing to determine whether the permit should be canceled. If such written request is timely filed, the cancellation will be suspended until a final order is issued pursuant to the hearing. If such request is not received within the required time period, the permit will be canceled. In the event of an emergency which presents an imminent pollution, waste, or public safety threat, the commission may suspend the permit until an order is issued pursuant to the hearing.

(9) A permit to operate a reclamation plant is not transferable. A new permit must be obtained by the new operator.

(10) Reclamation plants permitted under this section shall file financial security as required under §3.78(l) of this title (relating to Fees and Financial Security Requirements).

(d) Operation of a reclamation plant.

(1) The following provisions apply to any removal of tank bottoms or other hydrocarbon wastes from any oil producing lease tank, pipeline storage tank, or other production facility.

(A) Notwithstanding the provisions of §3.85(a)(8) of this title (relating to Manifest To Accompany Each Transport of Liquid Hydrocarbons by Vehicle), an operator of a reclamation plant or an authorized person shall execute a manifest in accordance with §3.85 of this title (relating to Manifest To Accompany Each Transport of Liquid Hydrocarbons by Vehicle), upon each removal of tank bottoms or other hydrocarbon wastes from any oil producing lease tank, pipeline storage tank, or other production facility. In addition to the information required pursuant to §3.85 of this title (relating to Manifest To Accompany Each Transport of Liquid Hydrocarbons by Vehicle), the operator of the reclamation plant or other authorized person shall also include on the manifest:

(i) the commission identification number of the lease or facility from which the material is removed; and

(ii) the gross and net volume of the material as determined by the required shakeout test.

(B) The operator of the reclamation plant or other authorized person shall fill out the manifest before leaving the lease or facility from which the liquid hydrocarbons are removed, and shall retain a copy on file for two years.

(C) The operator of the reclamation plant or other authorized person shall leave a copy of the manifest in the vehicle transporting the material.

(2) The operator of a reclamation plant or other authorized person shall conduct a shakeout (centrifuge) test on all tank bottoms or other hydrocarbon wastes upon removal from any producing lease tank, pipeline storage tank, or other production facility, to determine the crude oil content and lease condensate thereof.

(3) The shakeout test shall be conducted in accordance with the most current American Petroleum Institute or American Society for Testing Materials method.

(e) Reporting of reclaimed crude oil or lease condensate on commission required report.

(1) For wastes taken to a reclamation plant the following provisions shall apply.

(A) The net crude oil content or lease condensate from a producing lease's tank bottom as indicated by the shakeout test shall be used to calculate the amount of oil to be reported as a disposition on the monthly production report. The net amount of crude oil or lease condensate from tank bottoms taken from a pipeline facility shall be reported as a delivery on the monthly transporter report.

(B) For other hydrocarbon wastes, the net crude oil content or lease condensate of the wastes removed from a tank, treater, firewall, pit, or other container at an active facility, including a pipeline facility, shall also be reported as a disposition or delivery from the facility.

(2) The net crude oil content or lease condensate of any tank bottoms or other hydrocarbon wastes removed from an active facility, including a pipeline facility, and disposed of on-site or delivered to a site other than a reclamation plant shall also be reported as a delivery or disposition from the facility. All such disposal shall be in accordance with §§3.8, 3.9, and 3.46 of this title (relating to Water Protection; Disposal Wells; and Fluid Injection into Productive Reservoirs). Operators may be required to obtain a minor permit for such disposal using procedures set out in §3.8(d) and (g) of this title (relating to Water Protection). Prior to approval of the minor permit, the commission may require an analysis of the disposable material to be performed.

(f) General provisions applicable to materials taken to a reclamation plant.

(1) The removal of tank bottoms or other hydrocarbon wastes from any facility for which monthly reports

are not filed with the commission must be authorized in writing by the commission prior to such removal. A written request for such authorization must be sent to the commission office in Austin, and must detail the location, description, estimated volume, and specific origin of the material to be removed, as well as the name of the reclaimer and intended destination of the material. If the authorization is denied, the applicant may request a hearing.

(2) The receipt of any tank bottoms or other hydrocarbon wastes from outside the State of Texas must be authorized in writing by the commission prior to such receipt. However, written approval is not required if another entity will indicate, in the appropriate monthly report, a corresponding delivery of the same material. If the request is denied, the applicant may request a hearing.

(3) The receipt of any waste materials other than tank bottoms or other hydrocarbon wastes must be authorized in writing by the commission prior to such receipt. The commission may require the reclamation plant operator to submit an analysis of such waste materials prior to a determination of whether to authorize such receipt. If the request is denied, the applicant may request a hearing.

(4) The operator of a reclamation plant shall file a report on the appropriate commission form for each reclamation plant facility by the 15th day of each calendar month, covering the facility's activities for the previous month. The operator of a reclamation plant shall file a copy of the monthly report in the district office of any district in which the operator made receipts or deliveries for the month covered by the report.

(5) All wastes generated by reclaiming operations shall be disposed of in accordance with §§3.8, 3.9, and 3.46 of this title (relating to Water Protection; Disposal Wells; and Fluid Injection into Productive Reservoirs). No person conducting activities subject to regulation by the commission may cause or allow pollution of surface or subsurface water in the state.

(g) Commission review of administrative actions. Administrative actions performed by the director or commission staff pursuant to this rule are subject to review by the commissioners.

(h) Policy. The provisions of this rule shall be administered so as to prevent waste and protect correlative rights.

Source Note: The provisions of this §3.57 adopted to be effective April 11, 1990, 15 TexReg 1693; amended to be effective June 1, 1998, 23 TexReg 5656; amended to be effective July 10, 2000, 25 TexReg 6487; amended to be effective September 1, 2004, 29 TexReg 8271

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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.56	**Scrubber Oil and Skim Hydrocarbons**

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings unless the context clearly indicates otherwise:

(1) Identifiable liquid hydrocarbons--Volume of scrubber oil/skim hydrocarbons that is received at a gas plant/produced water disposal facility where the origin of such liquid hydrocarbons can be clearly identified.

(2) Producing property--A location from which hydrocarbons are being produced that has been assigned a lease identification number by the Commission and which is used in reporting production.

(3) Scrubber oil--Liquid hydrocarbons which accumulate in lines that are transporting casinghead gas and which are captured at the inlet to a gas processing plant.

(4) Skim hydrocarbons--Oil and condensate which accumulate during produced water disposal operations.

(5) Tolerance--The amount of skim hydrocarbons that may be recovered before the produced water disposal system operator must allocate to the producing property.

(6) Unidentifiable liquid hydrocarbons--Scrubber oil/skim hydrocarbons received at a gas plant/produced water disposal facility where the origin of such liquid hydrocarbons cannot be identified.

(b) Disposition of scrubber oil, skim hydrocarbons, and identifiable liquid hydrocarbon volumes.

(1) Scrubber oil. Any scrubber oil that has not been returned to a producing property by the end of a monthly report period shall be reported by the operator of the gas plant on the monthly plant report, Form R-3 (Monthly Report for Gas Processing Plants). The unidentifiable liquid hydrocarbons recovered and reported on Form R-3 may be disposed of at the point of accumulation. The accepted Form R-3 shall be the authority for the movement of the hydrocarbons to beneficial disposition.

(2) Skim hydrocarbons.

(A) All unidentifiable liquid hydrocarbons recovered by a single operator or multiple operator produced water disposal system shall be reported on the Form P-18 (Skim Oil/Condensate Report) for each reporting period.

(B) The unidentifiable liquid hydrocarbons recovered and reported on Form P-18 may be disposed of at the point of accumulation. The accepted Form P-18 shall be the authority for the movement of the hydrocarbons to beneficial disposition.

(C) Unidentifiable liquid hydrocarbons recovered by a single operator produced water disposal system shall be allocated to each producing property in the proportion that the volume of water received from the producing property bears to the total volume of water received by the system during a reporting period.

(D) Unidentifiable liquid hydrocarbons recovered by a multiple operator produced water disposal system in excess of a tolerance ratio of one barrel of liquid hydrocarbons for each 2,000 barrels of produced water received shall be allocated to each producing property in the proportion that the volume of water received from the producing property bears to the total volume of water received by the system during a reporting period. The produced water disposal system operator shall notify the operator of each producing property of any allocations to that property by furnishing a copy of the allocations as shown on Form P-18 (Skim Oil/Condensate Report).

(E) The operator of each producing property shall report the volume of liquid hydrocarbons allocated to the producing property as production from the property on either Form P-1 (Producer's Monthly Report of Oil Wells) or Form P-2 (Producer's Monthly Report of Gas Wells). The volume allocated back shall be shown as skim oil or skim condensate on the appropriate form.

(3) Identifiable liquid hydrocarbon volumes.

(A) Identifiable liquid hydrocarbon volumes returned to the producing property during the reporting period in which the volume is received at the gas plant/produced water disposal facility shall not be reported to the Commission by the gas plant/facility operator. The gas plant/produced water disposal facility operator shall notify the appropriate Commission district office by telephone prior to the return of such volumes. The movement of these volumes back to the producing property shall comply with §3.85 of this title (relating to Manifest to Accompany Each Transport of Liquid Hydrocarbons by Vehicle), commonly referred to as Statewide Rule 85.

(B) Identifiable volumes not returned to the producing property shall be reported to the Commission and to the operator of the producing property on Form R-3 or Form P-18 as prescribed in paragraph (1) or (2) of this subsection. Volumes shall be specifically credited to the appropriate producing property. The operator of the producing property shall report the disposition of such identifiable volumes as either skim hydrocarbons or scrubber oil on the appropriate production report.

Source Note: The provisions of this §3.56 adopted to be effective January 10, 2000, 25 TexReg 80; amended to be effective November 24, 2004, 29 TexReg 10728

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RULE §3.55	**Reports on Gas Wells Commingling Liquid Hydrocarbons before Metering**

(a) When the full well stream from a gas well is moved to a plant or central separation facilities, and the liquid hydrocarbons produced by two or more wells are commingled without being measured or metered from each gas well, the operator of each well so producing shall periodically file with the commission, as provided for in this section, a report showing the following information for each well:

(1) the specific gravity of the gas at 60 degrees Fahrenheit, after the removal of the liquid hydrocarbons;

(2) the API gravity corrected to 60 degrees Fahrenheit of the liquid hydrocarbons removed;

(3) the number of stock tank barrels of liquid hydrocarbons (corrected to 60 degrees Fahrenheit) recovered per 1,000 standard cubic feet of gas.

(b) Tests.

(1) The tests necessary for this report shall be made by one or more of the following methods:

(A) conventional mechanical separation;

(B) low temperature separation;

(C) split stream method;

(D) in accordance with AGA-NGAA Testing Code 101-43.

(2) The tests shall be made semiannually, or quarterly if contracts for royalty payments require quarterly tests. Semiannual tests must be made during the first and third or second and fourth quarters of the year. If a contract for royalty payments requires quarterly tests, the tests shall be made during each quarter. Both semiannual and quarterly tests may be made during any month of the quarter if the same (first, second, or third) month of each quarter is used thereafter for any well.

(c) The results of each test shall be submitted in duplicate on the appropriate commission form to the proper commission district office not later than the 15th day of each month following the month in which the test is made. The tests shall be required when the conditions set out in the first paragraph of this section exist, regardless of whether or not the conditions are an exception to §3.26 of this title (relating to Separating Devices, Tanks, and Surface Commingling of Oil) (Statewide Rule 26). The tests shall not be required, however, in any reservoir in which 100% of the operating and royalty ownership has been unitized.

(d) This section does not purport to alter any procedure for periodic tests of gas wells that has previously been approved by the commission. If test periods agreed upon by the interested parties have not been approved by the commission, and if the periods agreed upon differ from the test periods provided for in this section, alternative testing periods may be approved by the commission upon application.

Source Note: The provisions of this §3.55 adopted to be effective January 1, 1976; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective November 24, 2004, 29 TexReg 10728

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RULE §3.54	**Gas Reports Required**

(a) Gas processing plant report. As soon after the first day of each calendar month as practicable, and never later than the 25th day of each calendar month, the operator of each plant manufacturing or extracting liquid hydrocarbons, including gasoline, butane, propane, condensate, kerosene, or other derivatives from natural gas, or refinery or storage vapors, shall file, in duplicate, in the Austin office, a report concerning the operation of the plant during the immediately preceding month, which must contain the data and information required on the form.

(b) Pressure maintenance and repressuring plant report.

(1) As soon after the first day of each month as practicable, but never later than the 15th day of each calendar month, the operator of each plant that returns natural gas to oil or gas producing reservoirs, or both, for the purpose of maintaining pressure or repressuring an oil or gas reservoir, but is not reporting such gas on any other commission approved form, shall file in duplicate in the district office a report concerning the operation of the plant during the immediately preceding month, which must contain the data and information required on the form.

(2) Pressure maintenance.

(A) The operator of each pressure-maintenance or repressuring plant shall file the report although no liquid hydrocarbons are recovered.

(B) The term "pressure-maintenance plant" or "repressuring plant" as used herein means any equipment or device, mechanical or otherwise, used for the purpose of returning any natural gas, residue gas from a gas processing plant, including plant and storage vapors, to an underground oil reservoir if the plant is operated as a separate unit. If pressure maintenance or repressuring operations are conducted as an integral part of a gas processing plant extracting, manufacturing, or recovering liquid hydrocarbons from natural gas or vapors, or both, the operations shall be reported by the operator of the processing plant.

(c) Producer's report of condensate and/or crude oil produced from gas wells. As soon as practicable after the first day, and never later than the last day of the calendar month, subsequent to the period of the report, the operator of each gas well from which liquids are recovered on the lease shall file the required form.

(d) Carbon black plant report. As soon as practicable after the first day and never later than the 15th day of each calendar month, each operator of a carbon black plant shall file a report. The report shall cover the operation of the plant for the immediately preceding month and shall be filed in duplicate in the district office.

(e) Monthly gas production report. As soon after the first day of each month as practicable, and never later than the last day of the calendar month, subsequent to the period of the report, every operator producing natural gas from wells classified as either gas wells or oil wells by the commission, except those expressly exempted by the commission shall file a report on the required form.

Source Note: The provisions of this §3.54 adopted to be effective January 1, 1976; amended to be effective February 23, 1979, 4 TexReg 436; amended to be effective May 7, 1991, 16 TexReg 2297.

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TITLE 16	ECONOMIC REGULATION
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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.53	**Annual Well Tests and Well Status Reports Required**

(a) Oil wells.

(1) Unless otherwise provided for in this section, each operator of producing oil wells shall annually test each producing oil well for a 24-hour period during the test period specified on the well status report form and shall record all oil, gas and water volumes resulting from the test on the form.

(2) For any oil well capable of producing no more than five barrels of oil per 24-hour period, the operator of such well may report the required oil, gas and water volumes based on an allocation of that well's production on a prorated daily basis, rather than an actual well test. This option of using production allocation instead of actual well tests does not apply to surface-commingled wells, swabbed wells, the East Texas Field or the following Panhandle fields: Panhandle Carson County Field (Field Number 68845-001); Panhandle Collingsworth County Field (Field Number 68859-001); Panhandle Gray County Field (Field Number 68873-001); Panhandle Hutchison County Field (Field Number 68887-001); Panhandle Moore County field (Field Number 68901-001); Panhandle Potter County Field (Field Number 68915-001); and Panhandle Wheeler County Field (Field Number 68929-001).

(3) Each operator of a well or wells listed in the oil proration schedule shall file with the commission an oil well status report form in accordance with instructions on the form. All wells on a lease, and injection and disposal wells, must be reported.

(4) Changes in oil well status filed between regularly scheduled oil well status surveys shall be submitted on oil well status report forms in accordance with instructions thereon.

(b) Gas wells. Each operator of a gas well producing liquid hydrocarbons shall file with the commission gas well status reports in accordance with instructions thereon.

Source Note: The provisions of this §3.53 adopted to be effective January 1, 1976; amended to be effective November 21, 1980, 5 TexReg 4419; amended to be effective February 13, 1997, 22 TexReg 1313; amended to be effective January 10, 2000, 25 TexReg 79

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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.52	**Oil Well Allowable Production**

(a) The daily allowable production of any lease or property shall not include production based upon the daily potential production of the field or area in which such well is located unless such well is actually on production, and such lease or property shall share in the total allowable production of the field or area, only to the extent of such well's actual ability to produce from day to day regardless of the rated potential production thereof according to the commission schedules.

(b) Production of a well in any one day shall not exceed 110% of the top well allowable as fixed by applicable rules and orders. Production and runs from a lease during the monthly allowable period shall not exceed 105% of the monthly allowable for the well or wells on the lease. However, the volume of oil that is produced and removed from the producing property as tolerance production shall be treated as overproduction and overruns shall be made up during the next succeeding month.

(c) All oil allowable volumes shall be measured in a manner consistent with §3.71 of this title (relating to Pipeline Tariffs) (Statewide Rule 71).

(d) A newly completed well coming into production during a proration period will be gauged either by a commission agent, or pipeline gauger if a commission agent is not available, if an offset lease owner witnesses the gauge taken by the pipeline gauger. The allowable production of such newly completed well shall be in addition to the existing total allowable production of the field as previously ascertained. The well whose allowable is thus fixed shall take its ratable share of production at the next succeeding schedule date according to rule.

(e) All oil produced from any well governed by any proration order of the commission shall be charged against the allowable daily production of such well regardless of the disposition which is made of the oil so produced.

(f) The operator of any lease or unitized area in the State of Texas may be permitted to produce the total allowable for any such lease or unitized area subject to the following provisions:

(1) The operator must submit an application to produce that total allowable on a lease or unit production basis to the commission with a plat showing the subject lease or unit as well as the adjacent properties thereto. Such plat shall identify properly all properties and wells. The applicant shall give written notice to all operators in the field when application is made for permission to produce on a lease basis in a field. If no protest is received by the commission within 15 days of the date of mailing, the application may be granted by administrative action. If protest is received, notice will be given and the matter set for hearing.

(2) The total daily allowable of the lease or unit shall be initially established as an allowable equal to the sum of the current allowables for all wells on the lease or unit. The allowable credited to any new or existing well may be increased to the top well allowable permitted by subsequently filing a new potential test on that well. The maximum total daily allowable of the lease or unit will be equal to the sum of the scheduled top allowables assignable to each well for its proration unit.

(3) The total daily allowable of the lease or unit may be produced in any quantity from any well or

combination of wells with the exception that wells nearer than a regular location from a lease or unit line shall not be permitted to produce more than their normal allowables and wells at a distance of a regular location from a lease or unit line shall not be produced at a rate of more that two times the top allowable for such well unless waivers of objection to rates in excess of this limit have been obtained from the operators of wells offsetting the well.

(4) Annual well test or allocation:

(A) An annual well test, or an allocation pursuant to §3.53(a)(2) of this title (relating to Annual Well Tests and Well Status Reports Required) shall be made and reported on the oil well status report form on each lease or unit property to which a lease production basis has been granted showing an individual well test or allocation on each oil well on the property made during the prescribed test period determined by the commission. Annual well tests may be witnessed by offset operators. An offset operator that desires to witness an annual well test shall give the testing operator written notice of its desire to witness the next scheduled annual well test of a specific well. A testing operator that has received prior written notice that an offset operator desires to witness an annual well test shall give that offset operator at least 24 hours advance notice of the date of the next annual well test for that well. The Commission will use the test or allocation data in the preparation of the oil proration schedule. The total schedule daily lease allowable shall be the sum of the individual well allowables as determined under applicable rules and the lease production basis shall be designated on the oil proration schedule by an appropriate symbol. All wells on the lease for which an allowable is requested shall have their production volumes reported pursuant to §3.53(a).

(B) Any producing well with a gas-oil ratio in excess of that permitted by the applicable rules shall have its daily allowable calculated by dividing the producing gas-oil ratio into the daily gas limit of the well.

(5) The Commission shall continue to require special tests in cases of commingled production where individual lease apportionment is determined by this method. Other special tests may be required as the Commission deems necessary.

(6) In the event that the monthly gas production of the lease or unit exceeds the permissible monthly lease gas limit, the volume of gas in excess of the lease gas limit shall be considered overproduction and must be made up by underproduction of the lease gas limit. Whenever the overproduced amount equals the next month's lease gas limit the overproduced amount shall immediately be reduced to zero by shutting in the lease or by other means acceptable to the Commission.

(7) The East Texas Field is excluded from the provisions of this section.

Source Note: The provisions of this §3.52 adopted to be effective January 1, 1976; amended to be effective May 1, 1991, 16 TexReg 2095; amended to be effective February 18, 1994, 19 TexReg 783; amended to be effective February 13, 1997, 22 TexReg 1313; amended to be effective January 10, 2000, 25 TexReg 79; amended to be effective November 24, 2004, 29 TexReg 10728

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.51	**Oil Potential Test Forms Required**

(a) A potential test form with all information requested thereon filled in shall be filed in the district office not later than 10 days after the test is completed. If the operator fails to file a potential test in an acceptable form within the 10-day period, then the effective date of the allowable resulting from the test shall not extend back more than 10 days prior to the date that the test form, properly completed, is filed in the district office. The 10-day provision shall govern regardless of whether the potential test is taken during the month in which it is received in the district office or any prior month.

(b) The initial potential test form for any new completion or recompletion must be accompanied by the well record.

Source Note: The provisions of this §3.51 adopted to be effective January 1, 1976.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.50	**Enhanced Oil Recovery Projects--Approval and Certification for Tax Incentive**

(a) Purpose. The purpose of this section is to provide a procedure by which an operator can obtain Railroad Commission approval and certification of enhanced oil recovery (EOR) projects pursuant to the Tax Code, Title 2, Chapter 202, Subchapter B, §202.052 and §202.054.

(b) Applicability.

(1) This section applies to:

(A) new EOR projects and the change from secondary EOR projects to tertiary projects which qualify as new EOR projects, and which begin active operation on or after September 1, 1989; and

(B) expansions of existing EOR projects.

(2) An EOR project may not qualify as an expansion if the project has qualified as a new EOR project under this section.

(c) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Active operation--The start and continuation of a fluid injection program for a secondary or tertiary recovery project to enhance the displacement process in the reservoir. Applying for permits and moving equipment into the field alone are not considered active operations.

(2) Commission--The Railroad Commission of Texas.

(3) Commission representative--A commission employee authorized to act for the commission. Any authority given to a commission representative is also retained by the commission. Any action taken by the commission representative is subject to review by the commission.

(4) Comptroller--The Comptroller of Public Accounts.

(5) Enhanced oil recovery project (EOR)--The use of any process for the displacement of oil from the reservoir other than primary recovery and includes the use of an immiscible, miscible, chemical, thermal, or biological process. This term does not include pressure maintenance or water disposal projects.

(6) Existing enhanced recovery project--An EOR project that has begun active operation but was not approved by the Commission as a new EOR project.

(7) Expanded enhanced recovery project or expansion--The addition of injection and producing wells, the change of injection pattern, or other commission approved operating changes to an existing enhanced oil recovery project that will result in the recovery of oil that would not otherwise be recovered.

(8) Fluid injection--Injection through an injection well of a fluid (liquid or gaseous) into a producing

formation as part of an EOR project.

(9) Incremental production--The volume of oil produced by an expanded enhanced recovery project in excess of the production decline rate established under conditions before expansion of an existing enhanced recovery project.

(10) Oil recovery from an enhanced recovery project--The oil produced from the designated area the commission certifies to be affected by the project.

(11) Operator--The person recognized by the commission as being responsible for the actual physical operation of an EOR project and the wells associated with the EOR project.

(12) Positive production response--Occurs when the rate of oil production from wells within the designated area affected by an EOR project is greater than the rate that would have occurred without the project.

(13) Pressure maintenance--The injection of fluid into the reservoir for the purpose of maintaining the reservoir pressure at or near the bubble point or other critical pressure wherein fluid injection volumes are not sufficient to refill existing reservoir voidage in the approved project area and displace oil that would not be displaced by primary recovery operations.

(14) Primary recovery--The displacement of oil from the reservoir into the wellbore(s) by means of the natural pressure of the oil reservoir, including artificial lift.

(15) Production decline rate--The projected future oil production from a project area as extrapolated by a method approved by the commission.

(16) Recovered oil tax rate--The tax rate provided by the Tax Code, §202.052(b).

(17) Secondary recovery project--An enhanced recovery project that is not a tertiary recovery project.

(18) Termination--Occurs when the approved fluid injection program associated with an EOR project stops or is discontinued.

(19) Tertiary recovery project--An EOR project using a tertiary recovery method (as defined in the federal June 1979 energy regulations referred to in the Internal Revenue Code of 1986, §4993, or approved by the United States secretary of the treasury for purposes of administering the Internal Revenue Code of 1986, §4993, without regard to whether that section remains in effect) including those listed as follows:

(A) Alkaline (or caustic) flooding--An augmented waterflooding technique in which the water is made chemically basic as a result of the addition of alkali metals.

(B) Carbon dioxide augmented waterflooding--Injection of carbonated water, or water and carbon dioxide, to increase waterflood efficiency.

(C) Cyclic steam injection--The alternating injection of steam and production of oil with condensed steam from the same well or wells.

(D) Immiscible carbon dioxide displacement--Injection of carbon dioxide into an oil reservoir to effect oil displacement under conditions in which miscibility with reservoir oil is not obtained.

(E) In situ combustion--Combustion of oil in the reservoir, sustained by continuous air injection, to displace unburned oil toward producing wells.

(F) Microemulsion, or micellar/emulsion, flooding--An augmented waterflooding technique in which a surfactant system is injected in order to enhance oil displacement toward producing wells. A surfactant system normally includes a surfactant, hydrocarbon, cosurfactant, an electrolyte and water, and polymers for mobility control.

(G) Miscible fluid displacement--An oil displacement process in which gas or alcohol is injected into an oil reservoir, at pressure levels such that the injected gas or alcohol and reservoir oil are miscible. The process may include the concurrent, alternating, or subsequent injection of water. The injected gas may be natural gas, enriched natural gas, a liquefied petroleum gas slug driven by natural gas, carbon dioxide, nitrogen, or flue gas. Gas cycling, i.e., gas injection into gas condensate reservoirs, is not a miscible fluid displacement technique nor a tertiary enhanced recovery technique within the meaning of this section.

(H) Polymer augmented waterflooding--Augmented waterflooding in which organic polymers are injected with the water to improve a real and vertical sweep efficiency.

(I) Steam drive injection--The continuous injection of steam into one set of wells (injection wells) or other injection source to effect oil displacement toward and production from a second set of wells (production wells).

(20) Water disposal project--The injection of produced water into the reservoir for the purpose of disposing of the produced water wherein the water injection volumes are not sufficient to refill existing reservoir voidage in the approved project area and displace oil that would not be displaced by primary recovery operations.

(d) Application requirements. To qualify for the recovered oil tax rate the operator shall:

(1) submit an application for approval on the appropriate form. All applications must be filed at the Commission's Austin office. The form shall be executed and certified by a person having knowledge of the facts entered on the form. If an application is already on file under the Natural Resources Code, Chapter 101, Subchapter B, or for approval as a tertiary recovery project for purposes of the Internal Revenue Code of 1986, §4993, the operator may file a new EOR project and area designation application if the active operation of the project does not begin before the application under this section is approved by the Commission;

(2) submit all necessary forms to the Oil and Gas Division and provide the Commission with any relevant information required to administer this section such as: area plats showing the proposed project area and all injection and producing wells within the area, production and injection history, planned enhanced oil recovery procedures, and any other pertinent data;

(3) obtain a unitization agreement if required for purposes of carrying out the project under the Natural Resources Code, Chapter 101, Subchapter B. The Commission may not approve the project unless the unitization is approved; and

(4) submit an application on the appropriate form and obtain the necessary permits to conduct fluid injection operations pursuant to §3.46 of this title (relating to Fluid Injection into Productive Reservoirs) (Statewide Rule 46), if such permits have not already been obtained.

(e) Concurrent applications. The operator may file concurrently:

(1) an application for approval of a new or expanded EOR project under this section, together with;

(2) an application for approval of a unitization agreement for purposes of carrying out the enhanced oil

recovery project under the Natural Resources Code, §§101.001 et seq.; or

(3) an application for approval for certification of the project as a tertiary recovery project.

(f) Opportunity for hearing. A commission representative may administratively approve the application. If the commission representative denies administrative approval, the applicant shall have the right to a hearing upon request. After hearing, the examiner shall recommend final action by the commission.

(g) Approval and certification.

(1) Project approval. In order to be eligible for the recovered oil tax rate as provided in the Tax Code, §202.052(b), the operator shall apply for and be granted Commission approval of a new EOR project or an expansion of an existing EOR project, prior to commencing active operation of the new project or expanded project. For a project to be approved the operator shall:

(A) prove that it qualifies as an EOR project;

(B) designate the area to be affected by the project and obtain Commission approval of the designation; and

(C) if production from the wells within the project area is reported with production from wells not in the project area, designate the method to account for and report production from the project area.

(2) Positive production response certificate.

(A) The operator of an EOR project that meets the requirements of this section shall demonstrate to the Commission a positive oil production response before the operator can receive Commission certification of such a positive production response. The certification date may be any date desired by the operator, subject to Commission approval, following the date on which a positive oil production response first occurred. The operator shall apply for a positive production response certificate within three years of project approval for secondary projects, and within five years of project approval for tertiary projects, to qualify for the recovered oil tax rate. The oil produced from the designated area of a new EOR project or incremental oil produced from the designated area of an expanded EOR project after the date of certification of a positive production response is eligible for the recovered oil tax rate. The operator shall apply to the comptroller pursuant to the Tax Code, §202.052 and §202.054, to qualify for the recovered oil tax rate.

(B) The application for positive response certification shall include:

(i) production and injection graphs with supporting tabular data illustrating a positive production response and volumes of water or other substances that have been injected on the designated area since the initiation of the new or the expanded EOR project;

(ii) a plat of the affected area showing all injection and producing wells, with completion dates; and

(iii) any other data requested by the Oil and Gas Division.

(C) The application for the positive production response certificate shall be processed administratively. If the Commission representative denies administrative approval, the applicant shall have the right to a hearing upon request. After hearing, the examiner shall recommend final action by the Commission.

(h) Annual reporting.

(1) The operator shall file an annual report on the appropriate form with the Oil and Gas Division each year

the project remains eligible for the reduced severance tax rate. This form shall be filed within 30 days of the first anniversary of the date that the Commission acted on the EOR positive production response certification application and annually thereafter.

(2) The report shall contain the following:

(A) Commission certification date of positive production response;

(B) monthly volume of injected fluid(s);

(C) number of well(s) used for injection;

(D) monthly production of oil, gas, and water;

(E) number of active producing wells; and

(F) any other relevant information requested by the Oil and Gas Division.

(i) Reduced or enlarged areas. The operator may apply for reduced or enlarged project area certification if the application for reduction or enlargement is received prior to the filing of an application for positive production response certification of the original enhanced oil recovery project.

(j) Termination and penalty. Upon approval by the Commission and the comptroller, the recovered oil tax rate shall continue for a maximum of 10 years, unless the project is sooner terminated. If the project is terminated prior to the 10-year period, the operator shall notify the Commission and the comptroller in writing within 30 days after the last day of active operations. Failure to so notify may result in civil penalties, interest, and the tax due. If the Commission determines a project has been terminated or there is action that affects the tax rate, it shall notify the comptroller immediately in writing.

Source Note: The provisions of this §3.50 adopted to be effective February 20, 1990, 15 TexReg 652; amended to be effective March 18, 1992, 17 TexReg 1615; amended to be effective November 17, 1993, 18 TexReg 7922; amended to be effective April 6, 1998, 23 TexReg 3435; amended to be effective October 12, 2003, 28 TexReg 8585

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.49	**Gas-Oil Ratio**

(a) Any oil well producing with a gas-oil ratio in excess of 2,000 cubic feet of gas per barrel of oil produced shall be allowed to produce daily only that volume of gas obtained by multiplying its maximum daily oil allowable, as determined by the allocation formula applicable to the well, by 2,000. The gas volume thus obtained shall be known as the daily gas limit of the well. The daily oil allowable of the well shall then be determined by dividing its daily gas limit, obtained as provided in this section, by its producing gas-oil ratio in cubic feet per barrel of oil produced.

(b) Any gas well producing from the same reservoir in which oil wells are completed and producing shall be allowed to produce daily only that amount of gas which is the volumetric equivalent in reservoir displacement of the gas and oil produced from the oil well in the reservoir that withdraws the maximum amount of gas in the production of its daily oil allowable.

(1) The following formula shall be used in the determination of the allowable of a gas well producing with a gas-oil ratio of 100,000 or more.

Attached Graphic

(2) The following formula shall be used in the determination of the allowable of a gas well producing with a gas-oil ratio of less than 100,000 under the provisions of the rule stated.

Attached Graphic

(3) The allowable for an associated gas well as determined by this subsection shall be limited to the lesser of:

(A) the gas well allowable as calculated by paragraph (1) or (2) of this subsection;

(B) the well's capability as determined by §3.31(e) of this title (relating to Gas Reservoirs and Gas Well Allowable) (Statewide Rule 31); or

(C) the highest monthly production during those months averaged to a daily amount for wells that reported production during any of the three most recently reported production months.

(c) The necessary reservoir data shall be obtained from the file of the most recent MER hearing or shall be estimated by the commission unless more recent information is submitted by the operators.

(d) If the gas produced from an oil reservoir is returned to the same reservoir from which it was produced, only the volume of gas not returned to the reservoir shall be considered in applying the rule stated.

(e) Associated gas wells.

(1) Subsection (b) of this section will not be applicable to associated gas wells in reservoirs for which unlimited net gas-oil ratio authority has been granted for oil wells, where such net gas is defined as total gas produced less gas diverted to legal uses; however, this subsection does not apply to reservoirs where net gas

is defined as total gas produced less gas returned to the reservoir from which it was produced, or where special field rules have been adopted for associated gas wells, or where a total gas volume limitation is placed upon the oil well producing under a net ratio, except that each associated gas well in such a reservoir shall be entitled to an additional gas voidage not to exceed the limitation placed upon the net ratio authority granted and the facts are shown on the current oil proration schedule for the field.

(2) Allowables for associated gas wells producing from reservoirs that are subject to an unlimited net gas-oil ratio authority will be dropped from the associated gas well schedule, effective that date such an unlimited net gas-oil ratio is authorized for any oil well in such reservoir.

(f) All gas-oil ratios determined by test or allocation shall be reported on the oil well status report form in accordance with instructions thereon and the provisions of §3.53(a) of this title (relating to Annual Well Tests and Well Status Reports Required).

(g) Allowables.

(1) No well shall have its allowable curtailed below the allowable fixed by the applicable field rules and the general statewide market demand order, unless such well is incapable of producing this allowable on a calendar day basis.

(2) Any well that has a gas-oil ratio in excess of the prescribed ratio for the field in which it is located will have its schedule daily allowable penalized due to such ratio.

Source Note: The provisions of this §3.49 adopted to be effective January 1, 1976; amended to be effective July 1, 1992, 17 TexReg 3236; amended to be effective February 13, 1997, 22 TexReg 1313; amended to be effective November 24, 2004, 29 TexReg 10728

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.48	**Capacity Oil Allowables for Secondary or Tertiary Recovery Projects**

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Capacity oil allowable--The allowable assigned from time to time by the director of the Oil and Gas Division or the director's delegate to an oil lease or unit engaged in a secondary or tertiary recovery program, that is consistent with the ability of the lease or unit to produce and that will prevent the occurrence of overproduced status for the lease or unit. Capacity oil allowables encompass and supercede what the Railroad Commission formerly designated as waterflood allowables.

(2) Offsetting operators and unleased mineral interest owners affected by the application--All offsetting operators and unleased mineral interest owners to the lease or unit except for those offsetting operators and unleased mineral owners the director of the Oil and Gas Division or the director's delegate determines to be unaffected by the application.

(b) Application. The director of the Oil and Gas Division or the director's delegate may grant a capacity oil allowable for a lease or unit, to the operator of a secondary or tertiary recovery project, when evidence of production increase in response to the secondary or tertiary recovery project is noted. The operator's application for a capacity oil allowable shall consist of:

(1) a written request that shall contain a statement indicating that all offsetting operators and unleased mineral interest owners affected by the application have been sent a copy of the complete application, and a list of such offsetting operators and unleased mineral interest owners indicating the date that notification was sent;

(2) evidence of the operator's participation in the subject secondary or tertiary recovery project;

(3) a plat indicating all producing wells and injection wells on the lease or unit and all offsetting operators and unleased mineral interest owners to the lease or unit;

(4) if available, signed waivers of objection from all offsetting operators and unleased mineral interest owners affected by the application; and

(5) a production graph illustrating both increased production and volumes of water or other substances used in the secondary or tertiary recovery project that have been injected on the lease or unit since initiation of the secondary or tertiary recovery project.

(c) Notice and hearing. If the operator does not submit signed waivers of objection from all offsetting operators and unleased mineral interest owners affected by the application, there shall be a minimum of 21 days notice of the application for a capacity oil allowable; provided that, if the operator requests a hearing to consider the application, such hearing shall be held only after at least 10 days notice. If the director of the Oil and Gas Division or the director's delegate declines to approve the initial application, or if a protest is received by the Oil and Gas Division within the prescribed notice period, the operator may request a hearing to show that the capacity oil allowable is necessary either to prevent waste or to protect correlative rights. Any hearing held pursuant to this section shall be held only after at least 10 days notice. If the operator submits signed waivers of objection from all offsetting operators and unleased mineral interest owners affected by the application, or if no protest is received by the Oil and Gas Division within the 21-day notice period, or if no protestant appears at a hearing to consider an application for a capacity oil allowable, the capacity oil allowable may be granted administratively by the director of the Oil and Gas Division or the director's delegate if the application establishes that the capacity oil allowable is necessary to ensure maximum recovery from the secondary or tertiary recovery project.

(d) Temporary basis. A capacity oil allowable may be granted on a temporary basis by the director of the Oil and Gas Division or the director's delegate upon receipt of a complete application indicating that an immediate allowable increase is necessary to ensure maximum recovery from the secondary or tertiary recovery project. If a hearing is held to consider the application, any capacity oil allowable previously granted on a temporary basis under this section will remain in effect until a signed order of the Railroad Commission is issued in the matter. If the commission order denies the application, or if an applicant fails to request a hearing to consider a protested application, additional production resulting from the capacity oil allowable granted on a temporary basis will be treated as overproduction.

Source Note: The provisions of this §3.48 adopted to be effective March 28, 1988, 13 TexReg 1257.

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PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.47	**Allowable Transfers for Saltwater Injection Wells**

An allowable transfer will not be authorized for a well converted from oil production to saltwater disposal; however, an operator may make application to use the well for dual-purpose waterflood and saltwater disposal if injection is into an oil productive zone, and it is shown that the water injection will not injure the reservoir but will probably be of benefit to the reservoir as a secondary recovery program even though the beneficial effect of the water injection cannot be readily determined.

Source Note: The provisions of this §3.47 adopted to be effective January 1, 1976.

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TITLE 16	ECONOMIC REGULATION
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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.46	**Fluid Injection into Productive Reservoirs**

(a) Permit required. Any person who engages in fluid injection operations in reservoirs productive of oil, gas, or geothermal resources must obtain a permit from the commission. Permits may be issued when the injection will not endanger oil, gas, or geothermal resources or cause the pollution of freshwater strata unproductive of oil, gas, or geothermal resources. Permits from the commission issued before the effective date of this section shall continue in effect until revoked, modified, or suspended by the commission.

(b) Filing of application.

(1) Application. An application to conduct fluid injection operations in a reservoir productive of oil, gas, or geothermal resources shall be filed in Austin on the form prescribed by the commission accompanied by the prescribed fee. On the same date, one copy shall be filed with the appropriate district office. The form shall be executed by a party having knowledge of the facts entered on the form. The applicant shall file the freshwater injection data form if fresh water is to be injected.

(2) Commercial disposal well. An applicant for a permit to dispose of oil and gas waste in a commercial disposal well shall clearly indicate on the application and in the notice of application that the application is for a commercial disposal well permit. For the purposes of this rule, "commercial disposal well" means a well whose owner or operator receives compensation from others for the disposal of oil field fluids or oil and gas wastes that are wholly or partially trucked or hauled to the well, and the primary business purpose for the well is to provide these services for compensation.

(c) Notice and opportunity for hearing.

(1) The applicant shall give notice by mailing or delivering a copy of the application to affected persons who include the owner of record of the surface tract on which the well is located; each commission-designated operator of any well located within one half mile of the proposed injection well; the county clerk of the county in which the well is located; and the city clerk or other appropriate city official of any city where the well is located within the corporate limits of the city, on or before the date the application is mailed to or filed with the commission. For the purposes of this section, the term "of record" means recorded in the real property or probate records of the county in which the property is located.

(2) In addition to the requirements of subsection (c)(1), a commercial disposal well permit applicant shall give notice to owners of record of each surface tract that adjoins the proposed injection tract by mailing or delivering a copy of the application to each such surface owner.

(3) If, in connection with a particular application, the commission or its delegate determines that another class of persons should receive notice of the application, the commission or its delegate may require the applicant to mail or deliver a copy of the application to members of that class. Such classes of persons could include adjacent surface owners or underground water conservation districts.

(4) In order to give notice to other local governments, interested, or affected persons, notice of the application shall be published once by the applicant in a newspaper of general circulation for the county where the well will be located in a form approved by the commission or its delegate. The applicant shall file

with the commission in Austin proof of publication prior to the hearing or administrative approval.

(5) Protested applications:

(A) If a protest from an affected person or local government is made to the commission within 15 days of receipt of the application or of publication, whichever is later, or if the commission or its delegate determines that a hearing is in the public interest, then a hearing will be held on the application after the commission provides notice of hearing to all affected persons, local governments, or other persons, who express an interest, in writing, in the application.

(B) For purposes of this section, "affected person" means a person who has suffered or will suffer actual injury or economic damage other than as a member of the general public or as a competitor, and includes surface owners of property on which the well is located and commission-designated operators of wells located within one-half mile of the proposed disposal well.

(6) If no protest from an affected person is received by the commission, the commission's delegate may administratively approve the application. If the commission's delegate denies administrative approval, the applicant shall have a right to a hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(d) Subsequent commission action.

(1) An injection well permit may be modified, suspended, or terminated by the commission for just cause after notice and opportunity for hearing, if:

(A) a material change of conditions occurs in the operation or completion of the injection well, or there are material changes in the information originally furnished;

(B) fresh water is likely to be polluted as a result of continued operation of the well;

(C) there are substantial violations of the terms and provisions of the permit or of commission rules;

(D) the applicant has misrepresented any material facts during the permit issuance process;

(E) injected fluids are escaping from the permitted injection zone; or

(F) waste of oil, gas, or geothermal resources is occurring or is likely to occur as a result of the permitted operations.

(2) An injection well permit may be transferred from one operator to another operator provided that the commission's delegate does not notify the present permit holder of an objection to the transfer prior to the date the lease is transferred on commission records.

(3) Voluntary permit suspension.

(A) An operator may apply to temporarily suspend its injection authority by filing a written request for permit suspension with the commission in Austin, and attaching to the written request the results of an MIT test performed during the previous three-month period in accordance with the provisions of subsection (j)(4) of this section. The provisions of this paragraph shall not apply to any well that is permitted as a commercial injection well.

(B) The commission or its delegate may grant the permit suspension upon determining that the results of the MIT test submitted under subparagraph (A) of this paragraph indicate that the well meets the performance standards of subsection (j)(4) of this section.

(C) During the period of permit suspension, the operator shall not use the well for injection or disposal purposes.

(D) During the period of permit suspension, the operator shall comply with all applicable well testing requirements of §3.14 of this title (relating to plugging, and commonly referred to as Statewide Rule 14) but need not perform the MIT test that would otherwise be required under the provisions of subsection (j)(4) of this section or the permit. Further, during the period of permit suspension, the provisions of subsection (i)(1) - (3) of this section shall not apply.

(E) The operator may reinstate injection authority under a suspended permit by filing a written notification with the commission in Austin. The written notification shall be accompanied by an MIT test performed during the three-month period prior to the date notice of reinstatement is filed. The MIT test shall have been performed in accordance with the provisions and standards of subsection (j)(4) of this section.

(e) Area of Review.

(1) Except as otherwise provided in this subsection, the applicant shall review the data of public record for wells that penetrate the proposed disposal zone within a 1/4 mile radius of the proposed disposal well to determine if all abandoned wells have been plugged in a manner that will prevent the movement of fluids from the disposal zone into freshwater strata. The applicant shall identify in the application any wells which appear from such review of public records to be unplugged or improperly plugged and any other unplugged or improperly plugged wells of which the applicant has actual knowledge.

(2) The commission or its delegate may grant a variance from the area-of-review requirements of paragraph (1) of this subsection upon proof that the variance will not result in a material increase in the risk of fluid movement into freshwater strata or to the surface. Such a variance may be granted for an area defined both vertically and laterally (such as a field) or for an individual well. An application for an areal variance need not be filed in conjunction with an individual permit application or application for permit amendment. Factors that may be considered by the commission or its delegate in granting a variance include:

(A) the area affected by pressure increases resulting from injection operations;

(B) the presence of local geological conditions that preclude movement of fluid that could endanger freshwater strata or the surface; or

(C) other compelling evidence that the variance will not result in a material increase in the risk of fluid movement into freshwater strata or to the surface.

(3) Persons applying for a variance from the area-of-review requirements of paragraph (1) of this subsection on the basis of factors set out in paragraph (2)(B) or (C) of this subsection for an individual well shall provide notice of the application to those persons given notice under the provisions of subsection (c)(1) of this section. The provisions of subsection (c) of this section shall apply in the case of an application for a variance from the area-of-review requirements for an individual well.

(4) Notice of an application for an areal variance from the area-of-review requirements under paragraph (1) of this subsection shall be given on or before the date the application is filed with the commission:

(A) by publication once in a newspaper having general circulation in each county, or portion thereof, where the variance would apply. Such notice shall be in a form approved by the commission or its delegate prior to publication and must be at least three inches by five inches in size. The notice shall state that protests to the application may be filed with the commission during the 15-day period following the date of publication. The notice shall appear in a section of the newspaper containing state or local news items;

(B) by mailing or delivering a copy of the application, along with a statement that any protest to the application should be filed with the commission within 15 days of the date the application is filed with the commission, to the following:

(i) the manager of each underground water conservation district in which the variance would apply, if any;

(ii) the city clerk or other appropriate official of each incorporated city in which the variance would apply, if any;

(iii) the county clerk of each county in which the variance would apply; and

(iv) any other person or persons that the commission or its delegate determines should receive notice of the application.

(5) If a protest to an application for an areal variance is made to the commission by an affected person, local government, underground water conservation district, or other state agency within 15 days of receipt of the application or of publication, whichever is later, or if the commission's delegate determines that a hearing on the application is in the public interest, then a hearing will be held on the application after the commission provides notice of the hearing to all local governments, underground water conservation districts, state agencies, or other persons, who express an interest, in writing, in the application. If no protest from an affected person is received by the commission, the commission's delegate may administratively approve the application. If the application is denied administratively, the person(s) filing the application shall have a right to hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(6) An areal variance granted under the provisions of this subsection may be modified, terminated, or suspended by the commission after notice and opportunity for hearing is provided to each person shown on commission records to operate an oil or gas lease in the area in which the proposed modification, termination, or suspension would apply. If a hearing on a proposal to modify, terminate, or suspend an areal variance is held, any applications filed subsequent to the date notice of hearing is given must include the area-of-review information required under paragraph (1) of this subsection pending issuance of a final order.

(f) Casing. Injection wells shall be cased and the casing cemented in compliance with §3.13 of this title (relating to Casing, Cementing, Drilling, and Completion Requirements) in such a manner that the injected fluids will not endanger oil, gas, or geothermal resources and will not endanger freshwater formations not productive of oil, gas, or geothermal resources.

(g) Special equipment.

(1) Tubing and packer. Wells drilled or converted for injection shall be equipped with tubing set on a mechanical packer. Packers shall be set no higher than 200 feet below the known top of cement behind the long string casing but in no case higher than 150 feet below the base of usable quality water. For purposes of this section, the term "tubing" refers to a string of pipe through which injection may occur and which is neither wholly nor partially cemented in place. A string of pipe that is wholly or partially cemented in place is considered casing for purposes of this section.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.45	**Oil Allowables**

(a) Oil allowable yardsticks.

(1) 1947 allowable yardstick. The following schedule allowable shall be assigned all wells according to depth of the reservoir and proration unit size authorized by the commission upon expiration of the discovery allowable, if discovery of the field occurred prior to January 1, 1965, provided that paragraph (3) of this subsection does not apply.

Attached Graphic

(2) 1965 allowable yardstick. The following schedule allowable shall be assigned all wells according to depth of the reservoir and proration unit size authorized by the commission upon expiration of the discovery allowable, if discovery of the field occurred on or after January 1, 1965.

Attached Graphic

(3) Exception. Wells in fields discovered prior to January 1, 1965, whose discovery allowables either have expired or will expire subsequent to July 1, 1964, upon expiration of the discovery allowable, may be assigned allowable pursuant to the 1965 yardstick, if such allowables exceed those which would be assigned pursuant to the 1947 yardstick, or if the proration unit size authorized by the commission is not provided for in the 1947 yardstick. It is provided that any adjustment made in allowable assignment pursuant to this paragraph shall not be made prior to the effective date of this order. Retroactive adjustment shall not be allowed.

(4) Texas offshore allowable yardstick.

Attached Graphic

(b) Assignment of allowables for wells under statewide rules.

(1) All wells completed in fields operating under statewide rules which were assigned the 20-acre yardstick allowable prior to the adoption of the new spacing rule on October 1, 1962, will be continued at the same allowable rate unless, after notice and hearing, special rules or other special orders are adopted that would provide for a higher producing rate. Any new well completed in such a reservoir will be given the same allowable rate as is assigned the other wells even though it has been drilled as a regular location under the new statewide spacing rule and density rule.

(2) All wells completed in fields operating under statewide rules that are presently on discovery status or have had discovery status terminated subsequent to the adoption of the new state spacing rule on October 1, 1962, will be given the 40-acre yardstick allowable, until such time as a change is ordered by the commission.

(c) Production of marginal wells.

(1) To artificially curtail the production of any "marginal well" below the marginal limit prior to its ultimate plugging and abandonment is hereby declared to be waste, and no rule or order of the Railroad Commission of Texas, or other constituted legal authority shall be entered requiring restriction of the production of any "marginal well" as defined in this chapter.

(2) Application of paragraph (1) of this subsection shall be confined to unrestricted operating conditions which accord with established operating rules of the commission, and shall be subject to all operating conditions designed to prevent waste imposed by the commission, which conditions apply to all wells alike. (Reference Order Number 20-54,115, effective January 1, 1965.)

Source Note: The provisions of this §3.45 adopted to be effective January 1, 1976; amended to be effective March 10, 1986, 11 TexReg 901

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TITLE 16	ECONOMIC REGULATION
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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.43	**Application for Temporary Field Rules**

(a) The commission will accept applications for temporary field rule hearings for oil, gas, or geothermal resource fields after the first well has been completed.

(b) When requesting such hearings, the applicant must furnish the commission a list of the names and addresses of all operators holding leases on land touching the tract on which the discovery well is located. The applicant must list the names and addresses of the owners of the abutting unleased land.

(c) Temporary field rules will apply until permanent field rules are adopted.

Source Note: The provisions of this §3.43 adopted to be effective January 1, 1976.

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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.42	**Oil Discovery Allowable**

(a) The commission shall determine the discovery allowable rate for oil wells proven to be completed in a new and separate reservoir from the following discovery allowable schedule.

Attached Graphic

(b) Duration and exemption from market demand limitation.

(1) Onshore. Each oil well completed in an oil reservoir determined by the commission to be a new onshore oil field onshore may receive, as a maximum daily, its discovery allowable, exempt from market demand limitation, for a period of 24 months (36 months for depth intervals deeper than 10,000 feet) from the date of assignment of the oil allowable to such discovery well or until the 11th oil well has been completed therein, whichever occurs first.

(2) Offshore. Each oil well completed in an oil reservoir determined by the commission to be a new offshore oil field may receive, as a maximum daily allowable, its discovery oil allowable, exempt from market demand limitation, for a period of 24 months (36 months for depth intervals deeper than 10,000 feet) from the date of assignment of the oil allowable to such discovery well or until the sixth oil well has been completed therein, whichever occurs first.

(c) The director or the director's delegate shall review the production performance of discovery wells to evaluate whether waste is occurring due to the discovery allowable. If the director or the director's delegate believes waste is or may be occurring, the director or the director's delegate may request any additional relevant information from the operator and may set the matter for hearing to allow the commission to determine if the discovery allowable should be lowered to prevent waste.

Source Note: The provisions of this §3.42 adopted to be effective January 1, 1976; amended to be effective August 6, 1980, 5 TexReg 2930; amended to be effective November 28, 1989, 14 TexReg 6006; amended to be effective January 4, 1999, 24 TexReg 131

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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.41	**Application for New Oil or Gas Field Designation and/or Allowable**

(a) The commission shall assign a new field designation and/or discovery allowable after an operator furnishes to the commission's Austin office proper evidence, other than horizontal distance, proving that a well is a new discovery. An operator shall include the following in the application:

(1) a legible area map, drawn to scale, preferably on white paper, which shows the following:

(A) all oil, gas, and abandoned wells within at least a 2 1/2-mile radius of the well claimed to be a discovery well;

(B) the producing intervals of all pertinent oil and gas wells identified in subparagraph (A) of this paragraph;

(C) all commission-recognized fields within a 2 1/2-mile radius of the well claimed to be a discovery well, that are presently active or were active in the past, identified by commission-assigned field names, names of the producing formations, and approximate average depth of the producing interval;

(D) the total depth of all wells identified in subparagraph (A) of this paragraph that penetrated the subject zone;

(E) scale, legend, and name of person who prepared the map;

(2) a complete legible electric log of the well. However, an operator is not required to file a complete electric log if the operator has filed all other required data, a portion of the log showing the top and bottom of the proposed reservoir interval, log headings, and applicable scales, and satisfactorily proves discovery as a new reservoir. Any electric log filed shall be considered public information pursuant to §3.16 of this title (relating to Log and Completion or Plugging Report) (Statewide Rule 16).

(3) a bottom-hole pressure for oil wells, submitted on the appropriate form. This bottom-hole pressure may be determined by a pressure build-up test, drill stem test, or wire- line formation tester. Calculations based on fluid level surveys or calculations made on flowing wells using shut-in wellhead pressures may be used if no test data is available.

(4) a subsurface structure map and/or cross section(s), if separation is based on structural differences, including faulting and pinch-outs. The structure map shall show the contour of the top of the producing formation and the line(s) of cross section. The cross section(s) shall be prepared from comparable electric logs (not tracings) with the wells, producing formation, and hydrocarbon reservoir identified. The engineer or geologist who prepared the map and cross section shall sign them.

(5) reservoir pressure measurements or calculations, if separation is based on pressure differentials.

(6) core data, drillstem test data, cross sections of nearby wells, and/or production data estimating the fluid level, if separation is based on differences in fluid levels. The operator shall obtain the fluid level data

within 10 days of the potential test date.

(b) The staff may require additional data deemed necessary to make a determination. Deviation from the requirements of subsection (a) of this section may be allowed at the staff's discretion.

(c) The director, oil and gas, may administratively grant an application if all required data is submitted with the form prescribed, and the evidence proves that the new reservoir is effectively separated from any other reservoir previously shown to be productive.

(d) If the director of the Oil and Gas Division, or the director's delegate, declines administratively to grant an application, the operator may request a hearing. If the commission receives the hearing request within 10 days of the date of the notice of administrative denial of the application, the commission shall schedule a hearing. After hearing, the examiner shall recommend final commission action.

Source Note: The provisions of this §3.41 adopted to effective January 1, 1976; amended to be effective July 24, 1980, 5 TexReg 2859; amended to be effective February 28, 1986, 11 TexReg 545; amended to be effective January 4, 1999, 24 TexReg 131

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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.40	**Assignment of Acreage to Pooled Development and Proration Units**

(a) An operator may pool acreage, in accordance with appropriate contractual authority and applicable field rules, for the purpose of creating a drilling unit or proration unit by filing an original certified plat delineating the pooled unit and a Certificate of Pooling Authority, Form P-12 (revised 5/2001), according to the following requirements:

(1) Each tract in the certified plat shall be identified with an outline and a tract identifier that corresponds to the tract identifier listed on the Form P-12.

(2) The operator shall provide information on the Certificate of Pooling Authority, Form P-12, accurately and according to the instructions on the form.

(A) The operator shall separately list each tract committed to the pooled unit by authority granted to the operator.

(B) For each tract listed on Form P-12, the operator shall state the number of acres contained within the tract. The operator shall indicate by checking the appropriate box on Form P-12 if, within an individual tract, there exists a non-pooled and/or unleased interest.

(C) The operator shall state on Form P-12 the total number of acres in the pooled unit. The total number of acres in the pooled unit shall equal the sum of all acres in each individual tract listed.

(D) If a pooled unit contains more tracts than can be listed on a single Form P-12, the operator shall file as many additional Forms P-12 as necessary to list each pooled tract individually. The additional Forms P-12 shall be numbered in sequence.

(E) The operator shall provide the requested identification and contact information on the Form P-12.

(F) The operator shall certify the information on the Form P-12 by signing and dating the form.

(3) Failure to timely file the required information on the certified plat or the Form P-12 may result in the dismissal of the W-1 application. "Timely" means within three months of the Commission notifying the operator of the need for additional information on the certified plat and/or the Form P-12.

(4) The operator shall file the original certified plat and Form P-12 at the Commission's Austin office. The operator shall file a copy of the certified plat and Form P-12 with the appropriate Commission district office or offices. If the operator files electronically through the Commission's Electronic Compliance and Approval Process (ECAP) system, the operator is not required to file additional paper copies in the appropriate Commission district office, because all Commission offices will have electronic access to the Form P-12 and certified plat.

(5) The operator shall file the Form P-12 and certified plat:

(A) with the drilling permit application when two or more tracts are joined to form a pooled unit for Commission purposes to obtain a drilling permit;

(B) with completion paperwork when the pooled unit's acreage is being used or assigned for allowable purposes;

(C) to designate a pooled unit formed after completion paperwork has been filed when the pooled unit's acreage is being used or assigned for allowable purposes; or

(D) to designate a change in a pooled unit previously recognized by the Commission. The operator shall file any changes to a pooled unit in accordance with the requirements of §3.38(d)(3) of this title, relating to Well Densities.

(b) If a tract to be pooled has an outstanding interest for which pooling authority does not exist, the tract may be assigned to a unit where authority exists in the remaining undivided interest, provided, that total gross acreage in the tract is included for allocation purposes, and the certificate filed with the commission shows that a certain undivided interest is outstanding in the tract. The commission will not allow an operator to assign only his undivided interest out of a basic tract, where a nonpooled interest exists.

(c) The nonpooled undivided interest holder retains his development rights in his basic tract, and should such rights be exercised, authority to develop the basic tract be approved by the commission, and a well completed as a producer thereon, then the entire interest in the basic tract must be allocated to said well, and any interest insofar as it is pooled with another tract must be assigned to the well on the basic tract for allocation purposes. Splitting of undivided interest in a basic tract between two or more wells on two or more tracts is not acceptable.

(d) Acreage assigned to a well for drilling and development, or for allocation of allowable, shall not be assigned to any other well or wells projected to or completed in the same reservoir; such duplicate assignment of acreage is not acceptable, provided, however, that this limitation shall not prevent the reformation of development or proration units so long as no duplicate assignment of acreage occurs, and further, that such reformation does not violate other conservation regulations.

Source Note: The provisions of this §3.40 adopted to be effective January 1, 1976; amended to be effective January 9, 2002, 27 TexReg 150

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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.39	**Proration and Drilling Units: Contiguity of Acreage and Exception Thereto**

(a) Proration and drilling units established for individual wells drilled or to be drilled shall consist of acreage which is contiguous.

(b) An exception to the contiguous acreage provision may be granted at the operator's request if acreage that is to be included in the proration or drilling unit is separated by a long, narrow right-of-way tract.

Source Note: The provisions of this §3.39 adopted to be effective January 1, 1976.

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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.38	**Well Densities**

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Commission designee--Director of the Oil and Gas Division or any Commission employee designated in writing by the director or the Commission.

(2) Drilling unit--The acreage assigned to a well for drilling purposes.

(3) Proration unit--The acreage assigned to a well for the purpose of assigning allowables and allocating allowable production to the well.

(4) Substandard acreage--Less acreage than the smallest amount established for standard or optional drilling units.

(5) Surplus acreage--Substandard acreage within a lease, pooled unit, or unitized tract that remains unassigned after the assignment of acreage to each applied for, permitted, or completed well in a field, in an amount equaling or exceeding the amount established for standard or optional drilling units. Surplus acreage is distinguished from the term "tolerance acreage,"in that tolerance acreage is defined in context with proration regulation, while surplus acreage is defined by this rule only in context with well density regulation.

(6) Tolerance acreage--Acreage within a lease, pooled unit, or unitized tract that may be assigned to a well for proration purposes pursuant to special field rules in addition to the amount established for a prescribed or optional proration unit.

(b) Density requirements.

(1) General prohibition. No well shall be drilled on substandard acreage except as hereinafter provided.

(2) Standard units.

(A) The standard drilling unit for all oil, gas, and geothermal resource fields wherein only spacing rules, either special, country regular, or statewide, are applicable is hereby prescribed to be the following.

Attached Graphic

(B) The spacing rules listed in subparagraph (A) of this paragraph are not exclusive. If any spacing rule not listed in subparagraph (A) of this subsection is brought to the attention of the commission, it will be given an appropriate acreage assignment.

(c) Development to final density. An application to drill a well for oil, gas, or geothermal resource on a drilling unit composed of surplus acreage, commonly referred to as the "tolerance well," may be granted as regular when the operator seeking such permit certifies to the commission in a prescribed form the necessary data to show that such permit is needed to develop a lease, pooled unit, or unitized tract to final density, and only in the following circumstances:

(1) when the amount of surplus acreage equals or exceeds the maximum amount provided for tolerance acreage by special or county regular rules for the field, provided that this paragraph does not apply for a lease, pooled unit, or unitized tract that is completely developed with optional units and the special or county regular rules for the field do not have a tolerance provisions expressly made applicable to optional proration units;

(2) if the special or county regular rules for the field do not have a tolerance provision expressly made applicable to optional proration units, when the amount of surplus acreage equals or exceeds one-half of the smallest amount established for an optional drilling unit; or

(3) if the applicable rules for the field do not have a tolerance provision for the standard drilling or proration unit, when the amount of surplus acreage equals or exceeds one-half the amount prescribed for the standard unit.

(d) Applications involving the voluntary subdivision rule.

(1) Density exception not required. An exception to the minimum density provision is not required for the first well in a field on a lease, pooled unit, or unitized tract composed of substandard acreage, when the leases, or the drillsite tract of a pooled unit or unitized tract:

(A) took its present size and shape prior to the date of attachment of the voluntary subdivision rule (§3.37(g) of this title (relating to Statewide Spacing Rule)); or

(B) took its present size and shape after the date of attachment of the voluntary subdivision rule (§3.37(g) of this title (relating to Statewide Spacing Rule)) and was not composed of substandard acreage in the field according to the density rules in effect at the time it took its present size and shape.

(2) Density exception required. An exception to the density provision is required, and may be granted only to prevent waste, for a well on a lease, pooled unit, or unitized tract that is composed of substandard acreage and that:

(A) took its present size and shape after the date of attachment of the voluntary subdivision rule (§3.37(g) of this title (relating to the Statewide Spacing Rule)); and

(B) was composed of substandard acreage in the field according to the density rules in effect at the time it took its present size and shape.

(3) Unit dissolution.

(A) If two or more separate tracts are joined to form a unit for oil or gas development, the unit is accepted by the Commission, and the unit has produced hydrocarbons in the preceding twenty (20) years, the unit may not thereafter be dissolved into the separate tracts with the rules of the commission applicable to each separate tract if the dissolution results in any tract composed of substandard acreage for the field from which the unit produced, unless the Commission approves such dissolution.

(B) The Commission shall grant approval only after application, notice, and an opportunity for hearing. The applicant seeking the unit dissolution shall provide a list of the names and addresses of all current lessees and unleased mineral interest owners of each tract within the joined or unitized tract at the time the application is filed. The Commission shall give notice of the application to all current lessees and unleased mineral interest owners of each tract within the joined or unitized tract. Additionally, if one or more wells on the unitized tract has produced from the field within the 12-month period prior to the application, the applicant shall include on the list all affected persons described in subsection (h)(1)(A) of this section, and the Commission shall give notice of the application to these affected persons.

(C) A Commission designee may grant administrative approval if the Commission designee determines that granting the application will not result in the circumvention of the density restrictions of this section or other Commission rules, and if either:

(i) written waivers are filed by all affected persons; or

(ii) no protest is filed within the time set forth in the notice of application.

(e) Application involving unitized areas with entity for density orders. An exception to the minimum density provision is not required for a well in a unitized area for which the commission has granted an entity for density order, if the sum of all applied for, permitted, or completed producing wells in the field within the unitized area, multiplied by the applicable density provision, does not exceed the total number of acres in the unitized area. The operator must indicate the docket number of the entity for density order on the application form.

(f) Exceptions to density provisions authorized. The Commission, or Commission designee, in order to prevent waste or, except as provided in subsection (d)(2) of this section, to prevent the confiscation of property, may grant exceptions to the density provisions set forth in this section. Such an exception may be granted only after notice and an opportunity for hearing.

(g) Filing requirements.

(1) Application. An application for permit to drill shall include the fees required in §3.78 of this title (relating to Fees and Financial Security Requirements) and shall be certified by a person acquainted with the facts, stating that all information in the application is true and complete to the best of that person's knowledge.

(2) Plat. When filing an application for an exception to the density requirements of this section, in addition to the plat requirements in §3.5 of this title (relating to Application to Drill, Deepen, Reenter, or Plug Back) (Statewide Rule 5), the applicant shall attach to each copy of the application a plat that:

(A) depicts the lease, pooled unit, or unitized tract, showing thereon the acreage assigned to the drilling unit for the proposed well and the acreage assigned to all current applied for, permitted, or completed oil, gas, or oil and gas wells in the same field or reservoir which are located within the lease, pooled unit, or unitized tract;

(B) on large leases, pooled units, or unitized tracts, if the established density is not exceeded as shown on the face of the application, outlines the acreage assigned to the well for which the permit is sought and the immediately adjacent wells on the lease, pooled unit, or unitized tract;

(C) on leases, pooled units, or unitized tracts from which production is secured from more than one field, outlines the acreage assigned to the wells in each field that is the subject of the current application;

(D) corresponds to the listing required under subsection (g)(1)(A) of this section.

(E) is certified by a person acquainted with the facts pertinent to the application that the plat is accurately drawn to scale and correctly reflects all pertinent and required data.

(3) Substandard acreage. An application for a permit to drill on a lease, pooled unit, or unitized tract

composed of substandard acreage must include a certification in a prescribed form indicating the date the lease, or the drillsite tract of a pooled unit or unitized tract, took its present size and shape.

(4) Surplus acreage. An application for permit to drill on surplus acreage pursuant to subsection (c) of this section must include a certification in a prescribed form indicating the date the lease, pooled unit, or unitized tract took its present size and shape.

(5) Certifications. Certifications required under paragraphs (3) and (4) of this subsection shall be filed on Form W-1A, Substandard Acreage Certification.

(A) The operator shall file the Form W-1A with the drilling permit application and shall indicate the purpose of filing. The operator shall accurately complete all information required on the form in accordance with instructions on the form.

(B) The operator shall list the field or fields for which the substandard acreage certification applies in the designated area on the form. If there are more than three fields for which the certification applies, the operator shall attach additional Forms W-1A and shall number the additional pages in sequence.

(C) The operator shall file the original Form W-1A with the Commission's Austin office and a copy with the appropriate district office, unless the operator files electronically through the Commission's Electronic Compliance and Approval Process (ECAP) system.

(D) The operator or the operator's agent shall certify the information provided on the Form W-1A is true, complete, and correct by signing and dating the form, and listing the requested identification and contact information.

(E) Failure to timely file the required information on the appropriate form may result in the dismissal of the application.

(h) Procedure for obtaining exceptions to the density provisions.

(1) Filing requirements. If a permit to drill requires an exception to the applicable density provision, the operator must file, in addition to the items required by subsection (g) of this section:

(A) a list of the names and addresses of all affected persons. For the purpose of giving notice of application, the Commission presumes that affected persons include the operators and unleased mineral interest owners of all adjacent offset tracts, and the operators and unleased mineral interest owners of all tracts nearer to the proposed well than the prescribed minimum lease-line spacing distance. The Commission designee may determine that such a person is not affected only upon written request and a showing by the applicant that:

(i) competent, convincing geological or engineering data indicate that drainage of hydrocarbons from the particular tracts subject to the request will not occur due to production from the proposed well; and

(ii) notice to the particular operators and unleased mineral interest owners would be unduly burdensome or expensive;

(B) engineering and/or geological data, including a written explanation of each exhibit, showing that the drilling of a well on substandard acreage is necessary to prevent waste or to prevent the confiscation of property;

(C) additional data requested by the Commission designee.

(2) Notice of application. Upon receipt of a complete application, the Commission will give notice of the application by mail to all affected persons for whom signed waivers have not been submitted.

(3) Approval without hearing. If the Commission designee determines, based on the data submitted, that a permit requiring an exception to the applicable density provision is justified according to subsection (f) of this section, then the Commission designee may issue the exception permit administratively if:

(A) signed waivers from all affected persons were submitted with the application; or

(B) notice of application was given in accordance with paragraph (2) of this subsection and no protest was filed within 21 days of the notice; or

(C) no person appeared to protest the application at a hearing scheduled pursuant to paragraph (4)(A) of this subsection.

(4) Hearing on the application.

(A) If a written protest is filed within 21 days after the notice of application is given in accordance with paragraph (2) of this subsection, the application will be set for hearing.

(B) If the application is not protested and the Commission designee determines that a permit requiring an exception to the applicable density provision is not justified according to subsection (f) of this section, the operator may request a hearing to consider the application.

(i) Duration. A permit is issued as an exception to the applicable density provision shall expire two years from the effective date of the permit; unless drilling operations are commenced in good faith within the two year period.

Source Note: The provisions of this §3.38 adopted to be effective November 1, 1989, 14 TexReg 5255; amended to be effective April 21, 1997, 22 TexReg 3404; amended to be effective July 10, 2000, 25 TexReg 6487; amended to be effective June 11, 2001, 26 TexReg 4088; amended to be effective February 13, 2002, 27 TexReg 906; amended to be effective September 1, 2004, 29 TexReg 8271

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.37	**Statewide Spacing Rule**

(a) Distance requirements.

(1) No well for oil, gas, or geothermal resource shall hereafter be drilled nearer than 1,200 feet to any well completed in or drilling to the same horizon on the same tract or farm, and no well shall be drilled nearer than 467 feet to any property line, lease line, or subdivision line; provided the commission, in order to prevent waste or to prevent the confiscation of property, may grant exceptions to permit drilling within shorter distances than prescribed in this paragraph when the commission shall determine that such exceptions are necessary either to prevent waste or to prevent the confiscation of property.

(2) When an exception to this section is desired, application shall be made by filing the proper fee as provided in §3.78 of this title (relating to Fees and Financial Security Requirements) and the appropriate form according to the instructions on the form, accompanied by a plat as described in subsection (c) of this section. A person acquainted with the facts pertinent to the application shall certify that all facts stated in it are true and within the knowledge of that person.

(A) When an exception to only the minimum lease-line spacing requirement is desired, the applicant shall file a list of the mailing addresses of all affected persons, who, for tracts closer to the well than the greater of one-half of the prescribed minimum between-well spacing distance or the minimum lease-line spacing distance, include:

(i) the designated operator;

(ii) all lessees of record for tracts that have no designated operator; and

(iii) all owners of record of unleased mineral interests.

(B) When an exception to the minimum between-well spacing requirement of this section is desired, the applicant is required to file the mailing addresses of those persons identified in subparagraph (A)(i)-(iii) of this paragraph for each adjacent tract and each tract nearer to the well than the greater of one-half the prescribed minimum between-well spacing distance or the minimum lease-line spacing.

(3) An exception may be granted pursuant to subsection (h)(2) of this section, or after a public hearing held after at least 10 days notice to all persons described in paragraph (2) of this subsection. At any such hearing, the burden shall be on the applicant to establish that an exception to this section is necessary either to prevent waste or to prevent the confiscation of property. For purposes of giving notice of an application for an exception, the commission will presume that every person described in paragraph (2) of this subsection will be affected by the application, unless the Oil and Gas Division director or the director's delegate determines they are unaffected. Such determination will be made only upon written request and a showing by the applicant that:

(A) competent, conclusive geological or engineering data indicate that no drainage of hydrocarbons from the particular tract(s) subject to the request will occur due to production from the applicant's proposed well; and

(B) notice to the particular operator(s), lessee(s) of record, or owner(s) of record of unleased mineral interest would be unduly burdensome or expensive.

(b) The distances mentioned in subsection (a) of this section are minimum distances to provide standard development on a pattern of one well to each 40 acres in areas where proration units have not been established.

(c) In filing an application for an exception to the distance requirements of this section, in addition to the plat requirements in §3.5 of this title (relating to Application to Drill, Deepen, Reenter, or Plug Back) (Statewide Rule 5), the applicant shall attach to each copy of the form a plat that:

(1) shows to scale the property on which the exception is sought; all other applied for, permitted, and completed oil, gas, or oil and gas wells in the same field and reservoir on said property; and all adjoining surrounding properties and completed wells in the same field and reservoir within the prescribed minimum between-well spacing distance of the applicant's well;

(2) shows the entire lease, pooled unit, or unitized tract indicating the names and offsetting properties of all affected offset operators;

(3) corresponds to the listing required under subsection (a)(2) of this section;

(4) is certified by a person acquainted with the facts pertinent to the application that the plat is accurately drawn to scale and correctly reflects all pertinent and required data.

(d) In the interest of protecting life and for the purpose of preventing waste and preventing the confiscation of property, the commission reserves the right in particular oil, gas, and geothermal resource fields to enter special orders increasing or decreasing the minimum distances provided by this section.

(e) No well drilled in violation of this section without special permit obtained, issued, or granted in the manner prescribed in said section, and no well drilled under such special permit or on the commission's own order which does not conform in all respects to the terms of such permit shall be permitted to produce either oil, gas, or geothermal resources and any such well so drilled in violation of said section or on the commission's own order shall be plugged.

(f) No operator shall commence the drilling of a well, either on a regular location or on a Rule 37 exception location, until first having been notified by the commission that the regular location has been approved, or that the Rule 37 exception location has been approved. Failure of an operator to comply with this subsection will cause such well to be closed in and the holding up of the allowable of such well.

(g) Subdivision of property.

(1) In applying Rule 37 (Statewide Spacing Rule) of statewide application and in applying every special rule with relation to spacing in every field in this state, no subdivision of property made subsequent to the adoption of the original spacing rule will be considered in determining whether or not any property is being confiscated within the terms of such spacing rule, and no subdivision of property will be regarded in applying such spacing rule or in determining the matter of confiscation if such subdivision took place subsequent to the promulgation and adoption of the original spacing rule.

(2) Any subdivision of property creating a tract of such size and shape that it is necessary to obtain an exception to the spacing rule before a well can be drilled thereon is a voluntary subdivision and not entitled to a permit to prevent confiscation of property if it were either:

(A) segregated from a larger tract in contemplation of oil, gas, or geothermal resource development; or

(B) segregated by fee title conveyance from a larger tract after the spacing rule became effective and the voluntary subdivision rule attached.

(3) The date of attachment of the voluntary subdivision rule is the date of discovery of oil, gas, or geothermal resource production in a certain continuous reservoir, regardless of the subsequent lateral extensions of such reservoir, provided that such rule does not attach in the case of a segregation of a small

tract by fee title conveyance which is not located in an oil, gas, or geothermal resource field having a discovery date prior to the date of such segregation.

(4) The date of attachment of the voluntary subdivision rule for multiple reservoir fields located in the same structural feature and separated vertically but not laterally (i.e., the multiple reservoirs overlap geographically at least in part), shall be the same date as that assigned to the earliest discovery well for such multiple reservoir structure.

(5) If a newly discovered reservoir is located outside the then productive limits of any previously discovered reservoirs and is classified by the commission as a newly discovered field, then the date of discovery of such newly found reservoir remains the date of attachment for the voluntary subdivision rule, even though subsequent development may result in the extension of such newly discovered reservoir until it overlies or underlies older reservoirs with prior discovery dates.

(6) The date of attachment of the voluntary subdivision rule for a reservoir that has been developed through expansion of separately recognized fields into a recognized single reservoir and is merged by commission order is the earliest discovery date of production from such merged reservoir, and that date will be used subsequent to the date of merger of the fields into a single field.

(7) The date of attachment of the voluntary subdivision rule for a reservoir under any special circumstance which the commission deems sufficient to provide for an exception may be established other than as prescribed in this section, so that innocent parties may have their rights protected.

(h) Exceptions to Rule 37.

(1) An order granting exception to Rule 37 wherein protest is had shall carry as its last paragraph the following language: It is further ordered by the commission that this order shall not be final until 20 days after it is actually mailed to the parties by the commission; provided that if a motion for rehearing of the application is filed by any party at interest within such 20-day period, this order shall not become final until such motion is overruled, or if such motion is granted, this order shall be subject to further action by the commission. Permits issued pursuant to paragraph (2) of this subsection shall be issued without the 20-day waiting period.

(2) The director of the Oil and Gas Division or a delegate of the director may issue an exception permit for drilling, deepening, or additional completion, recompletion, or reentry in an existing well bore if:

(A) a notice of at least 10 days has been given, and no protest has been made to the application; or

(B) written waivers of objection are received from all persons to whom notice would be given pursuant to subsection (a)(2) of this section.

(3) Applications filed for drilling, deepening, or additional completion, recompletion, or reentry will be processed and permit issued in accordance with this regulation, subject to the commission's discretion to set any application for hearing. If the director or a delegate of the director declines to grant an application, the operator may request a hearing.

(i) Rule 37 permits.

(1) Unless otherwise specified in a permit or in a final order granting an exception to this section, permits issued by the commission for completions requiring an exception to this section shall expire two years from the effective date of the permit unless drilling operations are commenced in good faith within the two-year permit period. The permit period will not be extended.

(2) So long as a Rule 37 exception is in litigation, the two-year permit period will not commence. On final adjudication and decree from the last court of appeal the two-year permit period will commence, beginning on the date of final decree.

(j) Once an application for a spacing exception has been denied, no new application shall be entertained except on changed conditions. Changed conditions in the commission's administration of its Spacing Rule 37 and amendments thereto applicable to the various special fields and reservoirs of Texas and in passing upon applications for permits under said rule and amendments shall include, among other things, the following.

(1) Any material changes in the physical conditions of the producing reservoir under the tract under consideration or under the area surrounding said tract which would materially affect the recovery of oil, gas, or geothermal resource from the given tract.

(2) Any material changes in the distribution or allocation of allowable production in the area surrounding the tract under consideration which would materially affect or tend to affect the recovery of oil, gas, or geothermal resource from the given tract.

(3) Any additional permits granted by the commission for wells drilled in the area surrounding or on offset tracts to the tract under consideration which would materially affect or tend to affect the recovery of oil, gas, or geothermal resource from the given tract.

(4) Any additional facts or evidence thereof materially affecting or tending to affect the recovery of oil, gas, or geothermal resource from the applicant's tract, or the property rights of applicant, which were not known of and considered by the commission at any previous hearing or application thereon.

(k) Exceptions to Statewide Rule 37 apply to the total depth for which the permit is granted or if special field rules are applicable, an exception to the spacing rule shall be granted only for the reservoir or reservoirs or applicable depth to which the well is projected. Subsequent recompletion of the well to reservoirs other than that covered by the permit issued would be granted only after the filing and processing of a new application.

(l) Salt dome oil or gas fields.

(1) The provisions of this section shall not apply to certain approved salt dome oil or gas fields. An application for classification as a salt dome oil or gas field shall include the following:

(A) geological evidence proving that an oil or gas field is a piercement-type salt dome, that faulting has caused the producing formation to be at a 45 angle or greater, and that each well is likely to be completed in a separate reservoir;

(B) establishment, by plat or otherwise, of the probable productive limits of the salt dome area;

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.36	**Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas**

(a) Applicability. Each operator who conducts operations as described in paragraph (1) of this subsection shall be subject to this section and shall provide safeguards to protect the general public from the harmful effects of hydrogen sulfide. This section applies to both intentional and accidental releases of hydrogen sulfide.

(1) Operations including drilling, working over, producing, injecting, gathering, processing, transporting, and storage of hydrocarbon fluids that are part of, or directly related to, field production, transportation, and handling of hydrocarbon fluids that contain gas in the system which has hydrogen sulfide as a constituent of the gas, to the extent as specified in subsection (c) of this section, general provisions.

(2) This section shall not apply to:

(A) operations involving processing oil, gas, or hydrocarbon fluids which are either an industrial modification or products from industrial modification, such as refining, petrochemical plants, or chemical plants;

(B) operations involving gathering, storing, and transporting stabilized liquid hydrocarbons;

(C) operations where the concentration of hydrogen sulfide in the system is less than 100 ppm.

(b) Definitions.

(1) Industrial modification--This term is used to identify those operations related to refining, petrochemical plants, and chemical plants. The term does not include field processing such as that performed by gasoline plants and their associated gathering systems.

(2) Stabilized liquid hydrocarbon--The product of a production operation in which the entrained gaseous hydrocarbons have been removed to the degree that said liquid may be stored at atmospheric conditions.

(3) Radius of exposure--That radius constructed with the point of escape as its starting point and its length calculated as provided for in subsection (c)(2) of this section.

(4) Area of exposure--The area within a circle constructed with the point of escape as its center and the radius of exposure as its radius.

(5) Public area--A dwelling, place of business, church, school, hospital, school bus stop, government building, a public road, all or any portion of a park, city, town, village, or other similar area that can expect to be populated.

(6) Public road--Any federal, state, county, or municipal street or road owned or maintained for public access or use.

(7) Sulfide stress cracking--The cracking phenomenon which is the result of corrosive action of hydrogen

sulfide on susceptible metals under stress.

(8) Facility modification--Any change in the operation such as an increase in throughput, in excess of the designed capacity, or any change that would increase the radius of exposure.

(9) Public infringement--This shall mean that a public area and/or a public road, or both, has been established within an area of exposure to the degree that such infringement would change the applicable provisions of this rule to those operations responsible for creating the area of exposure.

(10) Potentially hazardous volume of hydrogen sulfide--A volume of hydrogen sulfide gas of such concentration that:

(A) the 100 ppm radius of exposure is in excess of 50 feet and includes any part of a "public area" except a public road; or

(B) the 500 ppm radius of exposure is greater than 50 feet and includes any part of a public road; or

(C) the 100 ppm radius of exposure is greater than 3,000 feet.

(11) Contingency plan--A written document that shall provide an organized plan of action for alerting and protecting the public within an area of exposure prior to an intentional release, or following the accidental release of a potentially hazardous volume of hydrogen sulfide.

(12) Reaction-type contingency plan--A preplanned, written procedure for alerting and protecting the public, within an area of exposure, where it is impossible or impractical to brief in advance all of the public that might possibly be within the area of exposure at the moment of an accidental release of a potentially hazardous volume of hydrogen sulfide.

(13) Definition of referenced organizations and publications.

(A) ANSI--American National Standard Institute, 1430 Broadway, New York, New York 10018, Table I, Standard 253.1-1967.

(B) API--American Petroleum Institute, 300 Corrigan Tower Building, Dallas, Texas 75201, Publication API RP-49, Publication API RP-14E, Sections 1.7(c), 2.1(c) 4.7.

(C) ASTM--American Society for Testing and Materials, 1916 Race Street, Philadelphia, Pennsylvania 19103, Standard D-2385-66.

(D) GPA--Gas Processors Association, 1812 First Place, Tulsa, Oklahoma 74120, Plant Operation Test Manual C-1, GPA Publication 2265-68.

(E) NACE--National Association of Corrosion Engineers, P.O. Box 1499, Houston, Texas 77001, Standard MR-01-75.

(F) DOT--Department of Transportation, Office of Pipeline Safety, 400 Seventh Street, S.W., Washington, D.C. 20590, Title 49, Code of Federal Regulations, Parts 192 and 195.

(G) OSHA--Occupational Safety and Health Administration, United States Department of Labor, 200 Constitution Avenue, NW, Washington D.C. 20270, Title 29, Code of Federal Regulations, Part 1910.145(c)(4)(i).

(H) RRC--Railroad Commission of Texas, Gas Utilities Division, P.O. Drawer 12967, Capitol Station, Austin, Texas 78711, Gas Utilities Dockets 446 and 183.

(c) General provisions.

(1) Each operator shall determine the hydrogen sulfide concentration in the gaseous mixture in the operation or system.

(A) Tests shall be made in accordance with standards as set by ASTM Standard D-2385-66, or GPA Plant Operation Test Manual C-1, GPA Publication 2265-68, or other methods approved by the commission.

(B) Test of vapor accumulation in storage tanks may be made with industry accepted colormetric tubes.

(2) For all operations subject to this section, the radius of exposure shall be determined, except in the cases of storage tanks, by the following Pasquill-Gifford equations, or by other methods that have been approved by the commission.

(A) For determining the location of the 100 ppm radius of exposure: x = [(1.589) (mole fraction H_2 S)(Q)] to the power of (.6258).

(B) For determining the location of the 500 ppm radius of exposure: x = [(0.4546) (mole fraction H_2 S)(Q)] to the power of (.6258). Where x = radius of exposure in feet; Q = maximum volume determined to be available for escape in cubic feet per day; H_2 S = mole fraction of hydrogen sulfide in the gaseous mixture available for escape.

(3) The volume used as the escape rate in determining the radius of exposure shall be that specified in subparagraph (A) - (E) of this paragraph, as applicable.

(A) The maximum daily volume rate of gas containing hydrogen sulfide handled by that system element for which the radius of exposure is calculated.

(B) For existing gas wells, the current adjusted open-flow rate, or the operator's estimate of the well's capacity to flow against zero back-pressure at the wellhead shall be used.

(C) For new wells drilled in developed areas, the escape rate shall be determined by using the current adjusted open-flow rate of offset wells, or the field average current adjusted open-flow rate, whichever is larger.

(D) The escape rate used in determining the radius of exposure shall be corrected to standard conditions of 14.65 pounds per square inch (psia) and 60 degrees Fahrenheit.

(E) For intentional releases from pipelines and pressurized vessels, the operator's estimate of the volume and release rate based on the gas contained in the system elements to be de-pressured.

(4) For the drilling of a well in an area where insufficient data exists to calculate a radius of exposure, but where hydrogen sulfide may be expected, then a 100 ppm radius of exposure equal to 3,000 feet shall be assumed. A lesser-assumed radius may be considered upon written request setting out the justification for same.

(5) Storage tank provision: storage tanks which are utilized as a part of a production operation, and which are operated at or near atmospheric pressure, and where the vapor accumulation has a hydrogen sulfide concentration in excess of 500 ppm, shall be subject to the following.

(A) No determination of a radius of exposure shall be made for storage tanks as herein described.

(B) A warning sign shall be posted on or within 50 feet of the facility to alert the general public of the potential danger.

(C) Fencing as a security measure is required when storage tanks are located inside the limits of a townsite or city, or where conditions cause the storage tanks to be exposed to the public.

(D) The warning and marker provision, paragraph (6)(A)(i), (ii), and (iv) of this subsection.

(E) The certificate of compliance provision, subsection (d)(1) of this section.

(6) All operators whose operations are subject to this section, and where the 100 ppm radius of exposure is in excess of 50 feet, shall be subject to the following.

(A) Warning and marker provision.

(i) For above-ground and fixed surface facilities, the operator shall post, where permitted by law, clearly visible warning signs on access roads or public streets, or roads which provide direct access to facilities located within the area of exposure.

(ii) In populated areas such as cases of townsites and cities where the use of signs is not considered to be acceptable, then an alternative warning plan may be approved upon written request to the commission.

(iii) For buried lines subject to this section, the operator shall comply with the following.

(I) A marker sign shall be installed at public road crossings.

(II) Marker signs shall be installed along the line, when it is located within a public area or along a public road, at intervals frequent enough in the judgment of the operator so as to provide warning to avoid the accidental rupturing of line by excavation.

(III) The marker sign shall contain sufficient information to establish the ownership and existence of the line and shall indicate by the use of the words "Poison Gas" that a potential danger exists. Markers installed in compliance with the regulations of the federal Department of Transportation shall satisfy the requirements of this provision. Marker signs installed prior to the effective date of this section shall be acceptable provided they indicate the existence of a potential hazard.

(iv) In satisfying the sign requirement of clause (i) of this subparagraph, the following will be acceptable.

(I) Sign of sufficient size to be readable at a reasonable distance from the facility.

(II) New signs constructed to satisfy this section shall use the language of "Caution" and "Poison Gas" with a black and yellow color contrast. Colors shall satisfy Table I of American National Standard Institute Standard 253.1-1967. Signs installed to satisfy this section are to be compatible with the regulations of the federal Occupational Safety and Health Administration.

(III) Existing signs installed prior to the effective date of this section will be acceptable if they indicate the existence of a potential hazard.

(B) Security provision.

(i) Unattended fixed surface facilities shall be protected from public access when located within 1/4 mile of a dwelling, place of business, hospital, school, church, government building, school bus stop, public park, town, city, village, or similarly populated area. This protection shall be provided by fencing and locking, or removal of pressure gauges and plugging of valve opening, or other similar means. For the purpose of this provision, surface pipeline shall not be considered as a fixed surface facility.

(ii) For well sites, fencing as a security measure is required when a well is located inside the limits of a townsite or city, or where conditions cause the well to be exposed to the public.

(iii) The fencing provision will be considered satisfied where the fencing structure is a deterrent to public access.

(C) Materials and equipment provision.

(i) For new construction or modification of facilities (including materials and equipment to be used in drilling and workover operations) completed or contemplated subsequent to the effective date of this section, the metal components shall be those metals which have been selected and manufactured so as to be resistant to hydrogen sulfide stress cracking under the operating conditions for which their use is intended, provided that they satisfy the requirements described in the latest editions of NACE Standard MR-01-75 and API RP-14E, sections 1.7(c), 2.1(c), 4.7. The handling and installation of materials and equipment used in hydrogen sulfide service are to be performed in such a manner so as not to induce susceptibility to sulfide stress cracking. Other materials which are nonsusceptible to sulfide stress cracking, such as fiberglass and plastics, may be used in hydrogen sulfide service provided such materials have been manufactured and inspected in a manner which will satisfy the latest published, applicable industry standard, specifications, or recommended practices.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.35	**Procedures for Identification and Control of Wellbores in Which Certain Logging Tools Have Been Abandoned**

(a) Abandonment of radioactive source.

(1) Immediate notice of the loss of a radioactive source shall be filed by the operator with the commission designating the location, by county, survey name and abstract number, lease name and well number, distances from survey boundaries and Lambert Coordinates.

(2) Procedures for recovery of the lost radioactive source will be furnished to the commission and such radioactive source shall not be declared abandoned until all reasonable effort has been expended to retrieve the tool.

(3) The operator shall erect, under supervision of the commission, a standardized permanent surface marker as a visual warning to any person who may reenter the hole for any reason, showing that it contains a radioactive source. This marker shall contain the following information: well name, commission number, surface location, name of the operator, name of the lease, the source or material abandoned in the well, the total depth of the well, the depth at which the source is abandoned, the plug back depth, the date of the abandonment of the source, the activity of the source, and a warning not to drill below the plug back depth.

(b) Abandonment procedures.

(1) Wells in which radioactive sources are abandoned shall be mechanically equipped so as to prevent either accidental or intentional mechanical disintegration of the radioactive source.

(A) Sources abandoned in the bottom of the well shall be covered with a substantial standard color dyed (red iron oxide) cement plug on top of which a whipstock or other approved deflection device shall be set. The dye is to alert the reentry operator prior to encountering the source.

(B) Upon abandoning the well in which a logging source has been cemented in place behind a casing string above total depth, a standard color dyed cement plug shall be placed opposite the abandoned source and a whipstock or other approved deflection device placed on top of the plug.

(C) In the event the operator finds that after expending a reasonable effort, because of hole conditions, it is not possible to abandon the source as prescribed in subparagraphs (A) and (B) of this paragraph, he shall seek commission approval to an alternate abandonment procedure.

(D) When a logging source must be abandoned in a producing zone, a standard color dyed cement plug shall be set and a whipstock or other approved deflection device placed above to direct the sidetrack at least 15 feet away from the source.

(2) Upon permanent abandonment of any well in which a radioactive source is left in the hole, and after removal of the wellhead, a permanent plaque shall be attached to the top of the casing left in the hole in such a manner that reentry cannot be accomplished without disturbing the plaque. This plaque shall serve as a visual warning to any person reentering the hole that a radioactive source has been abandoned in place in the

well. The plaque shall contain the trefoil radiation symbol with a radioactive warning and shall be constructed of a long-lasting material such as monel, stainless steel, or brass, in accordance with specifications established by the commission. The plugging report filed with the commission shall identify the well as an abandoned radioactive source well, and shall show compliance with the procedures required by this section.

(3) The commission will maintain a current listing of all abandoned radioactive source wells, and each district office will keep such a list for radioactive source wells in that district.

Source Note: The provisions of this §3.35 adopted to be effective January 1, 1976.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.34	**Gas To Be Produced and Purchased Ratably**

(a) Definitions. The following words and terms, when used in this section and in §3.31 of this title (relating to Gas Reservoirs and Gas Well Allowable) (Statewide Rule 31) shall have the following meanings, unless the context clearly indicates otherwise.

(1) Affiliate--A person or entity that owns, is owned by, or is under common ownership with another person or entity to the extent of 50% or more or that otherwise controls or is controlled by another person or entity. Affiliates of a common entity are also affiliates of each other. A person or entity that purchases gas solely for purposes other than resale shall not be considered an affiliate, and an interstate pipeline, as defined in the Natural Gas Policy Act of 1978, §2(15) (15 United States Code §3301 et seq.), shall not be considered an affiliate of an intrastate pipeline.

(2) Commission designee--A Railroad Commission employee authorized to act for the commission. Any authority given to a commission designee is also retained by the commission. Any action taken by the commission designee is subject to review by the commission.

(3) Downstream purchaser--One that purchases natural gas for resale and is not a first purchaser.

(4) First purchaser or initial purchaser--The first purchaser of natural gas produced from a well. A first purchaser and any affiliate of the purchaser that transports any natural gas it purchases from a well by use of the same pipeline system used by the first purchaser of which it is an affiliate shall be treated as a single first purchaser for purposes of ratability requirements; provided, however, that an affiliate that is purchasing and accepting deliveries pursuant to a special marketing program that is in compliance with this section, shall be treated as a separate first purchaser; and, provided further that the designation of such affiliate as a separate first purchaser is reviewable by the commission and may be disallowed upon a showing that the designation was for purposes of circumventing this section. Any affiliate may file forms in its own name.

(5) Pipeline system--A network of physically connected pipelines that are operated as a single unit under normal conditions.

(A) A first purchaser's pipeline system is that portion of a physical segment of a pipeline that the first purchaser owns.

(B) If a first purchaser does not own the pipeline it uses to transport its gas, the first purchaser's pipeline system shall include all the wells from which it purchases that are on the pipeline system of the transport pipeline.

(C) A first purchaser may not segregate its purchases from any one field into two or more pipeline systems by transporting on another pipeline gas that it purchases as a first purchaser if the first purchaser is also purchasing as a first purchaser from the same field and transporting on a pipeline that it owns.

(D) A first purchaser may not segregate its purchases from any one field into two or more pipeline systems by executing gas exchange agreements.

(E) Any of a first purchaser's pipeline systems which serve a common customer or common customers in a common geographic location shall be operated in a manner to avoid unjust or unreasonable discrimination in takes as between those systems.

(F) A first purchaser shall not segregate its physically connected pipelines that are capable of being operated as a single unit under normal conditions into two or more pipeline systems or designate a gathering system as a separate system for purposes of circumventing this section.

(6) Prorated gas field--A reservoir or field in which an allocation formula is in effect.

(b) General provisions. This section is promulgated to promote and maintain ratable production of natural gas and to require production in compliance with priority categories established by the commission for the purposes of preventing waste, including production in excess of market demand, protecting correlative rights, preventing discrimination, and conserving the natural resources of this state. An operator shall not produce in excess of its ratable share of the market demand as determined by this section and §3.28 and §3.31 of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported, and Gas Reservoirs and Gas Well Allowable) (Statewide Rules 28 and 31). An operator shall produce ratably as set out in subsection (e) of this section and shall produce in compliance with subsection (i) of this section which establishes priority categories of natural gas. Because production is dictated by pipeline capacity and market demand, pipelines are an integral part of production regulation. The requirements imposed on pipelines by this section and §3.28 and §3.31 of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported, and Gas Reservoirs and Gas Well Allowable) (Statewide Rules 28 and 31) are enforced to assist in the regulation of production and provide the only method by which such production regulation can be enforced and market demand met as required by statutory law. A first purchaser shall not discriminate between different wells from which it purchases in the same field, nor shall it discriminate unjustly or unreasonably between separate fields. The provisions of this section requiring ratable production and purchasing of gas apply to purchase and production from wells from which a first purchaser is purchasing on its pipeline system.

(c) Designation of pipeline system. A first purchaser shall, on or before a date designated by the commission or a commission designee, designate its pipeline system(s) and shall identify its affiliates that use the same pipeline system, including an affiliate operating a special marketing program that is in compliance with subsection (k) of this section. A pipeline system designation must identify the physical segment of pipeline that constitutes the pipeline system and identify by Railroad Commission of Texas lease and/or identification number and field the wells on that pipeline system from which the first purchaser is purchasing. A change in pipeline system designation is not required to add or delete well connections. The designation of a pipeline system cannot be changed by a first purchaser without prior approval by the commission or a commission designee. Approval of a change in pipeline system designation cannot be given without prior notice of the requested designation given by the first purchaser to affected operators of wells on the system(s) for which a change in designation is sought. A hearing to determine the proper designation of a first purchaser's pipeline system may be called by the commission, or may be requested by a first purchaser or by an operator filing a complaint. The burden of proof in the hearing shall be on the first purchaser.

(d) Operators who use produced gas. Any person who purchases natural gas at the wellhead, at a common point within a field or fields or at the outlet of a processing or treating plant must determine if it is the initial purchaser.

(e) Production guidelines. An operator shall produce without discrimination between its wells in the same field on the same first purchaser's pipeline system and without unjust or unreasonable discrimination between its wells in separate fields on the same first purchaser's pipeline system. An operator shall apportion a first purchaser's delivery requests ratably to its wells in each field on the same first purchaser's pipeline system without discrimination in the same manner as provided in this section and §3.28 and §3.31 of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported, and Gas Reservoirs and Gas Well Allowable) (Statewide Rules 28 and 31) and shall not produce in excess of its ratable share of the market demand as its share is determined by those rules. An operator shall produce in compliance with the priority categories of gas production established by the commission in subsection (i) of this section.

(f) Purchases from different fields.

(1) In making purchases and accepting deliveries between fields, a first purchaser of natural gas that purchases and accepts delivery of gas from more than one field on its same pipeline system must accept from each field a consistent percentage of the portion of the aggregate deliverability as determined by the deliverability tests and total gas limits that it is entitled to purchase from all wells from which it purchases on its pipeline system, unless the purchaser can demonstrate a just and reasonable basis for discriminating between fields.

(2) Natural gas purchases from a well by a first purchaser that uses another first purchaser's pipeline system to transport its gas and sells the gas purchased on that pipeline system solely to the first purchaser that owns the transport pipeline must be treated as first purchases of gas by the first purchaser that owns the transport pipeline.

(g) Purchases within a field.

(1) In making purchases and accepting deliveries within fields, a first purchaser of natural gas that purchases and accepts delivery of gas from different gas wells in the same priority category (see subsection (i) of this section) in the same field on its same pipeline system shall purchase and accept from the wells from which it purchases in the field a consistent percentage of the portion that it is entitled to purchase of the maximum allowable that a well is entitled to under the field's allocation formula. If purchases and deliveries from different wells in the same field become nonratable, the first purchaser shall consider commission-assigned underproduction and overproduction to establish an appropriate pattern of purchases or acceptance of deliveries to restore ratability.

(2) Natural gas purchases from a well by a first purchaser that uses another first purchaser's pipeline system to transport its gas and sells the gas purchased on that pipeline system solely to the first purchaser that owns the transport pipeline must be treated as first purchases of gas by the first purchaser that owns the transport pipeline.

(3) Purchases and deliveries of casinghead gas shall be based on the well's gas limit as specified in §3.49 of this title (relating to Gas-Oil Ratio) (Statewide Rule 49) as provided in subsection (h) of this section. Overproduction and underproduction of gas is administered by the provisions of §3.31 of this title (relating to Gas Reservoirs and Gas Well Allowable) (Statewide Rule 31). A first purchaser shall not reduce purchases from a limited well as described in §3.31(g)(5) until all prorated gas wells from which it purchases in the field connected to its same pipeline system are ratably reduced to the assigned allowable of the limited well. Below that point, purchases from all prorated wells and limited wells should be reduced ratably by purchasing and accepting delivery of the same percentage of the portion that it is entitled to purchase of the maximum allowable established for the well by the field's allocation formula. If purchases and deliveries from different wells in the same field become nonratable, the first purchaser shall consider commission-assigned underproduction and overproduction in establishing an appropriate pattern of purchases or acceptances of deliveries to restore ratability. When purchases of gas described in subsection (i)(2) or (5) of this section are to be reduced, they shall be reduced ratably within each priority category.

(h) Casinghead gas reductions. When purchases and deliveries of casinghead gas described in subsection (i)(1) or (3) of this section are to be reduced, each well's share of the reduction shall be calculated by multiplying the total reduction by the fractional share that each well's gas limit bears to the arithmetic sum of the aggregate gas limits of all wells in the field from which the first purchaser has been purchasing on its same pipeline system. In calculating its reduction of a well, a first purchaser shall use that portion of the gas limits that it is entitled to purchase. A well operating under net gas/oil ratio authority shall produce no more gas than its gas limit as it would be reduced by the previously mentioned procedure absent the net gas/oil ratio authority.

(i) Priority categories. First purchasers of gas shall satisfy their pipeline system demand for gas by purchasing and accepting delivery of gas from the following priority categories in ascending numerical order. Lower priority category gas is gas from a higher numerical category. A first purchaser shall not within its pipeline system curtail gas from a priority category if the purchaser is purchasing and accepting delivery of lower priority category gas as a first purchaser on its same pipeline system. A first purchaser's purchases and acceptance of delivery of first, second, or third priority category gas under an obligation to purchase and accept delivery from the tailgate of a plant processing gas to extract liquids, or from a gathering system that purchases from wells and is required by contract or by its physical connections to sell its gas entirely to the purchaser, whether or not these purchases are made as a first purchaser, shall not be curtailed if the first purchaser is purchasing and accepting delivery of lower priority category gas as a first purchaser on its same pipeline system. If curtailed, the curtailment must be ratable with like priority category gas which the first purchaser is purchasing and accepting delivery of from wells on its same pipeline system.

(1) First priority shall be given to casinghead gas produced from certified tertiary recovery projects approved by the commission and secondary recovery projects involving water injection, gas injection, or pressure maintenance approved by the commission to prevent waste.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.33	**Geothermal Resource Production Test Forms Required**

(a) A production test form, with all information requested thereon filled in, shall be filed in the district office not later than 10 days after the test is completed. Production operations shall not be commenced before the test form is filed and the commission grants authority to initiate operations.

(b) The initial production test form for any new completion or recompletion must be accompanied by the well record.

Source Note: The provisions of this §3.33 adopted to be effective January 1, 1976.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.32	**Gas Well Gas and Casinghead Gas Shall Be Utilized for Legal Purposes**

(a) The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Fugitive emissions--Releases of gas from lease production, gathering, compression, or gas plant equipment components, including emissions from valve stems, pressure relief valves, flanges and connections, gas-operated valves, compressor and pump seals, pumping well stuffing boxes, casing-to-casing bradenheads subject to the provisions of §3.17 of this title (relating to Pressure on Bradenhead), pits, and sumps, that cannot reasonably be captured and sold or routed to a vent or flare.

(2) Gathering system--Facilities employed to collect, compress, and transport gas to another gas gathering system, a gas plant, compression facility, or transmission line.

(3) Lease production facilities--Production, separation, treating, compression, flowlines, storage, and other production handling equipment employed on a lease in the production of gas, condensate, and oil.

(4) Low pressure separator gas--Gas separated or liberated from a gas-liquid stream in a low pressure separation facility. Low pressure separation facilities include but are not limited to separators, treaters, free water knockouts, and other associated equipment.

(5) Tank vapors--Gas which evolves from oil, condensate, or water when placed in a gunbarrel or storage tank.

(b) Activities authorized by this section may be subject to rules and regulations promulgated by the United States Environmental Protection Agency under the federal Clean Air Act or the Texas Commission on Environmental Quality under the Texas Clean Air Act.

(c) General Provisions. All gas from any oil well, gas well, gas gathering system, gas plant or other gas handling equipment shall be utilized for purposes and uses authorized by law, except as provided in this section. This section does not apply to gas transmission or gas distribution facilities or operations.

(d) Exempt Gas Releases.

(1) Releases of gas that are not readily measured by devices routinely used in the operation of oil wells, gas wells, gas gathering systems, or gas plants, such as meters, are not required by the commission to be reported or charged against lease allowable production and are not subject to the remaining requirements of this section. Releases of gas exempt from the requirements of this section under this paragraph include, but are not limited to, the following:

(A) tank vapors from crude oil storage tanks, gas well condensate storage tanks, or salt water storage tanks, including makeup gas for gas blanket maintenance;

(B) fugitive emissions of gas;

(C) amine treater, glycol dehydrator flash tank and/or reboiler emissions;

(D) blowdown gas from flow lines, gathering lines, meter runs, pressurized vessels, compressors, or other gas handling equipment for construction, maintenance or repair;

(E) gas purged from compressor cylinders or other gas handling equipment for startup;

(F) gas released at a wellsite during drilling operations and prior to the completion date of the well, including gas produced during air or gas drilling operations or gas which must be separated from drilling fluids using a mud-gas separator, or mud-degasser; or

(G) gas released at a wellsite during initial completion, recompletion in another field, or workover operations in the same field, including but not limited to perforating, stimulating, deepening, cleanout, well maintenance or repair operations.

(2) Notwithstanding the foregoing, the commission or the commission's delegate may require the flaring of releases of gas not readily measured by devices routinely used in the operation of oil wells, gas wells, gas gathering systems, or gas plants, such as meters, if the commission or the commission's delegate determines that flaring is required for safety reasons.

(e) Gas Releases to be Burned in a Flare.

(1) Except as otherwise provided in subsections (d), (f)(1)(B) and (C), (g)(2), or an exception granted under subsection (h) of this section, all gas releases of greater than 24 hours duration authorized under the provisions of this section shall be burned in a flare if the gas can be burned safely. All gas releases of 24 hours' duration or less authorized under the provisions of this section may be vented to the air if flaring is not required for safety reasons or by other regulation and the gas can be safely vented.

(2) Gas releases authorized under this section must be managed in accordance with the provisions of §3.36 of this title (relating to Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas) when applicable.

(3) An exception to the requirements of this subsection may be granted under subsection (h) by the commission or the commission's delegate to allow the venting of gas to the air for releases of greater than 24 hours' duration if the operator presents information that shows the gas cannot be both safely and continuously burned in a flare, and the gas can be safely vented.

(4) Notwithstanding the provisions of paragraph (1) of this subsection or an exception granted under subsection (h), the commission or the commission's delegate may require that the gas be flared if flaring is required for safety reasons.

(f) Gas Releases in Oil and Gas Production Operations.

(1) The following releases of gas resulting from routine oil and gas production operations are necessary in the efficient drilling and operation of oil and gas wells and are hereby authorized subject to the requirements of subsection (e) of this section. The released gas shall be measured or estimated in accordance with §3.27 of this title (relating to Gas To Be Measured and Surface Commingling of Gas) and reported and charged against lease allowable production.

(A) Gas may be released for a period not to exceed ten producing days after initial completion, recompletion in another field, or workover operations in the same field, including but not limited to perforating, stimulating, deepening, cleanout, well maintenance or repair operations.

(B) Gas from a well that must be unloaded or cleaned-up to atmospheric pressure may be vented to the air for periods not to exceed 24 hours in one continuous event or a total of 72 hours in one calendar month.

(C) In the event of a full or partial shutdown by a gas gathering system, compression facility, or gas plant, gas from a lease production facility served by that gas gathering system, compression facility or gas plant may be released for a period not to exceed 24 hours. The operator shall notify the appropriate commission district office by telephone or facsimile as soon as reasonably possible after the release of gas begins. An operator may continue the release by flaring or by venting of the gas, if flaring is not required for safety reasons or by other regulation, beyond the initial 24-hour period, pending commission approval or denial of a request for an administrative exception under subsection (h) of this section. The operator shall file the request with the commission by the end of the next full business day following the first 24 hours of the release unless the deadline is extended by the commission or the commission's delegate.

(D) Hydrocarbon gas contained in the waste stream from a membrane unit or molecular sieve used to remove carbon dioxide, hydrogen sulfide, or other contaminants from a gas stream may be released, provided that at least 85% of the hydrocarbon gas in the inlet gas stream is recovered and directed to a legal use.

(E) Low pressure separator gas, not to exceed 15 mcfd of hydrocarbon gas per gas well or 50 mcfd of hydrocarbon gas per commission-designated oil lease or commingling point for commingled operations, may be released.

(2) The commission or the commission's delegate may administratively grant or renew an exception to the requirements or limitations of this subsection subject to the requirements of subsection (h) to allow additional releases of gas if the operator of a well or production facility presents information to show the necessity for the release. The volume of gas that is released must be measured or estimated in accordance with §3.27 of this title (relating to Gas To Be Measured and Surface Commingling of Gas) and reported on the appropriate commission form and shall be charged to the operator's allowable production. Necessity for the release includes, but is not limited to, the following situations:

(A) Cleaning a well of solids or fluids or both for more than ten producing days following initial completion, recompletion in another field, or workover operations in the same field, including but not limited to perforating, stimulating, deepening, cleanout, or well maintenance or repair operations;

(B) Unloading excess formation fluid buildup in a wellbore for periods in excess of 24 hours in one continuous event or 72 hours total in one calendar month;

(C) Volumes of low pressure gas that can be measured with devices routinely used in oil and gas exploration, development, and production operations and that are not directed by an operator to a gas gathering system, gas pipeline, or other marketing facility, or other purposes and uses authorized by law due to mechanical, physical, or economic impracticability;

(D) For casinghead gas only, the unavailability of a gas pipeline or other marketing facility, or other purposes and uses authorized by law; or

(E) Avoiding curtailment of gas production which will result in a reduction of ultimate recovery from a gas well or oil reservoir.

(g) Gas releases from gas gathering system, gas plant or gas handling operations.

(1) The operator of a gas gathering system, gas plant, gas compressor facility or other gas handling equipment not directly associated with lease production of gas, shall not intentionally allow gas to be released for a period of more than 24 hours after the start of an upset condition. The operator shall notify the appropriate commission district office by telephone or facsimile as soon as reasonably possible after the release of gas begins. The volume of gas that is released must be measured or estimated in accordance with §3.27 of this title (relating to Gas To Be Measured and Surface Commingling of Gas) and reported on the appropriate commission form. The provisions of this subsection do not apply to accidental releases which are subject to or reported pursuant to any other commission rule.

(2) The commission or the commission's delegate may administratively grant or renew an exception to the requirements or limitations of this subsection and allow additional releases of gas for a period greater than 24 hours if the operator presents information that shows the necessity for the release. An operator may

continue the release by flaring or by venting of the gas, if flaring is not required for safety reasons or by other regulation, beyond the initial 24-hour period pending commission consideration of a request for an administrative exception under subsection (h) of this section. The request for exception is to be filed with the commission by the end of the next full business day following the first 24 hours of the release unless the deadline is extended by the commission or the commission's delegate. The following are examples of situations that may qualify for an exception under this paragraph:

(A) gas gathering system or gas plant construction, repairs or maintenance;

(B) gas plant turnaround; or

(C) emergency situations.

(h) Exceptions. The commission or the commission's delegate may administratively grant an exception authorized by this section provided that the requirements of this subsection are met.

(1) The request for an exception shall be accompanied by the fee required by §3.78(b)(5) of this title (relating to Fees and Financial Security Requirements).

(2) An administrative exception shall not exceed a period of 180 days.

(3) The 180-day limitation shall not apply for volumes of gas less than or equal to 50 mcf of hydrocarbon gas per day for each gas well, commission-designated oil lease, or commingled vent or flare point.

(4) Requests for exceptions for more than 180 days and for volumes greater than 50 mcf of hydrocarbon gas per day shall be granted only in a final order signed by the commission.

(5) A request for an exception to cover an operating emergency, system upset, or other unplanned condition may be submitted by facsimile transmission or other means, provided that an original signed request is accompanied by the fee required by subsection (h)(1) of this section and is received by the commission within three working days of the facsimile transmission request.

(6) Exceptions shall be issued to the operator of a gas well or commission-designated oil lease or commingling point for commingled operations and to the operator of a processing plant or other facility subject to this section.

(7) Exceptions are not transferable upon a change of operatorship. Operators shall have 90 days from the date of commission approval of a transfer of operatorship to review existing exceptions to this section and, if continuation of the exception is needed, to make application for a new exception. The existing exception and existing authority shall remain in effect during the 90-day review period. If an operator files an application and fee for a new exception before the 90-day review period expires and the 90-day review period expires before the commission acts on the application, the operator is authorized to continue to operate under the existing authority pending final commission action on the application.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.31	**Gas Reservoirs and Gas Well Allowable**

(a) General.

(1) Allowables of gas wells not currently assigned an allowable will not be made effective:

(A) prior to the well's completion or reclassification date; or

(B) more than 15 days prior to the date all reports or information necessary to the assignment of an allowable are received in the appropriate commission office.

(2) If a report or item of information necessary to the assignment of an allowable is not filed on time, there shall be a one-day allowable reduction for each day the report or information is late.

(b) Changes in gas well allowables.

(1) Changes in allowable of gas wells currently assigned an allowable will be effective on the date of the test or date of the change affecting the well's allowable (when the operator submits special tests or information), provided this is not more than 15 days prior to the date the special test or information is received in the appropriate district office.

(2) With respect to a multicompleted well, the allowable of the second and succeeding zones will be made effective no earlier than the date the last report or item necessary for the assignment of an allowable is received in the appropriate commission office.

(3) When a well is recompleted as a gas well in a different field, any overproduction that has occurred in the old field must be made up before an allowable will be assigned in the new field.

(c) Requirements for gas wells in a field for which an allocation formula has been adopted.

(1) If acreage is a factor in the allocation formula, a certified plat showing the acreage assigned to the well for proration purposes shall be submitted. The plat must be accompanied by a statement that all of the acreage claimed can reasonably be considered productive of gas and that the distance limitations of the field rules have not been exceeded. If all of the acreage claimed is not contained in a single lease, a certificate of pooling authority must be submitted, on the appropriate commission form. If the distance limitations of the field rules are shown to have been exceeded, the plat must show the number of acres within and beyond the distance limitations. An operator may request an exception to the distance limitations which may be administratively approved by the commission or a commission designee if all the acreage can be considered productive. If approval of the request is declined or protest is received, the request may be set for hearing. If all of the acreage cannot be considered productive, the plat must also show the productive limit of the acreage. If a plat shows acreage in the unit in excess of the maximum number of acres permitted by the field rules, it will not be accepted.

(2) If bottom-hole or reservoir pressure is a factor in the allocation formula, it shall be submitted on the appropriate commission form and shall be measured at, or corrected to, the proper datum plane.

(3) If any other information, data or parameter is a factor in the allocation formula, it must be submitted on the appropriate commission form.

(d) Determining prorated reservoir allowable and lawful market demand.

(1) On or before the 25th day of each month, the commission will determine the lawful market demand for gas to be produced from each reservoir during the upcoming allowable month. The monthly reservoir allowable shall be equal to the lawful market demand for that reservoir. The lawful reservoir market demand for prorated reservoirs shall be equal to the adjusted reservoir market demand forecast adjusted by a forecast

correction adjustment, and a commission adjustment (i.e., lawful reservoir market demand = adjusted reservoir market demand forecast + forecast correction adjustment + commission adjustment).

(A) Allowable month--The month during which allowables determined pursuant to this section will be effective.

(B) Adjusted reservoir market demand forecast--The sum of all operator reservoir market demand forecasts for a reservoir after any necessary downward adjustments have been made to individual operator reservoir market demand forecasts and optional operator forecasts so that no such forecast will exceed the total capability of the operator's wells for the reservoir during the allowable month.

(C) Operator reservoir market demand forecast--The sum of the operator's well forecasts for a reservoir determined by the commission pursuant to this subsection.

(i) The commission will determine a forecast for each well that will be active during the allowable month that:

(I) for prorated and limited wells is equal to the well's production during the same allowable month in the prior year; and

(II) for special or administrative special allowable wells is equal to the well's production during the most recently reported production month.

(ii) If the well had no reported production during the same allowable month in the prior year or if a special or administrative special allowable well had no reported production in the most recently reported production month, the forecast shall be equal to:

(I) the well's highest reported monthly production during any of the three most recently reported production months; or, if no production has been reported for those months;

(II) the well's capability.

(iii) Alternatively, the operator reservoir market demand forecast may be determined by an optional operator forecast.

(D) Optional operator forecast--The commission designated operator may file an optional market demand forecast for all of the operator's wells in the reservoir that is equal to the anticipated market demand for the production from the operator's wells in the field during the allowable month. The optional operator forecast for the operator's wells in the reservoir can be no greater than the total capability of the operator's wells or less than zero. An optional operator forecast must be filed by the 10th day of the month preceding the allowable month.

(E) Forecast correction adjustment--

(i) The February 1994 forecast correction adjustment shall be the reservoir market demand for November 1993 for all wells in a reservoir that are not administrative special allowable wells for February 1994, subtracted from the production reported for November 1993 for those wells;

(ii) The March 1994 forecast correction adjustment shall be the reservoir market demand for December 1993 for all wells in a reservoir that are not administrative special allowable wells for March 1994, subtracted from the production reported for December 1993 for those wells;

(iii) The April 1994 forecast correction adjustment shall be the reservoir market demand for January

1994 for all wells in a reservoir that are not administrative special allowable wells for April 1994, subtracted from the production reported for January 1994 for those wells;

(iv) For May 1994 and subsequent months, the forecast correction adjustment shall be equal to the total reservoir production from the most recent reported month, minus (total adjusted reservoir market demand forecast for the production month + supplemental change adjustment for that month + commission adjustment for that month), minus (production from all special and administrative special allowable wells minus allowable assigned to those special wells for that month).

(F) Supplemental change adjustment--Any adjustment to the reservoir allowable that is necessary to account for an automatic allowable revision in a prior month, a change of well or well test status during a prior month, the provisions of a final order modifying field or well production status, or any other ministerial change.

(G) Commission adjustment--Any other adjustments to the adjusted reservoir market demand forecast that the commission determines are necessary.

(2) The commission may reject or modify any optional operator forecast if it determines that the forecast is inaccurate or being used to manipulate the allocation of gas rather than to determine the reasonable market demand.

(e) Well capability.

(1) No gas well shall be given an initial allowable in excess of its capability.

(A) Except as provided in subparagraphs (B) and (C) of this paragraph, a well's capability is defined as the lesser of:

(i) the well's latest deliverability test on file with the commission; or

(ii) the well's highest monthly production during any of the three most recently reported production months.

(B) If a well is a special or an administrative special allowable well, its capability is defined as the lesser of:

(i) the well's latest deliverability test on file with the commission; or

(ii) the well's most recently reported monthly production.

(C) If a well is new to a reservoir and has been active for less than six months, its capability shall be defined as the well's latest deliverability test on file with the commission.

(2) An operator may submit a substitute capability determination for any well in a prorated field that represents the maximum monthly production capability of the well under normal operating conditions for a specific six-month period.

(A) The determination may be made on the basis of a well test or other acceptable information by a registered professional engineer who certifies that the determination was made by the engineer or under the supervision of the engineer, and that the capability has been determined in accordance with generally accepted engineering practices. Alternatively, the substitute capability determination may be made by an independent tester on the basis of a well test conducted in accordance with §3.28(c) of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported) (Statewide Rule 28). The request for a substitute capability must be submitted on the appropriate form.

(B) The commission or a commission designee may reject any substitute capability determination for good cause.

(C) The capability determined pursuant to this paragraph shall be used as the well's capability for a period of six months from the effective date of the determination unless:

(i) the operator files a written request that the substitute capability determination be cancelled. If such a request is submitted, the substitute capability may be cancelled by the commission or commission designee; or

(ii) an affected person files a protest alleging, with specificity, the inaccuracy or invalidity of the determination. If a protest is filed, the commission may set the matter for hearing. A protested substitute capability determination shall be effective on the intended effective date, unless the commission orders otherwise. If the commission determines that the protested substitute capability was incorrect, appropriate allowable or status adjustments will be made for the affected well.

(f) Fields operating under statewide rules. A statewide prorated field is any gas field in which no special field rules have been adopted and in which at least one well in the field has a current reported deliverability test of greater than 250 Mcf a day. Daily allowable production of gas from individual wells in a statewide prorated field shall be determined by allocating the allowable production among the individual wells in the proportion that each well's deliverability (based on the latest deliverability test of record) bears to the summation of the most recent reported deliverability tests of all wells producing from the same field. Allocated allowables shall be subject to the well capability provisions of this section.

(g) Definitions of prorated and nonprorated wells and fields.

(1) A prorated well is a well for which an allowable is determined by an allocation formula.

(2) A nonprorated well is a well for which an allowable is not determined by an allocation formula.

(3) A prorated field is a field that has two or more wells one of which is a prorated well.

(4) A nonprorated field is any field that is not a prorated field.

(5) Statewide Exempt Fields:

(A) A statewide exempt field is any gas field in which no special field rules have been adopted and in which no well in the field has a current reported deliverability test of greater than 250 Mcf per day. Wells in statewide exempt fields shall be assigned allowables equal to their capacity to produce but in no event greater than 250 Mcf per day.

(B) In fields where special field rules exist and no well has a current deliverability test of greater than 250 Mcf per day, an operator may request statewide exempt field status. The request may be granted administratively by the commission or commission designee if the applicant provides the commission with a declaration, signed by all operators, subject to the false filing penalties provided for in the Texas Natural Resources Code, §91.143, stating all operators in the field agree to exempt status. If declarations are not provided from all operators in the field or if the commission or commission designee declines to grant any request administratively, the applicant may request a hearing. If a notice of intent to appear in protest of the application has not been filed by five days before the date of the hearing, then there shall be a presumption that each well's first purchaser has a market for 100% of the well's deliverability as determined by the most recent deliverability tests on file with the Commission and that granting exempt status to the field will not harm correlative rights or cause waste and exempt status will be granted. Wells in exempt fields with special rules shall be assigned allowables equal to their capability to produce but in no event greater than 250 Mcf per day. If 250 Mcf per day is exceeded by any well, the field will be changed to the existing special field rule allocation. Reinstatement of allocation formula may be initiated by the commission designee, or by one of the operators in the field.

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Texas Administrative Code

TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.30	**Memorandum of Understanding between the Railroad Commission of Texas (RRC) and the Texas Commission on Environmental Quality (TCEQ)**

(a) Need for agreement.

(1) Section 10 of House Bill 1407, 67th Legislature, 1981, which appeared as a footnote to the Texas Solid Waste Disposal Act, Texas Civil Statutes, Article 4477-7, provides as follows: On or before January 1, 1982, the Texas Department of Water Resources, the Texas Department of Health, and the Railroad Commission of Texas shall execute a memorandum of understanding that specifies in detail these agencies' interpretation of the division of jurisdiction among the agencies over waste materials that result from or are related to activities associated with the exploration for and the development, production, and refining of oil or gas. The agencies shall amend the memorandum of understanding at any time that the agencies find it to be necessary.

(2) The original Memorandum of Understanding (MOU) between the agencies became effective January 1, 1982. The MOU was revised effective December 1, 1987, to reflect legislative clarification of the Railroad Commission's jurisdiction over oil and gas wastes and the Texas Water Commission's (successor to the Texas Department of Water Resources) jurisdiction over industrial and hazardous wastes.

(3) The agencies have determined that the revised MOU that became effective on December 1, 1987, should again be revised to further clarify jurisdictional boundaries and to reflect legislative changes in agency responsibility and the combination of the Texas Water Commission, the Texas Air Control Board, and portions of the Texas Department of Health to form the Texas Natural Resource Conservation Commission.

(b) General agency jurisdictions.

(1) Texas Commission on Environmental Quality (TCEQ) (the successor agency to the Texas Natural Resource Conservation Commission (TNRCC)). References in this section to TCEQ shall mean TCEQ or any successor agencies.

(A) The TCEQ has jurisdiction over solid waste under Chapter 361 of the Texas Health and Safety Code, §§361.001-361.754. The TCEQ's jurisdiction encompasses both hazardous and nonhazardous, industrial and municipal, solid wastes.

(B) Under Texas Health and Safety Code, §361.003(34), solid waste under the jurisdiction of the TCEQ is defined to include "garbage, rubbish, refuse, sludge from a waste treatment plant, water supply treatment plant, or air pollution control facility, and other discarded material, including solid, liquid, semisolid, or contained gaseous material resulting from industrial, municipal, commercial, mining, and agricultural operations and from community and institutional activities."

(C) Solid waste is further defined in Texas Health and Safety Code, §361.003(34), to exclude "material which results from activities associated with the exploration, development, or production of oil or gas or geothermal resources and other substance or material regulated by the Railroad Commission of Texas pursuant to Section 91.101, Natural Resources Code...."

(D) In addition, Texas Health and Safety Code, §361.003(34), defines the term solid waste to include the following until the United States Environmental Protection Agency (EPA) delegates its authority under the Resource Conservation and Recovery Act, 42 United States Code (U.S.C.) §6901, et seq., (RCRA) to the RRC: "waste, substance or material that results from activities associated with gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance plants, or repressurizing plants and is a hazardous waste as defined by the administrator of the EPA...."

(E) After delegation of RCRA authority to the Railroad Commission of Texas (RRC), the definition of solid waste (which defines TCEQ's jurisdiction) will not include hazardous wastes generated at natural gas or natural gas liquids processing plants, or reservoir pressure maintenance or repressurizing plants. The term natural gas or natural gas liquids processing plant refers to a plant the primary function of which is the extraction of natural gas liquids from field gas or fractionation of natural gas liquids. The term does not include a separately located natural gas treating plant for which the primary function is the removal of carbon dioxide, hydrogen sulfide, or other impurities from the natural gas stream. A separator, dehydration unit, heater treater, sweetening unit, compressor, or similar equipment is considered a part of a natural gas or natural gas liquids processing plant only if it is located at a plant the primary function of which is the extraction of natural gas liquids from field gas or fractionation of natural gas liquids. Further, a pressure maintenance or repressurizing plant is a plant for processing natural gas for reinjection (for reservoir pressure maintenance or repressurization) in a natural gas recycling project. A compressor station along a natural gas pipeline system or a pump station along a crude oil pipeline system is not a pressure maintenance or repressurizing plant.

(2) Railroad Commission of Texas (RRC).

(A) Generally, under Texas Natural Resources Code, Title 3, and Texas Water Code, Chapter 26, wastes (both hazardous and nonhazardous) resulting from activities associated with the exploration, development, or production of oil or gas or geothermal resources, including transportation of crude oil or natural gas by pipeline, and other activities regulated by the RRC are under the jurisdiction of the RRC. These wastes are termed "oil and gas wastes." In compliance with Texas Health and Safety Code, §361.025 (concerning exempt activities), a list of activities that generate wastes that are subject to the jurisdiction of the RRC is found at §3.8(a)(30) of this title (relating to Water Protection) and at 30 Texas Administrative Code §335.1 (concerning definitions), which contains a definition of "activities associated with the exploration, development, and production of oil or gas or geothermal resources." This MOU provides further guidance regarding the agencies' interpretation of these rules and statutes.

(B) Notwithstanding subparagraph (A) of this paragraph, hazardous wastes generated at natural gas or natural gas liquids processing plants or reservoir pressure maintenance or repressurizing plants are subject to the jurisdiction of the TCEQ until the RRC is authorized by EPA to administer RCRA. When the RRC is authorized by EPA to administer RCRA, jurisdiction over such hazardous wastes will transfer from the TCEQ to the RRC.

(c) Definition of hazardous waste.

(1) Under the Texas Health and Safety Code, §361.003(12), a "hazardous waste" subject to the jurisdiction of the TCEQ is defined as "solid waste identified or listed as a hazardous waste by the administrator of the United States Environmental Protection Agency under the federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, as amended (42 U.S.C. §6901, et seq.)." Similarly, under Texas Natural Resources Code, §91.601(1), "oil and gas hazardous waste" subject to the jurisdiction of the RRC is defined as an "oil and gas waste that is a hazardous waste as defined by the administrator of the United States Environmental Protection Agency under the federal Solid Waste Disposal Act, as amended

by the Resource Conservation and Recovery Act of 1976 (42 U.S.C. §6901, et seq.)."

(2) Federal regulations adopted under authority of the federal Solid Waste Disposal Act, as amended by RCRA, exempt from regulation as hazardous waste certain oil and gas wastes. Under 40 Code of Federal Regulations (CFR) §261.4(b)(5), "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy" are described as wastes that are exempt from federal hazardous waste regulations.

(3) A partial list of wastes associated with oil, gas, and geothermal exploration, development, and production that are considered exempt from hazardous waste regulation under RCRA can be found in EPA's "Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes," 53 FedReg 25,446 (July 6, 1988). A further explanation of the exemption can be found in the "Clarification of the Regulatory Determination for Wastes from the Exploration, Development and Production of Crude Oil, Natural Gas and Geothermal Energy, " 58 FedReg 15,284 (March 22, 1993). The exemption codified at 40 CFR §261.4(b)(5) and discussed in the Regulatory Determination has been, and may continue to be, clarified in subsequent guidance issued by the EPA.

(d) Jurisdiction over specific disposal activities.

(1) Discharges under Texas Water Code, Chapter 26. Under the Texas Water Code, Chapter 26, the TCEQ has jurisdiction over discharges of waste into or adjacent to water in the state, other than discharges regulated by the RRC. The RRC regulates discharges of waste from activities associated with the exploration, development, or production of oil, gas, or geothermal resources, including transportation of crude oil and natural gas by pipeline, and from solution brine mining activities (except solution mining activities conducted for the purpose of creating caverns in naturally-occurring salt formations for the storage of wastes regulated by the TCEQ) under Texas Natural Resources Code, Title 3, and Texas Water Code, Chapter 26. Discharges of waste regulated by the RRC into water in the state shall not cause a violation of the water quality standards. While water quality standards are established by the TCEQ, the RRC has the responsibility for enforcing any violations of such standards. Texas Water Code, Chapter 26, does not require that discharges regulated by the RRC comply with regulations of the TCEQ that are not water quality standards. Because of the complexity of 30 Texas Administrative Code §307.6 (concerning toxic materials), the staffs of the TCEQ and the RRC will consult from time to time regarding application and interpretation of the Texas Surface Water Quality Standards.

(2) Disposal wells under Texas Water Code, Chapter 27. Jurisdiction over wastes disposed by injection is divided between the RRC and the TCEQ as set forth in Texas Water Code, Chapter 27 (the Injection Well Act). The RRC has jurisdiction under Texas Water Code, Chapter 27, over injection wells used to dispose of oil and gas waste. Texas Water Code, Chapter 27, defines "oil and gas waste" to mean "waste arising out of or incidental to drilling for or producing of oil, gas, or geothermal resources, waste arising out of or incidental to the underground storage of hydrocarbons other than storage in artificial tanks or containers, or waste arising out of or incidental to the operation of gasoline plants, natural gas processing plants, or pressure maintenance or repressurizing plants. The term includes but is not limited to salt water, brine, sludge, drilling mud, and other liquid or semi-liquid waste material." The term "waste arising out of or incidental to drilling for or producing of oil, gas, or geothermal resources" includes waste associated with transportation of crude oil or natural gas by pipeline pursuant to Texas Natural Resources Code, §91.101. The TCEQ has jurisdiction over injection wells used to dispose of other types of waste.

(3) Disposal of naturally occurring radioactive material (NORM). (The term "disposal" does not include receipt, possession, use, processing, transfer, transport, storage, or commercial distribution of radioactive materials, including NORM. These activities are under the jurisdiction of the Texas Department of Health per Texas Health and Safety Code, §401.011(a).)

(A) Under Texas Health and Safety Code, §401.415, the RRC has jurisdiction over the disposal of NORM that constitutes, is contained in, or has contaminated oil and gas waste. This waste material is called "oil and gas NORM waste." Oil and gas NORM waste may be generated in connection with the exploration, development, or production of oil or gas. Oil and gas NORM waste may also be generated in connection with geothermal resource exploration, development, or production activities or solution brine mining activities.

(B) Under Texas Health and Safety Code, §401.412, the TCEQ has jurisdiction over the disposal of NORM which is not oil and gas NORM waste.

(e) Jurisdiction over waste from specific oil and gas activities.

(1) Drilling, operation, and plugging of wells associated with the exploration, development, or production of oil, gas, or geothermal resources. Wells associated with the exploration, development, or production of oil, gas, or geothermal resources include exploratory wells, cathodic protection holes, core holes, oil wells, gas wells, geothermal resource wells, fluid injection wells used for secondary or enhanced recovery of oil or gas, oil and gas waste disposal wells, and injection water source wells. Several types of waste materials can be generated during the drilling, operation, and plugging of these wells. These waste materials include drilling fluids (including water-based and oil-based fluids), cuttings, produced water, produced sand, waste hydrocarbons (including used oil), fracturing fluids, spent acid, workover fluids, treating chemicals (including scale inhibitors, emulsion breakers, paraffin inhibitors, and surfactants), waste cement, filters (including used oil filters), domestic sewage (including waterborne human waste and waste from activities such as bathing and food preparation), and trash (including inert waste, barrels, dope cans, oily rags, mud sacks, and garbage). Generally, these wastes, whether disposed of by discharge, landfill, land farm, evaporation, or injection, are subject to the jurisdiction of the RRC.

(2) Field treatment of produced fluids. Oil, gas, and water produced from oil, gas, or geothermal resource wells may be treated in the field in facilities such as separators, skimmers, heater treaters, dehydrators, and sweetening units. Waste materials that result from the field treatment of oil and gas include waste hydrocarbons (including used oil), produced water, hydrogen sulfide scavengers, dehydration wastes, treating and cleaning chemicals, filters (including used oil filters), asbestos insulation, domestic Cont'd...

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.28	**Potential and Deliverability of Gas Wells To Be Ascertained and Reported**

(a) The information necessary to determine the absolute daily open flow potential of each producing associated or nonassociated gas well shall be ascertained, and a report shall be filed as required on the appropriate Commission form in the appropriate Commission office within 30 days of completion of the well. The test shall be performed in accordance with the commission's publication, Back Pressure Test for Natural Gas Wells, State of Texas, or other test procedure approved in advance by the Commission and shall be reported on the Commission's prescribed form. An operator, at his option, may determine absolute open flow potential from a stabilized one-point test. For a one-point test, the well shall be flowed on a single choke setting until a stabilized flow is achieved, but not less than 72 hours. The shut-in and flowing bottom hole pressures shall be calculated in the manner prescribed for a four-point test. The Commission may authorize a one-point test of shorter duration for a well which is not connected to a sales line, but a test which is in compliance with this section must be conducted and reported after the well is connected before an allowable will be assigned to the well. Back-dating of allowables will be performed in accordance with §3.31 of this title (relating to Gas Reservoirs and Gas Well Allowable).

(b) After conducting the test required by subsection (a) of this section each operator of a gas well shall conduct an initial deliverability test not later than ten days after the start of production for one or more legal purposes and shall report such initial deliverability test on the prescribed form. If a 72-hour one-point back pressure test on a well connected to a sales line was conducted as provided in subsection (a) of this section, the same test may be used to determine initial deliverability, provided the test was conducted in accordance with subsection (c) of this section. After the initial deliverability test has been conducted, the following schedule for well testing applies. Nonassociated gas wells shall be tested semiannually. Associated 49(b) gas wells shall be tested annually. Wells with current reported deliverability of 100 Mcf a day or less are not required to test as long as deliverability and production remain at or below 100 Mcf a day but are required to file Form G-10 according to the instructions on the form. Wells with a deliverability greater than 100 Mcf a day and less than or equal to 250 Mcf a day in fields without special field rules are not required to be tested as long as deliverability and production remain equal to or less than 250 Mcf a day. Wells operating under special field rules which conflict with this subsection shall test in accordance with the special field rules. Notwithstanding the above provisions on frequency of testing, gas wells commingling liquid hydrocarbons before metering must comply with the testing provisions applicable to such wells. All deliverability tests shall be conducted in accordance with subsection (c) of this section and the instructions printed on the Form G-10. The results of each test shall be attested to by the operator or his appointed agent. The first purchaser or its representative upon request to the operator shall have the right to witness such tests. Gas meter charts, printouts, or other documents showing the actual measurement of the gas produced or other data required to be recorded during any deliverability test conducted under this subsection shall be preserved as required by §3.1 of this title (relating to Organization Report; Retention of Records; Notice Requirements) (Statewide Rule 1). In the event that the first purchaser and the operator cannot agree upon the validity of the test results, then either party may request a retest of the well. The first purchaser upon request to the operator shall have the right to witness the retest. If either party requests a representative from the Commission to witness a retest of the well, the results of a Commission-witnessed test shall be conclusive for the purposes of this section until the next regularly scheduled test of the well. In the event a retest is witnessed by the Commission, the retest shall be signed by the representative of the Commission. In the event that downhole remedial work or other substantial production enhancement work is performed, or if a pumping unit, compressor, or other equipment is installed to increase deliverability of a well subject to the Commission-witnessed testing procedure described in this subsection, a new test may be requested and shall be performed according to the procedure outlined in this subsection.

(c) Unless applicable special field rules provide otherwise or the director of the oil and gas division or the director's delegate authorizes an alternate procedure due to a well's producing characteristics, deliverability tests shall be performed as follows. Deliverability tests shall be scheduled by the producer within the testing period designated by the Railroad Commission, and only the recorded data specified by the Form G-10 is required to be reported. All deliverability tests shall be performed by producing the subject well at stabilized rates for a minimum time period of 72 hours. A deliverability test shall be conducted under normal and usual operating conditions using the normal and usual operating equipment in place on the well being tested, and the well shall be produced against the normal and usual line pressure prevailing in the line into which the well produces. The average daily producing rate for each 24-hour period, the wellhead pressure before the commencement of the 72-hour test, and the flowing wellhead pressure at the beginning of each 24-hour period shall be recorded. In addition, a 24-hour shut-in wellhead pressure shall be determined either within the six-month period prior to the commencement of the 72-hour deliverability test or immediately after the completion of the deliverability test. The shut-in wellhead pressure that was determined and the date on which the 24-hour test was commenced shall be recorded on Form G-10. Exceptions and extensions to the timing requirements for deliverability tests and shut-in wellhead pressure tests may be granted by the Commission for good cause. The flow rate during each day of the first 48 hours of the test must be as close as possible to the flow rate during the final 24 hours of the test, but must equal at least 75% of such flow rate. The deliverability of the well during the last 24 hours of the flow test shall be used for allowable and allocation purposes. If pipeline conditions exist such that a producer believes a representative deliverability test cannot be performed, the producer with pipeline notification may request in writing that the commission use either of the following as a representative deliverability:

(1) the deliverability test performed during the previous testing period; or

(2) the maximum daily production from any of the 12 months prior to the due date of the test as determined by dividing the highest monthly production by the number of days in that month.

(d) If the deliverability of a well changes after a test is reported to the Commission, the deliverability of record for a well will be decreased upon receipt of a written request from the operator to reduce the deliverability of record to a specified amount. If the deliverability of a well increases, a retest must be conducted in the manner specified in this section and must be reported on Form G-10 before the deliverability of record will be increased.

(e) First purchasers with packages of gas dedicated entirely to a downstream purchaser shall coordinate testing with and provide test results to that downstream purchaser if requested by the downstream purchaser. In these cases, the downstream purchaser upon request to the operator shall have the right to witness all deliverability tests and retests.

(f) Tests of wells connected to a pipeline shall be made in a manner that no gas is flared, vented, or otherwise wastefully used.

Source Note: The provisions of this §3.28 adopted to be effective September 1, 1986, 11 TexReg 3680; amended to be effective October 12, 1998, 23 TexReg 10397; amended to be effective February 28, 2000, 25 TexReg 1592; amended to be effective November 24, 2004, 29 TexReg 10728

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.27	**Gas To Be Measured and Surface Commingling of Gas**

(a) All natural gas, except casinghead gas, produced from wells shall be measured, with each completion being measured separately, before the gas leaves the lease, and the producer shall report the volume produced from each completion to the commission. Exceptions to this provision may be granted by the commission upon written application.

(b) All casinghead gas sold, processed for its gasoline content, used in a field other than that in which it is produced, or used in cycling or repressuring operations, shall be measured before the gas leaves the lease, and the producer shall report the volume produced to the commission. Exceptions to this provision may be granted by the commission upon written application.

(c) All casinghead gas produced in this state which is not covered by the provisions of subsection (b) of this section, shall be measured before the gas leaves the lease, is used as fuel, or is released into the air, based on its use or on periodic tests, and reported to the commission by the producer. The volume of casinghead gas produced by wells exempt from gas/oil ratio surveys must be estimated, based on general knowledge of the characteristics of the wells. Exceptions to this provision may be granted by the commission upon written application.

(d) Releases and production of gas at a volume or daily flow rate, commonly referred to as "too small to measure" (TSTM), which, due to minute quantity, cannot be accurately determined or for which a determination of gas volume is not reasonably practical using routine oil and gas industry methods, practices, and techniques are exempt from compliance with this rule and are not required to be reported to the commission or charged against lease allowable production.

(e) In order to prevent waste, to promote conservation or to protect correlative rights, the commission may approve surface commingling of gas or oil and gas described in subsections (a), (b) or (c) of this section and produced from two or more tracts of land producing from the same commission-designated reservoir or from one or more tracts of land producing from different commission-designated reservoirs in accordance with §3.26(b) of this title (relating to Separating Devices, Tanks, and Surface Commingling of Oil).

(f) In reporting gas well production, the full-well stream gas shall be reported and charged against each gas well for allowable purposes. All gas produced, including all gas used on the lease or released into the air, must be reported regardless of its disposition.

(g) If gas is produced from a lease or other property covered by the coastal or inland waters of the state, the gas produced may, at the option of the operator, be measured on a shore or at a point removed from the lease or other property from which it was produced.

(h) All natural hydrocarbon gas produced and utilized from wells completed in geothermal resource reservoirs shall be measured and allocated to each individual lease based on semiannual tests conducted on full well stream lease production.

(i) For purposes of this rule, "measured" shall mean a determination of gas volume in accordance with this rule and other rules of the commission, including accurate estimates of unmetered gas volumes released into the air or used as fuel.

(j) No meter or meter run used for measuring gas as required by this rule shall be equipped with a manifold which will allow gas flow to be diverted or bypassed around the metering element in any manner unless it is of the type listed in paragraphs (1) or (2) of this subsection:

(1) double chambered orifice meter fittings with proper meter manifolding to allow equalized pressure across the meter during servicing;

(2) double chambered or single chambered orifice meter fittings equipped with proper meter manifolding or other types of metering devices accompanied by one of the following types of meter inspection manifolds:

(A) a manifold with block valves on each end of the meter run and a single block valve in the manifold complete with provisions to seal and a continuously maintained seal record;

(B) an inspection manifold having block valves at each end of the meter run and two block valves in the manifold with a bleeder between the two and with one valve equipped with provisions to seal and continuously maintained seal records;

(C) a manifold equipped with block valves at each end of the meter run and one or more block valves in the manifold, when accompanied by a documented waiver from the owner or owners of at least 60% of the royalty interest and the owner or owners of at least 60% of the working interest of the lease from which the gas is produced.

(k) Whenever sealing procedures are used to provide security in the meter inspection manifold systems, the seal records shall be maintained for at least three years at an appropriate office and made available for Railroad Commission inspection during normal working hours. At any time a seal is broken or replaced, a notation will be made on the orifice meter chart along with graphic representation of estimated gas flow during the time the meter is out of service.

(l) All meter requirements apply to all meters which are used to measure lease production, including sales meters if sales meter volumes are allocated back to individual leases.

(m) The commission may grant an exception to measurement requirements under subsections (a), (b) and (c) of this section if the requirements of this subsection are met. An exception granted under this subsection will be revoked if the most recent well test or production reported to the commission reflects a production rate of more than 20 MCF of gas per day or if any of the other requirements for an exception under this subsection are no longer satisfied. An applicant seeking an exception under this subsection must file an application establishing:

(1) the most recent production test reported to the commission demonstrates that the gas well or oil lease for which an exception is sought produces at a rate of no more than 20 MCF of gas per day;

(2) an annual test of the production of the gas well or oil lease provides an accurate estimate of the daily rate of gas flow;

(3) the flow rate established in paragraph (2) of this subsection multiplied by the recorded duration determined by any device or means that accurately records the duration of production each month yields an accurate estimate of monthly production; and

(4) the operator of the pipeline connected to the gas well or oil lease concurs in writing with the

application.

(n) Failure to comply with the provisions of this rule will result in severance of the producing well, lease, facility, or gas pipeline or in other appropriate enforcement proceeding.

Source Note: The provisions of this §3.27 adopted to be effective January 1, 1976; amended to be effective April 12, 1983, 8 TexReg 1019; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective June 23, 1997, 22 TexReg 5747.

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TITLE 16	ECONOMIC REGULATION
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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.26	**Separating Devices, Tanks, and Surface Commingling of Oil**

(a) Where oil and gas are found in the same stratum and it is impossible to separate one from the other, or when a well has been classified as a gas well and such gas well is not connected to a cycling plant and such well is being produced on a lease and the gas is utilized under Texas Natural Resources Code §§86.181 - 86.185, the operator shall install a separating device of approved type and sufficient capacity to separate the oil and liquid hydrocarbons from the gas.

(1) The separating device shall be kept in place as long as a necessity for it exists, and, after being installed, such device shall not be removed nor the use thereof discontinued without the consent of the commission.

(2) All oil and any other liquid hydrocarbons as and when produced shall be adequately measured according to the pipeline rules and regulations of the commission before the same leaves the lease from which they are produced, except for gas wells where the full well stream is moved to a plant or central separation facility in accordance with §3.55 of this title (relating to Reports on Gas Wells Commingling Liquid Hydrocarbons before Metering) (Statewide Rule 55) and the full well stream is measured, with each completion being separately measured, before the gas leaves the lease.

(3) Sufficient tankage and separator capacity shall be provided by the producer to adequately take daily gauges of all oil and any other liquid hydrocarbons unless LACT equipment, installed and operated in accordance with the latest revision of American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 6.1 or another method approved by the commission or its delegate, is being used to effect custody transfer.

(b) In order to prevent waste, to promote conservation or to protect correlative rights, the commission may approve surface commingling of oil, gas, or oil and gas production from two or more tracts of land producing from the same commission-designated reservoir or from one or more tracts of land producing from different commission-designated reservoirs as follows:

(1) Administrative approval. Upon written application, the commission may grant approval for surface commingling administratively when any one of the following conditions is met:

(A) The tracts or commission-designated reservoirs have identical working interest and royalty interest ownership in identical percentages and therefore there is no commingling of separate interests;

(B) Production from each tract and each commission-designated reservoir is separately measured and therefore there is no commingling of separate interests; or

(C) When the tracts or commission-designated reservoirs do not have identical working interest and royalty interest ownership in identical percentages and the commission has not received a protest to an application within 21 days of notice of the application being mailed by the applicant to all working and royalty interest owners or, if publication is required, within 21 days of the date of last publication and the applicant provides:

(i) a method of allocating production to ensure the protection of correlative rights, in accordance with paragraph (3) of this subsection; and

(ii) an affidavit or other evidence that all working interest and royalty interest owners have been notified of the application by certified mail or have provided applicant with waivers of notice requirements; or

(iii) in the event the applicant is unable, after due diligence, to provide notice by certified mail to all working interest and royalty interest owners, a publisher's affidavit or other evidence that the commission's notice of application has been published once a week for four consecutive weeks in a newspaper of general circulation in the county or counties in which the tracts that are the subject of the application are located.

(2) Request for hearing. When the tracts or commission-designated reservoirs do not have identical working interest and royalty interest ownership in identical percentages and a person entitled to notice of the application has filed a protest to the application with the commission, the applicant may request a hearing on the application. The commission shall give notice of the hearing to all working interest and royalty interest owners. The commission may permit the commingling if the applicant demonstrates that the proposed commingling will protect the rights of all interest owners in accordance with paragraph (3) of this subsection and will prevent waste, promote conservation or protect correlative rights.

(3) Reasonable allocation required. The applicant must demonstrate to the Commission or its designee that the proposed commingling of hydrocarbons will not harm the correlative rights of the working or royalty interest owners of any of the wells to be commingled. The method of allocation of production to individual interests must accurately attribute to each interest its fair share of aggregated production.

(A) In the absence of contrary information, such as indications of material fluctuations in the monthly production volume of a well proposed for commingling, the Commission will presume that allocation based on the daily production rate for each well as determined and reported to the Commission by semi-annual well tests will accurately attribute to each interest its fair share of production without harm to correlative rights. As used in this section, "daily production rate" for a well means the 24 hour production rate determined by the most recent well test conducted and reported to the commission in accordance with §§3.28, 3.52, 3.53, and 3.55 of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported, Oil Well Allowable Production, Annual Well Tests and Well Status Reports Required, and Reports on Gas Wells Commingling Liquid Hydrocarbons before Metering).

(B) Operators may test commingled wells annually after approval by the Commission or the commission's delegate of the operator's written request demonstrating that annual testing will not harm the correlative rights of the working or royalty interest owners of the commingled wells. Allocation of commingled production shall not be based on well tests conducted less frequently than annually.

(C) Nothing in this section prohibits allocations based on more frequent well tests than the semi-annual well test set out in subparagraph (A) of this paragraph. Additional tests used for allocation do not have to be filed with the commission but must be available for inspection at the request of the commission, working interest owners or royalty interest owners.

(D) Allocations may be based on a method other than periodic well tests if the Commission or its designee determines that the alternative allocation method will insure a reasonable allocation of production as required by this paragraph.

(4) Additional notice required. In addition to giving notice to the persons entitled to notice under paragraph (1)(C) of this subsection, an applicant for a surface commingling exception must give notice of the application to the operator of each tract adjacent to one or more of the tracts proposed for commingling that has one or more wells producing from the same commission-designated reservoir as any well proposed for

commingling if:

(A) any one of the wells proposed for commingling produces from a commission-designated reservoir for which special field rules have been adopted; or

(B) any one of the wells proposed for commingling produces from multiple commission-designated reservoirs, unless:

(i) an exception to §3.10 of this title (relating to Restriction of Production of Oil and Gas from Different Strata) has previously been obtained for production from the well; or

(ii) the applicant continues to separately measure production from each different commission-designated reservoir produced from the same wellbore.

(c) If oil or any other liquid hydrocarbon is produced from a lease or other property covered by the coastal or inland waters of the state, the liquid produced may, at the option of the operator, be measured on a shre or at a point removed from the lease or other property on which it is produced.

(d) Oil gravity tests and reports (Reference Order Number 20-55, 647, effective 4-1-66, and Reference Order Number 20-58, 528, effective 5-10-68.) If oil or any other liquid hydrocarbon is produced from a lease or other property covered by the coastal or inland waters of the state, the liquid produced may, at the option of the operator, be measured on a shore or at a point removed from the lease or other property on which it is produced.

(1) Where individual lease oil production, or authorized commingled oil production, separator, treating, and/or storage vessels, other than conventional emulsoin breaking treaters, are connected to a gas gathering system so that heat or vacuum may be applied prior to oil measurement for commission-required production reports, the operator may, at his option, apply heat or vacuum to the oil only to the extent the average gravity of the stock tank oil will not be reduced below a limiting gravity for each lease as established by an average oil gravity test conducted under the following conditions (Reference Order Number 20-55, 647, effective 4-1-66):

(A) the separator or separator system, which shall include any type vessel that is used to separate hydrocarbons, shall be operated at not less than atmospheric pressure;

(B) no heat shall be applied;

(C) the test interval shall be for a minimum of 24 hours, and the average oil gravity after weathering for not more than 24 hours shall then become the limiting gravity factor for applying heat or vacuum to unmeasured oil on the tested lease.

(2) Initial gravity tests shall be made by the operator when such separator, treating, and/or storage vessels are first used pursuant to this section. Subsequent tests shall be made at the request of either the commission or any interested party; and such subsequent tests shall be witnessed by the requesting party. Any interested party may witness the tests.

(3) Each operator shall enter on the face of his required production report the gravity of the oil delivered to market from the lease reported, and it is provided that should a volume of oil delivered to market from such lease separation facilities not meet the gravity requirement established by the described test, adjustment shall be made by charging the allowable of the lease on the relationship of the volume and the gravity of the particular crude.

(4) Where a conventional heater treater is required and is used only to break oil from an emulsion prior to oil measurement, this section will not be applicable; provided, however, that by this limitation on the section, it is not intended that excessive heat may be used in conventional heater treater, and in circumstances where such heater treater is connected to a gas gathering system and it is found by commission investigation made on its own volition or on complaint of any interested party that excessive heat is used, either the provisions of this section or special restrictive regulation may be made applicable.

Source Note: The provisions of this §3.26 adopted January 1, 1976; amended to be effective February 23, 1979, 4 TexReg 436; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective February 18, 1994, 19 TexReg 783; amended to be effective June 23, 1997, 22 TexReg 5747; amended to be effective May 1, 2000, 25 TexReg 3741; amended to be effective November 24, 2004, 29 TexReg 10728

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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.25	**Use of Common Storage**

(a) In all fields or areas in which the commission has approved the use of common storage where oil is produced from two or more separate reservoirs or zones and separate proration schedules are published by the commission for each reservoir or zone, the operator of said lease shall not be required to file a separate Producer's Certificate of Compliance and Authorization to Transport Oil or Gas From Lease Form for each reservoir or zone, but may file one form to authorize the transportation of oil or gas from all reservoirs or zones producing into common storage.

(b) A gatherer transporting oil from such common storage shall not be required to file a separate transporter's report for each separate reservoir or zone or each separate lease but shall file such report on a combined basis for the total amount of commingled oil in common storage.

(c) The operator of a lease or leases for which the commission has authorized the use of common storage of oil produced from two or more reservoirs or zones and from two or more leases shall file a Monthly Producer's Report for each separate reservoir or zone and/or for each separate lease and, in addition thereto, said operator shall file a report showing the data included on the individual reports on a combined basis for the total amount of commingled oil in common storage.

Source Note: The provisions of this §3.25 adopted to be effective January 1, 1976.

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RULE §3.24	**Check Valves Required**

(a) Where two or more wells are being produced through a common line, a common separator, or a common manifold, the flow lines leading from each well to such common line, common separator, or common manifold shall be equipped with a check valve or other means of shut-off which shall at all times be kept in good working order. The check valve or other means of shut-off shall be placed in each flow line above the surface of the ground and shall be located in the flow line as close to the wellhead connection as is practicable. Where a manifold system is employed in which each well produced through the manifold system has its own individual flow line leading from the wellhead to the manifold, then it shall be permissible for the check valve or other means of shut-off to be placed in the flow line near a point where the flow line enters the manifold system. The check valve or other means of shut-off must be above ground, and must be in the flow line serving the well and must be located between the wellhead and the point where the flow line connects with any other flow line, common separator, or common manifold. Each check valve or other means of shut-off shall be placed in the flow line serving the well so that it will permit the passage of fluids from the well and will act as a check to prevent any fluid from entering the well through the flow line from any outside source.

(b) Operator shall do all things necessary to keep the check valve or other means of shut-off in good working order, and operators, when requested by an agent of the commission, will test the check valve or other means of shut-off for leakage.

Source Note: The provisions of this §3.24 adopted to be effective January 1, 1976.

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RULE §3.23	**Vacuum Pumps**

The installation of a vacuum pump or other device for the purpose of putting vacuum on any gas or oil-bearing formation, or the application of any vacuum to any gas or oil-bearing formation is prohibited, except as follows.

(1) If casinghead gas is utilized in a casinghead-gas plant, vacuum may be used, but no more than is sufficient to gather the gas and deliver it at the plant. In no event shall more than two points of vacuum (two inches of mercury) be used at the casinghead.

(2) In a field which is depleted or practically depleted vacuum may be used, but no vacuum pump shall be installed or used without a permit from the commission obtained upon application after notice to adjacent lease owners and operators and a public hearing on such application.

Source Note: The provisions of this §3.23 adopted to be effective January 1, 1976.

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RULE §3.22	**Protection of Birds**

(a) If an operator who maintains a tank or pit does not take protective measures necessary to prevent harm to birds, the operator may incur liability under federal and state wildlife protection laws. Federal statutes, such as the Migratory Bird Treaty Act, provide substantial penalties for the death of certain species of birds due to contact with oil in a tank or pit. These penalties may include imprisonment. State statutes also protect certain species of birds. The Railroad Commission of Texas (commission) is cooperating with federal and state wildlife authorities in their efforts to protect birds.

(b) An operator must screen, net, cover, or otherwise render harmless to birds the following categories of open-top tanks and pits associated with the exploration, development, and production of oil and gas, including transportation of oil and gas by pipeline:

(1) open-top storage tanks that are eight feet or greater in diameter and contain a continuous or frequent surface film or accumulation of oil; however, temporary, portable storage tanks that are used to hold fluids during drilling operations, workovers, or well tests are exempt;

(2) skimming pits as defined in §3.8 of this title (relating to Water Protection) (Statewide Rule 8); and

(3) collecting pits as defined in §3.8 of this title (relating to Water Protection) that are used as skimming pits.

(c) If the commission finds a surface film or accumulation of oil in any other pit regulated under §3.8 of this title (relating to Water Protection), the commission will instruct the operator to remove the oil. If the operator fails to remove the oil from the pit in accordance with the commission's instructions or if the commission finds a surface film or accumulation of oil in the pit again within a 12-month period, the commission will require the operator to screen, net, cover, or otherwise render the pit harmless to birds. Before complying with this requirement, the operator will have a right to a hearing upon request. In addition to the enforcement actions specified by this subsection, the commission may take any other appropriate enforcement actions within its authority.

Source Note: The provisions of this §3.22 adopted to be effective September 1, 1991, 16 TexReg 2523; amended to be effective November 1, 1991, 16 TexReg 4737.

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RULE §3.21	**Fire Prevention and Swabbing**

(a) No hydrocarbon flow tank, unless entirely buried, shall hereafter be placed nearer than 150 feet from any derrick, rig, building, power plant, or boiler of any description. The director of the Oil and Gas Division or his delegate may administratively grant exceptions to this requirement. If the director of the Oil and Gas Division declines to administratively grant, continue, or extend an exception, the operator shall move the hydrocarbon flow tank to the required distance or request a hearing on the matter. After hearing, the examiner shall recommend final action to the commission.

(b) No field working hydrocarbon tank having a capacity of 10,000 barrels or more shall be built nearer than 200 feet (measured from shell to shell) to any other like tank.

(c) No person engaged in the production, transportation, storage, handling, refining, reclaiming, processing, treating, or marketing of crude petroleum oil or the products or by-products thereof shall store, either permanently or temporarily, crude petroleum oil or the products and by-products thereof in open pits or earthen storage.

(d) All oil tanks where there is a gas hazard shall be gas tight and provided with proper gas vents.

(e) No forge or open light shall be placed inside the derrick of a well showing oil or gas.

(f) Boilers must be equipped with steam lines for fighting fire and must not be set nearer than 150 feet to any producing well.

(g) All wells shall be cleaned into a pit not less than 40 feet from the derrick floor and 150 feet from any fire hazard.

(h) No boiler or electric lighting generator shall be placed or remain nearer than 150 feet to any producing well or oil tank.

(i) Any rubbish or debris that might constitute a fire hazard shall be removed to a distance of at least 150 feet from the vicinity of any well, tank, or pump station. All waste shall be burned or disposed of in such manner as to avoid creating a fire hazard.

(j) Dikes or fire walls shall not be required except such fire walls must be erected and kept around all permanent oil tanks, or battery of tanks, that are within the corporate limits of any city, town, or village; or where such tanks are closer than 500 feet to any highway or inhabited dwelling or closer than 1,000 feet to any school or church; or where such tanks are so located as to be deemed by the commission to be an objectionable hazard.

(k) Swabbing, bailing, or air jetting of wells is prohibited as a production method for wells unless the Commission has, after notice and hearing, granted an exception to this subsection. The Commission shall give notice of the hearing at least 10 days prior to the date of the hearing.

(1) An operator seeking an exception to allow swabbing, bailing, or air jetting of a well shall:

(A) provide the Commission with the names and mailing addresses of the mineral interest owners of record and surface owners of record of the lease on which a well for which an exception is sought is located;

(B) present evidence at the hearing establishing:

(i) the method of production proposed;

(ii) that any production is properly accounted for pursuant to §3.26 of this title (relating to Separating Devices, Tanks, and Surface Commingling of Oil);

(iii) that the proposed exception is necessary to prevent waste or protect correlative rights;

(iv) that wellhead control is sufficient to prevent releases from the well;

(v) that no pollution of usable quality water or safety hazard will result from either the proposed production method or the condition of the well; and

(vi) that the operator possesses a continuing good faith claim to the right to operate the well.

(2) In addition to the information set out in paragraph (1) of this subsection, factors that the Commission may consider in ruling on a request for an exception include:

(A) whether the well has passed a mechanical integrity test within the preceding 12 months;

(B) the estimated monthly and cumulative production from the well if the requested exception is granted;

(C) whether production will be into an on-lease tank battery or a mobile tank;

(D) the adequacy of the financial assurance provided by the operator to assure that the well will be timely and properly plugged;

(E) whether production volume, fine sands in the reservoir, or other factors render pumping of the well impracticable;

(F) whether the reservoir from which the well produces contains hydrogen sulfide; and

(G) the operator's history of compliance with Commission rules.

(3) This section does not prohibit swabbing as a non-recurring method to start initial production, to test or clean out a well, or to restore a well to flowing or pumping status.

Source Note: The provisions of this §3.21 adopted to be effective January 1, 1976, amended to be effective October 3, 1980, 5 TexReg 3794; amended to be effective October 2, 2002, 27 TexReg 9149

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RULE §3.20	**Notification of Fire Breaks, Leaks, or Blow-outs**

(a) General requirements.

(1) Operators shall give immediate notice of a fire, leak, spill, or break to the appropriate commission district office by telephone or telegraph. Such notice shall be followed by a letter giving the full description of the event, and it shall include the volume of crude oil, gas, geothermal resources, other well liquids, or associated products lost.

(2) All operators of any oil wells, gas wells, geothermal wells, pipelines receiving tanks, storage tanks, or receiving and storage receptacles into which crude oil, gas, or geothermal resources are produced, received, stored, or through which oil, gas, or geothermal resources are piped or transported, shall immediately notify the commission by letter, giving full details concerning all fires which occur at oil wells, gas wells, geothermal wells, tanks, or receptacles owned, operated, or controlled by them or on their property, and all such persons shall immediately report all tanks or receptacles struck by lightning and any other fire which destroys crude oil, natural gas, or geothermal resources, or any of them, and shall immediately report by letter any breaks or leaks in or from tanks or other receptacles and pipelines from which oil, gas, or geothermal resources are escaping or have escaped. In all such reports of fires, breaks, leaks, or escapes, or other accidents of this nature, the location of the well, tank, receptacle, or line break shall be given by county, survey, and property, so that the exact location thereof can be readily located on the ground. Such report shall likewise specify what steps have been taken or are in progress to remedy the situation reported and shall detail the quantity (estimated, if no accurate measurement can be obtained, in which case the report shall show that the same is an estimate) of oil, gas, or geothermal resources, lost, destroyed, or permitted to escape. In case any tank or receptacle is permitted to run over, the escape thus occurring shall be reported as in the case of a leak. (Reference Order Number 20-60,399, effective 9-24-70.)

(b) The report hereby required as to oil losses shall be necessary only in case such oil loss exceeds five barrels in the aggregate.

(c) Any operation with respect to the pickup of pipeline break oil shall be done subject to the following provisions. The provisions hereafter set out shall not apply to the picking up and the returning of pipeline break oil to the pipeline from which it escaped either at the place of the pipeline break, or at the nearest pipeline station to the break where facilities are available to return such oil to the pipeline; provided, that such operations are conducted by the pipeline operator at the time of the pipeline break and its repair; provided, further, that such authority as is herein granted for the picking up of pipeline break oil shall not relieve the operator of such pipeline of notifying the commission of such pipeline break, and the furnishing to the commission of the information required by the provisions set out in subsection (a) of this section for reporting such pipeline breaks.

(1) Any person desiring to pick up, reclaim, or salvage pipeline break oil, other than as provided in this subsection, shall obtain in writing a permit before commencing operations. All applications for permits to pick up, reclaim, or salvage such oil shall be made in writing under oath to the district office.

(2) Applications to pick up, reclaim, or salvage pipeline break oil shall state the location of such oil, the location of the break in the pipeline causing the leakage of such oil, the name of the pipeline, the owner

thereof, and the date of the break.

(3) Pipeline break oil that is not returned to the pipeline from which it escaped shall be offered to the applicant to reclaim by the operator of such pipeline but shall be charged to such pipeline stock account.

Source Note: The provisions of this §3.20 adopted to be effective January 1, 1976.

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RULE §3.19	**Density of Mud-Fluid**

In cable tool drilling, no operator shall drill into a known oil, gas, or geothermal resource producing formation with water from a higher formation in the hole, or with a sufficient head of water introduced into the hole to prevent gas blowing to the surface. The well shall either be allowed to blow until it has been drilled-in or it shall be drilled under a head of fluid whose weight shall average not less than 9 1/2 pounds per gallon; but in no case shall gas be allowed to blow for a longer period than three days after completion of the well. Mud-laden fluid used for protecting oil, gas, or geothermal resource bearing sands in upper formations while oil, gas, or geothermal resource is being produced from deeper formations shall have an average weight of not less than 91 pounds per gallon.

Source Note: The provisions of this §3.19 adopted to be effective January 1, 1976.

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RULE §3.18	**Mud Circulation Required**

When coming out of the hole with the drill pipe, drilling fluid shall be circulated until equalized, and a fill-up line shall be turned into the casing to insure a full load of fluid on the bottom of the hole at all times.

Source Note: The provisions of this §3.18 adopted to be effective January 1, 1976.

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RULE §3.17	**Pressure on Bradenhead**

(a) All wells shall be equipped with a Bradenhead. Whenever pressure develops between any two strings of casing, the district office shall be notified immediately. No cement may be pumped between any two strings or pipe at the top of the hole, except after permission has been granted by the district office.

(b) Any well showing pressure on the Bradenhead, or leaking gas, oil, or geothermal resource between the surface and the production or oil string shall be tested in the following manner. The well shall be killed and pump pressure applied through the tubing head. Should the pressure gauge on the Bradenhead reflect the applied pressure, the casing shall be condemned and a new production or oil string shall be run and cemented. This method shall be used when the origin of the pressure cannot be determined otherwise.

Source Note: The provisions of this §3.17 adopted to be effective January 1, 1976.

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RULE §3.16	**Log and Completion or Plugging Report**

(a) The owner or operator of an oil, gas, or geothermal resource well, within 30 days after the completion of such well or the plugging of such well, if the well is a dry hole, shall file with the commission the appropriate completion or plugging report, and if a basic electric log is run on the well, a legible, unaltered final copy of such a log shall be attached. A basic electric log means a lithology, porosity, or resistivity log run over the entire wellbore or in the alternative, if no such log is run over the entire wellbore, the log which is the most complete of such logs run. Amended completion reports must be filed for any change in perforations, or openhole or casing records within 30 days after recompleting the well. In addition, if the well is deepened, a copy of a basic electric log run after September 1, 1985, should be submitted if such log is run over a deeper interval than the interval covered by a basic electric log already on file with the commission for that wellbore.

(b) Each log filed with the commission shall be considered public information and shall be available to the public during normal business hours. If the owner or operator of such well described in subsection (a) of this section desires log(s) to be confidential, the owner or operator must submit a written request for a delayed filing of the log(s). When filing such a request, the owner or operator must retain the log(s) and may delay filing such log(s) for one year beginning from the date the completion or plugging report is required to be filed with the commission. The owner or operator of such well may request an additional filing delay of two years, provided the written request is filed prior to the expiration date of the initial confidentiality period. If a well is drilled on land submerged in state water, the owner or operator may request an additional filing delay of two years so that a possible total filing delay of five years may be obtained. A request for the additional two year filing delay period must be in writing and be received prior to the expiration of the first two year filing delay. Logs must be filed with the commission within 30 days after the expiration of the final confidentiality period.

(c) If the logs are not filed in accordance with the provisions of this section, the commission may refuse to assign an allowable to a well or may set the allowable for such well at zero. If the well is a dry hole and the logs are not filed in accordance with the provisions of this section, the commission may initiate penalty action pursuant to the Texas Natural Resources Code, Title 3.

Source Note: The provisions of this §3.16 adopted to be effective January 1, 1976; amended to be effective February 20, 1986, 11 TexReg 545.

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RULE §3.15	**Surface Casing To Be Left in Place**

Unless alternative methods are approved pursuant to §3.13 of this title (relating to Casing, Cementing, Drilling, and Completion of Requirements), fresh water sands are to be protected with surface casing which has been cemented, and such casing shall not be removed from the well at abandonment. This applies to wells drilled by cable tool and rotary rigs alike.

Source Note: The provisions of this §3.15 adopted to be effective January 1, 1976; amended to be effective March 10, 1986, 11 TexReg 901.

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RULE §3.14	**Plugging**

(a) Definitions and application to plug.

(1) The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise:

(A) Active operation--Regular and continuing activities related to the production of oil and gas for which the operator has all necessary permits. In the case of a well that has been inactive for 12 consecutive months or longer and that is not permitted as a disposal or injection well, the well remains inactive for purposes of this section, regardless of any minimal activity, until the well has reported production of at least 10 barrels of oil for oil wells or 100 mcf of gas for gas wells each month for at least three consecutive months.

(B) Approved cementer--A cementing company, service company, or operator approved by the Commission to mix and pump cement for the purpose of plugging a well in accordance with the provisions of this section. The term shall also apply to a cementing company, service company, or operator authorized by the Commission to use an alternate material other than cement to plug a well.

(C) Delinquent inactive well--An unplugged well that has had no reported production, disposal, injection, or other permitted activity for a period of greater than 12 months and for which, after notice and opportunity for hearing, the Commission has not extended the plugging deadline.

(D) Funnel viscosity--Viscosity as measured by the Marsh funnel, based on the number of seconds required for 1,000 cubic centimeters of fluid to flow through the funnel.

(E) Good faith claim--A factually supported claim based on a recognized legal theory to a continuing possessory right in a mineral estate, such as evidence of a currently valid oil and gas lease or a recorded deed conveying a fee interest in the mineral estate.

(F) Groundwater conservation district--Any district or authority created under §52, Article III, or §59, Article XVI, Texas Constitution, that has the authority to regulate the spacing of water wells, the production from water wells, or both.

(G) Operator designation form--A certificate of compliance and transportation authority or an application to drill, deepen, recomplete, plug back, or reenter which has been completed, signed and filed with the Commission.

(H) Productive horizon--Any stratum known to contain oil, gas, or geothermal resources in producible quantities in the vicinity of an unplugged well.

(I) Related piping--The surface piping and subsurface piping that is less than three feet beneath the ground surface between pieces of equipment located at any collection or treatment facility. Such piping would include piping between and among headers, manifolds, separators, storage tanks, gun barrels, heater treaters, dehydrators, and any other equipment located at a collection or treatment facility. The term is not intended to refer to lines, such as flowlines, gathering lines, and injection lines that lead up to and away from any such collection or treatment facility.

(J) Reported production--Production of oil or gas, excluding production attributable to well tests, accurately reported to the Commission on a monthly producer's report.

(K) To serve notice on the surface owner or resident--To hand deliver a written notice identifying the well or wells to be plugged and the projected date the well or wells will be plugged to the surface owner, or resident if the owner is absent, at least three days prior to the day of plugging or to mail the notice by first class mail, postage pre-paid, to the last known address of the surface owner or resident at least seven days prior to the day of plugging.

(L) Unbonded operator--An operator that has a current and active organization report on file with the Commission that filed a nonrefundable annual fee as financial security prior to September 1, 2004, and is not required by §3.78 of this title (relating to Fees and Financial Security Requirements) to file an individual performance bond, blanket performance bond, letter of credit, or cash deposit as its financial security until the first date for annual renewal of the operator's organization report after September 1, 2004.

(M) Usable quality water strata--All strata determined by the Texas Commission on Environmental Quality or its successor agencies to contain usable quality water.

(N) Written notice--Notice actually received by the intended recipient in tangible or retrievable form, including notice set out on paper and hand-delivered, facsimile transmissions, and electronic mail transmissions.

(2) The operator shall give the Commission notice of its intention to plug any well or wells drilled for oil, gas, or geothermal resources or for any other purpose over which the Commission has jurisdiction, except those specifically addressed in §3.100(e)(1) of this title (relating to Seismic Holes and Core Holes) (Statewide Rule 100), prior to plugging. The operator shall deliver or transmit the written notice to the district office on the appropriate form.

(3) The operator shall cause the notice of its intention to plug to be delivered to the district office at least five days prior to the beginning of plugging operations. The notice shall set out the proposed plugging procedure as well as the complete casing record. The operator shall not commence the work of plugging the well or wells until the proposed procedure has been approved by the district director or the director's delegate. The operator shall not initiate approved plugging operations before the date set out in the notification for the beginning of plugging operations unless authorized by the district director or the director's delegate. The operator shall notify the district office at least four hours before commencing plugging operations and proceed with the work as approved. The district director or the director's delegate may grant exceptions to the requirements of this paragraph concerning the timing of notices when a workover or drilling rig is already at work on location, and ready to commence plugging operations. Operations shall not be suspended prior to plugging the well unless the hole is cased and casing is cemented in place in compliance with Commission rules. The Commission's approval of a notice of intent to plug and abandon a well shall not relieve an operator of the requirement to comply with subsection (b)(2) of this section, nor does such approval constitute an extension of time to comply with subsection (b)(2) of this section.

(4) The surface owner and the operator may file an application to condition an abandoned well located on the surface owner's tract for usable quality water production operations. The application shall be made on the form prescribed by the Commission, the Application of Landowner to Condition an Abandoned Well for Fresh Water Production.

(A) Standard for Commission Approval. Before the Commission will consider approval of an application:

(i) the surface owner shall assume responsibility for plugging the well and obligate himself, his heirs, successors, and assignees to complete the plugging operations;

(ii) the operator responsible for plugging the well shall place all cement plugs required by this rule up to the base of the usable quality water strata; and

(iii) the surface owner shall submit:

(I) a signed statement attesting to the fact that:

(-a-) there is no groundwater conservation district for the area in which the well is located; or

(-b-) there is a groundwater conservation district for the area where the well is located, but the groundwater conservation district does not require that the well be permitted or registered; or

(-c-) the surface owner has registered the well with the groundwater conservation district for the area where the well is located; or

(II) a copy of the permit from the groundwater conservation district for the area where the well is located.

(B) The duty of the operator to properly plug ends only when:

(i) the operator has properly plugged the well in accordance with Commission requirements up to the base of the usable quality water stratum;

(ii) the surface owner has registered the well with, or has obtained a permit for the well from, the groundwater conservation district, if applicable; and

(iii) the Commission has approved the application of surface owner to condition an abandoned well for fresh water production.

(5) The operator of a well shall serve notice on the surface owner of the well site tract, or the resident if the owner is absent, before the scheduled date for beginning the plugging operations. A representative of the surface owner may be present to witness the plugging of the well. Plugging shall not be delayed because of the lack of actual notice to the surface owner or resident if the operator has served notice as required by this paragraph. The district director or the director's delegate may grant exceptions to the requirements of this paragraph concerning the timing of notices when a workover or drilling rig is already at work on location and ready to commence plugging operations.

(b) Commencement of plugging operations, extensions, and testing.

(1) The operator shall complete and file in the district office a duly verified plugging record, in duplicate, on the appropriate form within 30 days after plugging operations are completed. A cementing report made by the party cementing the well shall be attached to, or made a part of, the plugging report. If the well the operator is plugging is a dry hole, an electric log status report shall be filed with the plugging record.

(2) Plugging operations on each dry or inactive well shall be commenced within a period of one year after drilling or operations cease and shall proceed with due diligence until completed. Plugging operations on delinquent inactive wells shall be commenced immediately unless the well is restored to active operation. For good cause, a reasonable extension of time in which to start the plugging operations may be granted pursuant to the following procedures.

(A) Plugging of inactive wells operated by unbonded operators. During the interim period between September 1, 2004, and the first date for annual renewal of an unbonded operator's organization report after September 1, 2004, the Commission or its delegate may administratively grant an extension of up to one year of the deadline for plugging an inactive well that is operated by an unbonded operator if the following criteria are met:

(i) The well and associated facilities are in compliance with all other laws and Commission rules;

(ii) The operator's organization report is current and active;

(iii) The operator has, and upon request provides evidence of, a good faith claim to a continuing right to operate the well; and

(iv) The operator has tested the well in accordance with the provisions of paragraph (3) of this subsection and files with its application proof of either:

(I) a fluid level test conducted within 90 days prior to the application for a plugging extension demonstrating that any fluid in the wellbore is at least 250 feet below the base of the deepest usable quality water stratum; or,

(II) a hydraulic pressure test conducted during the period the well has been inactive and not more than four years prior to the date of application demonstrating the mechanical integrity of the well.

(B) Plugging of inactive wells operated by bonded operators. An operator that maintains valid, Commission-approved financial security in the form of an individual performance bond, blanket performance bond, letter of credit, or cash deposit as provided in §3.78 of this title (relating to Fees and Financial Security Requirements) (Statewide Rule 78) will be granted a one-year plugging extension for each well it operates that has been inactive for 12 months or more at the time its annual organizational report is approved by the Commission if the following criteria are met:

(i) The well and associated facilities are in compliance with all laws and Commission rules; and,

(ii) The operator has, and upon request provides evidence of, a good faith claim to a continuing right to operate the well.

(C) Revocation or denial of plugging extension.

(i) The Commission or its delegate may revoke a plugging extension if the operator of the well that is the subject of the extension fails to maintain the well and all associated facilities in compliance with Commission rules; fails to maintain a current and accurate organizational report on file with the Commission; fails to provide the Commission, upon request, with evidence of a continuing good faith claim to operate the well; or fails to obtain or maintain financial security as required by §3.78 of this title (relating to Fees and Financial Security Requirements) (Statewide Rule 78).

(ii) If the Commission or its delegate declines to grant or continue a plugging extension or revokes a previously granted extension, the operator shall either return the well to active operation or, within 30 days, plug the well or request a hearing on the matter.

(3) The operator of any well more than 25 years old that becomes inactive and subject to the provisions of this subsection or the operator of any well for which a plugging extension is sought under the terms of subparagraph (A) of paragraph (2) of this subsection shall plug the well or successfully conduct a fluid level or hydraulic pressure test establishing that the well does not pose a potential threat of harm to natural

resources, including surface and subsurface water, oil and gas.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.13	**Casing, Cementing, Drilling, and Completion Requirements**

(a) General.

(1) The operator is responsible for compliance with this section during all operations at the well. It is the intent of all provisions of this section that casing be securely anchored in the hole in order to effectively control the well at all times, all usable-quality water zones be isolated and sealed off to effectively prevent contamination or harm, and all potentially productive zones be isolated and sealed off to prevent vertical migration of fluids or gases behind the casing. When the section does not detail specific methods to achieve these objectives, the responsible party shall make every effort to follow the intent of the section, using good engineering practices and the best currently available technology.

(2) Definitions. The following words and terms, when used in this chapter, shall have the following meanings, unless the context clearly indicates otherwise.

(A) Stand under pressure--To leave the hydrostatic column pressure in the well acting as the natural force without adding any external pump pressure. The provisions are complied with if a float collar is used and found to be holding at the completion of the cement job.

(B) Zone of critical cement--For surface casing strings shall be the bottom 20% of the casing string, but shall be no more than 1,000 feet nor less than 300 feet. The zone of critical cement extends to the land surface for surface casing strings of 300 feet or less.

(C) Protection depth--Depth to which usable-quality water must be protected, as determined by the Texas Commission on Environmental Quality (TCEQ) or its successor agencies, which may include zones that contain brackish or saltwater if such zones are correlative and/or hydrologically connected to zones that contain usable-quality water.

(D) Productive horizon--Any stratum known to contain oil, gas, or geothermal resources in commercial quantities in the area.

(b) Onshore and inland waters.

(1) General.

(A) All casing cemented in any well shall be steel casing that has been hydrostatically pressure tested with an applied pressure at least equal to the maximum pressure to which the pipe will be subjected in the well. For new pipe, the mill test pressure may be used to fulfill this requirement. As an alternative to hydrostatic testing, a full length electromagnet, ultrasonic, radiation thickness gauging, or magnetic particle inspection may be employed.

(B) Wellhead assemblies shall be used on wells to maintain surface control of the well. Each component of the wellhead shall have a pressure rating equal to or greater than the anticipated pressure to which that particular component might be exposed during the course of drilling, testing, or producing the well.

(C) A blowout preventer or control head and other connections to keep the well under control at all times shall be installed as soon as surface casing is set. This equipment shall be of such construction and capable of such operation as to satisfy any reasonable test which may be required by the commission or its duly accredited agent.

(D) When cementing any string of casing more than 200 feet long, before drilling the cement plug the operator shall test the casing at a pump pressure in pounds per square inch (psi) calculated by multiplying the length of the casing string by 0.2. The maximum test pressure required, however, unless otherwise ordered by the commission, need not exceed 1,500 psi. If, at the end of 30 minutes, the pressure shows a drop of 10% or more from the original test pressure, the casing shall be condemned until the leak is corrected. A pressure test demonstrating less than a 10% pressure drop after 30 minutes is proof that the condition has been corrected.

(E) Wells drilling to formations where the expected reservoir pressure exceeds the weight of the drilling fluid column shall be equipped to divert any wellbore fluids away from the rig floor. All diverter systems shall be maintained in an effective working condition. No well shall continue drilling operations if a test or other information indicates the diverter system is unable to function or operate as designed.

(2) Surface casing.

(A) Amount required.

(i) An operator shall set and cement sufficient surface casing to protect all usable-quality water strata, as defined by the TCEQ. Before drilling any well in any field or area in which no field rules are in effect or in which surface casing requirements are not specified in the applicable field rules, an operator shall obtain a letter from the TCEQ stating the protection depth. In no case, however, is surface casing to be set deeper than 200 feet below the specified depth without prior approval from the commission.

(ii) Any well drilled to a total depth of 1,000 feet or less below the ground surface may be drilled without setting surface casing provided no shallow gas sands or abnormally high pressures are known to exist at depths shallower than 1,000 feet below the ground surface; and further, provided that production casing is cemented from the shoe to the ground surface by the pump and plug method.

(B) Cementing. Cementing shall be by the pump and plug method. Sufficient cement shall be used to fill the annular space outside the casing from the shoe to the ground surface or to the bottom of the cellar. If cement does not circulate to ground surface or the bottom of the cellar, the operator or his representative shall obtain the approval of the district director for the procedures to be used to perform additional cementing operations, if needed, to cement surface casing from the top of the cement to the ground surface.

(C) Cement quality.

(i) Surface casing strings must be allowed to stand under pressure until the cement has reached a compressive strength of at least 500 psi in the zone of critical cement before drilling plug or initiating a test. The cement mixture in the zone of critical cement shall have a 72-hour compressive strength of at least 1,200 psi.

(ii) An operator may use cement with volume extenders above the zone of critical cement to cement the casing from that point to the ground surface, but in no case shall the cement have a compressive strength of less than 100 psi at the time of drill out nor less than 250 psi 24 hours after being placed.

(iii) In addition to the minimum compressive strength of the cement, the API free water separation shall average no more than six milliliters per 250 milliliters of cement tested in accordance with the current API

RP 10B.

(iv) The commission may require a better quality of cement mixture to be used in any well or any area if evidence of local conditions indicates a better quality of cement is necessary to prevent pollution or to provide safer conditions in the well or area.

(D) Compressive strength tests. Cement mixtures for which published performance data are not available must be tested by the operator or service company. Tests shall be made on representative samples of the basic mixture of cement and additives used, using distilled water or potable tap water for preparing the slurry. The tests must be conducted using the equipment and procedures adopted by the American Petroleum Institute, as published in the current API RP 10B. Test data showing competency of a proposed cement mixture to meet the above requirements must be furnished the commission prior to the cementing operation. To determine that the minimum compressive strength has been obtained, operators shall use the typical performance data for the particular cement used in the well (containing all the additives, including any accelerators used in the slurry) at the following temperatures and at atmospheric pressure.

(i) For the cement in the zone of critical cement, the test temperature shall be within 10 degrees Fahrenheit of the formation equilibrium temperature at the top of the zone of critical cement.

(ii) For the filler cement, the test temperature shall be the temperature found 100 feet below the ground surface level, or 60 degrees Fahrenheit, whichever is greater.

(E) Cementing report. Upon completion of the well, a cementing report must be filed with the commission furnishing complete data concerning the cementing of surface casing in the well as specified on a form furnished by the commission. The operator of the well or his duly authorized agent having personal knowledge of the facts, and representatives of the cementing company performing the cementing job, must sign the form attesting to compliance with the cementing requirements of the commission.

(F) Centralizers. Surface casing shall be centralized at the shoe, above and below a stage collar or diverting tool, if run, and through usable-quality water zones. In nondeviated holes, pipe centralization as follows is required: a centralizer shall be placed every fourth joint from the cement shoe to the ground surface or to the bottom of the cellar. All centralizers shall meet API spec 10D specifications. In deviated holes, the operator shall provide additional centralization.

(G) Alternative surface casing programs.

(i) An alternative method of fresh water protection may be approved upon written application to the appropriate district director. The operator shall state the reason (economics, well control, etc.) for the alternative fresh water protection method and outline the alternate program for casing and cementing through the protection depth for strata containing usable-quality water. Alternative programs for setting more than specified amounts of surface casing for well control purposes may be requested on a field or area basis. Alternative programs for setting less than specified amounts of surface casing will be authorized on an individual well basis only. The district director may approve, modify, or reject the proposed program. If the proposal is modified or rejected, the operator may request a review by the director of field operations. If the proposal is not approved administratively, the operator may request a public hearing. An operator shall obtain approval of any alternative program before commencing operations.

(ii) Any alternate casing program shall require the first string of casing set through the protection depth to be cemented in a manner that will effectively prevent the migration of any fluid to or from any stratum exposed to the wellbore outside this string of casing. The casing shall be cemented from the shoe to ground surface in a single stage, if feasible, or by a multi-stage process with the stage tool set at least 50 feet below the protection depth.

(iii) Any alternate casing program shall include pumping sufficient cement to fill the annular space from the shoe or multi-stage tool to the ground surface. If cement is not circulated to the ground surface or the bottom of the cellar, the operator shall run a temperature survey or cement bond log. The appropriate district office shall be notified prior to running the required temperature survey or bond log. After the top of cement outside the casing is determined, the operator or his representative shall contact the appropriate district director and obtain approval for the procedures to be used to perform any required additional cementing operations. Upon completion of the well, a cementing report shall be filed with the commission on the prescribed form.

(iv) Before parallel (nonconcentric) strings of pipe are cemented in a well, surface or intermediate casing must be set and cemented through the protection depth.

(3) Intermediate casing.

(A) Cementing method. Each intermediate string of casing shall be cemented from the shoe to a point at least 600 feet above the shoe. If any productive horizon is open to the wellbore above the casing shoe, the casing shall be cemented from the shoe up to a point at least 600 feet above the top of the shallowest productive horizon or to a point at least 200 feet above the shoe of the next shallower casing string that was set and cemented in the well.

(B) Alternate method. In the event the distance from the casing shoe to the top of the shallowest productive horizon make cementing, as specified above, impossible or impractical, the multi-stage process may be used to cement the casing in a manner that will effectively seal off all such possible productive horizons and prevent fluid migration to or from such strata within the wellbore.

(4) Production casing.

(A) Cementing method. The producing string of casing shall be cemented by the pump and plug method, or another method approved by the commission, with sufficient cement to fill the annular space back of the casing to the surface or to a point at least 600 feet above the shoe. If any productive horizon is open to the wellbore above the casing shoe, the casing shall be cemented in a manner that effectively seals off all such possibly productive horizons by one of the methods specified for intermediate casing in paragraph (3) of this subsection.

(B) Isolation of associated gas zones. The position of the gas-oil contact shall be determined by coring, electric log, or testing. The producing string shall be landed and cemented below the gas-oil contact, or set completely through and perforated in the oil-saturated portion of the reservoir below the gas-oil contact.

(5) Tubing and storm choke requirements.

(A) Tubing requirements for oil wells. All flowing oil wells shall be equipped with and produced through tubing. When tubing is run inside casing in any flowing oil well, the bottom of the tubing shall be at a point not higher than 100 feet above the top of the producing interval nor more than 50 feet above the top of a line, if one is used. In a multiple zone structure, however, when an operator elects to equip a well in such a manner that small through-the-tubing type tools may be used to perforate, complete, plug back, or recomplete without the necessity of removing the installed tubing, the bottom of the tubing may be set at a distance up to, Cont'd...

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.12	**Directional Survey Company Report**

(a) For each well drilled for oil, gas, or geothermal resources for which a directional survey report is required by rule, regulation, or order, there shall be prepared and filed the following information. The information shall be certified by the person having personal knowledge of the facts, by execution and dating of the data compiled:

(1) name of surveying company;

(2) name of person performing the survey for the company;

(3) the position the person holds with the company;

(4) the date on which the survey was performed;

(5) type of survey conducted and whether multishot;

(6) a complete identification of the well so as to include the name of the operator of the well; the fee owner; the commission lease number, if assigned; the well number; the land survey; the field name; and the county and state;

(7) survey conducted from a depth of ____ feet to ____ feet.

(b) Each directional survey, with its accompanying certification and a certified plat on which the bottom hole location is oriented both to the surface location and to the lease lines (or unit lines in case of pooling) shall be mailed by registered, certified, or overnight mail direct to the commission in Austin by the surveying company making the survey.

Source Note: The provisions of this §3.12 adopted to be effective January 1, 1976; amended to be effective August 25, 2003, 28 TexReg 6816

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.11	**Inclination and Directional Surveys Required**

(a) General. All wells shall be drilled as nearly vertical as possible by normal, prudent, practical drilling operations. Nothing in this section shall be construed to permit the drilling of any well in such a manner that the wellbore crosses lease and/or property lines (or unit lines in cases of pooling) without special permission.

(b) Inclination surveys.

(1) Requirements.

(A) An inclination survey made by persons or concerns approved by the commission shall be filed on a form prescribed by the commission for each well drilled or deepened with rotary tools, except as hereinafter provided, or when, as a result of any operation, the course of the well is changed. The first shot point of such inclination survey shall be made at a depth not greater than 500 feet below the surface of the ground, and succeeding shot points shall be made either at 500-foot intervals or at the nearest drill bit change thereto, but not to exceed 1,000 feet apart.

(B) Inclination surveys conforming to these requirements may be made either during the normal course of drilling or after the well has reached total depth. Acceptable directional surveys may be filed in lieu of inclination surveys.

(C) Copies of all directional or inclination surveys, regardless of the reason for which they are run, shall be filed as a part of or in addition to the inclination surveys otherwise required by this section. If computations are made from dipmeter surveys to determine the course of the wellbore in any portion of the surveyed interval, a report of such computations shall be required.

(D) Inclination surveys shall not be required in any well drilled to a total depth of 2,000 feet or less on a regular location at least 150 feet from the nearest lease line, provided the well is not intentionally deviated from the vertical in any manner whatsoever.

(E) Inclination surveys shall not be required on wells deepened with rotary tools if the well is deepened no more than 300 feet or the distance from the surface location to the nearest lease or boundary line, whichever is the lesser, and provided that the well was not intentionally deviated from the vertical at any time before or after the beginning of deepening operations.

(F) Inclination surveys will not be required on wells that are drilled and completed as dry holes and are permanently plugged and abandoned. If such wells are reentered at a later date and completed as producers or injection or disposal wells, inclination reports will be required and must be filed with the appropriate completion form for the well.

(G) Inclination survey filings will not be required on wells that are reentries within casing of previously producing wells if inclination data are already on file with the Railroad Commission of Texas (commission). If such data are not on file with the commission, the results of an inclination survey must be reported on the appropriate form and filed with the completion form, except as provided by subparagraph (D) of this paragraph.

(2) Reports.

(A) The report form shall be signed and certified by a party having personal knowledge of the facts therein contained. The report shall include a tabulation of the maximum drifts which could occur between the surface and the first shot point, and each two successive shot points, assuming that all of the unsurveyed hole between any two shot points has the same inclination as that measured at the lowest shot point, and the total possible accumulative drift, assuming that all measured angles of inclination are in the same direction.

(B) In addition, the report shall be accompanied by a certified statement of the operator, or of someone acting at his direction on his behalf, either:

(i) that the well was not intentionally deviated from vertical; or

(ii) that the well was deviated at random, with an explanation of the circumstances.

(C) The report shall be filed in the district office by attaching one copy to each appropriate completion form for the well.

(D) The commission may require the submittal of the original charts, graphs, or discs resulting from the surveys.

(c) Directional surveys.

(1) When required.

(A) When the maximum displacement indicated by an inclination survey is greater than the actual distance from the surface location to the nearest lease line or pooled unit boundary, it will be considered to be a violating well subject to plugging and to penalty action. However, an operator may submit a directional survey, run at his own expense by a commission approved surveying company, to show the true bottom hole location of the well to be within the prescribed limits. When such directional survey shows the well to be bottomed within the confines of the lease, but nearer to a well or lease line or pooled unit boundary than allowed by applicable rules, or by the permit for the well if the well has been granted an exception to §3.37 of this title (relating to Statewide Spacing Rule), a new permit will be required if it is established that the bottom hole location or completion location is not a reasonable location.

(B) Directional surveys shall be required on each well drilled under the directional deviation provisions of this section.

(C) No oil, gas, or geothermal resource allowable shall be assigned any well on which a directional survey is required under any provision of this section until a directional survey has been filed with and accepted by the commission.

(2) Filing and type of survey.

(A) Directional surveys required under this section must be run by competent surveying companies, approved by the commission, signed and certified by a person having actual knowledge of the facts, in the manner prescribed by the commission in accordance with §3.12 of this title (relating to Directional Survey Company Report).

(B) All directional surveys, unless otherwise specified by the commission, shall be either single shot surveys or multi-shot surveys with the shot points not more than 200 feet apart, beginning within 200 feet of the surface, and the bottom hole location must be oriented both to the surface location and to the lease lines (or unit lines in cases of pooling).

(C) If more than 200 feet of surface casing has been run, the operator may begin the directional survey immediately below the surface casing depth. However, if such method is used, the inclination drifts from the surface of the ground to the surface casing depth must be added cumulatively and reported on the appropriate form. This total shall be assumed to be in the direction least favorable to the operator, and such point shall be considered the starting point of the directional survey.

(d) Intentional deviation of wells.

(1) Definitions.

(A) Directional deviation--The intentional deviation of a well from vertical in a predetermined compass direction.

(B) Random deviation--The intentional deviation of a well without regard to compass direction for one of the following reasons:

(i) to straighten a hole which has become crooked in the normal course of drilling;

(ii) to sidetrack a portion of a hole because of mechanical difficulty in drilling.

(2) When permitted.

(A) Directional deviation. A permit for directionally deviating a well may be granted by the commission:

(i) for the purpose of seeking to reach and control another well which is out of control or threatens to evade control;

(ii) where conditions on the surface of the ground prevent or unduly complicate the drilling of a well at a regular location;

(iii) where conditions are encountered underground which prevent or unduly hinder the normal completion of the well;

(iv) where it can be shown to be advantageous from the standpoint of mechanical operation to drill more than one well from the same surface location to reach the productive horizon at essentially the same positions as would be reached if the several wells were normally drilled from regular locations prescribed by the well spacing rules in effect;

(v) for the purpose of drilling a horizontal drainhole; or

(vi) for other reasons found by the commission to be sufficient after notice and hearing.

(B) Random deviation. Permission for the random deviation of a well may be granted by the commission whenever the necessity for such deviation is shown, as prescribed in paragraph (3)(C) of this subsection.

(3) Applications for deviation.

(A) Applications for wells to be directionally deviated must specify on the application to drill both the surface location of the well and the projected bottom hole location of the well. On the plat, in addition to the plat requirements provided for in §3.5 of this title (relating to Application to Drill, Deepen, Reenter, or Plug

Back) (Statewide Rule 5), the following shall be included:

(i) two perpendicular lines providing the distance in feet from the projected bottomhole location, rather than the surface location, to the nearest points on the lease, pooled unit, or unitized tract line. If there is an unleased interest in a tract of the pooled unit or unitized tract that is nearer than the pooled unit or unitized tract line, the nearest point on that unleased tract boundary shall be used;

(ii) a line providing the distance in feet from the projected bottomhole location to the nearest point on the lease line, pooled unit line, or unitized tract line. If there is an unleased interest in a tract of the pooled unit that is nearer than the pooled unit line, the nearest point on that unleased tract boundary shall be used;

(iii) a line providing the distance in feet from the projected bottomhole location, rather than the surface location, to the nearest oil, gas, or oil and gas well, identified by number, applied for, permitted, or completed in the same lease, pooled unit, or unitized tract and in the same field and reservoir; and

(iv) perpendicular lines providing the distance in feet from the two nearest non-parallel survey/section lines to the projected bottomhole location.

(B) If the necessity for directional deviation arises unexpectedly after drilling has begun, the operator shall give written notice by letter or telegram of such necessity to the appropriate district office and to the commission office in Austin, and upon giving such notice, the operator may proceed with the directional deviation. The commission may, at its discretion, accept written notice electronically transmitted. If the operator proceeds with the drilling of a deviated well under such circumstances, he proceeds at his own risk. Before any allowable shall be assigned to such well, a permit for the subsurface location of each completion interval shall be obtained from the commission under the provisions set out in the commission rules. However, should the operator fail to show good and sufficient cause for such deviation, no permit will be granted for the well.

(C) If the necessity for random deviation arises unexpectedly after the drilling has begun, the operator shall give written notice by letter or telegram of such necessity to the appropriate district office and to the commission office in Austin, and, upon giving such notice, the operator may proceed with the random deviation, subject to compliance with the provisions of this section on inclination surveys. The commission may, at its discretion, accept written notice electronically transmitted.

(e) Surveys on request of other operators. The commission, at the written request of any operator in a field, shall determine whether a directional survey, an inclination survey, or any other type of survey approved by the commission for the purpose of determining bottom hole location of wells, shall be made in regard to a well complained of in the same field.

(1) The complaining party must show probable cause to suspect that the well complained of is not bottomed within its own lease lines.

(2) The complaining party must agree to pay all costs and expenses of such survey, shall assume all liability, and shall be required to post bond in a sufficient sum as determined by the commission as security against all costs and risks associated with the survey.

(3) The complaining party and the commission shall agree upon the selection of the well surveying company to conduct the survey, which shall be a surveying company on the commission's approved list.

(4) The survey shall be witnessed by the commission, and may be witnessed by any party, or his agent, who has an interest in the field.

(5) Nothing in these rules shall be construed to prevent or limit the commission, acting on its own authority, from conducting spot checks and surveys at any time and place for the purpose of determining compliance with the commission rules and regulations.

(f) Penalties.

(1) False reports. The filing of a false or incorrect directional survey shall be grounds for cancellation of the well permit, for pipeline severance of the lease on which the well is located, for penalty action under the applicable statutes, and/or for such other and further action as may be appropriate.

(2) Other. The same penalties and actions as set forth in paragraph (1) of this subsection shall be assessable against any operator who refuses to comply with a commission order which issues under subsection (e) of this section.

Source Note: The provisions of this §3.11 adopted to be effective January 1, 1976; amended to be effective July 4, 1979, 4 TexReg 2197; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective May 23, 1990, 15 TexReg 2634; amended to be effective June 11, 2001, 26 TexReg 4088

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.10	**Restriction of Production of Oil and Gas from Different Strata**

(a) General prohibition. Oil or gas shall not be produced from different strata through the same string of tubulars except as provided in this section. As used in this section, "different strata" means two or more different commission-designated fields, or one or more commission-designated fields and any other hydrocarbon reservoir.

(b) Exception. After notice and an opportunity for a hearing, the commission or its delegate may grant an exception to subsection (a) of this section to permit production from a well or wells commingling oil or gas or oil and gas from different strata, if commingled production will prevent waste or promote conservation or protect correlative rights.

(c) Notice of Application for Exception.

(1) Timing of Notice.

(A) The applicant shall give notice of each request for an exception by serving a copy of the application to commingle production on all affected operators at the same time the application is filed with the commission.

(B) Service shall be accomplished by delivering a copy of the application to the operator to be served, or to the operator's duly authorized representative, in person, by agent, by courier receipted delivery, by first class mail to the operator's mailing address as shown on the operator's most recently filed Form P-5 (Organization Report) or the most recently filed letter notification of change of address, or by such other manner as the commission may direct.

(2) Operators Presumptively Affected By Application.

(A) An initial exception to commingle production exclusively from different commission-designated fields is presumed to affect all operators in each of the commission-designated fields proposed to be produced through the same string of tubulars.

(B) An initial exception to commingle production from a commission-designated field with production from one or more hydrocarbon reservoirs that have not been designated by the commission as a field is presumed to affect all operators in each of the different commission-designated fields proposed to be produced through the same string of tubulars and all operators of adjacent tracts, and of tracts nearer to the well for which a commingling exception is sought than the longest applicable minimum lease-line distance.

(C) An exception to commingle production exclusively from the same commission-designated fields for which an initial commingling application has previously been granted is presumed to affect all operators of adjacent tracts, and of tracts nearer to the well for which a subsequent commingling exception is sought than the longest applicable minimum lease-line distance, who have a well completed in one or more of the commission-designated fields for which commingling is sought.

(D) An exception to commingle production from a commission-designated field and one or more hydrocarbon reservoirs in specified correlative intervals that have not been designated by the commission as fields, for which an initial commingling exception involving the same fields and hydrocarbon reservoirs has previously been granted, is presumed to affect all operators of adjacent tracts, and of tracts nearer to the well for which a commingling exception is sought than the longest applicable minimum lease-line distance.

(3) Notice Required Only to Affected Operators.

(A) Except as provided in subparagraph (B) of this paragraph, all operators described in paragraph (2)(A)-(D) of this subsection are affected by a requested exception to allow commingling and the applicant shall give each of them notice of the application as provided in paragraph (1)(A) of this subsection.

(B) The commission or its delegate may determine that an operator described in paragraph (2)(A)-(D) will be unaffected by a requested exception to allow commingling. This determination shall be made only upon the applicant's written request and provision to the commission of competent geological or engineering data establishing conclusively that commingling production as requested by the applicant will not physically interfere with the production of hydrocarbons by the operator for which an unaffected determination is requested. An applicant for an exception to allow commingling is not required to give notice of the application to an operator who has been determined to be unaffected as provided in this subparagraph.

(d) Commingled production. Commingled production of gas from different strata pursuant to subsection (b) of this section shall be considered production from a common source of supply for purposes of proration and allocation.

Source Note: The provisions of this §3.10 adopted to be effective January 1, 1976; amended to be effective February 23, 1979, 4 TexReg 436; amended to be effective September 12, 1979, 4 TexReg 3082; amended to be effective May 14, 1996, 21 TexReg 3791.

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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.9	**Disposal Wells**

Any person who disposes of saltwater or other oil and gas waste by injection into a porous formation not productive of oil, gas, or geothermal resources shall be responsible for complying with this section, Texas Water Code, Chapter 27, and Title 3 of the Natural Resources Code.

(1) General. Saltwater or other oil and gas waste, as that term is defined in the Texas Water Code, Chapter 27, may be disposed of, upon application to and approval by the commission, by injection into nonproducing zones of oil, gas, or geothermal resources bearing formations that contain water mineralized by processes of nature to such a degree that the water is unfit for domestic, stock, irrigation, or other general uses. Every applicant who proposes to dispose of saltwater or other oil and gas waste into a formation not productive of oil, gas, or geothermal resources must obtain a permit from the commission authorizing the disposal in accordance with this section. Permits from the commission issued before the effective date of this section shall continue in effect until revoked, modified, or suspended by the commission.

(2) Geological requirements. Before such formations are approved for disposal use, the applicant shall show that the formations are separated from freshwater formations by impervious beds which will give adequate protection to such freshwater formations. The applicant must submit a letter from the Texas Commission on Environmental Quality or its successor agencies stating that the use of such formation will not endanger the freshwater strata in that area and that the formations to be used for disposal are not freshwater-bearing.

(3) Application. The application to dispose of saltwater or other oil and gas waste by injection into a porous formation not productive of oil, gas, or geothermal resources shall be filed with the commission in Austin accompanied by the prescribed fee. On the same date, one copy shall be filed with the appropriate district office.

(4) Commercial disposal well. An applicant for a permit to dispose of oil and gas waste in a commercial disposal well shall clearly indicate on the application and in the published notice of application that the application is for a commercial disposal well permit. For the purposes of this rule, "commercial disposal well" means a well whose owner or operator receives compensation from others for the disposal of oil field fluids or oil and gas wastes that are wholly or partially trucked or hauled to the well, and the primary business purpose for the well is to provide these services for compensation.

(5) Notice and opportunity for hearing.

(A) The applicant shall give notice by mailing or delivering a copy of the application to affected persons who include the owner of record of the surface tract on which the well is located; each commission-designated operator of any well located within one-half mile of the proposed disposal well; the county clerk of the county in which the well is located; and the city clerk or other appropriate city official of any city where the well is located within the municipal boundaries of the city, on or before the date the application is mailed to or filed with the commission. For the purposes of this section, the term "of record" means recorded in the real property or probate records of the county in which the property is located.

(B) In addition to the requirements of subsection (a)(5)(A) of this section, a commercial disposal well permit applicant shall give notice to owners of record of each surface tract that adjoins the proposed disposal tract by mailing or delivering a copy of the application to each such surface owner.

(C) If, in connection with a particular application, the commission or its delegate determines that another class of persons should receive notice of the application, the commission or its delegate may require the applicant to mail or deliver a copy of the application to members of that class. Such classes of persons could include adjacent surface owners or underground water districts.

(D) In order to give notice to other local governments, interested, or affected persons, notice of the application shall be published once by the applicant in a newspaper of general circulation for the county where the well will be located in a form approved by the commission or its delegate. The applicant shall file with the commission in Austin proof of publication prior to the hearing or administrative approval.

(E) Protested applications:

(i) If a protest from an affected person or local government is made to the commission within 15 days of receipt of the application or of publication, whichever is later, or if the commission or its delegate determines that a hearing is in the public interest, then a hearing will be held on the application after the commission provides notice of hearing to all affected persons, local governments, or other persons, who express an interest, in writing, in the application.

(ii) For purposes of this section, "affected person" means a person who has suffered or will suffer actual injury or economic damage other than as a member of the general public or as a competitor, and includes surface owners of property on which the well is located and commission-designated operators of wells located within one-half mile of the proposed disposal well.

(F) If no protest from an affected person is received by the commission, the commission's delegate may administratively approve the application. If the commission's delegate denies administrative approval, the applicant shall have a right to a hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(6) Subsequent commission action.

(A) A permit for saltwater or other oil and gas waste disposal may be modified, suspended, or terminated by the commission for just cause after notice and opportunity for hearing, if:

(i) a material change of conditions occurs in the operation or completion of the disposal well, or there are material changes in the information originally furnished;

(ii) freshwater is likely to be polluted as a result of continued operation of the well;

(iii) there are substantial violations of the terms and provisions of the permit or of commission rules;

(iv) the applicant has misrepresented any material facts during the permit issuance process;

(v) injected fluids are escaping from the permitted disposal zone; or

(vi) waste of oil, gas, or geothermal resources is occurring or is likely to occur as a result of the permitted operations.

(B) A disposal well permit may be transferred from one operator to another operator provided that the commission's delegate does not notify the present permit holder of an objection to the transfer prior to the date the lease is transferred on Commission records.

(C) Voluntary permit suspension.

(i) An operator may apply to temporarily suspend its injection authority by filing a written request for permit suspension with the commission in Austin, and attaching to the written request the results of an MIT test performed during the previous three-month period in accordance with the provisions of paragraph (12)(D) of this section. The provisions of this subparagraph shall not apply to any well that is permitted as a commercial disposal well.

(ii) The commission or its delegate may grant the permit suspension upon determining that the results of the MIT test submitted under clause (i) of this subparagraph indicate that the well meets the performance standards of paragraph (12)(D) of this section.

(iii) During the period of permit suspension, the operator shall not use the well for injection or disposal purposes.

(iv) During the period of permit suspension, the operator shall comply with all applicable well testing requirements of §3.14 of this title (relating to plugging, and commonly referred to as Statewide Rule 14) but need not perform the MIT test that would otherwise be required under the provisions of paragraph (12)(D) of this section or the permit. Further, during the period of permit suspension, the provisions of paragraph (11)(A) - (C) of this section shall not apply.

(v) The operator may reinstate injection authority under a suspended permit by filing a written notification with the commission in Austin. The written notification shall be accompanied by an MIT test performed during the three-month period prior to the date notice of reinstatement is filed. The MIT test shall have been performed in accordance with the provisions and standards of paragraph (12)(D) of this section.

(7) Area of Review.

(A) Except as otherwise provided in this paragraph, the applicant shall review the date of public record for wells that penetrate the proposed disposal zone within a 1/4 mile radius of the proposed disposal well to determine if all abandoned wells have been plugged in a manner that will prevent the movement of fluids from the disposal zone into freshwater strata. The applicant shall identify in the application any wells which appear from such review of public records to be unplugged or improperly plugged and any other unplugged or improperly plugged wells of which the applicant has actual knowledge.

(B) The commission or its delegate may grant a variance from the area-of-review requirements of subparagraph (A) of this paragraph upon proof that the variance will not result in a material increase in the risk of fluid movement into freshwater strata or to the surface. Such a variance may be granted for an area defined both vertically and laterally (such as a field) or for an individual well. An application for an areal variance need not be filed in conjunction with an individual permit application or application for permit amendment. Factors that may be considered by the commission or its delegate in granting a variance include:

(i) the area affected by pressure increases resulting from injection operations;

(ii) the presence of local geological conditions that preclude movement of fluid that could endanger freshwater strata or the surface; or

(iii) other compelling evidence that the variance will not result in a material increase in the risk of fluid movement into freshwater strata or to the surface.

(C) Persons applying for a variance from the area-of-review requirements of subparagraph (A) of this paragraph on the basis of factors set out in subparagraph (B)(ii) or (iii) of this paragraph for an individual well shall provide notice of the application to those persons given notice under the provisions of paragraph (5)(A) of this subsection. The provisions of paragraph (5)(D) and (E) shall apply in the case of an application for a variance from the area-of-review requirements for an individual well.

(D) Notice of an application for an areal variance from the area-of-review requirements under subparagraph (A) of this paragraph shall be given on or before the date the application is filed with the commission:

(i) by publication once in a newspaper having general circulation in each county, or portion thereof, where the variance would apply. Such notice shall be in a form approved by the commission or its delegate prior to publication and must be at least three inches by five inches in size. The notice shall state that protests to the application may be filed with the commission during the 15-day period following the date of publication. The notice shall appear in a section of the newspaper containing state or local news items;

(ii) by mailing or delivering a copy of the application, along with a statement that any protest to the application should be filed with the commission within 15 days of the date of the application is filed with the commission, to the following:

(I) the manager of each underground water conservation district(s) in which the variance would apply, if any;

(II) the city clerk or other appropriate official of each incorporated city in which the variance would apply, if any;

(III) the county clerk of each county in which the variance would apply; and

(IV) any other person or persons that the commission or its delegate determine should receive notice of the application.

(E) If a protest to an application for an areal variance is made to the commission by an affected person, local government, underground water conservation district, or other state agency within 15 days of receipt of the application or of publication, whichever is later, or if the commission's delegate determines that a hearing on the application is in the public interest, then a hearing will be held on the application after the commission provides notice of the hearing to all local governments, underground water conservation districts, state agencies, or other persons, who express an interest, in writing, in the application. If no protest from an affected person is received by the commission, the commission's delegate may administratively approve the application. If the application is denied administratively, the person(s) filing the application shall have a right to hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(F) An areal variance granted under the provisions of this paragraph may be modified, terminated, or suspended by the commission after notice and opportunity for hearing is provided to each person shown on commission records to operate an oil or gas lease in the area in which the proposed modification, termination, or suspension would apply. If a hearing on a proposal to modify, terminate, or suspend an areal variance is held, any applications filed subsequent to the date notice of hearing is given must include the area-of-review information required under subparagraph (A) of this paragraph pending issuance of a final order.

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RULE §3.8	**Water Protection**

(a) The following words and terms when used in this section shall have the following meanings, unless the context clearly indicates otherwise.

(1) Basic sediment pit--Pit used in conjunction with a tank battery for storage of basic sediment removed from a production vessel or from the bottom of an oil storage tank. Basic sediment pits were formerly referred to as burn pits.

(2) Brine pit--Pit used for storage of brine which is used to displace hydrocarbons from an underground hydrocarbon storage facility.

(3) Collecting pit--Pit used for storage of saltwater prior to disposal at a tidal disposal facility, or pit used for storage of saltwater or other oil and gas wastes prior to disposal at a disposal well or fluid injection well. In some cases, one pit is both a collecting pit and a skimming pit.

(4) Completion/workover pit--Pit used for storage or disposal of spent completion fluids, workover fluids and drilling fluid, silt, debris, water, brine, oil scum, paraffin, or other materials which have been cleaned out of the wellbore of a well being completed or worked over.

(5) Drilling fluid disposal pit--Pit, other than a reserve pit, used for disposal of spent drilling fluid.

(6) Drilling fluid storage pit--Pit used for storage of drilling fluid which is not currently being used but which will be used in future drilling operations. Drilling fluid storage pits are often centrally located among several leases.

(7) Emergency saltwater storage pit--Pit used for storage of produced saltwater for limited period of time. Use of the pit is necessitated by a temporary shutdown of disposal well or fluid injection well and/or associated equipment, by temporary overflow of saltwater storage tanks on a producing lease or by a producing well loading up with formation fluids such that the well may die. Emergency saltwater storage pits may sometimes be referred to as emergency pits or blowdown pits.

(8) Flare pit--Pit which contains a flare and which is used for temporary storage of liquid hydrocarbons which are sent to the flare during equipment malfunction but which are not burned. A flare pit is used in conjunction with a gasoline plant, natural gas processing plant, pressure maintenance or repressurizing plant, tank battery, or a well.

(9) Fresh makeup water pit--Pit used in conjunction with drilling rig for storage of water used to make up drilling fluid.

(10) Gas plant evaporation/retention pit--Pit used for storage or disposal of cooling tower blowdown, water condensed from natural gas, and other wastewater generated at gasoline plants, natural gas processing plants, or pressure maintenance or repressurizing plants.

(11) Mud circulation pit--Pit used in conjunction with drilling rig for storage of drilling fluid currently

being used in drilling operations.

(12) Reserve pit--Pit used in conjunction with drilling rig for collecting spent drilling fluids; cuttings, sands, and silts; and wash water used for cleaning drill pipe and other equipment at the well site. Reserve pits are sometimes referred to as slush pits or mud pits.

(13) Saltwater disposal pit--Pit used for disposal of produced saltwater.

(14) Skimming pit--Pit used for skimming oil off saltwater prior to disposal of saltwater at a tidal disposal facility, disposal well, or fluid injection well.

(15) Washout pit--Pit located at a truck yard, tank yard, or disposal facility for storage or disposal of oil and gas waste residue washed out of trucks, mobile tanks, or skid-mounted tanks.

(16) Water condensate pit--Pit used in conjunction with a gas pipeline drip or gas compressor station for storage or disposal of fresh water condensed from natural gas.

(17) Generator--Person who generates oil and gas wastes.

(18) Carrier--Person who transports oil and gas wastes generated by a generator. A carrier of another person's oil and gas wastes may be a generator of his own oil and gas wastes.

(19) Receiver--Person who stores, handles, treats, reclaims, or disposes of oil and gas wastes generated by a generator. A receiver of another person's oil and gas wastes may be a generator of his own oil and gas wastes.

(20) Director--Director of the Oil and Gas Division or his staff delegate designated in writing by the director of the Oil and Gas Division or the commission.

(21) Person--Natural person, corporation, organization, government or governmental subdivision or agency, business trust, estate, trust, partnership, association, or any other legal entity.

(22) Affected person--Person who, as a result of the activity sought to be permitted, has suffered or may suffer actual injury or economic damage other than as a member of the general public.

(23) To dewater--To remove the free water.

(24) To dispose--To engage in any act of disposal subject to regulation by the commission including, but not limited to, conducting, draining, discharging, emitting, throwing, releasing, depositing, burying, landfarming, or allowing to seep, or to cause or allow any such act of disposal.

(25) Landfarming--A waste management practice in which oil and gas wastes are mixed with or applied to the land surface in such a manner that the waste will not migrate off the landfarmed area.

(26) Oil and gas wastes--Materials to be disposed of or reclaimed which have been generated in connection with activities associated with the exploration, development, and production of oil or gas or geothermal resources, as those activities are defined in paragraph (30) of this subsection, and materials to be disposed of or reclaimed which have been generated in connection with activities associated with the solution mining of brine. The term "oil and gas wastes" includes, but is not limited to, saltwater, other mineralized water, sludge, spent drilling fluids, cuttings, waste oil, spent completion fluids, and other liquid, semiliquid, or solid waste material. The term "oil and gas wastes" includes waste generated in connection with activities associated with gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance plants, or repressurizing plants unless that waste is a hazardous waste as defined by the administrator of the

United States Environmental Protection Agency pursuant to the federal Solid Waste Disposal Act, as amended (42 United States Code §6901 et seq.).

(27) Oil field fluids--Fluids to be used or reused in connection with activities associated with the exploration, development, and production of oil or gas or geothermal resources, fluids to be used or reused in connection with activities associated with the solution mining of brine, and mined brine. The term "oil field fluids" includes, but is not limited to, drilling fluids, completion fluids, surfactants, and chemicals used to detoxify oil and gas wastes.

(28) Pollution of surface or subsurface water--The alteration of the physical, thermal, chemical, or biological quality of, or the contamination of, any surface or subsurface water in the state that renders the water harmful, detrimental, or injurious to humans, animal life, vegetation, or property, or to public health, safety, or welfare, or impairs the usefulness or the public enjoyment of the water for any lawful or reasonable purpose.

(29) Surface or subsurface water--Groundwater, percolating or otherwise, and lakes, bays, ponds, impounding reservoirs, springs, rivers, streams, creeks, estuaries, marshes, inlets, canals, the Gulf of Mexico inside the territorial limits of the state, and all other bodies of surface water, natural or artificial, inland or coastal, fresh or salt, navigable or nonnavigable, and including the beds and banks of all watercourses and bodies of surface water, that are wholly or partially inside or bordering the state or inside the jurisdiction of the state.

(30) Activities associated with the exploration, development, and production of oil or gas or geothermal resources--Activities associated with:

(A) the drilling of exploratory wells, oil wells, gas wells, or geothermal resource wells;

(B) the production of oil or gas or geothermal resources, including:

(i) activities associated with the drilling of injection water source wells that penetrate the base of usable quality water;

(ii) activities associated with the drilling of cathodic protection holes associated with the cathodic protection of wells and pipelines subject to the jurisdiction of the commission to regulate the production of oil or gas or geothermal resources;

(iii) activities associated with gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance plants, or repressurizing plants;

(iv) activities associated with any underground natural gas storage facility, provided the terms "natural gas" and "storage facility" shall have the meanings set out in the Texas Natural Resources Code, §91.173;

(v) activities associated with any underground hydrocarbon storage facility, provided the terms "hydrocarbons" and "underground hydrocarbon storage facility" shall have the meanings set out in the Texas Natural Resources Code, §91.201; and

(vi) activities associated with the storage, handling, reclamation, gathering, transportation, or distribution of oil or gas prior to the refining of such oil or prior to the use of such gas in any manufacturing process or as a residential or industrial fuel;

(C) the operation, abandonment, and proper plugging of wells subject to the jurisdiction of the commission to regulate the exploration, development, and production of oil or gas or geothermal resources;

and

(D) the discharge, storage, handling, transportation, reclamation, or disposal of waste or any other substance or material associated with any activity listed in subparagraphs (A)-(C) of this paragraph, except for waste generated in connection with activities associated with gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance plants, or repressurizing plants if that waste is a hazardous waste as defined by the administrator of the United States Environmental Protection Agency pursuant to the federal Solid Waste Disposal Act, as amended (42 United States Code §6901, et seq.).

(31) Mined brine--Brine produced from a brine mining injection well by solution of subsurface salt formations. The term "mined brine" does not include saltwater produced incidentally to the exploration, development, and production of oil or gas or geothermal resources.

(32) Brine mining pit--Pit, other than a fresh mining water pit, used in connection with activities associated with the solution mining of brine. Most brine mining pits are used to store mined brine.

(33) Fresh mining water pit--Pit used in conjunction with a brine mining injection well for storage of water used for solution mining of brine.

(34) Inert wastes--Nonreactive, nontoxic, and essentially insoluble oil and gas wastes, including, but not limited to, concrete, glass, wood, metal, wire, plastic, fiberglass, and trash.

(35) Coastal zone--The area within the boundary established in Title 31, Texas Administrative Code, §503.1 (Coastal Management Program Boundary).

(36) Coastal management program (CMP) rules--The enforceable rules of the Texas Coastal Management Program codified at Title 31, Texas Administrative Code, Chapters 501, 505, and 506.

(37) Coastal natural resource area (CNRA)--One of the following areas defined in Texas Natural Resources Code, §33.203: coastal barriers, coastal historic areas, coastal preserves, coastal shore areas, coastal wetlands, critical dune areas, critical erosion areas, gulf beaches, hard substrate reefs, oyster reefs, submerged land, special hazard areas, submerged aquatic vegetation, tidal sand or mud flats, water in the open Gulf of Mexico, and water under tidal influence.

(38) Coastal waters--Waters under tidal influence and waters of the open Gulf of Mexico.

(39) Critical area--A coastal wetland, an oyster reef, a hard substrate reef, submerged aquatic vegetation, or a tidal sand or mud flat as defined in Texas Natural Resources Code, §33.203.

(40) Practicable--Available and capable of being done after taking into consideration existing technology, cost, and logistics in light of the overall purpose of the activity.

(b) No pollution. No person conducting activities subject to regulation by the commission may cause or allow pollution of surface or subsurface water in the state.

(c) Exploratory wells. Any oil, gas, or geothermal resource well or well drilled for exploratory purposes shall be governed by the provisions of statewide or field rules which are applicable and pertain to the drilling, safety, casing, production, abandoning, and plugging of wells.

(d) Pollution control.

(1) Prohibited disposal methods. Except for those disposal methods authorized for certain wastes by paragraph (3) of this subsection, subsection (e) of this section, or §3.98 of this title (relating to Standards for

Management of Hazardous Oil and Gas Waste), or disposal methods required to be permitted pursuant to §3.9 of this title (relating to Disposal Wells) (Rule 9) or §3.46 of this title (relating to Fluid Injection into Productive Reservoirs) (Rule 46), no person may dispose of any oil and gas wastes by any method without obtaining a permit to dispose of such wastes. The disposal methods prohibited by this paragraph include, but are not limited to, the unpermitted discharge of oil field brines, geothermal resource waters, or other mineralized waters, or drilling fluids into any watercourse or drainageway, including any drainage Cont'd...

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RULE §3.7	**Strata To Be Sealed Off**

Whenever hydrocarbon or geothermal resource fluids are encountered in any well drilled for oil, gas, or geothermal resources in this state, such fluid shall be confined in its original stratum until it can be produced and utilized without waste. Each such stratum shall be adequately protected from infiltrating waters. Wells may be drilled deeper after encountering a stratum bearing such fluids if such drilling shall be prosecuted with diligence and any such fluids be confined in its stratum and protected as aforesaid upon completion of the well. The commission will require each such stratum to be cased off and protected, if in its discretion it shall be reasonably necessary and proper to do so.

Source Note: The provisions of this §3.7 adopted to be effective January 1, 1976.

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RULE §3.6	**Application for Multiple Completion**

(a) Authority will be granted to multicomplete a well in separate reservoirs that are not in communication without the necessity of notice and hearing on each separate application; provided, that an application for multiple completion on the form prescribed and the required accompanying data, as hereafter listed, is filed with the Engineering unit of the Commission's Permitting and Production Section for its consideration and approval.

(b) If the proposed zones of completion are not presently recognized by the commission as being acceptable for multicompletion approval, all data necessary to substantiate a conclusion by the commission that the proposed zones of completion are feasible and reasonably susceptible of having multicompleted and producing wells drilled thereto and therein must be filed with the application.

(c) If the additional data furnished with the application is not considered by the commission to be sufficient to establish the proposed zones of completion as separate zones of production which are feasible and reasonably susceptible of having multicompleted and producing wells drilled thereto and therein, or if any party protests such an application, then, if an operator so elects, his application will be set for hearing.

(d) Multiple completion authority for a well will not be granted unless the following required data have been filed with the Engineering unit of the Commission's Permitting and Production Section:

(1) application for multiple completion properly executed and attested;

(2) electrical log or portion of the electric log of the well or a type electric log or a portion of the type electric log showing clearly thereon the subsurface location of the separate reservoirs claimed. Any electric log filed will be considered public information pursuant to §3.16 of this title (relating to Log and Completion Report (Statewide Rule 16);

(3) packer setting report where applicable;

(4) packer leakage test or communication test;

(5) diagrammatic sketch of the mechanical installation;

(6) letters of waiver from offset operators, or evidence that notice of application to multicomplete was given to said operators.

Source Note: The provisions of this §3.6 adopted to be effective January 1, 1976; amended to be effective February 28, 1986, 11 TexReg 545; amended to be effective November 24, 2004, 29 TexReg 10728

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CHAPTER 3	OIL AND GAS DIVISION
RULE §3.5	**Application To Drill, Deepen, Reenter, or Plug Back**

(a) Requirements for spacing, density, and units. An application for a permit to drill, deepen, plug back, or reenter any oil well, gas well, or geothermal resource well shall be made under the provisions of §§3.37, 3.38, 3.39, and/or 3.40 of this title (relating to Statewide Spacing Rule; Well Densities; Proration and Drilling Units: Contiguity of Acreage and Exception Thereto; and Assignment of Acreage to Pooled Development and Proration Units) (Statewide Rules 37, 38, 39, and 40), or as an exception thereto, or under special rules governing any particular oil, gas, or geothermal resource field or as an exception thereto and filed with the commission on a form approved by the commission. An application must be accompanied by any relevant information, form, or certification required by the Railroad Commission or a commission representative necessary to determine compliance with this rule and state law.

(b) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Application--Request by an organization made either on the prescribed form or electronically pursuant to procedures for electronic filings adopted by the commission for a permit to drill, deepen, plug back, or reenter any oil well, gas well, or geothermal resource well.

(2) Commission--The Railroad Commission of Texas.

(3) Commission representative--A commission employee authorized to act for the commission. Any authority given to a commission representative is also retained by the commission. Any action taken by the commission representative is subject to review by the commission.

(c) Commencement of operations. Operations of drilling, deepening, plugging back, or reentering shall not be commenced until the permit has been granted by the commission and the waiting period, if any, has terminated, or authorization has been granted pursuant to subsection (d) of this section.

(d) Testing of existing wells in other reservoirs inside the casing. For an existing well, an operator may request authorization to commence operations to deepen inside the casing or plug back prior to the granting of a permit to deepen or plug back.

(1) This authorization shall be requested by submitting a request with the district office to deepen inside the casing or plug back. The request shall include:

(A) the operator name;

(B) the lease name;

(C) the lease number or gas identification number;

(D) well number;

(E) county;

(F) field name;

(G) a list of all reservoir(s) to be tested;

(H) the casing setting depth and the depth of the deepest reservoir to be tested;

(I) a plat showing the well location; and

(J) a statement as to whether or not the well location would require an exception to §§3.37, 3.38, 3.39, and/or 3.40 of this title (relating to Statewide Spacing Rule; Well Densities; Proration and Drilling Units: Contiguity of Acreage and Exception Thereto; and Assignment of Acreage to Pooled Development and Proration Units) (Statewide Rules 37, 38, 39, and 40) if completed in any of the reservoirs to be tested. If an exception would be required, the request shall also include a statement that all affected offsets have been given written notice of the intent to test with the opportunity to witness the testing and the offsets shall be identified on the plat.

(2) Operations of deepening inside the casing or plugging back shall not be commenced until the district office has reviewed and approved the request. Testing pursuant to this authorization shall be completed within 90 days from the date the district office approves the request.

(A) No reservoir tested pursuant to the provisions of this subsection shall be tested for more than 15 days.

(B) If the operator desires to place the well on production, the operator shall shut in the well, with no production being sold, and file a permit application for the tested reservoirs with the appropriate fees. If the permit application for the tested reservoirs requires an exception to §§3.37, 3.38, 3.39, and/or 3.40 of this title (relating to Statewide Spacing Rule; Well Densities; Proration and Drilling Units: Contiguity of Acreage and Exception Thereto; and Assignment of Acreage to Pooled Development and Proration Units) (Statewide Rules 37, 38, 39, and 40), no consideration will be given by the commission to the cost of recompleting and testing the well in determining whether or not to grant the exception.

(C) Within 30 days of completion of testing, the operator must either file an application for a permit to produce a reservoir tested pursuant to this subsection or file an amended completion report in accordance with §3.16 of this title (relating to Log and Completion or Plugging Report) (Statewide Rule 16) with a copy of the request signed by the district office and a statement that a permit to produce a tested reservoir is not being sought, or if the well has been plugged and abandoned, a plugging report including reservoir and perforation data. If a permit is not obtained for the tested reservoirs and/or an allowable is not assigned, the producer shall report all test production in the producer's monthly report filed for the last permitted reservoir in which the well was completed and may request authorization to sell the test production. The test production may be sold after such authorization is granted.

(e) Exploratory and specialty wells. An application for any exploratory well or cathodic protection well that penetrates the base of the fresh water strata, fluid injection well, injection water source well, disposal well, brine solution mining well, or underground hydrocarbon storage well shall be made and filed with the commission on a form approved by the commission. Operations for drilling, deepening, plugging back, or reentering shall not be commenced until the permit has been granted by the commission. For an exploratory well, an exception to filing such form prior to commencing operations may be obtained if an application for a core hole test is filed with the commission.

(f) Drilling permit fee. With each application or materially amended application, the applicant shall submit to the commission a nonrefundable fee as determined by §3.78 of this title (relating to Fees and Financial Security Requirements) (Statewide Rule 78).

(g) Expiration. Any permit to drill, deepen, plug back, or reenter granted by the commission expires no later than two years after the date of original approval.

(h) Plats. An application to drill, deepen, plug back, or reenter shall be accompanied by a neat, accurate plat, with a scale of one inch equals 1,000 feet. The plat for the initial well on the lease, pooled unit, or unitized tract shall show the entire lease, pooled unit, or tract, including all tracts being pooled. If necessary to show the entire lease, the scale may be one inch equals 2,000 feet. Plats for subsequent wells on a lease or pooled unit shall show at least the lease or pooled unit line nearest the proposed location and the nearest survey/section lines. The Division Director or the director's delegate may approve plats with other scales upon request.

(1) The lease shall be outlined on the plat using either a heavy line or crosshatching.

(2) The plat is to include the following:

(A) surface location of the proposed drilling site;

(B) perpendicular lines providing the distance in feet from two nearest non-parallel survey/section lines to the surface location;

(C) perpendicular lines providing the distance in feet from two nearest non-parallel lease lines to the surface location;

(D) a line providing the distance in feet from the surface location to the nearest point on the lease line, pooled unit line, or unitized tract line. If there is an unleased interest in a tract of the pooled unit that is nearer than the pooled unit line, the nearest point on that unleased tract boundary shall be used;

(E) a line providing the distance in feet from the surface location to the nearest oil, gas, or oil and gas well identified by number either applied for, permitted, or completed in the same lease, pooled unit, or unitized tract and in the same field and reservoir;

(F) the geographic location information;

(G) a labeled scale bar; and

(H) northerly direction.

(3) Requirements for plats as provided for in §3.11, §3.37, §3.38, and §3.86 of this title (relating to Inclination and Directional Surveys Required, Statewide Spacing Rule, Well Densities, and Horizontal Drainhole Wells) may supplement or replace the plat requirements set out above.

Source Note: The provisions of this §3.5 adopted to be effective January 1, 1976; amended to be effective September 1, 1983, 8 TexReg 3184; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective October 30, 1986, 11 TexReg 4214; amended to be effective February 24, 1992, 17 TexReg 1225; amended to be effective September 1, 1992, 17 TexReg 5283; amended to be effective July 10, 2000, 25 TexReg 6487; amended to be effective June 11, 2001, 26 TexReg 4088; amended to be effective September 1, 2004, 29 TexReg 8271

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.4	**Oil and Geothermal Lease Numbers and Gas Well ID Numbers Required on All Forms**

(a) Lease name and number.

(1) All operators with oil and geothermal producing properties must ascertain from the appropriate proration schedule the lease number assigned to each separate lease, and thereafter include on each commission-required form or report the exact lease name and its number as they appear on the current proration schedule for all leases.

(2) No commission-required form or report will be accepted until the form or report is properly completed, including both the lease name and lease number applicable thereto.

(3) If a lease has not been issued a lease number on the current proration schedule, the lease shall have assigned to it the exact lease name as shown on the form first submitted, and in addition thereto a lease number will be assigned at the same time the form reflecting the potential test is submitted and processed. Subsequent to the assignment of a lease number, such number together with the exact lease name as submitted on the appropriate form must appear on all future forms and reports submitted to the commission, the lease number and lease name as assigned by the commission to be evidenced to the operator on the face of the supplement establishing the allowable for the lease.

(b) Gas well identification numbers shall be assigned by the commission for each separate gas well completion, and such gas well identification number shall be used on all forms and reports required by and filed with the commission concerning operations for such well so long as it remains a gas well, such commission gas well identification number to be effective as provided in the following paragraphs.

(1) All operators having a gas well must ascertain from the appropriate current gas allowable schedule the commission gas well identification number assigned to each separate gas well completion, and thereafter include on each commission required form or report its exact well lease name and number and its commission gas well identification number as they appear on the current gas allowable schedule for all gas wells completed in the same reservoir.

(2) No commission-required form or report will be accepted until the form or report is properly completed, including both the well lease name and number and the commission gas well identification number applicable thereto.

(3) If a gas well has not been assigned a gas well identification number on the current gas allowable schedule, such well shall have assigned to it the exact well lease name and number as shown on the appropriate form and, in addition thereto, a gas well identification number will be assigned at the time the commission-required form is submitted and processed. After the assignment of a gas well identification number, such number together with the exact well lease name and number on the form first submitted, must appear on all future forms and reports submitted to the commission, the gas well lease name and gas well identification number as assigned by the commission to be evidenced to the operator on the face of the supplement establishing the initial allowable for such well.

Source Note: The provisions of this §3.4 adopted to be effective January 1, 1976.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.3	**Identification of Properties, Wells, and Tanks**

Each property that produces oil, gas, or geothermal resources and each oil, gas, or geothermal resource well and tank, or other approved crude oil measuring facility where tanks are not utilized thereon, shall at all times be clearly identified as follows.

(1) A sign shall be posted at the principal entrance to each such property which shall show the name by which the property is commonly known and is carried on the records of the commission, the name of the operator, and the number of acres in the property.

(2) A sign shall be posted at each well site which shall show the name of the property, the name of the operator, and the well number.

(3) A sign shall be posted at or painted on each oil stock tank and on each remotely located satellite tank, or on each approved crude oil measuring facility where tanks are not utilized, that is located on or serving each property, which signs shall show, in addition to the information provided for in paragraph (1) of this section, the commission lease number for the formation from which oil in the tank, or in an approved crude oil measuring facility, is produced, and where oil from more than one formation is commingled in the same tank, or in an approved crude oil measuring facility, the sign shall show the number of the commission permit that authorized the commingling of the oil; provided that, if there is more than one tank in a battery which contains oil from only one formation or oil from different formations that is commingled pursuant to a single commingling permit, it will not be necessary for the sign to be posted at or painted on each tank if the sign posted at or painted on a tank in the battery shows the required information and clearly identifies, by tank number or otherwise, the tanks to which the information is applicable.

(4) If a well is separately completed in two or more producing formations, the wellhead valve and flow line serving each separate formation shall be identified by a metal tag or other lettering attached to or painted on either the valve or flow line which shows the name of the formation and identifies the completion string of casing or tubing, as for example "C" for casing; "UT" for upper tubing; "LT" for lower tubing, etc., each being preceded or followed by the name of the producing formation.

(5) The signs and identification required by this section shall be in the English language, clearly legible, and in the case of the signs required by paragraphs (1), (2), and (3) of this section shall be in letters and numbers at least one inch in height.

Source Note: The provisions of this §3.3 adopted to be effective January 1, 1976.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.2	**Commission Access to Properties**

(a) The commission or its representatives shall have access to come upon any lease or property operated or controlled by an operator, producer, or transporter of oil, gas, or geothermal resources, and to inspect any and all leases, properties, and wells and all records of said leases, properties, and wells.

(b) Designated agents of the commission are authorized to make any tests on any well at any time necessary to conservation regulation, and the owner of such well is hereby directed to do all things that may be required of him by the commission's agent to make such tests in a proper manner.

Source Note: The provisions of this §3.2 adopted to be effective January 1, 1976.

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TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 3	OIL AND GAS DIVISION
RULE §3.106	**Sour Gas Pipeline Facility Construction Permit**

(a) Definitions. The following words and terms when used in this section shall have the following meanings, unless the context clearly indicates otherwise.

(1) Affected person--The owner or occupant of real property located in the area of influence of the proposed route of a sour gas pipeline facility. If the final proposed route of the pipeline is unknown at the time of application, then an affected person is any person who owns or occupies real property located within the area of influence associated with any possible pipeline route identified by the applicant. For purposes of this definition, the owner shall be the owner of record as of the final day to protest an application. The occupant shall be the occupant as of the final day to protest an application.

(2) Applicant--A person who has filed an application for a permit to construct a sour gas pipeline facility, or a representative of that person.

(3) Application--Application for a Permit to Construct a Sour Gas Pipeline Facility, and all required attachments.

(4) Area of influence--Area along a sour gas pipeline facility represented by all possible areas of exposure using the 100 ppm radius.

(5) Construction of a facility--Any activity conducted during the initial construction of a pipeline including the removal of earth, vegetation, or obstructions along the proposed pipeline right-of-way. The term does not include:

(A) surveying or acquiring the right-of-way;

(B) clearing the right-of-way with the consent of the owner;

(C) repairing or maintaining an existing sour gas pipeline facility; or

(D) installing valves or meters or other devices or fabrications on an existing pipeline if such devices or fabrication do not result in an increase in the area of influence.

(6) Extension of a sour gas pipeline facility--An addition to an operating sour gas pipeline facility regardless of ownership of the addition.

(7) Nominal pipe size--The industry convention for naming pipe. Six inch nominal size pipe corresponds to pipe with an approximate inner diameter of six inches. The actual inner diameter varies based on the wall thickness of the pipe.

(8) Person--An individual, partnership, firm, corporation, joint venture, trust, association, or any other business entity, a state agency or institution, county, municipality, school district, or other governmental subdivision.

(9) Preliminary contingency plan--A contingency plan containing all of the elements required for a

contingency plan under §3.36 of this title (relating to oil, gas, or geothermal resource operation in hydrogen sulfide areas), except that:

(A) the plan need not contain the list of names and telephone numbers of residents within the area of influence if required under §3.36(c)(9)(I) of this section. In lieu of this list of names and telephone numbers, the plan shall contain a detailed explanation of the manner in which the names and telephone numbers of residents within the area of influence will be compiled prior to commencement of operations;

(B) the plat detailing the area of influence may be:

(i) the detailed plat required under §3.36(c)(9)(H);

(ii) a plat containing the information required under §3.36(c)(9)(H), that identifies residential, business, and industrial areas with an estimate of the number of people that may be within any such areas; or

(iii) one or more aerial photographs covering the area and providing the information required under §3.36(c)(9)(H); and

(C) a fixed pipeline route need not be specified in the preliminary plan provided the preliminary plan identifies the boundaries of the area within which the pipeline will be constructed and provided that all public notices of the application required under this section note such boundaries and identify the potential area of influence as the total area encompassed by the area of influence associated with all possible pipeline routes.

(10) Sour gas pipeline facility--A pipeline and ancillary equipment that:

(A) contains a concentration of 100 parts per million or more of hydrogen sulfide;

(B) is located outside the tract of production; and

(C) is subject to the requirements of §3.36 of this title.

(11) Tract of production--The surface area which overlies the area encompassed by a mineral lease or unit from which oil, gas, or other minerals are produced if such area is treated by the Oil and Gas Division of the commission as a single tract.

(12) 100 ppm radius--The 100 parts per million radius of exposure as calculated in §3.36(c)(1) - (3) of this title (relating to oil, gas, or geothermal resource operation in hydrogen sulfide areas) for the sour gas pipeline facility.

(b) Permit Required; Exceptions. No person may commence construction of a facility within this State without a permit if the facility is initially used as a sour gas pipeline facility except for the following:

(1) an extension of an existing sour gas pipeline facility that at the time of construction of the extension is in compliance with §3.36 of this title (relating to oil, gas, or geothermal resource operation in a hydrogen sulfide area) if:

(A) the extension is not longer than five miles;

(B) the nominal pipe size is not larger than six inches; and

(C) the operator causes to be delivered to the Safety Division written notice of construction of the extension not later than 24 hours before the start of construction;

(2) a new gathering system that operates at a working pressure of less than 50 pounds per square inch gauge;

(3) an extension of a gathering system which operates at a working pressure of less than 50 pounds per square inch gauge;

(4) an interstate gas pipeline facility, as defined by 49 U.S.C. §60101, that is used for the transportation of sour gas; or

(5) replacement of all or part of a sour gas pipeline facility if the area of influence of the replaced portion of the facility does not increase so as to include a public area, as defined in §3.36(b)(5) of this title, not included in the area of influence of the portion of the replaced sour gas pipeline facility.

(c) Filing and Assignment of Docket Number. Upon filing of an application with the Oil and Gas Division, staff will assign a docket number to the application and will notify the applicant of the assigned docket number. Staff will also assign and provide a docket number to a person who submits a notice of intent to file an application.

(d) Application. A complete application consists of:

(1) a properly completed application Form PS-79, with the original signature, in ink, of the applicant;

(2) if applicant desires notification under subsection (h)(1) by electronic mail, a written request for electronic mail notification and the applicant's electronic mail address;

(3) a plat which meets the requirements of subsection (f)(4) of this section and identifies the boundaries of surveys and blocks or sections as appropriate within the area of influence;

(4) a copy of the applicant's Application for Permit to Operate a Pipeline, Form T-4, if applicable, including all attachments; and

(5) a copy of the completed application for a Statewide Rule 36 Certificate of Compliance, Form H-9, including any attachment required under §3.36 of this title. A preliminary contingency plan may be filed in lieu of a contingency plan if required under §3.36 of this title.

(e) Notice.

(1) For each county that contains all or part of the area of influence of a proposed sour gas pipeline facility, the applicant shall:

(A) cause to be delivered to the county clerk no later than the first date of publication in that county a copy of the items described in subsection (d)(1) - (3) of this section;

(B) publish notice of its application in a newspaper of general circulation in each county that contains all or a portion of the area of influence of the proposed sour gas pipeline facility. Such notice shall meet the requirements of subsection (f) of this section and be published in a section of the newspaper containing news items of state or local interest.

(2) Final action may not be taken on any application under this section until proof of notice, evidenced as follows, is provided:

(A) a return receipt from each county clerk with whom an application form and plat is required to be filed pursuant to paragraph (1) of this subsection; and

(B) the full page or pages of the newspaper containing the published notice required under paragraph (2) of this subsection including the name of the paper, the date the notice was published, and the page number.

(f) The published notice of application shall be at least three inches by five inches in size, exclusive of the plat, and shall contain the following:

(1) the name, business address, and telephone number of the applicant and of the applicant's authorized representative, if any;

(2) a description of the geographic location of the sour gas pipeline facility and the area of influence, to the extent not clearly identified in the plat required to be published in subsection (f)(4) of this section;

(3) the following statement, completed as appropriate: "This proposed pipeline facility will transport sour gas that contains 100 parts per million, or more, of hydrogen sulfide. A copy of application forms and a map showing the location of the pipeline is available for public inspection at the offices of the (insert County name) County Clerk, located at the following address: (insert address of County Clerk). Any owner or occupant of land located within the area of influence of the proposed sour gas pipeline facility desiring to protest this application can do so by mailing or otherwise delivering a letter referring to the application (by docket number if available) and stating their desire to protest to: Docket Services, Office of General Counsel, Railroad Commission of Texas, P.O. Box 12967, Austin, Texas 78711-2967. Protests shall be in writing and received by Docket Services not later than (specify 30th day after the first date notice of the application is to be published). The letter shall include the name, address, and telephone number of every person on whose behalf the protest is filed and shall state the reasons each such person believes that he or she is the owner or occupant of property within the area of influence of the proposed pipeline facility. It is recommended that a copy of this notice be included with the letter."; and

(4) a plat identifying:

(A) the location of the pipeline facility;

(B) area of influence;

(C) north arrow;

(D) scale;

(E) geographic subdivisions appropriate for the scale; and

(F) by inset or otherwise, landmarks or other features such as roads and highways in relation to the proposed route of the sour gas pipeline facility. These landmarks or other features shall be of sufficient detail to allow a person to reasonably ascertain whether an owned or occupied property that is within the area of influence of the proposed sour gas pipeline facility. Examples of acceptable plats are included in this subsection.

Attached Graphic

(g) Protests. Affected persons have standing to file a protest to an application. In the event the final proposed pipeline route is not known at the time of application, any person who owns or occupies real property located within the area of influence identified in the application shall have standing to file a protest to an application. All such protests shall:

(1) be in writing and filed at the commission no later than the 30th day after the notice is published in a newspaper in the county in which the person filing the protest owns or occupies real property;

(2) state the name, address, and telephone number of every person on whose behalf the protest is being filed; and

(3) include a statement of the facts on which the person filing the protest relies to conclude that each person on whose behalf the protest is being filed is an affected person, as defined in subsection (a)(1) of this section.

(h) Division Review.

(1) Within 14 days of receipt of the application, the commission's designee will provide notice to the applicant that the application is either complete and accepted for filing, or incomplete and specify the additional information required for acceptance. Such notice shall be provided in writing by mail or by electronic mail if the applicant submits with the application a written request that communications regarding application completeness or deficiencies be communicated by electronic mail and provides an accurate electronic mail address. The application shall be completed within 30 days of notification that the application is incomplete or such longer time as may be requested by the applicant, in writing, and approved by the commission's designee. If the application is not completed within the specified time period, the commission's designee shall send notice of intent to deny the application to the applicant. Within ten days of issuance of a notice of intent to deny the application for failure to complete the application, the applicant may request a hearing on the application as it exists at that time. If a request for hearing is not filed within ten days of issuance of a notice of intent to deny the application for failure to complete the application, the application shall be Cont'd...

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Appendix F – Utah Regulatory Summary (General)

Utah Division of Oil, Gas, and Mining

R649. Natural Resources; Oil, Gas and Mining; Oil and Gas.
R649-1. Oil and Gas General Rules.
R649-1-1. Definitions.

"Authorized Agent" means a representative of the director as authorized by the board.

"Aquifer" means a geological formation including a group of formations or part of a formation which is capable of yielding a significant amount of water to a well or spring.

"Artificial Liner" means a pit liner made of material other than clay or other in situ material and which meets the requirements of R649-9-3, Permitting of Disposal Pits.

"Barrel" means 42 (US) gallons at 60 degrees Fahrenheit at atmospheric pressure.

"Board" means the Board of Oil, Gas and Mining.

"Carrier, Transporter or Taker" means any person moving or transporting oil or gas away from a well or lease or from any pool.

"Casing Pressure" means the pressure within the casing or between the casing and tubing at the wellhead.

"Central Disposal Facility" means a facility which is used by one or more producers for disposal of exempt E and P wastes and for which the operator of the facility receives no monetary remuneration, other than operating cost sharing.

"Class II Injection Well" means a well which is used for:

(a) The disposal of fluids which are brought to the surface in connection with conventional oil or natural gas production and which may be commingled with wastewater produced from the operation of a gas plant that is an integral part of production operations, unless that wastewater is classified as a hazardous waste at the time of injection, or

(b) Enhanced recovery of oil or gas, or

(c) Storage of hydrocarbons which are liquids at standard temperature and pressure conditions.

"Closed System" means but is not limited to, the use of a combination of solids control equipment (i.e., shale shakers, flowline cleaners, desanders, desilters, mud cleaners, centrifuges, agitators, and necessary pumps and piping) incorporated in a series on the rig's steel mud tanks, or a self contained unit that eliminates the use of a reserve pit for the purpose of dumping and dilution of drilling fluids for the removal of entrained drill solids. A closed system for the purpose of these rules may with Division approval include the use of a small pit to receive cuttings, but does not include the use of trenches for the collection of fluids of any kind.

"Coalbed Methane" means natural gas that is produced, or may be produced, from coalbeds and rock strata associated with the coalbed.

"Commercial Disposal Facility" means a disposal well, pit or treatment facility whose owner(s) or operator(s) receives compensation from others for the temporary storage, treatment, and disposal of produced water, drilling fluids, drill cuttings, completion fluids, and any other exempt E and P wastes, and whose primary business objective is to provide these services.

"Completion of a Well" means that the well has been adequately worked to be capable of producing oil or gas or that well testing as required by the division has been concluded.

"Confining Strata" refers to a body of material that is relatively impervious to the passage of liquids or gases and that occurs either below, above, or lateral to a more permeable material in such a way that it confines or limits the movement of liquids or gases that may be present.

"Correlative Rights" means the opportunity of each owner in a pool to produce his just and equitable share of the oil and gas in the pool without waste.

"Cubic Foot" of gas means the volume of gas contained in one cubic foot of space at a standard pressure base of 14.73 psia and a standard temperature base of 60 degrees Fahrenheit.

"Day" means a period of 24 consecutive hours.

"Development Wells" means all oil and gas producing wells other than wildcat wells.

"Director" means the executive and administrative head of the division.

"Disposal Facility" means an injection well, pit, treatment facility or combination thereof which receives E and P Wastes for the purpose of disposal. This includes both commercial and noncommercial facilities.

"Disposal Pit" means a lined or unlined pit approved for the disposal and/or storage of E and P Wastes.

"Division" means the Division of Oil, Gas and Mining.

"Drilling Fluid" means a circulating fluid usually called mud, which is introduced in a drill hole to lubricate the action of the rotary bit, remove the drilling cuttings, and control formation pressures.

"E and P Waste" means those wastes resulting from the drilling of and production from oil and gas wells as determined by the Environmental Protection Agency (EPA), prior to January 1, 1992, to be exempt from Subtitle C of the Resource Conservation and Recovery Act (RCRA).

"Emergency Pit" means a pit used for containing fluids at an operating well during an actual emergency or for a temporary period of time.

"Enhanced Recovery" means the process of introducing fluid or energy into a pool for the purpose of increasing the recovery of hydrocarbons from the pool.

"Enhanced Recovery Project" means the injection of liquids or hydrocarbon or nonhydrocarbon gases directly into a reservoir for the purpose of augmenting reservoir energy, modifying the properties of the fluids or gases in the reservoir, or changing the reservoir conditions to increase the recoverable oil, gas, or oil and gas through the joint use of two or more well bores.

"Entity" means a well or a group of wells that have identical division of interest, have the same operator, produce from the same formation, have product sales from a common tank, LACT meter, gas meter, or are in the same participating area of a properly designated unit. Entity number assignments are made by the division in cooperation with the Division of State Lands and

Forestry and the State Tax Commission.

"Field" means the general area underlaid by one or more pools.

"Gas" means natural gas or natural gas liquids or other gas or any mixture thereof defined as follows:

"Natural Gas" means those hydrocarbons, other than oil and other than natural gas liquids separated from natural gas, that occur naturally in the gaseous phase in the reservoir and are produced and recovered at the wellhead in gaseous form. Natural gas includes coalbed methane.

"Other Gas" means hydrogen sulfide, carbon dioxide, helium, nitrogen, and other nonhydrocarbon gases that occur naturally in the gaseous phase in the reservoir or are injected into the reservoir in connection with pressure maintenance, gas cycling, or other secondary or enhanced recovery projects.

"Natural Gas Liquids" means those hydrocarbons initially in reservoir natural gas, regardless of gravity, that are separated in gas processing plants from the natural gas as liquids at the surface through the process of condensation, absorption, adsorption, or other methods.

"Gas-Oil Ratio" means the ratio of the number of cubic feet of natural gas produced to the number of barrels of oil concurrently produced during any stated period. The term GOR is synonymous with gas-oil ratio.

"Gas Processing Plant" means a facility in which liquefiable hydrocarbons are removed from natural gas, including wet gas or casinghead gas, and the remaining residue gas is conditioned for delivery for sale, recycling or other use.

"Gas Well" means any well capable of producing gas in substantial quantities that is not an oil well.

"Ground Water" means water in a zone of saturation below the ground surface.

"Hearing" means any matter heard before the board or its designated hearing examiner.

"Horizontal Well" means a well bore drilled laterally at an angle of at least eighty (80) degrees to the vertical or with a horizontal projection exceeding one hundred (100) feet measured from the initial point of penetration into the productive formation through the terminus of the lateral in the same common source of supply.

"Illegal Oil or Illegal Gas" means oil or gas that has been produced from any well within the state in violation of Chapter 6 of Title 40, or any rule or order of the board.

"Illegal Product" means any product derived in whole or in part from illegal oil or illegal gas.

"Incremental Production" means that part of production which is achieved from an enhanced recovery project that would not have economically occurred under the reservoir conditions existing before the project and that has been approved by the division as incremental production.

"Injection or Disposal Well" means any Class II Injection Well used for the injection of air, gas, water or other substance into any underground stratum.

"Interest Owner" means a person owning an interest (working interest, royalty interest, payment out of production, or any other interest) in oil or gas, or in the proceeds thereof.

"Load Oil" means any oil or liquid hydrocarbon which is used in any remedial operation in an oil or gas well.

"Log or Well Log" means the written record progressively describing the strata, water, oil or gas encountered in drilling a well with such additional information as is usually recorded in the normal procedure of drilling including electrical, radioactivity, or other similar conventional logs, a lithologic description of samples and drill stem test information.

"Multiple Zone Completion" means a well completion in which two or more separate zones, mechanically segregated one from the other, are produced simultaneously from the same well.

"Oil" means crude oil or condensate or any mixture thereof, defined as follows:

"Crude Oil" means those hydrocarbons, regardless of gravity, that occur naturally in the liquid phase in the reservoir and are produced and recovered at the wellhead in liquid form.

"Condensate" means those hydrocarbons, regardless of gravity, that occur naturally in the gaseous phase in the reservoir that are separated from the natural gas as liquids through the process of condensation either in the reservoir, in the well bore or at the surface in field separators.

"Oil and Gas" shall not include gaseous or liquid substances derived from coal, oil shale, tar sands or other hydrocarbons classified as synthetic fuel.

"Oil and Gas Field" means a geographical area overlying an oil and gas pool.

"Oil Well" means any well capable of producing oil in substantial quantities.

"Operator or Designated Agent" means the person who has been designated by the owners or the board to operate a well or unit.

"Owner" means the person who has the right to drill into and produce from a reservoir and to appropriate the oil and gas that he produces, either for himself or for himself and others.

"Person" means and includes any natural person, bodies politic and corporate, partnerships, associations and companies.

"Pit" means an earthen surface impoundment constructed to retain fluids and oil field wastes.

"Pollution" means such contamination or other alteration of the physical, chemical or biological properties of any waters of the state, or the discharge of any liquid, gaseous or solid substance into any waters of the state in such manner as will create a nuisance or render such waters harmful, detrimental or injurious to the public health, safety or welfare; to domestic, commercial, industrial, agricultural, recreational, or other legitimate beneficial uses; or to livestock, wild animals, birds, fish or other aquatic life.

"Pool" means an underground reservoir containing a common accumulation of oil or gas or both. Each zone of a general structure that is completely separated from any other zone in the structure is a separate pool. "Common source of supply" and "reservoir" are synonymous with "pool."

"Pressure Maintenance" means the injection of gas, water or other fluids into a reservoir, either to increase or maintain the existing pressure in such reservoir or to retard the natural decline in the reservoir pressure.

"Produced Water" means water produced in conjunction with the conventional production of oil and/or gas.

"Producer" means the owner or operator of a well capable of producing oil or gas.

"Producing Well" means a well capable of producing oil or gas.

"Product" means any commodity made from oil and gas.

"Production Facilities" means all storage, separation, treating, dehydration, artificial lift, power supply, compression, pumping, metering, monitoring, flowline, and other equipment directly associated with oil wells, gas wells or injection wells, prior to any processing plant or refinery.

"Purchaser or Transporter" means any person who, acting alone or jointly with any other person, by means of his own, an affiliated, or designated carrier, transporter or taker, shall directly or indirectly purchase, take or transport by any means whatsoever, or who shall otherwise remove from any well or lease, oil or gas produced from any pool, excepting royalty portions of oil or gas taken in kind by an interest owner who is not the operator.

"Recompletion" means any completion in a new perforated interval or pool within an established wellbore and approved as a recompletion by the division.

"Refinery" means a facility, other than a gas processing plant, where controlled operations are performed by which the physical and chemical characteristics of petroleum or petroleum products are changed.

"Reserve Pit" means a pit used to retain fluid during the drilling, completion, and testing of a well.

"Seismic Operator" means a person who conducts seismic exploration for oil or gas, whether for himself or as a contractor for others.

"Shut-in Well" means a well that is completed, is shown to be capable of production in paying quantities, and is not presently being operated.

"Spud In" means the first boring of a hole in the drilling of a well by any type of rig.

"State" means the State of Utah.

"Stratigraphic Test or Core Hole" means any hole drilled for the sole purpose of obtaining geological information. The general rules applicable to the drilling of a well will apply to the drilling of a stratigraphic test or core hole.

"Temporarily Abandoned Well" means a well that is completed, is not shown capable of production in paying quantities, and is not presently being operated.

"Temporary Spacing Unit" means a specified area of land designated by the board for purposes of determining well density and location. A temporary spacing unit shall not be a drilling unit as provided for in U.C.A. 40-6-6, Drilling Units, and does not provide a basis for pooling the interest therein as does a drilling unit.

"Underground Source of Drinking Water" means a fresh water aquifer or a portion thereof that supplies drinking water for human consumption or that contains less than 10,000 mg/1 total dissolved solids and that is not an exempted aquifer under R649-5-4.

"Waste" means:

The inefficient, excessive or improper use or the unnecessary dissipation of oil or gas or reservoir energy.

The inefficient storing of oil or gas.

The locating, drilling, equipping, operating, or producing of any oil or gas well in a manner that causes reduction in the quantity of oil or gas ultimately recoverable from a reservoir under prudent and economical operations, or that causes unnecessary wells to be drilled, or that causes the loss or destruction of oil or gas either at the surface or subsurface.

The production of oil or gas in excess of:

Transportation or storage facilities.

The amount reasonably required to be produced in the proper drilling, completing, testing, or operating of a well or otherwise utilized on the lease from which it is produced.

Underground or above ground waste in the production or storage of oil or gas.

"Waste Crude Oil Treatment Facility" means any facility or site constructed or used for the purpose of wholly or partially reclaiming, treating, processing, cleaning, purifying or in any manner making nonmerchantable waste crude oil marketable.

"Well" means an oil or gas well, injection or disposal well, or a hole drilled for the purpose of producing oil or gas or both. The definition of well shall not include water wells, or seismic, stratigraphic test, core hole, or other exploratory holes drilled for the purpose of obtaining geological information only.

"Well Site" means the areas which are directly disturbed during the drilling and subsequent use of, or affected by production facilities directly associated with any oil well, gas well or injection well.

"Wildcat Wells" means oil and gas producing wells which are drilled and completed in a pool in which a well has not been previously completed as a well capable of producing in commercial quantities.

"Working Interest Owner" means the owner of an interest in oil or gas burdened with a share of the expenses of developing and operating the property.

"Workover" means any operation designed to sustain, to restore, or to increase the production rate, the ultimate recovery, or the reservoir pressure system of a well or group of wells and approved as a workover, a secondary recovery, a tertiary recovery, or a pressure maintenance project by the division. The definition shall not include operations which are conducted principally as routine maintenance or the replacement of worn or damaged equipment.

KEY: oil and gas law
June 2, 1998 **40-6-1 et seq.**
Notice of Continuation March 26, 2002

R649. Natural Resources; Oil, Gas and Mining; Oil and Gas.
R649-2. General Rules.
R649-2-1. Scope of Rules.

The following general rules adopted by the board pursuant to Chapter 6 of Title 40 shall apply to all lands in the state in order to conserve the natural resources of oil and gas in the state, to protect human health and the environment, to prevent waste, to protect the correlative rights of all owners and to realize the greatest ultimate recovery of oil and gas. Special rules and orders have been and will be issued by the board when required and shall prevail as against the general rules and orders of the board if in conflict therewith. Exceptions to the general rules may also be granted by the director or authorized agent for good cause shown and shall prevail as against the general rules. No exceptions granted by the board, director, or authorized agent to the rules applicable to the Underground Injection Control Program will be effective without the consent of the federal Environmental Protection Agency.

R649-2-2. Application Of Rules To Lands Owned Or Controlled By The United States.

These general rules shall apply to all lands in the state including lands of the United States and lands subject to the jurisdiction of the United States to the extent lawfully subject to the state's power.

R649-2-3. Application Of Rules To Unit Agreements.

The board may suspend the application of the general rules or orders or any part thereof, with regard to any unit agreement approved by a duly authorized officer of the appropriate federal agency, so long as the conservation of oil or gas and the prevention of waste is accomplished thereby, but such suspension shall not relieve any operator from making such reports as are otherwise required by the general rules or orders, or as may reasonably be requested by the board or the division in order to keep the board and the division fully informed as to operations under such unit agreements.

R649-2-4. Designation Of Agent Or Operator.

A designation of agent or operator shall be submitted to the division prior to the commencement of operations. A designation of agent or operator will, for purposes of the general rules and orders, be accepted as evidence of authority of agent to fulfill the obligations of the owner, to sign any required documents or reports on behalf of the owner, and to receive all authorized orders or notices given by the board or the division. All changes of address and any termination of the designated agent's or operator's authority shall be promptly reported in writing to the division, and in the latter case a designation of a new agent or operator shall be promptly made.

R649-2-5. Right To Inspect.

1. The director or authorized agent shall have the right at

all reasonable times to go upon and inspect any oil or gas properties and wells for the purpose of making any investigations or tests reasonably necessary to ensure compliance with the provisions of the statutes, the general rules and orders of the board or any special field rules and orders. The director or authorized agent shall report any observed violation to the board.

2. The documentation of off lease transportation of crude oil required by R649-2-6, Access to Records, shall be carried in the motor vehicle during transportation and shall be available for examination and inspection by the director or an authorized agent upon request.

R649-2-6. Access To Records.

1. Any person who produces, operates, sells, purchases, acquires, stores, transports, refines, or processes oil or gas or who injects fluids for cycling, pressure maintenance, secondary or enhanced recovery, or disposal of salt water or oil field waste within the state, shall make and keep appropriate books and records covering his operations in the state from which he shall be able to make and substantiate all reports required by the board or the division. Such books and records, together with copies of all reports and notices submitted to the board or the division shall be kept on file and available for inspection by the director or an authorized agent at all reasonable times for a period of at least six years. The director or the authorized agent shall also have access to all pertinent well records wherever located.

2. Each owner or operator shall permit the director or authorized agent at his sole risk and expense, in the absence of negligence on the part of the owner or operator, to come upon any lease, property or well operated or controlled by him; to inspect the records pertaining to and the manner of operation of such property or well; and to have access at all reasonable times to any and all records pertaining to such well. All information so obtained by the director or authorized agent shall be kept confidential and shall be reported only to the division or its authorized agent, unless the owner or operator gives written permission to the director to release such information.

3. All off lease transportation of oil by motor vehicle shall be accompanied by a run ticket or equivalent document. The documentation shall identify the name and address of the transporter, the name of the operator, the lease or facility from which the oil was taken, the date of removal, the API gravity of the oil, the calculated percentage of BS and W, the volume of oil or the opening and closing tank gauges or meter readings, and the destination of the oil.

R649-2-7. Naming of Oil and Gas Fields or Pools.

The division shall name oil and gas fields or pools within the state in cooperation with a Fields Names Advisory Committee and with due regard and consideration for any recommendation from the owners or operators of such fields or pools. The Field Names Advisory Committee shall be composed of a representative of the United States Bureau of Land Management and representatives of appropriate state agencies and the oil and gas industry.

R649-2-8. Measurement of Production.

1. The volume of oil production shall be computed in barrels of clean oil on the basis of acceptable meter measurements, tank measurements, or with such greater accuracy as may be required by the division. Computations of the volume of oil production shall be subject to the following corrections:

1.1. The gross volume of oil shall be corrected to exclude the entire volume of impurities not constituting a natural component part of the oil.

1.2. The observed volume of oil after correction for impurities shall be further corrected to the standard volume at 60 degrees Fahrenheit, in accordance with Table 6A of the API/ASTM D-1250, Chapter 11.1, Manual of Petroleum Measurement (1980), or any revisions or supplements, or any alternative publication or tables approved by the division.

1.3. The observed gravity of oil shall be corrected to the standard API gravity at 60 degrees Fahrenheit in accordance with Table 5A of API/ASTM, D-1250, Chapter 11.1, Manual of Petroleum Measurement (1980), or any revisions or supplements, or any alternative publication or tables approved by the division.

2. All gas shall be measured by an orifice type meter unless otherwise authorized by the division. In computing the volumes of all gas produced, sold, or injected, the standard pressure base shall be 14.73 pounds per square inch absolute (psia), and the standard temperature base shall be 60 degrees Fahrenheit. All measurements of gas shall be adjusted by computation to these standards, regardless of the pressure and temperature at which the gas was actually measured, unless otherwise authorized by the division.

R649-2-9. Refusal To Agree.

1. An owner shall be deemed to have refused to agree to bear his proportionate share of the costs of the drilling and operation of a well under Section 40-6-6(6) if:

1.1. The operator of the proposed well has, in good faith, attempted to reach agreement with such owner for the leasing of the owner's mineral interest or for that owner's voluntary participation in the drilling of the well.

1.2. The owner and the operator have been unable to agree upon terms for the leasing of the owner's interest or for the owner's participation in the drilling of the well.

2. If the operator of the proposed well shall fail to attempt, in good faith, to reach agreement with the owner for the leasing of that owner's mineral interest or for voluntary participation by that owner in the well prior to the filing of a Request for Agency Action for involuntary pooling of interests in the drilling unit under Section 40-6-6(6) then, upon written request and after notice and hearing, the hearing on the Request for Agency Action for involuntary pooling may, at the discretion of the board or its designated hearing examiner, be delayed for a period not to exceed 30 days, to allow for negotiations between the operator and the owner.

R649-2-10. Notification of Lease Sale or Transfer.

The owner of a lease shall provide notification to any person with an interest in such lease, when all or part of that interest in the lease is sold or transferred.

R649-2-11. Confidentiality Of Well Log Information.

1. Well logs marked confidential shall be kept confidential for one year after the date on which the log is required to be filed with the division, unless the operator gives written permission to release the log at an earlier date.

2. Information on a newly permitted well will be held confidential only upon receipt by the division of a written request from the owner or operator.

3. The period of confidentiality may begin at the time the APD is submitted for approval if a request for confidentiality is received at that time, although the information on the application itself will not be considered confidential.

4. Information which shall be held confidential includes well logs, electrical or radioactivity logs, electromagnetic, electrical, or magnetic surveys, core descriptions and analysis, maps, other geological, geophysical, and engineering information, and well completion reports which contain such information.

5. The owner or operator shall clearly mark documents as confidential. Such marking shall be in red to be clearly visible.

6. Confidential wells or information shall be reported separately from wells or information that is not in confidential status.

R649-2-12. Tests and Surveys.

When deemed necessary or advisable the Director or authorized agent is authorized to require that test or surveys be made to determine the presence of waste or oil, gas, water, or reservoir energy; the quantity of oil, gas or water; the amount and direction of deviation of any well from the vertical; formation, casing, tubing, or other pressures; or any other test or survey deemed necessary to carry out the purposes of the Oil and Gas Conservation Act. Directional, deviation, and/or measurements-while-drilling (MWD) surveys must be run on horizontal wells and submitted in accordance with R649-3-21, Well Completion and Filing of Well Logs, as amended for horizontal wells.

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June 2, 1998 **40-6-1 et seq.**
Notice of Continuation March 26, 2002

R649. Natural Resources; Oil, Gas and Mining; Oil and Gas.
R649-3. Drilling and Operating Practices.
R649-3-1. Bonding.

1. An owner or operator shall furnish a bond to the division prior to approval of a permit to drill a new well, reenter an abandoned well or assume responsibility as operator of existing wells.

1.1. An owner or operator shall furnish a bond to the division on Form 4, for wells located on lands with fee or privately owned minerals.

1.2. An owner or operator shall furnish evidence to the division that a bond has been filed in accordance with state, federal or Indian lease requirements and approved by the appropriate agency for all wells located on state, federal or Indian leases.

2. A bond furnished to the division shall be payable to the division and conditioned upon the faithful performance by the operator of the duty to plug each dry or abandoned well, repair each well causing waste or pollution, and maintain and restore the well site.

3. Bond liability shall be for the duration of the drilling, operating and plugging of the well and restoration of the well site.

3.1. The bond for drilling or operating wells shall remain in full force and effect until liability thereunder is released by the division.

3.2. Release of liability shall be conditioned upon compliance with the rules and orders of the Board.

4. For all drilling or operating wells, the bond amounts for individual wells and blanket bonds required in subsections 5. and 6. represent base amounts adjusted to year 2002 average costs for well plugging and site restoration. The base amounts are effective immediately upon adoption of this bonding rule, subject to division notification as described in subsection 4.1.

4.1. The division shall provide written notification to each operator of the need to revise or establish bonds in amounts required by this bonding rule. Within 120 days of such notification by the division, the operator shall post a bond with the division in compliance with this bonding rule.

4.2. If the division finds that a well subject to this bonding rule is in violation of Rule R649-3-36., Shut-in and Temporarily Abandoned Wells, the division shall require a bond amount for the applicable well in the amount of actual plugging and site restoration costs.

4.3. The division shall provide written notification to an operator found in violation of Rule R649-3-36., and identify the need to establish increased bonding for shut-in wells. Within 30 days of notification by the division, the operator shall submit to the division an estimate of plugging and site restoration costs for division review and approval. Upon review and approval of the cost estimate, the division will provide a notice of approval back to the operator specifying the approved bond amount for shut-in wells. Within 120 days of receiving such notice of approval, the operator shall post a bond with the division in compliance with this bonding rule.

5. The bond amount for drilling or operating wells located on lands with fee or privately owned minerals shall be one of the following:

5.1. For wells of less than 1,000 feet in depth, an individual well bond in the amount of at least $1,500, for each such well.

5.2. For wells of more that 1,000 feet in depth but less than 3,000 feet in depth, an individual well bond in the amount of at least $15,000 for each such well.

5.3. For wells of more that 3,000 feet in depth but less than 10,000 feet in depth, an individual well bond in the amount of at least $30,000 for each such well.

5.4. For wells of more than 10,000 feet in depth, an individual well bond in the amount of at least $60,000 for each such well.

6. If, prior to the January 1, 2003 revision of this bonding rule, an operator is drilling or operating more than one well on lands with fee or privately owned minerals, and a blanket bond was furnished and accepted by the division in lieu of individual well bonds, that operator shall remain qualified for a blanket bond with the division subject to the amounts described by this bonding rule.

6.1. A blanket bond shall be conditioned in a manner similar to individual well bonds and shall cover all wells that the operator may drill or operate on lands with fee or privately owned minerals within the state.

6.2. For wells of less than 1,000 feet in depth, a blanket bond in the amount of at least $15,000 shall be required.

6.3. For wells of more than 1,000 feet in depth, a blanket bond in the amount of at least $120,000 shall be required.

6.4. Subsequent to the January 1, 2003 revision of this rule, operators who desire to establish a new blanket bond that consists either fully or partially of a collateral bond as described in subsection 10.2. shall be qualified by the division for such blanket bond. Operators who elect to establish a surety bond as a blanket bond shall not require qualification by the division. In those cases where operator qualification for blanket bond is required, the division will review the following criteria and make a written finding of the operator's adequacy to meet the criteria before accepting a new blanket bond:

6.4.1. The ratio of current assets to current liabilities shall be 1.20 or greater, as evidenced by audited financial statements for the previous two years and the most current quarterly financial report.

6.4.2. The ratio of total liabilities to stockholder's equity shall be 2.50 or less, as evidenced by audited financial statements for the previous two years and the most current quarterly financial report.

7. If an operator desires bond coverage in a lesser amount than required by these rules, the operator may file a Request for Agency Action with the Board for a variance from the requirements of these rules.

7.1. Upon proper notice and hearing and for good cause shown, the Board may allow bond coverage in a lesser amount for specific wells.

8. If after reviewing an application to drill or reenter a well or when reviewing a change of operator for a well, the division determines that bond coverage in accordance with these rules will be insufficient to cover the costs of plugging the well and restoring the well site, the division may require a change in the form or the amount of bond coverage. In such cases, the

division will support its case for a change of bond coverage in the form of written findings to the operator of record of the well and provide a schedule for completion of the requisite changes.

8.1 Appeals of mandated bond amount changes will follow procedures established by Rule R649-10., Administrative Procedures.

9. The bond shall provide a mechanism for the surety or other guarantor of the bond, to provide prompt notice to the division and the operator of any action alleging the insolvency or bankruptcy of the surety or guarantor, or alleging any violations which would result in suspension or revocation of the surety's or guarantor's charter or license to do business.

9.1. Upon the incapacity of the surety or guarantor to guarantee payment of the bond by reason of bankruptcy, insolvency, or suspension or revocation of a charter or license, the operator shall be deemed to be without bond coverage.

9.2. Upon notification of insolvency or bankruptcy, the division shall notify the operator in writing and shall specify a reasonable period, not to exceed 90 days, to provide bond coverage.

9.3. If an adequate bond is not furnished within the allowed period, the operator shall be required to cease operations immediately, and shall not resume operations until the division has received an acceptable bond.

10. The division shall accept a bond in the form of a surety bond, a collateral bond or a combination of these bonding methods.

10.1. A surety bond is an indemnity agreement in a sum certain payable to the division, executed by the operator as principal and which is supported by the performance guarantee of a corporation authorized to do business as a surety in Utah.

10.1.1. A surety bond shall be executed by the operator and a corporate surety authorized to do business in Utah that is listed in "A.M. Best's Key Rating Guide" at a rating of A- or better or a Financial Performance Rating (FPR) of 8 or better, according to the "A.M. Best's Guide". All surety companies also will be continuously listed in the current issue of the U.S. Department of the Treasury Circular 570. Operators who do not have a surety bond with a company that meets the standards of subsection 10.1.1. will have 120 days from the date of division notification after enactment of the changes to subsection 10.1.1., or face enforcement action. When the division in the course of examining surety bonds notifies an operator that a surety company guaranteeing its performance does not meet the standards of subsection 10.1.1., the operator has 120 days after notice from the division by mail to correct the deficiency, or face enforcement action.

10.1.2. Surety bonds shall be noncancellable during their terms, except that surety bond coverage for wells not drilled may be canceled with the prior consent of the division.

10.1.3. The division shall advise the surety, within 30 days after receipt of a notice to cancel a bond, whether the bond may be canceled on an undrilled well.

10.2. A collateral bond is an indemnity agreement in a sum certain payable to the division, executed by the operator which is supported by one or more of the following:

10.2.1. A cash account.

10.2.1.1. The operator may deposit cash in one or more accounts at a federally insured bank authorized to do business in Utah, made payable upon demand only to the division.

10.2.1.2. The operator may deposit the required amount directly with the division.

10.2.1.3. Any interest paid on a cash account shall be retained in the account and applied to the bond value of the account unless the division has approved the payment of interest to the operator.

10.2.1.4. The division shall not accept an individual cash account in an amount in excess of $100,000 or the maximum insurable amount as determined by the Federal Deposit Insurance Corporation.

10.2.2. Negotiable bonds of the United States, a state, or a municipality.

10.2.2.1. The negotiable bond shall be endorsed only to the order of and placed in the possession of the division.

10.2.2.2. The division shall value the negotiable bond at its current market value, not at face value.

10.2.3. Negotiable certificates of deposit.

10.2.3.1. The certificates shall be issued by a federally insured bank authorized to do business in Utah.

10.2.3.2. The certificates shall be made payable or assigned only to the division both in writing and upon the records of the bank issuing the certificate.

10.2.3.3. The certificates shall be placed in the possession of the division or held by a federally insured bank authorized to do business in Utah.

10.2.3.4. If assigned, the division shall require the banks issuing the certificates to waive all rights of setoff or liens against those certificates.

10.2.3.5. The division shall not accept an individual certificate of deposit in an amount in excess of $100,000 or the maximum insurable amount as determined by the Federal Deposit Insurance Corporation.

10.2.4. An irrevocable letter of credit.

10.2.4.1. Letters of credit shall be placed in the possession of and payable upon demand only to the division.

10.2.4.2. Letters of credit shall be issued by a federally insured bank authorized to do business in Utah.

10.2.4.3. Letters of credit shall be irrevocable during their terms.

10.2.4.4. Letters of credit shall be automatically renewable or the operator shall ensure continuous bond coverage by replacing letters of credit, if necessary, at least 30 days before their expiration date with other acceptable bond types or letters of credit.

11. The required bond amount specified in subsections 5. and 6. of all collateral posted as assurance under this section shall be subject to a margin determined by the division which is the ratio of the face value of the collateral to market value, as determined by the division.

11.1. The margin shall reflect legal and liquidation fees, as well as value depreciation, marketability and fluctuations which might affect the net cash available to the division to complete plugging and restoration.

12. The market value of collateral may be evaluated at any time, and in no case shall the market value of collateral be less than the required bond amount specified in subsections 5. and 6.

12.1. Upon evaluation of the market value of collateral by the division, the division will notify the operator of any required changes in the amount of the bond and shall allow a reasonable period, not to exceed 90 days, for the operator to establish acceptable bond coverage.

12.2. If an adequate bond is not furnished within the allowed period the operator shall be required to cease operations immediately and shall not resume operations until the division has received an acceptable bond.

13. Persons with an interest in collateral posted as a bond, and who desire notification of actions pursuant to the bond, shall request the notification in writing from the division at the time collateral is offered.

14. The division may allow the operator to replace existing bonds with other bonds that provide sufficient coverage.

14.1. Replacement of a bond pursuant to this section shall not constitute a release of bond under subsection 15.

14.2. The division shall not allow liability to cease under an existing bond until the operator has furnished, and the division has approved, an acceptable replacement bond.

14.3. When the operator of wells covered by a blanket bond changes, the division will review the financial eligibility of a new operator for blanket bonding as described in subsection 6.4., and the division will make a written finding concerning the applicability of blanket bonding to the prospective new operator.

14.4. Transfer of the ownership of property does not cancel liability under an existing bond until the division reviews and approves a change of operator for any wells affected by the transfer of ownership.

14.5. If a transfer of the ownership of property is made and an operator wishes to request a change to a new operator of record for the affected wells, then the following requirements shall be met:

14.5.1. The operator shall notify the division in writing when ownership of any well associated with the property has been transferred to a named transferee, and the operator shall request a change of operator for the affected wells.

14.5.2. The request shall describe each well by reference to its well name and number, API number, and its location, as described by the section, township, range, and county,and shall also include a proposed effective date for the operator change.

14.5.3. The request shall contain the endorsement of the new operator accepting such change of operator.

14.5.4. The request shall contain evidence of the new operator's bond coverage.

14.5.5. The request may include a request to cancel liability for the well(s) included in the operator change that are listed under the existing operator's bond upon approval by the division of an adequate replacement bond in the name of the new operator.

14.6. Upon receipt of a request for change of operator, the division will review the proposed new operator's bond coverage, and if bond coverage is acceptable, the division will issue a notice of approval of the change of operator.

14.6.1. If the division determines that the new operator's bond coverage will be insufficient to cover the costs of plugging and site restoration for the applicable well(s), the division may deny the change of operator, or the division may require a change in the form and amount of the new operator's bond coverage in order to approve the change of operator. In such cases, the division will support its case for a change of the new operator's bond coverage in the form of written findings, and the division will provide a schedule for completion of the requisite changes in order to approve the operator change. The written findings and schedule for changes in bond coverage will be sent to both the operator of record of the applicable well(s) and the proposed new operator.

14.7. If the request for operator change included a request to cancel liability under the existing operator's bond in accordance with subsection 14.5.5., and the division approves the operator change, then the division will issue a notice of approval of termination of liability under the existing bond for the wells included in the operator change. When the division has approved the termination of liability under a bond, the original operator is relieved from the responsibility of plugging or repairing any wells and restoring any well site affected by the operator change.

14.8. If all of the wells covered by a bond are affected by an operator change, the bond may be released by the division in accordance with subsection15.

15. Bond release procedures are as follows:

15.1. Requests for release of a bond held by the division may be submitted by the operator at any time after a subsequent notice of plugging of a well has been submitted to the division or the division has issued a notice of approval of termination of liability for all wells covered by an existing bond.

15.1.1. Within 30 days after a request for bond release has been filed with the division, the operator shall submit signed affidavits from the surface landowner of any previously plugged well site certifying that restoration has been performed as required by the mineral lease and surface agreements.

15.1.2. If such affidavits are not submitted, the division shall conduct an inspection of the well site in preparation for bond release as explained in subsection 15.2.

15.1.3. Within 30 days after a request for bond release has been filed with the division, the division shall publish notice of the request in a daily newspaper of general circulation in the city and county of Salt Lake and in a newspaper of general circulation in the county in which the proposed well is located.

15.1.4. If a written objection to the request for bond release is not received by the division within 15 days after publication of the notice of request, the division may release liability under the bond as an administrative action.

15.1.5. If a written objection to the request for bond release is received by the division within 15 days after publication of the notice of request, the request shall be set for hearing and notice thereof given in accordance with the procedural rules of the Board.

15.2. If affidavits supporting the bond release application are not received by the division in accordance with subsection 15.1.1., the division shall within 30 days or as soon thereafter as weather conditions permit, conduct an inspection and evaluation of the well site to determine if restoration has been adequately performed.

15.2.1. The operator shall be given notice by the division of the date and time of the inspection, and if the operator is unable to attend the inspection at the scheduled date and time, the division may reschedule the inspection to allow the operator to participate.

15.2.2. The surface landowner, agent or lessee shall be given notice by the operator of such inspection and may participate in the inspection; however, if the surface landowner is unable to attend the inspection, the division shall not be required to reschedule the inspection in order to allow the surface landowner to participate.

15.2.3. The evaluation shall consider the adequacy of well site restoration, the degree of difficulty to complete any remaining restoration, whether pollution of surface and subsurface water is occurring, the probability of future occurrence of such pollution, and the estimated cost of abating such pollution.

15.2.4. Upon request of any person with an interest in bond release, the division may arrange with the operator to allow access to the well site or sites for the purpose of gathering information relevant to the bond release.

15.2.5. The division shall retain a record of the inspection and the evaluation, and if necessary and upon written request by an interested party, the division shall provide a copy of the results.

15.3. Within 60 days from the filing of the bond release request, if a public hearing is not held pursuant to subsection 15.1.5., or within 30 days after such public hearing has been held, the division shall provide written notification of the decision to release or not release the bond to the following parties:

15.3.1. The operator.

15.3.2. The surety or other guarantor of the bond.

15.3.3. Other persons with an interest in bond collateral who have requested notification under R649-3-1.13.

15.3.4. The persons who filed objections to the notice of application for bond release.

15.4. If the decision is made to release the bond, the notification specified in subsection 15.3. shall also state the effective date of the bond release.

15.5. If the division disapproves the application for release of the bond or portion thereof, the notification specified in subsection 15.3. shall also state the reasons for disapproval, recommending corrective actions necessary to secure the release, and allowing an opportunity for a public hearing.

15.6. The division shall notify the municipality in which the well is located by certified mail at least 30 days prior to the release of the bond.

16. The following guidelines will govern the Forfeiture of Bonds.

16.1. The division shall take action to forfeit the bond if any of the following occur:

16.1.1. The operator refuses or is unable to conduct plugging and site restoration.

16.1.2. Noncompliance as to the conditions of a permit issued by the division.

16.1.3. The operator defaults on the conditions under which the bond was accepted.

16.2. In the event forfeiture of the bond is necessary, the matter will be considered by the Board.

16.3. For matters of bond forfeiture, the division shall send written notification to the parties identified in subsection 15.3., in addition to the notice requirements of the Board procedural rules.

16.4. After proper notice and hearing, the Board may order the division to do any of the following:

16.4.1. Proceed to collect the forfeited amount as provided by applicable laws for the collection of defaulted bonds or other debts.

16.4.2. Use funds collected from bond forfeiture to complete the plugging and restoration of the well or wells to which bond coverage applies.

16.4.3. Enter into a written agreement with the operator or another party to perform plugging and restoration operations in accordance with a compliance schedule established by the division as long as such party has the ability to perform the necessary work.

16.4.4. Allow a surety to complete the plugging and restoration, if the surety can demonstrate an ability to complete the plugging and restoration.

16.4.5. Any other action the Board deems reasonable and appropriate.

16.5. In the event the amount forfeited is insufficient to pay for the full cost of the plugging and restoration, the division may complete or authorize completion of plugging and restoration and may recover from the operator all costs of plugging and restoration in excess of the amount forfeited.

16.6. In the event the amount of bond forfeited was more than the amount necessary to complete plugging and restoration, the unused funds shall be returned by the division to the party from whom they were collected.

16.7. In the event the bond is forfeited and there exists any unplugged well or wells previously covered under the forfeited bond, then the operator must establish new bond coverage in accordance with these rules.

16.8. If the operator requires new bond coverage under the provisions of subsection 16.7., then the division will notify the operator and specify a reasonable period, not to exceed 90 days, to establish new bond coverage.

R649-3-2. Location And Siting Of Vertical Wells and Statewide Spacing for Horizontal Wells.

1. In the absence of special orders of the board establishing drilling units or authorizing different well density or location patterns for particular pools or parts thereof, each oil and gas well shall be located in the center of a 40 acre quarter-quarter section, or a substantially equivalent lot or tract or combination of lots or tracts as shown by the most recent governmental survey, with a tolerance of 200 feet in any direction from the center location, a "window" 400 feet square. No oil or gas well shall be drilled less than 920 feet from any other well drilling to or capable of producing oil or gas from the same pool, and no oil or gas well shall be completed in a known pool unless it is located more than 920 feet from any other well completed in and capable of producing oil or gas from the same pool.

2. The division shall have the administrative authority to determine the pattern location and siting of wells adjacent to an area for which drilling units have been established or for which a request for agency action to establish drilling units has been filed with the board and adjacent to a unitized area, where there is sufficient evidence to indicate that the particular pool underlying the drilling unit or unitized area may extend beyond the boundary of the drilling unit or unitized area and the uniformity of location patterns is necessary to ensure orderly development of the pool.

3. In the absence of special orders of the Board, no portion of the horizontal interval within the potentially productive formation shall be closer than six hundred-sixty (660) feet to a drilling or spacing unit boundary, federally unitized area boundary, uncommitted tract within a unit, or boundary line of a lease not committed to the drilling of such horizontal well.

4. The surface location for a horizontal well may be anywhere on the lease.

5. Any horizontal interval shall be not closer than one thousand three hundred and twenty (1,320) feet to any vertical well completed in and producing from the same formation. Vertical wells drilled to and completed in the same formation as in a horizontal well are subject to applicable drilling unit orders of the board or the other conditions of this rule which do not specifically pertain to horizontal wells and may be drilled and produced as provided therein.

6. A temporary six hundred and forty (640) acre spacing unit, consisting of the governmental section in which the horizontal well is located, is established for the orderly development of the anticipated pool.

7. In addition to any other notice required by the statute or these rules, notice of the Application for Permit to Drill for a horizontal well shall be given by certified mail to all owners within the boundaries of the designated temporary spacing unit.

8. Horizontal wells to be located within federally supervised units are exempt from the above referenced conditions

of 5, 6 and 7.

9. Exceptions to any of the above referenced conditions of 3 through 7 may be approved upon proper application pursuant to R649-3-3, Exception to Location and Siting of Wells, or R649-10, Administrative Procedures.

10. Additional horizontal wells may be approved by order of the Board after hearing brought upon by a Request for Agency Action (Petition) filed in accordance with the Board's Procedural Rules.

R649-3-3. Exception to Location and Siting of Wells.

1. The division shall have the administrative authority to grant an exception to the locating and siting requirements of R649-3-2 or an order of the board establishing oil or gas well drilling units after receipt from the operator of the proposed well of the following items:

1.1. Proper written application for the exception well location.

1.2. Written consent from all owners within a 460 foot radius of the proposed well location when such exception is to the requirements of R649-3-2, or;

1.3. Written consent from all owners of directly or diagonally offsetting drilling units when such exception is to an order of the board establishing oil or gas well drilling units.

2. If for any reason the division shall fail or refuse to approve such an exception, the board may, after notice and hearing, grant an exception.

3. The application for an exception to R649-3-2 or board drilling unit order shall state fully the reasons why such an exception is necessary or desirable and shall be accompanied by a plat showing:

3.1. The location at which an oil or gas well could be drilled in compliance with R649-3-2 or Board drilling unit order.

3.2. The location at which the applicant requests permission to drill.

3.3. The location at which oil or gas wells have been drilled or could be drilled, in accordance with R649-3-2 or board drilling unit order, directly or diagonally offsetting the proposed exception.

3.4. The names of owners of all lands within a 460 foot radius of the proposed well location when such exception is to the requirements of R649-3-2, or

3.5. The names of owners of all directly or diagonally offsetting drilling units when such exception is to an order of the board establishing oil or gas drilling units.

4. No exception shall prevent any owner from drilling an oil or gas well on adjacent lands, directly or diagonally offsetting the exception, at locations permitted by R649-3-2, or any applicable order of the board establishing oil or gas well drilling units for the pool involved.

5. Whenever an exception is granted, the board or the division may take such action as will offset any advantage that the person securing the exception may obtain over other producers by reason of the exception location.

R649-3-4. Permitting of Wells to be Drilled, Deepened or Plugged-Back.

1. Prior to the commencement of drilling, deepening or plugging back of any well, exploratory drilling such as core holes and stratigraphic test holes, or any surface disturbance associated with such activity, the operator shall submit Form 3, Application for Permit to Drill, Deepen, or Plug Back and obtain approval. Approval shall be given by the division if it appears that the contemplated location and operations are not in violation of any rule or order of the board for drilling a well.

2. The following information shall be included as part of the complete Application for Permit to Drill, Deepen, or Plug Back.

2.1. The telephone number of the person to contact if additional information is needed.

2.2. Proper identification of the lease as state, federal, Indian, or fee.

2.3. Proper identification of the unit, if the well is located within a unit.

2.4. A plat or map, preferably on a scale of one inch equals 1,000 feet, prepared by a licensed surveyor or engineer, which shows the proposed well location. For directional wells, both surface and bottomhole locations should be marked.

2.5. A copy of the Division of Water Rights approval or the identifying number of the approval for use of water at the drilling site.

2.6. A drilling program containing the following information shall also be submitted as part of a complete APD.

2.6.1. The estimated tops of important geologic markers.

2.6.2. The estimated depths at which the top and the bottom of anticipated water, oil, gas, or other mineral-bearing formations are expected to be encountered, and the owner's or operator's plans for protecting such resources.

2.6.3. The owner's or operator's minimum specifications for pressure control equipment to be used and a schematic diagram thereof showing sizes, pressure ratings or API series, proposed testing procedures and testing frequency.

2.6.4. Any supplementary information more completely describing the drilling equipment and casing program as required by Form 3, Application for Permit to Drill, Deepen, or Plug Back.

2.6.5. The type and characteristics of the proposed circulating medium or mediums to be employed in drilling, the quantities and types of mud and weighting material to be maintained, and the monitoring equipment to be used on the mud system.

2.6.6. The anticipated type and amount of testing, logging, and coring.

2.6.7. The expected bottomhole pressure and any anticipated abnormal pressures or temperatures or potential hazards, such as hydrogen sulfide, expected to be encountered, along with contingency plans for mitigating such identified hazards.

2.6.8. Any other facets of the proposed operation which the lessee or operator desires to point out for the division's consideration of the application.

2.6.9. If an Application for Permit to Drill, Deepen, or Plug Back is for a proposed horizontal well, a horizontal well diagram clearly showing the well bore path from the surface through the terminus of the lateral shall be submitted.

2.7. Form 5, Designation of Agent or Operator shall be filed when the operator is a person other than the owner.

2.8. If located on State or Fee surface, an APD will not be approved until an Onsite Predrill Evaluation is performed as outlined in R649-3-18.

3. Two legible copies, carbon or otherwise, of the APD filed with the appropriate federal agency may be used in lieu of the forms prescribed by the board.

4. Approval of the APD shall be valid for a period of 12 months from the date of such approval. Upon approval of an APD, a well will be assigned an API number by the division. The API number should be used to identify the permitted well in all future correspondence with the division.

5. If a change of location or drilling program is desired, an amended APD shall be filed with the division and its approval obtained. If the new location is at an authorized location in the approved drilling unit, or the change in drilling program complies with the rules for that area, the change may be approved verbally or by telegraph. Within five days after obtaining verbal or telegraphic authorization, the operator shall file a written change application with the division.

6. After a well has been completed or plugged and abandoned, it shall not be reentered without the operator first submitting a new APD and obtaining the division's approval. Approval shall be given if it appears that a bond has been furnished or waived, as required by R649-3-1, Bonding, and the contemplated work is not in violation of any rule or order of the board.

7. An operator or owner who applies for an APD in an area not subject to a special order of the board establishing drilling units, may contemporaneously or subsequently file a Request for Agency Action to establish drilling units for an area not to exceed the area reasonably projected by the operator or owner to be underlaid by the targeted reservoir.

8. An APD for a well within the area covered by a proper Request for Agency Action which has been filed by an interested person, or the division or the board on its own motion, for the establishment of drilling units or the revision of existing drilling units for the spacing of wells shall be held in abeyance by the division until such time as the matter has been noticed, fully heard and determined.

9. An exception to R649-3-4-8 shall be made and a permit shall be issued by the division if an owner or operator files a sworn statement demonstrating to the division's satisfaction that on and after the date the Request for Agency Action requesting the establishment of drilling units was filed, or the action of the division or board was taken; and

9.1. The owner or operator has the right or obligation under the terms of an existing contract to drill the requested well; or

9.2. The owner or operator has a leasehold estate or right to acquire a leasehold estate under a contract that will be terminated unless he is permitted to commence the drilling of the required well before the matter can be fully heard and determined by the board.

R649-3-5. Identification.

Every drilling and producible well shall be identified by a sign posted on the derrick or in a conspicuous place near the well. The sign shall be of durable construction. The lettering on the sign shall be kept in a legible condition and shall be large enough to be legible under normal conditions at a distance of 25 feet. The wells on each lease or property shall be numbered in nonrepetitive, logical, and distinctive sequence. Each sign shall show the number of the well, the name of the owner or operator, the lease name, and the location of the well by quarter section, township, and range.

R649-3-6. Drilling Operations.

1. Drilling operations shall be conducted according to the drilling program submitted on the original APD and as approved by the division. Any change of plans to the original drilling program shall be submitted to the division by using Form 9, Sundry Notices and Reports on Wells and shall receive division approval prior to implementation. A change of plans necessary because of emergency conditions may be implemented without division approval. The operator shall provide the division with verbal notice of the emergency change within 24 hours and written notice within five days.

2. An operator of a drilling well as designated in R649-2-4 shall comply with reporting requirements as follows:

2.1. The spudding in of a well shall be reported to the division within 24 hours. The report should include the well name and number, drilling contractor, rig number and type, spud date and time, the date that continuous drilling will commence, the name of the person reporting the spud, and a contact telephone number.

2.2. The operator shall file Form 6, Entity Action Form with the division within five working days of spudding in a well. The division will assign the well an entity number which will identify the well on the operator's monthly oil and gas production and disposition reports.

2.3. The operator shall notify the division 24 hours in advance of all testing to be performed on the blowout preventor equipment on a well.

2.4. The operator shall submit a monthly status report for each drilling well on Form 9, Sundry Notices and Reports on Wells. The report should include the well depth and a description of the operations conducted on the well during the month. The report shall be submitted no later than the fifth day of the following calendar month until such time as the well is completed and the well completion report is filed.

2.5. The operator shall notify the division 24 hours in advance of all casing tests performed in accordance with R649-3-13.

2.6. The operator shall report to the division all fresh water sand encountered during drilling on Form 7, Report of Water Encountered During Drilling, The report shall be filed with Form 8, Well Completion or Recompletion Report and Log.

R649-3-7. Well Control.

1. When drilling in wildcat territory, the owner or operator shall take all reasonably necessary precautions for keeping the well under control at all times and shall provide, at the time the well is started, proper high pressure fittings and equipment. All pressure control equipment shall be maintained in good working condition at all times.

2. In all proved areas, the use of blowout prevention equipment "BOPE" shall be in accordance with the established and approved practice in the area. All pressure control equipment shall be maintained in good working condition at all times.

3. Upon installation, all ram type BOPE and related equipment, including casing, shall be tested to the lesser of the full manufacturer's working pressure rating of the equipment, 70% of the minimum internal yield pressure of any casing subject to test, or one psi/ft of the last casing string depth. Annular type BOPE are to be tested in conformance with the manufacturer's published recommendations. The operator shall maintain records of such testing until the well is completed and will submit copies of such tests to the division if required.

4. In addition to the initial pressure tests, ram and annular type preventers shall be checked for physical operation each trip. All BOPE components, with the exception of an annular type blowout preventer, shall be tested monthly to the lesser of 50% of the manufacturer's rated pressure of the BOPE, the maximum anticipated pressure to be contained at the surface, one psi/ft of the last casing string depth, or 70% of the minimum internal yield pressure of any casing subject to test.

5. If a pressure seal in the assembly is disassembled, a test of that seal shall be conducted prior to the resumption of any drilling operation. A shell test of the affected seal shall be adequate. If the affected seal is integral with the BOP stack, either pipe or blind ram, necessitating a test plug to be set in order to test the seal, the division may grant approval to proceed without testing the seal if necessary for prudent operations.

6. All tests of BOPE shall be noted on the driller's log, IADC report book, or equivalent and shall be available for examination by the director or an authorized agent during routine inspections.

7. BOPE used in possible or probable hydrogen sulfide or sour gas formations shall be suitable for use in such areas.

R649-3-8. Casing Program.

1. The method of cementing casing in the hole shall be by pump and plug method, displacement method, or other method approved by the division.

2. When drilling in wildcat territory or in any field where high pressures are probable, the conductor and surface strings of casing must be cemented throughout their lengths, unless another

procedure is authorized or prescribed by the division, and all subsequent strings of casing must be securely anchored.

3. In areas where the pressures and formations to be encountered during drilling are known, sufficient surface casing shall be run to:

3.1. Reach a depth below all known or reasonably estimated, utilizable, domestic, fresh water levels.

3.2. Prevent blowouts or uncontrolled flows.

4. The casing program adopted must be planned to protect any potential oil or gas horizons penetrated during drilling from infiltration of waters from other sources and to prevent the migration of oil, gas, or water from one horizon to another.

R649-3-9. Protection Of Upper Productive Strata.

1. No well shall be deepened for the purpose of producing oil or gas from a lower stratum until all upper productive strata are protected, either permanently by casing and cementing or temporarily through the use of tubing and packer, to the satisfaction of the division.

2. In any well that appears to have defective, poorly cemented, or corroded casing that will permit or may create underground waste or may contaminate underground or surface fresh water, the operator shall proceed with diligence to use the appropriate method and means to eliminate such hazard of underground waste or contamination of fresh water. If such hazard cannot be eliminated, the well shall be properly plugged and abandoned.

3. Natural gas that is encountered in substantial quantities in any section of a cable tool drilled hole above the ultimate objective shall be shut off with reasonable diligence, either by mudding, casing or other approved method, and shall be confined to its original source to the satisfaction of the division.

R649-3-10. Tolerances For Vertical Drilling.

Deviation from the vertical for short distances is permitted in the drilling of a well without special approval to straighten the hole, sidetrack junk, or correct other mechanical difficulties. All wells shall be drilled such that the surface location of the well and all points along the intended well bore shall be within the tolerances allowed by R649-3-2, Location and Siting of Vertical Wells and Statewide Spacing for Horizontal Wells, or the appropriate board order.

R649-3-11. Directional Drilling.

1. Except for the tolerances allowed under R649-3-10, no well may be intentionally deviated unless the operator shall first file application and obtain approval from the division. An application for directional drilling may be approved by the division without notice and hearing when the applicant is the owner of all the oil and gas within a radius of 460 feet from all points along the intended well bore, or the applicant has obtained the written consent of the owner to the proposed directional drilling program. An application for directional drilling may be included as part of the initial APD for a proposed well.

2. An application for directional drilling shall include the following information:

2.1. The name and address of the operator.

2.2. The lease name, well number, field name, reservoir name, and county where the proposed well is located.

2.3. A plat or sketch showing the distance from the surface location to section and lease lines, the target location within the intended producing interval, and any point along the intended well bore outside the 460 foot radius for which the consent of the owner has been obtained.

2.4. The reason for the intentional deviation.

2.5. The signature of designated agent or representative of operator.

3. Within 30 days following completion of a directionally drilled well, a complete angular deviation and directional survey of the well obtained by an approved well survey company shall be filed with the division, together with other regularly required reports.

R649-3-12. Drilling Practices For Hydrogen Sulfide Areas And Formations.

1. This rule shall apply to drilling, redrilling, deepening, or plugging back operations in areas where the formations to be penetrated are known to contain or are expected to contain H_2S in excess of 20 ppm and to areas where the presence or absence thereof is unknown.

2. A written contingency plan, providing details of actions to be taken to alert and protect operating personnel and members of the public in the event of an accidental release of H_2S gas shall be submitted to the division as part of the initial APD for a well or as a sundry notice.

3. All proposed drill site locations shall be planned to obtain the maximum safety benefits consistent with the rig configuration, terrain, prevailing winds, etc. The drilling rig shall, where possible, be situated so that prevailing winds blow across the rig in a direction toward the reserve pit and away from escape routes. On-site trailers shall be located to allow reasonably safe distances from both the well and the outlet of the flare line.

4. At least two cleared areas shall be designated as crew briefing or safety areas. Both areas shall be located at least 200 feet from the well, with at least one area located generally upwind from the well.

5. Protective equipment shall be provided by the operator or its drilling contractor for operating personnel and shall include the following:

5.1. An adequate number of positive pressure type self-contained breathing apparatus to allow all personnel normally involved in the drilling operation immediate access to such equipment, with a minimum of one working apparatus available for the immediate use of each rig hand in emergencies.

5.2. Chalk boards or note pads to be used for communication when wearing protective breathing apparatus.

5.3. First aid supplies.

5.4. One resuscitator complete with medical oxygen.
5.5. A litter or stretcher.
5.6. Harnesses and lifelines.
5.7. A telephone, radio, mobile phone, or other communication device that provides emergency two-way communication from a safe area at the well location.

6. Each drill site shall have an H_2S detection and monitoring system that activates audible and visible alarms when the concentration of H_2S reaches the threshold limit of 20 ppm in air. This equipment shall have a rapid response time and be capable of sensing a minimum of ten ppm H_2S in air, with at least three sensing points, located at the shale shaker, on the derrick floor, and in the cellar. Other sensing points shall be located at other critical areas where H_2S might accumulate. Portable H_2S detection equipment capable of sensing an H_2S concentration of 20 ppm shall be available for all working personnel and shall be equipped with an audible warning signal.

7. Equipment to indicate wind direction at all times shall be installed at prominent locations. At least two wind socks or streamers shall be located at separate elevations at the well location and shall be easily visible from all areas of the location. Windsocks or streamers shall be located in illuminated areas for night operations.

8. When H_2S is encountered during drilling, well marked, highly visible warning signs shall be displayed at the rig and along all access routes to the well location. The signs shall warn of the presence of H_2S and shall prohibit approach to the well location when red flags are displayed. Red flags shall be displayed when H_2S is present in concentrations greater than 20 ppm in air as measured on the equipment required under R649-3-12-6.

9. Unless adequate natural ventilation is present, portable fans or ventilation equipment shall be located in work areas to disperse H_2S when it is encountered.

10. A flare system shall be utilized to safely gather and burn H_2S bearing gas. Flare lines shall be located as far from the operating site as feasible and shall be located in a manner to compensate for wind changes. The outlets of all flare lines shall be located at least 150 feet from the well head unless otherwise approved by the division.

11. Sufficient quantities of additives shall be maintained on location to add to the mud system to scavenge or neutralize H_2S.

R649-3-13. Casing Tests.

In order to determine the integrity of the casing string set in the well, the operator shall, unless otherwise requested by the division, perform a pressure test of the casing to the pressures specified under R649-3-7-4 before drilling out of any casing string, suspending drilling operations, or completing the well.

R649-3-14. Fire Hazards On The Surface.

1. All rubbish or debris that might constitute a fire hazard shall be removed to a distance of a least 100 feet from the well location, tanks, separator, or any structure. All waste oil or gas shall be burned or disposed of in a manner to avert creation

of a fire hazard.

2. Any gas other than poisonous gas escaping from the well during drilling operations shall be, so far as practicable, conducted to a safe distance from the well site and burned in a suitable flare.

R649-3-15. Pollution And Surface Damage Control.

The operator shall take all reasonable precautions to avoid polluting lands, streams, reservoirs, natural drainage ways, and underground water. The owner or operator shall carry on all operations and maintain the property at all times in a safe and workmanlike manner having due regard for the preservation and conservation of the property and for the health and safety of employees and people residing in close proximity to those operations. At a minimum, the owner or operator shall:

1.1. Take reasonable steps to prevent and shall remove accumulations of oil or other materials deemed to be fire hazards from the vicinity of well locations, lease tanks and pits.

1.2. Remove from the property or store in an orderly manner, all scrap or other materials not in use.

1.3. Provide secure workmanlike storage for chemical containers, barrels, solvents, hydraulic fluid, and other non-exempt materials.

1.4. Maintain tanks in a workmanlike manner which will preclude leakage and provide for all applicable safety measures, and construct berms of sufficient height and width to contain the quantity of the largest tank at the storage facility. The use of crude or produced water storage tanks without tops is strictly prohibited except during well testing operations.

1.5. Catch leaks and drips, contain spills, and cleanup promptly. Waste reduction and recycling should be practiced in order to help reduce disposal volumes. Produced water, tank bottoms and other miscellaneous waste should be disposed of in a manner which is in compliance with these rules and other state, federal, or local regulations or ordinances. In general, good housekeeping practices should be used.

R649-3-16. Reserve Pits and Other Onsite Pits.

1. Small onsite oil field pits including but not limited to reserve pits, emergency pits, workover and completion pits, storage pits, pipeline drip pits, and sumps shall be located and constructed in such a manner as to contain fluids and not cause pollution of waters and soils. They shall be located and constructed according to the Division guidelines for onsite pits.

2. Reserve pit location and construction requirements including liner requirements will be discussed at the predrill site evaluation. Special stipulations concerning the reserve pit will be included as part of the Division's approval to drill.

3. Following drilling and completion of the well the reserve pit shall be closed within one year, unless permission is granted by the Division for a longer period. Pit contents shall meet the Division's Cleanup Levels (guidance document for numeric clean-up levels) or background levels prior to burial. The contents may require treatment to reduce mobility and/or toxicity in order to

meet cleanup levels. The alternative to meeting cleanup levels would be transporting of material to an appropriate disposal facility.

R649-3-17. Inspection.

Inspection of wells shall be performed by the division to determine operator compliance with the rules and orders of the board. The inspection shall not interfere with the mechanical operation of facilities or equipment used in drilling and production operations. Inspections of operations involving a safety hazard shall not be conducted, nor shall an inspection be conducted that may cause a safety hazard.

R649-3-18. On-site Predrill Evaluation.

1. An on-site predrill evaluation of drilling operations located on state or private land shall be scheduled and conducted by the division prior to approval of an APD and no later than 30 days after receipt by the division of a complete APD. An on-site predrill evaluation may be performed by the division prior to submittal of a complete APD at the written request of the operator. The division, the operator, and other persons associated with the surface management or construction of the well site shall attend the predrill evaluation. When appropriate, the operator's surveyor and archaeologist may also participate in the predrill evaluation. When the surface of the land involved is privately owned, the operator shall include in the APD the name, address, and telephone number of the private surface owner as shown on the real property records of the county where the well is located. The surface owner shall be invited by the division to attend the predrill evaluation. The surface owner's inability to attend the predrill evaluation shall not delay the scheduled evaluation.

2. Special stipulations concerning surface use or justifications for well spacing exceptions may be addressed and developed at the predrill evaluations. Special stipulations shall be incorporated as conditions of the approved APD, together with any additional conditions determined by the division to be necessary following a review of the complete application.

R649-3-19. Well Testing.

1. Each operator shall conduct a stabilized production test of at least 24 hours duration not later than 15 days following the completion or recompletion of any well for the production of oil or gas.

The results of the test shall be reported in writing to the division within 15 days after completion of the test. Additional tests shall be taken as requested by the division.

2. The division may request subsurface pressure measurements on a sufficient number of wells in any pool to provide adequate data to determine reservoir characteristics.

3. Upon written request, the division may waive or extend the time for conducting any test.

4. A gas-oil ratio "GOR" test shall be conducted not later than 15 days following the completion or recompletion of each well

in a pool which contains both oil and gas. The average daily oil production, the average daily gas production and the average GOR shall be recorded. The results of the GOR test shall be reported in writing to the division within 15 days after completion of the test. A GOR test of at least 24 hours duration shall satisfy the requirements of R649-3-19-1.

5. When the results of a multipoint test or other approved test for the determination of gas well potential have not been submitted to the division within 30 days after completion or recompletion of any producible gas well, the division may order that this test be made. All data pertinent to the test shall be submitted to the division in legible, written form within 15 days after completion of the test. The performance of a multipoint or other approved test shall satisfy the requirements of R649-3-19-1.

6. All tests of any producible gas well will be taken in accordance with the Manual of Back-Pressure Testing of Gas Wells published by the Interstate Oil Compact Commission, with necessary modifications as approved by the division.

R649-3-20. Gas Flaring Or Venting.

1. Produced gas from an oil well, also known as associated gas or casinghead gas, may be flared or vented only in the following amounts:

1.1. Up to 1,800 MCF of oil well gas may be vented or flared from an individual well on a monthly basis at any time without approval.

1.2. During the period of time allowed for conducting the stabilized production test or other approved test as required by R649-3-19, the operator may vent or flare all produced oil well gas as needed for conducting the test. The operator shall not vent or flare gas which is not necessary for conducting the test or beyond the time allowed for conducting the test.

1.3. During the first calendar month immediately following the time allowed for conducting the initial stabilized production test as required by R649-3-19.1, the operator may vent or flare up to 3,000 MCF of oil well gas without approval.

1.4. Unavoidable or short-term oil well gas venting or flaring may occur without approval in accordance with R649-3-20.4, 4.1, 4.2, and 4.3.

2. Produced gas from a gas well may be vented or flared only in the following amounts:

2.1. During the period of time allowed for conducting the stabilized production test, the multipoint test, or other approved test as required by R649-3-19, the operator may vent or flare all produced gas well gas as needed for conducting the test. The operator shall not vent or flare gas which is not necessary for conducting the tests or beyond the time allowed for conducting the tests.

2.2. Unavoidable or short-term gas well gas venting or flaring may occur without approval in accordance with R649-3-20.4, 4.1, 4.2, and 4.3.

3. If an operator desires to produce a well for the purpose of testing and evaluation beyond the time allowed by R649-3-19 and vent or flare gas in excess of the aforementioned limits of gas

venting or flaring, the operator shall make written request for administrative action by the division to allow gas venting or flaring during such testing and evaluation. The operator shall provide any information pertinent to a determination of whether marketing or otherwise conserving the produced gas is economically feasible. Upon such request and based on the justification information presented, the division may authorize gas venting or flaring at unrestricted rates for up to 30 days of testing or no more than 50 MMCF of gas vented or flared, whichever is less.

4. Once a well is completed for production and gas is being transported or marketed, the operator is allowed unavoidable or short-term gas venting or flaring without approval only in the following cases:

4.1. Gas may be vented or released from oil storage tanks or other low pressure oil production vessels unless the division determines that the recovery of such vapors is warranted.

4.2. Gas may be vented or flared from a well during periods of line failures, equipment malfunctions, blowouts, fires, or other emergencies if shutting in or restricting production from the well would cause waste or create adverse impact on the well or producing reservoir. The operator shall provide immediate notification to the division in all such cases in accordance with R649-3-32, Reporting of Undesirable Events. Upon notification, the division shall determine if gas venting or flaring is justified and specify conditions of approval if necessary.

4.3. Gas may be vented or flared from a well during periods of well purging or evaluation tests not exceeding a period of 24 hours or a maximum of 144 hours per month. The operator shall provide subsequent written notification to the division in all such cases.

5. If an operator wishes to flare or vent a greater amount of produced gas than allowed by this rule, the operator must submit a Request for Agency Action to the board to be considered as a formal board docket item. The request should include the following items:

5.1. A statement justifying the need to vent or flare more than the allowable amount.

5.2. A description of production test results.

5.3. A chemical analysis of the produced gas.

5.4. The estimated oil and gas reserves.

5.5. A description of the reinjection potential or other conservation oriented alternative for disposition of the produced gas.

5.6. A description of the amount of gas used in lease operations.

5.7. An economic evaluation supporting the operator's determination that conservation of the gas is not economically viable. The evaluation should utilize any engineering or geologic data available and should consider total well production, not just gas production, in presenting the profitability and costs for beneficial use of the gas.

5.8. Any other information pertinent to a determination of whether marketing or otherwise conserving the produced gas is economically feasible.

6. Upon review of the request for approval to vent or flare gas from a well, the board may elect to:

6.1. Allow the requested venting or flaring of gas.

6.2. Restrict production until the gas is marketed or otherwise beneficially utilized.

6.3. Take any other action the board deems appropriate in the circumstances.

7. When gas venting or flaring from a well has not been approved by the division or the magnitude and duration of venting or flaring exceeds the amounts specified in these rules or any division or board approval, then the board may issue a formal order to alleviate the noncompliance and/or require the operator to appear before the board to provide justification of such venting or flaring. The division shall notify the appropriate governmental taxing and royalty agencies of any unapproved venting or flaring and of any subsequent board action.

8. No extraction plant processing gas in Utah shall flare or vent such gas unless such venting or flaring is made necessary by mechanical difficulty of a very limited temporary nature or unless the gas vented or flared is of no commercial value. In the event of a more prolonged mechanical difficulty or in the event of plant shut-downs or curtailment because of scheduled or nonscheduled maintenance or testing operations or other reasons, or in the event a plant is unable to accept, process, and market all of the casinghead gas produced by wells connected to its system, the plant operator shall notify the division as soon as possible of the full details of such shut-down or curtailment, following which the division shall take such action as is necessary.

R649-3-21. Well Completion And Filing Of Well Logs.

1. For the purposes of this rule only, a well shall be determined to be completed when the well has been adequately worked to be capable of producing oil or gas or when well testing as required by the division is concluded.

2. Within 30 days after the completion of any well drilled or redrilled for the production of oil or gas, Form 8, Well Completion or Recompletion Report and Log, shall be filed with the division, together with a copy of the electric and radioactivity logs, if run.

3. In addition, one copy of all drillstem test reports, formation water analyses, porosity, permeability or fluid saturation determinations, core analyses and lithologic logs or sample descriptions if compiled, shall be filed with the division.

4. As prescribed under R649-2-12, Test and Surveys, the directional, deviation and/or measurement-while-drilling (MWD) survey for a horizontal well shall be filed within 30 days of being run. Such directional, deviation and/or MWD survey specifically related to well location or well bore path shall not be held confidential. Other MWD survey data which presents well log, or other geological, geophysical, or engineering information may be held confidential as provided in R649-2-11, Confidentiality of Well Log Information.

R649-3-22. Completion Into Two Or More Pools.

1. The completion of a single well into more than one pool may be permitted by submitting an application to the division and securing its approval. The application shall be submitted on Form 9, Sundry Notice and Report and shall be accompanied by an exhibit showing the location of all wells on contiguous oil and gas leases or drilling units overlying the pool. The application shall set forth all material facts involved and the manner and method of completion proposed.

2. If oil or gas is to be produced from two or more pools open to each other through the same string of casing so that commingling will take place, the application must also be accompanied by a description of the method used to account for and to allocate production from each pool so commingled.

3. The application shall include an affidavit showing that the operator has provided a copy of the application to the owners of all contiguous oil and gas leases or drilling units overlying the pool. If none of these owners file a written objection to the application within 15 days after the date the application is filed with the division, the application may be considered and approved by the division without a hearing. If a written objection is filed that cannot be resolved administratively, the application may be approved only after notice and hearing by the board.

R649-3-23. Well Workover and Recompletion.

1. Requests for approval of a notice of intention to perform a workover or recompletion shall be filed by an operator with the division on Form 9, Sundry Notices and Reports on Wells, or if the operation includes substantial redrilling, deepening, or plugging back of an existing well, on Form 3, Application for Permit to Drill, Deepen or Plug Back.

2. The division shall review the proposed workover or recompletion for conformance with the Oil and Gas Conservation General Rules and advise the operator of its decision and any necessary conditions of approval.

3. Recompletions shall be conducted in a manner to protect the original completion interval(s) and any other known productive intervals.

4. The same tests and reports are required for any well recompletion as are required following an original well completion.

5. The applicant shall file a subsequent report of workover on Form 9, Sundry Notices and Reports, or a subsequent report of recompletion on Form 8, Well Completion or Recompletion Report and Log, within 30 days after completing the workover or recompletion operations.

6. For the purpose of qualifying for a tax credit under Utah Code Ann. Section 59-5-102(3), the operator on his behalf and on behalf of each working interest owner must file a request with the division on Form 15, Designation of Workover or Recompletion. The request must be filed within 90 days after completing the workover or recompletion operations.

7. A workover which may qualify under Utah Code Ann. Section 59-5-102(3) shall be downhole operations conducted to maintain, restore or increase the producibility or serviceability of a well

in the geologic interval(s) that the well is currently completed in, but shall not include:

7.1. Routine maintenance operations such as pump changes, artificial lift equipment or tubing repair, or other operations which do not involve changes to the wellbore configuration or the geologic interval(s) that it penetrates and which do not stimulate production beyond that which would be anticipated as the result of routine maintenance.

7.2. Operations to convert any well for use as a disposal well or other use not associated with enhancing the recovery of hydrocarbons. Operations to convert a well to a Class II injection well for enhanced recovery purposes may qualify if the secondary or enhanced recovery project has received the necessary board approval.

8. A recompletion which may qualify under Utah Code Ann. Section 59-5-102(3) shall be downhole operations conducted to reestablish producibility or serviceability of a well in any geologic interval(s).

9. The division shall review the request for designation of a workover or recompletion and advise the operator and the State Tax Commission of its decision to approve or deny the operations for the purposes of Utah Code Ann. Section 59-5-102(3).

10. The division is responsible for approval of workover and recompletion operations which qualify for the tax credit. If the operator disagrees with the decision of the division, the decision may be appealed to the board. Appeals of all other workover and recompletion tax credit decisions should be made to the State Tax Commission.

R649-3-24. Plugging And Abandonment Of Wells.

1. Before operations are commenced to plug and abandon any well the owner or operator shall submit a notice of intent to plug and abandon to the division for its approval. The notice shall be submitted on Form DOGM-5, Sundry Notice and Report on Wells. A legible copy of a similar report and form filed with the appropriate federal agency may be used in lieu of the forms prescribed by the board. In cases of emergency the operator may obtain verbal or telegraphic approval to plug and abandon. Within five days after receiving verbal or telegraphic approval, the operator shall submit a written notice of intent to plug and abandon on Form 9.

2. Both verbal and written notice of intent to plug and abandon a well shall contain the following information.

2.1. The location of the well described by section, township, range, and county.

2.2. The status of the well, whether drilling, producing, injecting or inactive.

2.3. A description of the well bore configuration indicating depth, casing strings, cement tops if known, and hole size.

2.4. The tops of known geologic markers or formations.

2.5. The plugging program approved by the appropriate federal agency if the well is located on federal or Indian land.

2.6. An indication of when plugging operations will commence.

3. A dry or abandoned well must be plugged so that oil, gas, water, or other substance will not migrate through the well bore from one formation to another. Unless a different method and procedure is approved by the division, the method and procedure for plugging the well shall be as follows:

3.1. The bottom of the hole shall be filled to, or a bridge shall be placed at, the top of each producing formation open to the well bore, and a cement plug not less than 100 feet in length shall be placed immediately above each producing formation open to the well bore.

3.2. A solid cement plug shall be placed from 50 feet below a fresh water zone to 50 feet above the fresh water zone, or a 100 foot cement plug shall be centered across the base of the fresh water zone and a 100 foot plug shall be centered across the top of the fresh water zone.

3.3. At least ten sacks of cement shall be placed at the surface in a manner completely plugging the entire hole. If more than one string of casing remains at the surface, all annuli shall be so cemented.

3.4. The interval between plugs shall be filled with noncorrosive fluid of adequate density to prevent migration of formation water into or through the well bore.

3.5. The hole shall be plugged up to the base of the surface string with noncorrosive fluid of adequate density to prevent migration of formation water into or through the well bore, at which point a plug of not less than 50 feet of cement shall be placed.

3.6. Any perforated interval shall be plugged with cement and any open hole porosity zone shall be adequately isolated to prevent migration of fluids.

3.7. A cement plug not less than 100 feet in length shall be centered across the casing stub if any casing is cut and pulled, a second plug of the same length shall be centered across the casing shoe of the next larger casing.

4. An alternative method of plugging required under a federal or Indian lease, will be accepted by the division.

5. Within 30 days after the plugging of any well has been accomplished, the owner or operator shall file a subsequent report of plugging with the division. The report shall give a detailed account of the following items:

5.1. The manner in which the plugging work was carried out, including the nature and quantities of materials used in plugging and the location, nature, and extent by depths, of the plugs.

5.2. Records of any tests or measurements made.

5.3. The amount, size, and location, by depths of any casing left in the well.

5.4. A statement of the volume of mud fluid used.

5.5. A complete report of the method used and the results obtained, if an attempt was made to part any casing.

6. Upon application to and approval by the division, and following assumption of liability for the well by the surface owner, a well or other exploratory hole that may safely be used as a fresh water well need not be filled above the required sealing plugs set below the fresh water formation. The owner of the

surface of the land affected may assume liability for any well capable of conversion to a water well by sending a letter assuming such liability to the division and by filing an application with and obtaining approval for appropriation of underground water from the Division of Water Rights.

7. Unless otherwise approved by the division, all abandoned wells shall be marked with a permanent monument showing the well number, location, and name of the lease. The monument shall consist of a portion of pipe not less than four inches in diameter and not less than ten feet in length, of which four feet shall be above the ground level and the remainder shall be securely embedded in cement. The top of the pipe must be permanently sealed.

8. If any casing is to be pulled after a well has been abandoned, a notice of intent to pull casing must be filed with the division and its approval obtained before the work is commenced. The notice shall include full details of the contemplated work. If a log of the well has not already been filed with the division, the notice shall be accompanied by a copy of the log showing all casing seats as well as all water strata and oil and gas shows. Where the well has been abandoned and liability has been terminated with respect to the bond previously furnished under R649-3-1, a $10,000 plugging bond shall be filed with the division by the applicant.

R649-3-25. Underground Disposal Of Drilling Fluids.

1. Operators shall be permitted to inject and dispose of reserve pit drilling fluids downhole in a well upon submitting an application for such operations to the division and obtaining its approval. Injection of reserve pit fluids shall be considered by the division on a case-by-case basis.

2. Each proposed injection procedure will be reviewed by the division for conformance to the requirements and standards for permitting disposal wells under R649-5-2 to assure protection of fresh-water resources.

3. The subsurface disposal interval shall be verified by temperature log, or suitable alternative, during the disposal operation.

4. The division shall designate other conditions for disposal, as necessary, in order to ensure safe, efficient fluid disposal.

R649-3-26. Seismic Exploration.

1. Form 1, Application for Permit to Conduct Seismic Exploration shall be submitted to the division by the seismic contractor at least seven days prior to commencing any type of seismic exploration operations. In cases of emergency, approval may be obtained either verbally or by telegraphic communication. Changes of plans or line locations may be implemented in an emergency situation without division approval. Within five days after the change is performed, the seismic contractor shall submit written notice of the change to the division.

1.1 The permit may be revoked at any time by the division for failure to comply with the rules and orders of the board.

1.2. Any request to deviate from the general plugging and operations procedures of these rules shall be included on the permit application.

1.3. The name, address, and telephone number of the seismic contractor's local contact shall be submitted to the division as soon as determined if not available when the permit application is submitted.

1.4. After review of the application for a seismic permit, the division may require written permission of the owner of the surface of the affected land if it is determined that the seismic operation may significantly impact any building, pipeline, water well, flowing spring, or other cultural or natural feature in the area.

1.5. The permit will be in effect for six months from the date of approval. The permit may be extended upon application to and approval by the division.

2. Bonding shall not be required for seismic exploration requiring the drilling of shot holes.

3. Seismic contractors shall give the division at least 24 hours advance notice of the plugging of seismic holes. The notice shall include the date and time the plugging activities are expected to commence, the name and address of the seismic contractor responsible for the holes, and, if different, the name and address of the hole plugging company.

4. Unless the seismic contractor can prove to the satisfaction of the division that another method will provide adequate protection to ground water resources and other man-made or natural features and will provide long-term land stability, the following procedures shall be required for the conduct of seismic operations and hole plugging:

4.1. Seismic contractors shall take reasonable precautions to avoid conducting shot hole operations closer than 1,320 feet to any building, pipeline, water well, flowing spring, or other cultural/natural feature, e.g., a historical monument, marker, or structure, which may be adversely affected by the seismic operations.

4.2. When nonartesian water is encountered while drilling seismic shot holes, the holes shall be filled from the bottom up with a high grade bentonite/water slurry mixture. The slurry shall have a density that is at least four percent greater than the density of fresh water and shall have a marsh funnel viscosity of at least 60 seconds per quart. The density and viscosity of the slurry are to be measured prior to adding cuttings. Cuttings not added to the slurry are to be disposed of in accordance with R649-3-26-4.6. Upon approval by the division, any other suitable plugging material commonly used in the industry may be substituted for the bentonite/water slurry as long as the physical characteristics of the substitute plugging material are at least comparable to those of the bentonite/water slurry. The hole shall be filled with the substitute plugging material from the bottom up to a depth of three feet below ground level. A nonmetallic permaplug shall be set at a depth of three feet. The remaining hole shall be filled and tamped to the surface with cuttings and native soil. The permaplug shall be imprinted with an approved identification number or mark.

4.3. When drilling with air only, and in completely dry holes, plugging may be accomplished by returning the cuttings to the holes, tamping the returned cuttings to the depth of three feet below ground level, and setting the permaplug topped with more cuttings and soil. A small mound shall be left over the hole for settling allowance.

4.4. If artesian flow, water flowing at the surface, is encountered in the drilling of any seismic hole, cement shall be used to seal off the water flow to prevent cross-flow, erosion, or contamination of fresh water supplies. Unless severe weather conditions prevent access, the holes shall be cemented immediately. Approval may be granted to seismic operator to plug a flowing hole in another manner, if it is proved to this division that the alternate method will provide adequate protection to ground water resources and provide long term land stability. The owner of the surface of the land affected may assume liability for a seismic hole capable of conversion to a water well by sending a letter assuming such liability to the division and by filing an application with and obtaining approval for appropriation of underground water from the Division of Water Rights.

4.5. Shotholes shall be properly plugged and abandoned as soon as practical after the shot has been fired. No shothole shall be left unplugged for more than 30 days without approval of the division. Until properly plugged, shotholes shall be covered with a tin hat or other similar cover. The hats shall be imprinted with the seismic contractor's name or initials.

4.6. Any slurry, drilling fluids, or cuttings which are deposited on the surface around the seismic hole shall be raked or otherwise spread out to a height of not more than one inch above the surface, so that the growth of the natural grasses or foliage will not be impaired.

4.7. Restoration plans required by the Mined Land Reclamation Act, Chapter 8 of Title 40, or by any other surface management agency will be accepted by the division. The surface area around each seismic shothole shall be reclaimed and reseeded to its original condition insofar as such restoration is practical and is required by the surface management agency. All flagging, stakes, cables, cement, or mud sacks shall be removed from the drill site and disposed of in an acceptable manner.

5. Upon application to the division, approval may be obtained for preplugging of shotholes using coarse bentonite material or a suitable alternative used in the industry. Preplugging of holes in this manner shall be performed according to the following procedures:

5.1. A sales receipt indicating proof of purchase of an adequate amount of coarse bentonite to properly plug all shotholes shall be submitted to the division upon request.

5.2. For shotholes drilled with air which are completely dry, the seismic contractor shall have the option of preplugging with the coarse bentonite material or of using an alternate plugging material under R649-3-26-4.3.

5.3. For conventionally drilled, wet holes, enough approved material shall be used to cover the initial water level, i.e., the depth of the initial water level in the hole prior to adding coarse bentonite material shall be equal to the final plug depth. An additional ten feet of approved material shall be placed above this depth and hole cuttings shall be used to fill the remainder of the hole to a depth of three feet below ground level. A nonmetallic plug imprinted with an approved identification number or mark shall be installed at this depth. The remaining three feet of hole shall be filled and tamped to the surface with cuttings and native soil. The remaining cuttings shall be raked or spread to a height not to exceed one inch above ground level.

5.4. When using heliportable drills and insufficient cuttings are available, the hole shall be preplugged with bentonite plugging material or an approved alternate material to a depth of three feet below ground level. Installation of a nonmetallic plug and filling the remainder of the hole shall be performed as required by R649-3-26-5.3.

5.5. The coarse bentonite plugging material shall have the following specifications - chemically unaltered sodium bentonite, coarse ground, three quarter inch maximum size, not more than 19% moisture content and not more than 15% inert solids by volume.

6. Form 2, Seismic Exploration Completion Report shall be submitted to the Division within 60 days after completion of each seismic exploration project. The report shall include:

Certification by the seismic contractor that all shot holes have been plugged as prescribed by the division.

R649-3-27. Multiple Mineral Development.

1. Drilling operations conducted in areas designated by the board for multiple mineral development shall comply with all rules or orders of the board for drilling, casing, cementing, and plugging except as the general rules or orders may be modified by this rule.

2. It is the policy of the division to promote the development of all mineral resources on land under its jurisdiction. Consistent with that policy, operators engaged in oil and gas operations on lands on which operators are exploring for and developing mineral resources other than oil and gas may enter into a cooperative agreement with these other operators with respect to multiple mineral development. The agreement shall define:

2.1. The extent and limits of liability when one operator, either intentionally or unintentionally, interferes with or damages the deposits of another.

2.2. The coordination of access to and development of the area.

2.3. Mitigation of surface impact including but not limited to issues pertaining to relocation of natural gas pipeline gathering and distribution systems and other surface facilities occasioned by placement of a spent shale pile; phased or coordinated surface occupancy so as to allow each operator to enjoy his respective mineral estate with the least disruption of operations and damage to the oil and gas deposits, either directly or indirectly, through waste; and limitation of oil and gas operations in areas of concentrated surface oil shale facilities.

2.4. Mitigation of subsurface impact including but not limited to issues pertaining to the interface in the underground environment of oil shale mining operations with other mineral operations.

2.5. The extent of exchange of geological, engineering, and production data.

2.6. Other cooperative efforts consistent with multiple mineral development under the rules and orders of the board pertaining to oil and gas operations, oil shale operations, and mined land reclamation.

3. The division, together with the Division of State Lands and Forestry, where applicable, shall be signatory to the agreement.

4. In the event the operators cannot agree on cooperative development of their respective mineral deposits, or having once entered into a cooperative agreement subsequently disagree on the application of the terms and provisions thereof, any operator whose oil and gas or mining operation or deposit may be adversely affected or damaged by the operations of another operator may apply to the board for, or the board may on its own motion enter an order, after notice and hearing, delineating the respective rights and obligations of all operators with respect to development of all minerals concerned.

5. After notice and hearing the board may modify its order to more effectively carry out the policies of multiple mineral development.

R649-3-28. Designated Potash Areas.

1. In any area designated as a potash area, either by the board, the Division of State Lands and Forestry or an appropriate federal agency, all wells shall be drilled, cased, cemented, and plugged in accordance with the rules and orders of the board. The following minimum requirements and definitions shall also apply to the drilling, logging, casing, and plugging operations within the Salt Section to protect against migration of oil, gas, or water into or within any formation or zone containing potash. As used in this rule, Salt Section shall mean the Paradox Salt Section of Pennsylvanian Age.

2. Any drilling media used through the Salt Section shall be such that sodium chloride is not soluble in the media at normal temperatures.

3. Gamma ray-neutron, gamma ray-sonic or other appropriate logs shall be run promptly through the Salt Section. One field copy of the log through the Salt Section shall be submitted to the division within ten days, or upon the request of the division, whichever is the earlier.

4. A directional survey shall be run from a point at least 20 feet below the Salt Section to the surface. The survey shall be filed with the division prior to completion or plugging and abandonment of the well.

5. In addition to the requirements of the R649-3-8, any casing set into or through the Salt Section shall be cemented solidly through the Salt Section above the casing shoe.

6. Any cement used in setting casing or in plugging which

comes in contact with the Salt Section shall be of such chemical composition as to avoid dissolution of the Salt Section and to provide weight, strength, and physical properties sufficient to protect uphole formations and prevent blowouts or uncontrolled flows.

7. If a well is dry, cement plugs at least 200 feet in length shall be placed across the top and the base of the Salt Section, across any oil, gas or water show, and across any potash zone. Plugs shall not be required inside a properly cemented casing string. The division shall approve the location of the plugs after examining the appropriate logs, drilling and testing records for the well. No well shall be temporarily abandoned with open hole in the Salt Section.

8. The division may inspect the drilling operations at all times, including any mining operations that may affect any drilling or producing well bores. A potash owner, if contributing by agreement to the logging and directional survey costs of a well, may inspect the well for compliance with this rule.

9. Before commencing drilling operations for oil or gas on any land within designated potash area, the operator shall furnish by registered mail, a copy of the APD, together with the plat or map required under R649-3-4, to all potash owners and lessees whose interests are within a radius of 2,640 feet of the proposed well.

10. After proper notice and hearing, the board may modify this rule for a particular well or area by requiring that greater or lesser precautions be taken to prevent the escape of oil, gas, or water from one stratum into another. The board may also expand or contract from the designated potash areas.

R649-3-29. Workable Coal Beds.

1. Prior to commencing drilling operations for oil and gas on any lands where there are mine workings, the operator shall furnish a copy of the APD, a plat or map as required under R649-3-4, and a designation of the proposed angle and direction of the well, if the well is to be deviated substantially from a vertical course, to all coal owners and lessees whose interests are within a radius of 5,280 feet of the proposed well.

2. A well penetrating one or more workable coal beds or mine workings shall be drilled to a depth and shall be of a size, to permit the placing of casing in the hole at the points and in the manner necessary to exclude all oil, gas or gas pressure from the coal bed, other than oil, gas or gas pressure originating in the coal bed.

3. Unless otherwise authorized by the division, the casing run through a coal bed shall be seated at least 50 feet into the closest impervious formation below the coal bed. The casing shall be cemented solidly through the coal bed to a height at least 50 feet into the closest impervious formation above the coal bed.

4. A directional survey or a cement bond log shall be performed and furnished to the division upon written request by the division.

5. Upon penetrating a coal bed the operator shall notify the division, in writing, before completing or plugging and abandoning

the well.

R649-3-30. Underground Mining Operations.

1. Prior to commencing drilling operations for oil and gas on any land where there are known or suspected underground mining operations, solution mining operations or surface mining operations, including solar evaporation ponds, the operator shall include in the APD or in a separate cover letter, any information known to the operator concerning the name and address of the owner or operator of the mining workings.

2. The division may, with the concurrence of the operator, change the surface location of the proposed well if there appears to be any possibility of interference between the proposed well bore and the mine workings.

R649-3-31. Designated Oil Shale Areas.

1. Designated oil shale areas are subject to the general drilling, plugging and other performance standards described in this section, except where the board has adopted, by order, specific standards for individual oil shale areas. As of June 8, 2001, the board has adopted specific standards for individual oil shale areas by board orders in Cause Nos. 190-5(b), 190-3, and 190-13. The board may adopt specific standards in other areas, or modify the above orders, in the future.

2. Lands may be designated as an oil shale area by the board, either upon its own motion, or upon the petition of an interested person following notice and hearing.

3. As used in this rule, oil shale section means the sequence of strata containing oil shale beds, including any interbedded strata not containing oil shale, consisting of the Parachute Creek Member of the Green River Formation of Tertiary Age, defined as the stratigraphic equivalent of the interval between 1,428 feet and 2,755 feet below the Kelly Bushing on the induction-electrical log of the Ute Trail No. 10 well drilled by Dekalb Agricultural Association, Inc. and located in the NE 1/4 of Section 34, Township 9 South, Range 21 East, S.L.M., Uintah County, Utah.

The Mahogany Zone is defined as the stratigraphic equivalent of the interval between 2,230 feet and 2,360 feet below the Kelly Bushing on the induction-electrical log of the Ute Trail No. 10 well drilled by Dekalb Agricultural Association, Inc., and located in the NE 1/4 of Section 34, Township 9 South, Range 21 East, S.L.M., Uintah County, Utah.

4. For purposes of identifying the oil shale intervals, an appropriate electrical log shall be run through the oil shale section. One field copy of the log through the oil shale section shall be made available to the division pursuant to R649-3-23 or upon written request by the division.

5. On all wells which are intentionally deviated from the vertical within the oil shale section, pursuant to the provisions of R649-3-10 and R649-3-11, a directional survey shall be run from a point at least 20 feet below the oil shale section to the surface and shall thereafter be filed with the division within 20 days after reaching total depth.

6. Any oil shale lessee or operator whose oil shale mine

workings reach a distance of 2,640 feet from a producing well or any oil and gas lessee or operator whose producing well is approached by oil shale mine workings within a distance of 2,640 feet shall request agency action with the board. The board may promulgate an order after notice and hearing with respect to the running of a directional survey through the oil shale section, the cost and potential resource loss liability and responsibility as to the oil and gas operator and the oil shale lessee or operator and any other issues regarding multiple mineral development.

7. The directional survey shall be the confidential property of the parties paying for the survey and shall be kept confidential until released by said parties or the division.

8. In addition to the requirements pertaining to the cementing of casing contained in the R649-3-8, any casing set into or through the oil shale section shall be cemented over the entire oil shale section.

9. If a well is dry, junked or abandoned, a cement plug shall be placed across that portion of the oil shale section extending 200 feet above and 200 feet below the longitudinal center of the Mahogany Zone. The cement plug shall not be required inside a casing cemented in accordance with R649-3-31-7. When the casing is cemented, cement plugs 200 feet in length shall be centered across the top and across the base of the Parachute Creek Member of the Green River Formation.

10. In the event the casing is not cemented in accordance with R649-3-31-7, the division shall approve the method and procedure to prevent the migration of oil, gas, and other substances through the wellbore from one formation to another.

11. The division shall approve the adequacy and location of the cement plugs after examining the appropriate logs and drilling and testing records for the well, to ensure that the oil shale section is adequately protected.

12. Upon written request of the owner or operator under R649-8-6, the division shall keep all well logs confidential. The division may inspect the drilling operations at all times, including any mining operations that may affect drilling or producing well bores.

13. Before commencing drilling operations for oil or gas on any land within a designated oil shale area, the operator shall furnish a copy of the APD, together with a plat or map as directed under R649-3-4, to all oil shale owners or their lessees whose interests are within a radius of 2,640 feet of the proposed well. A notice of intention to plug and abandon any well in the oil shale area, as required under R649-3-24-1, shall be furnished to the owners or their lessees prior to commencement of plugging operations.

14. The operator shall use generally accepted techniques for vertical or directional drilling as defined under R649-3-10 and R649-3-11 to maintain the well bore within an intact core of a mine pillar. Within 20 days of reaching the total depth or before completion of the well, whichever is the earlier, a directional survey shall be run as prescribed by this rule.

R649-3-32. Reporting of Undesirable Events.

1. The division shall be notified of all fires, leaks, breaks, spills, blowouts, and other undesirable events occurring at any oil or gas drilling, producing, or transportation facility, or at any injection or disposal facility.

2. Immediate notification shall be required for all major undesirable events as outlined in R649-3-32-5. Immediate notification shall mean a verbal report submitted to the division as soon as practical but within a maximum of 24 hours after discovery of an undesirable event. A complete written report of the incident shall also be submitted to the division within five days following the conclusion of an undesirable event. The requirements for written reports are specified in R649-3-32-4.

3. Subsequent notification shall be required for all minor undesirable events as outlined in R649-3-32-6. Subsequent notification shall mean a complete written report of the incident submitted to the division within five days following the conclusion of an undesirable event. The requirements for written reports are specified in R649-3-32-4.

4. Complete written reports of undesirable events may be submitted on Form 9, Sundry Notice and Report on Wells. The report shall include:

4.1. The date and time of occurrence and, if immediate notification was required, the date and time the occurrence was reported to the Division.

4.2. The location where the incident occurred described by section, township, range, and county.

4.3. The specific nature and cause of the incident.

4.4. A description of the resultant damage.

4.5. The action taken, the length of time required for control or containment of the incident, and the length of time required for subsequent cleanup.

4.6. An estimate of the volumes discharged and the volumes not recovered.

4.7. The cause of death if any fatal injuries occurred.

5. Major undesirable events include the following:

5.1. Leaks, breaks or spills of oil, salt water or oil field wastes which result in the discharge of more than 100 barrels of liquid, which are not fully contained on location by a wall, berm, or dike.

5.2. Equipment failures or other accidents which result in the flaring, venting, or wasting of more than 500 Mcf of gas.

5.3. Any fire which consumes the volumes of liquid or gas specified in R649-3-32-5.1 and R649-3-32-5.2.

5.4. Any spill, venting, or fire, regardless of the volume involved, which occurs in a sensitive area stipulated on the approval notice of the initial APD for a well, e.g., parks, recreation sites, wildlife refuges, lakes, reservoirs, streams, urban or suburban areas.

5.5. Each accident which involves a fatal injury.

5.6. Each blowout, loss of control of a well.

6. Minor undesirable events include the following:

6.1. Leaks, breaks or spills or oil, salt water, or oil field wastes which result in the discharge of more than ten barrels of liquid and are not considered major events in R649-3-

32-5.

6.2 Equipment failures or other accidents which result in the flaring, venting or wasting of more than 50 Mcf of gas and are not considered major events in R649-3-32-5.

6.3. Any fire which consumes the volumes of liquid or specified in R649-3-32-6.1 and R649-3-32-6.2.

6.4. Each accident involving a major or life-threatening injury.

R649-3-33. Drilling Procedures in the Great Salt Lake.

1. For all drilling activities proposed within the Great Salt Lake, the APD required by R649-3-4 shall be filed at least 30 days prior to the date on which the operator intends to commence operations. As part of the APD, the operator shall include:

1.1. The name of the drilling contractor and the number and type of rig to be used.

1.2. An illustration of the boundaries of all state or federal parks, wildlife refuges, or waterfowl management areas within one mile of the proposed well location.

1.3. An illustration of the locations of all evaporation pits, producing wells, structures, buildings, and platforms within one mile of the proposed well location.

1.4. An oil spill emergency contingency plan.

2. Unless permitted by the board after notice and hearing, no well shall be drilled which has a surface location:

2.1. Within 1,320 feet from an evaporation pit without the consent of the operator of such pit.

2.2. Within one mile from the boundary of a state or federal park, wildlife refuge, or waterfowl management area without the consent of the appropriate state or federal regulatory agency.

2.3. Within three miles of Gunnison Island during the Pelican nesting season (March 15 through September 30) or within one mile from said island at any other time.

2.4. Within any area south of the Salt Lake Base Meridian Line.

2.5. Within any area north of Township 10 North.

2.6. Within one mile inside of what would be the water's edge if the water level of the Great Salt Lake were at the elevation of 4,193.3 feet above sea level.

3. Well casing and cementing shall be subject to the following special requirements for the purpose of this rule, the several casing strings in order of normal installation are drive or structural casing, conductor casing, surface casing, intermediate casing, and production casing. All depths refer to true vertical depth:

3.1. The drive or structural casing shall be set by drilling, driving or jetting to a minimum depth of 50 feet below the floor of the lake bed or to such greater depth required to support unconsolidated deposits and to provide hole stability for initial drilling operations. If drilled in, the drilling fluid shall be a type that will not pollute the lake; in addition, a quantity of cement sufficient to fill the annular space back to the lake floor with returns circulated, must be used.

3.2. The conductor casing shall be set at a minimum depth of

200 feet below the floor of the lake, and shall be cemented with a quantity sufficient to fill the annular space back to the lake surface with returns circulated.

3.3. The surface casing shall be set at a minimum depth of 500 feet if the proposed depth of the well is less than 7,000 feet; or 1,000 feet if the proposed depth is over 7,000 feet but less than 11,000 feet; or 1,500 feet if the depth is 11,000 feet. The casing shall be cemented with a quantity sufficient to fill the annular space back to the lake surface with returns circulated, and the bottom of the casing shall be in competent rock.

3.4. The intermediate and production casing shall be set at any time when drilling below the surface casing and hole conditions justify setting casing. This casing will be cemented in such a manner that all hydrocarbons, water aquifers, lost-circulation or zones of significant porosity and permeability, significant beds containing priority minerals, and abnormal pressure intervals are covered or isolated.

3.5. Prior to drilling the plug after cementing, all casing strings except the drive or structural casing, shall be pressure tested. This test shall not exceed the rated working pressure of the casing. If the pressure declines more than ten percent in 30 minutes, or if there are other indications of a leak, corrective measures must be taken until a satisfactory test is obtained. All casing pressure tests shall be recorded on the driller's log.

4. Blowout preventers and related well control equipment shall be installed, and tested in a manner necessary to prevent blowouts and shall be subject to the following special conditions:

4.1. Prior to drilling below the surface casing, blowout prevention equipment shall be installed and maintained ready for use until drilling operations are completed.

4.2. An inside blowout preventer assembly and a full opening string safety valve in the open position shall be maintained on the rig floor at all times while drilling operations are being conducted. Valves shall be maintained on the rig floor to fit all pipe in the drill string. A top kelly cock shall be installed below the swivel and another at the bottom of the kelly of such design that it can be run through the blowout preventers.

4.3. Before drilling below the surface casing the blowout prevention equipment shall include a minimum of:

4.3.1. Three remotely and manually controlled, hydraulically operated blowout preventers with a rated working pressure which exceeds the maximum anticipated surface pressure, including one equipped with pipe rams, one with blind rams and one hydril type.

4.3.2. A drilling spool with side outlets, if side outlets are not provided in the blowout preventer body.

4.3.3. A choke manifold.

4.3.4. A kill line.

4.3.5. A fill-up line.

4.4. Ram-type blowout preventers and related control equipment shall be tested to the rated working pressure of the stack assembly or to the working pressure of the casing, whichever is the lesser, at the following times:

4.4.1. When installed.

4.4.2. Before drilling out after each string of casing is set.

4.4.3. Not less than once each week while drilling.

4.4.4. Following repairs that require disconnecting a pressure seal in the assembly.

4.5. The hydril-type blowout preventer shall be tested to 70 percent of the pressure testing requirements of ram-type blowout preventers. The hydril-type blowout preventer shall be actuated on the drill pipe once each week.

4.6. Accumulators or accumulators and pumps shall maintain a reserve capacity at all times to provide for repeated operation of hydraulic preventers.

4.7. A blowout prevention drill shall be conducted weekly for each drilling crew to insure that all equipment is operational and that crews are properly trained to carry out emergency duties. All blowout preventer tests and crew drills shall be recorded on the driller's log.

5. The characteristics and use of drilling mud and the conduct of related drilling procedures shall be such as are necessary to maintain the well in a safe condition to prevent uncontrolled blowouts of any well. Quantities of mud materials sufficient to insure well control shall be maintained and readily accessible for use at all times.

6. Mud testing equipment shall be maintained on the derrick floor at all times, and mud tests consistent with good operating practice shall be performed daily, or more frequently as conditions warrant. The following mud system monitoring equipment must be installed, with derrick floor indicators, and used throughout the period of drilling after setting and cementing the surface casing:

6.1. A recording mud pit level indicator including a visual and audio warning device to determine mud pit volume gains and losses.

6.2. A mud return indicator to determine when returns have been obtained, or when they occur unintentionally, and additionally to determine that returns essentially equal the pump discharge rate.

7. In the conduct of all oil and gas operations, the operator shall prevent pollution of the waters of the Great Salt Lake. The operator shall comply with the following pollution prevention requirements:

7.1. Oil in any form, liquid or solid wastes containing oil, shall not be disposed of into the waters of the lake.

7.2. Liquid or solid waste materials containing substances which may be harmful to aquatic life or wildlife, or injurious in any manner to life and property, or which in any way unreasonably adversely affects the chemicals or minerals in the lake shall not be disposed of into the waters of the lake.

7.3. Waste materials, exclusive of cuttings and drilling media, shall be transported to shore for disposal.

8. All spills or leakage of oil and liquid or solid pollutants shall be immediately reported to the division. A complete written statement of all circumstances, including subsequent clean-up operation, shall be forwarded to said agencies

within 72 hours of such occurrences.

9. Standby pollution control equipment consistent with the state of the art, shall be maintained by, and shall be immediately available to, each operator.

R649-3-34. Well Site Restoration.

1. The operator of a well shall upon plugging and abandonment of the well restore the well site in accordance with these rules.

2. For all land included in the well site for which the surface is federal, Indian, or state ownership, the operator shall meet the well site restoration requirements of the appropriate surface management agency.

3. For all land included in the well site for which the surface is fee or private ownership, the operator shall meet the well site restoration requirements of the private landowner or the minimum well site restoration requirements established by the division.

4. Well site restoration on lands with fee or private ownership shall be completed within one (1) year following the plugging of a well unless an extension is approved by the division for just and reasonable cause.

5. These rules shall not preclude the opportunity for a private landowner to assume liability for the well as a water well in accordance with R649-3-24.6.

6. The operator shall make a reasonable effort to establish surface use agreements with the owners of land included in the well site prior to the commencement of the following actions on fee or private surface:

6.1 Drilling a new well.

6.2. Reentering an abandoned well.

6.3. Assuming operatorship of existing wells.

7. Upon application to the division to perform any of the aforementioned and prior to approval of such actions by the division, the operator shall submit an affidavit to the division stating whether appropriate surface use agreements have been established with and approved by the surface landowners of the well site.

8. If necessary and upon request by the division, the operator shall submit a copy of the established surface use agreements to the division.

9. If no surface use agreement can be established, the division shall establish minimum well site restoration requirements for any well located on fee or private surface for the purposes of final bond release.

10. Established surface use agreements may be modified or terminated at any time by mutual consent of the involved parties; however, the operator shall notify the division if such is the case and if a surface use agreement is terminated without a new agreement established, the division shall establish minimum well site reclamation requirements.

11. The operator shall be responsible for meeting the requirements of any surface use agreement, and it shall be assumed by the division until notified otherwise that surface use

agreements remain in full force and effect until all the requirements of the agreement are satisfied or until the agreement has been terminated by mutual consent of the involved parties.

12. The surface use agreement shall stipulate the minimum well site restoration to be performed by the operator in order to allow final release of the bond.

13. The final bond release by the division shall include a determination by the division whether or not the operator has met the requirements of an established surface use agreement, and the division may suspend final bond release until the operator has completed all the requirements of the surface use agreement.

14. The agreement may state requirements for well site grading, contouring, scarification, reseeding, and abandonment of any equipment or facilities for which the landowner agrees to assume liability.

15. The agreement shall not address operations regulated by the rules and orders of the board such as:

15.1. Disposal of drilling fluid, produced fluid, or other fluid waste associated with the drilling and production of the well.

15.2. Reclamation or treating of waste crude oil.

15.3. Any other operation or condition for which the board has jurisdiction.

16. If the operator cannot establish surface use agreements then the operator shall so notify the division.

17. Within 30 days of the notification or as soon as weather conditions permit, the division shall conduct an inspection and evaluation of the well site in order to establish minimum well site restoration requirements for the purpose of final bond release.

18. The operator shall be given notice by the division of the date and time of the inspection, and if the operator cannot attend the inspection at the scheduled date and time, the division may reschedule the inspection to allow the operator to participate.

19. The surface landowner, agent or lessee shall be given notice by the operator of such inspection and may participate in the inspection; however, if the surface landowner cannot attend the inspection, the division shall not be required to reschedule the inspection in order to allow the surface landowner to participate.

20. The evaluation shall consider the condition of the land prior to disturbance, the extent of proposed disturbance, the degree of difficulty to conduct complete restoration, the potential for pollution, the requirements for abating pollution, and the possible land use after plugging and restoration are completed.

21. Within 30 days after performing the inspection, the division shall provide the operator with the results of the inspection and the evaluation listing the minimum well site restoration requirements established by the division.

22. The division shall retain a record of the inspection and the evaluation, and if necessary and upon written request by an interested party, the division shall provide a copy of the minimum

well site restoration requirements established by the division.

23. If any person disagrees with the results of the inspection and the evaluation and desires a reconsideration of the minimum well site restoration requirements established by the division, such person may submit a request to the board for a hearing and order to modify the requirements.

24. The board, after proper notice and hearing, may issue an order modifying the minimum well site restoration requirements established by the division.

25. The minimum well site restoration requirements established by the division or by board order shall be considered part of any permit granted by the division to conduct operations at a well site, and the inability of the operator to meet such requirements shall be considered grounds for forfeiture of the bond.

26. If the minimum well site restoration requirements suggest to the division that bond coverage for a well should be increased, the division shall take action as stated in R649-3-1.

R649-3-35. Wildcat Wells.

1. For purposes of qualifying for a severance tax exemption under Section 59-5-102(2)(d), an operator must file an application with the division for designation of a wildcat well. The application may be filed prior to drilling the well, and a tentative determination of the wildcat designation will be issued at that time. An application or request for final designation of wildcat status as appropriate, must be filed at the time of filing of Form 8, Well Completion or Recompletion Report and Log. The application shall contain, where applicable, the following information:

1.1. A plat map showing the location of the well in relation to producing wells within a one mile radius of the wellsite.

1.2. A statement concerning the producing formation or formations in the wildcat well and also the producing formation or formations of the producing wells in the designated area, including completion reports and other appropriate data.

1.3. Stratigraphic cross sections through the producing wells in the designated area and the proposed wildcat well.

1.4. A statement as to whether the well is in a known geologic structure. However, whether the well is in a known geologic structure shall not be the sole basis of determining whether the well is a wildcat.

1.5. Bottomhole pressures, as applicable, in a wildcat well compared to the wells producing in the designated area from the same zone.

1.6. Any other information deemed relevant by the applicant or requested by the division.

2. Information derived from well logs, including certain information in completion reports, stratigraphic cross sections, bottomhole pressure data, and other appropriate data provided in R649-3-35-1 will be held confidential in accordance with R649-2-11 at the request of the operator.

3. The division shall review the submitted information and advise the operator and the State Tax Commission of its decision

regarding the wildcat well designation as related to Section 59-5-102(2)(d).

4. The division is responsible for approval of a request for designation of a well as a wildcat well. If the operator disagrees with the decision of the division, the decision maybe appealed to the board. Appeals of all other tax-related decisions concerning wildcat wells should be made to the State Tax Commission.

R649-3-36. Shut-in and Temporarily Abandoned Wells.

1. Wells may be initially shut-in or temporarily abandoned for a period of twelve (12) consecutive months. If a well is to be shut-in or temporarily abandoned for a period exceeding twelve (12) consecutive months, the operator shall file a Sundry Notice providing the following information:

1.1. Reasons for shut-in or temporarily abandonment of the well,

1.2. The length of time the well is expected to be shut-in or temporarily abandoned, and

1.3. An explanation and supporting data if necessary, for showing the well has integrity, meaning that the casing, cement, equipment condition, static fluid level, pressure, existence or absence of Underground Sources of Drinking Water and other factors do not make the well a risk to public health and safety or the environment.

2. After review the Division will either approve the continued shut-in or temporarily abandoned status or require remedial action to be taken to establish and maintain the well's integrity.

3. After five (5) years of nonactivity or nonproductivity, the well shall be plugged in accordance with R649-3-24, unless approval for extended shut-in time is given by the Division upon a showing of good cause by the operator.

4. If after a five (5) year period the well is ordered plugged by the Division, and the operator does not comply, the operator shall forfeit the drilling and reclamation bond and the well shall be properly plugged and abandoned under the direction of the Division.

R649-3-37. Enhanced Recovery Project Certification.

1. In order for incremental production achieved from an enhanced recovery project to qualify for the severance tax rate reduction provided under Subsection 59-5-102(4), the operator on behalf of the producers shall present evidence demonstrating that the recovery technique or techniques utilized qualify for an enhanced recovery determination and the Board must certify the project as an enhanced recovery project.

2. For enhanced recovery projects certified by the Board after January 1, 1996:

2.1. As part of the process of certifying incremental production which qualifies for a reduction in the severance tax rate under Subsection 59-5-102(4), the operator shall furnish the Division an extrapolation (projection) and tabulation of expected non-enhanced recovery of oil and gas production from the project.

The projection shall be for not less than seventy-two (72) months commencing with the first month following the project certification by the Board. The projection shall be based on production history of all wells within the project area for not less than twelve (12) months immediately preceding either certification or commencement of the project; reservoir and production characteristics; and the application of generally accepted petroleum engineering practices. The projected production volumes approved by the division shall serve as the base level production for purposes of determining the incremental oil and gas production which qualifies for a reduction in the severance tax rate.

2.2. The operator shall provide a statement as to all assumptions made in preparing the projection and any other information concerning the project that the division may reasonably require in order to evaluate the operator's projection.

2.3. An operator's request for incremental production certification may be approved administratively by the Director or authorized agent. The Director or authorized agent shall review the request within 30 days after its receipt and advise the operator of the decision. If the operator disagrees with the Director or authorized agent's decision, the operator may request a hearing before the Board at its next regularly scheduled hearing. The Director or authorized agent may also refer the matter to the Board if a decision is in doubt.

2.4. Upon approval of a request for incremental production certification, the Director or authorized agent shall forward a copy of the certification to the Utah Tax Commission.

KEY: oil and gas law
July 1, 2003 **40-6-1 et seq.**
Notice of Continuation March 26, 2002

R649. Natural Resources; Oil, Gas and Mining; Oil and Gas.
R649-4. Determination of Well Categories Under the Natural Gas Policy Act of 1978.
R649-4-1. Definitions.

1. Unless the context specifically requires otherwise, any special words, terms, or phrases used in the Section and not defined in Section 1 have the meanings defined under the Natural Gas Policy Act of 1978 (NGPA), and applicable Federal Energy Regulatory Commission (FERC) rules and regulations.

R649-4-2. Applications.

An operator requesting the classification of a well or reservoir pursuant to the authority granted to the Board by Section 503 of the NGPA, in order to enable the Board to determine the applicable category for any such well or reservoir pursuant to Title 1 of the NGPA, shall:

1. File the original and two copies of a written application made upon forms prescribed by the Board together with supporting documentation, including all information, data, forms, plats, maps, exhibits, and evidence as may be required by the applicable

statutes, rules, and regulations. An application may be amended, supplemented, or withdrawn by the applicant at any time prior to the Board determination.

1.1. Complete an individual application as to each well for which a status determination is being requested. If more than one status determination is being requested for a single well, all forms and information required for each requested determination shall be submitted jointly under one application, with notice to the Board that multiple determinations for one well are being sought under the application.

1.2. File an affidavit as to the truthfulness and correctness of all information contained in the application, including all documents, testimony, and evidence attached to or submitted with the application.

1.3. Certify that the purchaser and owners of the natural gas for which the determination is being submitted, have been served by personal delivery or by mail, postage prepaid, with a copy of the application, including a complete FERC Form 121, excluding required supporting documents.

R649-4-3. Notice and Hearing.

1. Upon receipt of an application for a well status determination under the NGPA, the Board shall:

1.1. Notify the applicant of the receipt of the application;

1.2. Determine the completeness of the application. If the application is incomplete in any respect, the Board shall indicate to the applicant the items to be filed which would make the application complete;

1.3. Assign a cause number to each application, determine a hearing date for each complete application, and notify the applicant of the cause number and hearing date;

1.4. Cause notice of hearing to be given.

2. If the same applicant has filed for multiple well determinations or for multiple determinations as to any well, the published notice of hearing may include more than one well or reservoir in one notice.

R649-4-4. Determination and Orders.

1. Following notice and hearing, the Board shall issue a determination and order for each complete application.

2. If no response or protest to the application is filed with the Board, an application may be considered and a determination may be made by the Director or a designated hearing examiner on the basis of sworn testimony, depositions, or affidavits, together with all exhibits, forms, and other matters properly filed with the Board. Such matters shall comprise the transcript of the hearing on which the determination is based.

3. An applicant may also request consideration and a determination by the Director or a designated hearing examiner by filing a letter with the Board agreeing that the determination can be made by the Director without the necessity of an appearance by the applicant. The Board may, however, upon its own motion, require an evidentiary hearing with sworn testimony to be held upon any application following proper notice. In the event the

Board determines that a hearing is required, the Board shall notify the applicant at least ten days prior to the scheduled hearing date.

R649-4-5. Notice of Determination.

Within five days after the last day for filing a motion for rehearing, or, if such a motion is filed, within 15 days after it is denied or overruled by operation of law, the Board shall give written notice to the FERC of its determination and order.

KEY: oil and gas law
January 3, 2001 **40-6-1 et seq.**

R649. Natural Resources; Oil, Gas and Mining; Oil and Gas.
R649-5. Underground Injection Control of Recovery Operations and Class II Injection Wells.
R649-5-1. Requirements For Injection Of Fluids Into Reservoirs.

1. Operations to increase ultimate recovery, such as cycling of gas, the maintenance of pressure, the introduction of gas, water or other substances into a reservoir for the purpose of secondary or other enhanced recovery or for storage and the injection of water into any formation for the purpose of water disposal shall be permitted only by order of the board after notice and hearing.

2. A petition for authority for the injection of gas, liquefied petroleum gas, air, water, or any other medium into any formation for any reason, including but not necessarily limited to the establishment of or the expansion of waterflood projects, enhanced recovery projects, and pressure maintenance projects shall contain:

2.1. The name and address of the operator of the project.

2.2. A plat showing the area involved and identifying all wells, including all proposed injection wells, in the project area and within one-half mile radius of the project area.

2.3. A full description of the particular operation for which approval is requested.

2.4. A description of the pools from which the identified wells are producing or have produced.

2.5. The names, description and depth of the pool or pools to be affected.

2.6. A copy of a log of a representative well completed in the pool.

2.7. A statement as to the type of fluid to be used for injection, its source and the estimated amounts to be injected daily.

2.8. A list of all operators or owners and surface owners within a one-half mile radius of the proposed project.

2.9. An affidavit certifying that said operators or owners and surface owners within a one-half mile radius have been provided a copy of the petition for injection.

2.10. Any additional information the board may determine is necessary to adequately review the petition.

3. Applications as required by R649-5-2 for injection wells

which are located within the project area, may be submitted for board consideration and approval with the request for authorization of the recovery project.

4. Established recovery projects may be expanded and additional wells placed on injection only upon authority from the board after notice and hearing or by administrative approval.

5. If the proposed injection interval can be classified as an USDW, approval of the project is subject to the requirements of R649-5-4.

R649-5-2. Requirements For Class II Injection Wells Including Water Disposal, Storage And Enhanced Recovery Wells.

1. Injection wells shall be completed, equipped, operated, and maintained in a manner that will prevent pollution and damage to any USDW, or other resources and will confine injected fluids to the interval approved.

2. The application for an injection well shall include a properly completed UIC Form 1 and the following:

2.1. A plat showing the location of the injection well, all abandoned or active wells within a one-half mile radius of the proposed well, and the surface owner and the operator of any lands or producing leases, respectively, within a one-half mile radius of the proposed injection well.

2.2. Copies of electrical or radioactive logs, including gamma ray logs, for the proposed well run prior to the installation of casing and indicating resistivity, spontaneous potential, caliper, and porosity.

2.3. A copy of a cement bond or comparable log run for the proposed injection well after casing was set and cemented.

2.4. Copies of logs already on file with the division should be referenced, but need not be refiled.

2.5. A description of the casing or proposed casing program of the injection well and of the proposed method for testing the casing before use of the well.

2.6. A statement as to the type of fluid to be used for injection, its source and estimated amounts to be injected daily.

2.7. Standard laboratory analyses of (1) the fluid to be injected, (2) the fluid in the formation into which the fluid is being injected, and (3) the compatibility of the fluids.

2.8. The proposed average and maximum injection pressures.

2.9. Evidence and data to support a finding that the proposed injection well will not initiate fractures through the overlying strata or a confining interval that could enable the injected fluid or formation fluid to enter the fresh water strata.

2.10. Appropriate geological data on the injection interval and confining beds, and nearby Underground Sources of Drinking Water, including the geologic name, lithologic description, thickness, depth, water quality, and lateral extent; also information relative to geologic structure near the proposed well which may effect the conveyance and/or storage of the injected fluids.

2.11. A review of the mechanical condition of each well within a one-half mile radius of the proposed injection well to assure that no conduit exists that could enable fluids to migrate up or down the wellbore and enter improper intervals.

2.12. An affidavit certifying that a copy of the application has been provided to all operators, owners, and surface owners within a one-half mile radius of the proposed injection well.

2.13. Any other additional information that the board or division may determine is necessary to adequately review the application.

3. Applications for injection wells which are within a recovery project area will be considered for approval:

3.1. Pursuant to R649-5-1-3.

3.2. Subsequent to board approval of a recovery project pursuant to R649-5-1-1.

4. Approval of an injection well is subject to the requirements of R649-5-4, if the proposed injection interval can be classified as an USDW.

5. In addition to the requirements of this section, the provisions of R649-3-1, R649-3-4, R649-3-24, R649-3-32, and R649-8-1 and R649-10 shall apply to all Class II injection wells.

R649-5-3. Noticing and Approval Of Injection Wells.

1. Applications for injection wells submitted pursuant to R649-5-1-3 shall be noticed in conformance with the procedural rules of the board as part of the hearing for the recovery project. Any person desiring to object to approval of such an application for an injection well shall file the objection in conformance with the procedural rules of the board.

2. The receipt of a complete and technically adequate application, other than an application submitted pursuant to R649-5-3-1, shall be considered as a request for agency action by the Division and shall be published in a daily newspaper of general circulation in the city and county of Salt Lake and in a newspaper of general circulation in the county where the proposed well is located. A copy of the notice of agency action shall also be sent to all parties including government agencies. The notice of agency action shall contain at least the following information:

2.1. The applicant's name, business address, and telephone number.

2.2. The location of the proposed well.

2.3. A description of proposed operation.

3. If no written objection to the application for administrative approval of an injection well is received by the division within 15 days after publication of the notice of agency action, or an aquifer exemption is not required in accordance with R649-5-4, and a board hearing is not otherwise required, the application may be considered and approved administratively.

4. If a written objection to an application for administrative approval of an injection well is received by the division within 15 days after publication of the notice of application, or if a hearing is required by these rules or deemed advisable by the director, the application shall be set for notice and hearing by the board.

5. The director shall have the authority to grant an exception to the hearing requirements of R649-5-1.1 for conversion to injection of additional wells which constitute a modification

or expansion of an authorized project provided that any such well is necessary to develop or maintain thorough and efficient recovery operations for any authorized project and provided that no objection is received pursuant to R649-5-3-3.

6. The director shall have authority to grant an exception to the hearing requirements of R649-5-1-1 for water disposal wells provided disposal is into a formation or interval that is not currently nor anticipated to be an underground source of drinking water and provided that no objection is received pursuant to R649-5-3-3.

R649-5-4. Aquifer Exemption.

1. The board may, after notice and hearing and subject to the EPA approval, authorize the exemption of certain aquifers from classification as an USDW based upon the following findings:

1.1. The aquifer does not currently serve as a source of drinking water.

1.2. The aquifer cannot now and will not in the future serve as a source of drinking water for any of the following reasons:

1.2.1. The aquifer is mineral, hydrocarbon or geothermal energy producing, or it can be demonstrated by the applicant as part of a permit application for a Class II well operation, to contain minerals or hydrocarbons that, considering their quantity and location, are expected to be commercially producible.

1.2.2. The aquifer is situated at a depth or location that makes recovery of water for drinking water purposes economically or technologically impractical.

1.2.3. The aquifer is contaminated to the extent that it would be economically or technologically impractical to render water from the aquifer fit for human consumption.

1.2.4. The aquifer is located above a Class III well mining area subject to subsidence or catastrophic collapse.

1.3. The total dissolved solids content of the water from the aquifer is more than 3,000 and less than 10,000 mg/l, and the aquifer is not reasonably expected to be used as a source of fresh or potable water.

2. Interested parties desiring to have an aquifer exempted from classification as a USDW, shall submit to the division an application that includes sufficient data to justify the proposal. The division shall consider the application and if appropriate, will advise the applicant to submit a request to the board for an aquifer exemption.

R649-5-5. Testing And Monitoring Of Injection Wells.

1. Before operating a new injection well, the casing shall be tested to a pressure not less than the maximum authorized injection pressure, or to a pressure of 300 psi, whichever is greater.

2. Before operating an existing well newly converted to an injection well, the casing outside the tubing shall be tested to a pressure not less than the maximum authorized injection pressure, or to a pressure of 1,000 psi, whichever is lesser, provided that each well shall be tested to a minimum pressure of 300 psi.

3. In order to demonstrate continuing mechanical integrity

after commencement of injection operations, all injection wells shall be pressure tested or monitored as follows:

3.1. Pressure Test. The casing-tubing annulus above the packer shall be pressure tested not less than once each five years to a pressure equal to the maximum authorized injection pressure or to a pressure of 1,000 psi, whichever is lesser, provided that no test pressure shall be less than 300 psi. A report documenting the test results shall be submitted to the division.

3.2. Monitoring. If approved by the director, and in lieu of the pressure testing requirement, the operator may monitor the pressure of the casing-tubing annulus monthly during actual injection operations and report the results to the division.

3.3. Other test procedures or devices such as tracer surveys, temperature logs or noise logs may be required by the division on a case-by-case basis.

3.4. The operator shall sample and analyze the fluids injected in each disposal well or enhanced recovery project at sufficiently frequent time intervals to yield data representative of fluid characteristics, and no less frequently than every year. The operator shall submit a copy of the fluid analysis to the division with the Annual Fluid Injection Report, UIC Form 4.

R649-5-6. Duration Of Approval For Injection Wells.

1. Approvals or orders authorizing injection wells shall be valid for the life of the well, unless revoked by the board for just cause, after notice and hearing.

2. An approval may be administratively amended if:

2.1. There is a substantial change of conditions in the injection well operation.

2.2. There are substantial changes to the information originally furnished.

2.3. Information as to the permitted operation indicates that an USDW is no longer being protected.

R649-5-7. Unit or Cooperative Development Or Operation.

Any person desiring to obtain the benefits of Section 40-6-7(1) insofar as the same relates to any method of unit or cooperative development or operation of a field or pool or a part of either, shall file a Request for Agency Action and a copy of such agreement with the board for approval after notice and hearing.

KEY: oil and gas law
June 2, 1998 **40-6-1 et seq.**
Notice of Continuation March 26, 2002

R649. Natural Resources; Oil, Gas and Mining; Oil and Gas.
R649-6. Gas Processing and Waste Crude Oil Treatment.
R649-6-1. Gas Processing Plants.

1. In accordance with Section 40-6-16 any operator of a facility or plant in which liquefiable hydrocarbons are removed from natural gas, including wet gas or casinghead gas, and the remaining residue gas is conditioned for delivery for sale,

recycling, or other use, shall file monthly, Form 13-A and Form 13-B.

1.1. Reports shall be filed for all gas processing plants or facilities to account for the receipt, processing, and disposition of all gas by the plant.

1.2. Plant operators that are required by contractual arrangements to allocate the residue gas and extracted liquids processed by the plant or facility to the individual producing wells, shall identify each well connected to the plant or facility by API number and report the metered wet gas volumes, residue gas volumes returned to the field, and all allocated residue gas and natural gas liquid volumes.

R649-6-2. Waste Crude Oil Treatment Facilities.

1. Prior to the construction of a waste crude oil treatment facility, an application shall be submitted to the division describing the ownership, location, type, and capacity of the facility contemplated; the extent and location of the surface area to be disturbed, including any pit, pond, or land associated with the facility; and a reclamation plan for the site. Approval of the application must be issued by the division before any ground clearing or construction shall occur.

2. As a condition for approval of any application, the owner or operator shall post a bond in an amount determined by the division to cover reclamation costs for the site. Failure to post the bond shall be considered sufficient grounds for denial of the application.

3. No waste crude oil treatment facility operator shall accept delivery of crude oil obtained from any tank, reserve pit, disposal pond or pit, or similar facility unless the delivery is accompanied by a run ticket, invoice, receipt or similar document showing the origin and quantity of the crude oil.

KEY: oil and gas law
1989 **40-6-1 et seq**
Notice of Continuation December 19, 2003

R649. Natural Resources; Oil, Gas and Mining; Oil and Gas.
R649-8. Reporting and Report Forms.
R649-8-1. General Report Forms.

1. The forms listed below, as modified by the Division from time to time shall be used for the purpose indicated in accordance with the instructions and the applicable rule.

Form 1 Application for Permit to Conduct Seismic Exploration R649-8-2
Form 2 Seismic Exploration Completion Report R649-8-3
Form 3 Application for Permit to Drill, Deepen, or Plug Back (APD) R649-8-4
Form 4 Bond R649-8-5
Form 5 Designation of Agent or Operator R649-8-6
Form 6 Entity Action Form R649-8-7
Form 7 Report of Water Encountered During Drilling R649-8-8
Form 8 Well Completion or Recompletion Report and Log R649-

8-9

Form 9 Sundry Notices and Reports on Wells R649-8-10
Form 10 Monthly Oil and Gas Production Report R649-8-11
Form 11 Monthly Oil and Gas Disposition Report R649-8-12
Form 12 Report of Transferred Oil R649-8-13
Form 13-A Monthly Summary Report of Gas Processing Plant Operations R649-8-14
Form 13-B Monthly Report of Gas Processing Plant Product Allocations R649-8-15
Form 14 Monthly Report of Waste Crude Oil Treatment Facility Operations R649-8-16
Form 15 Designation of Workover or Recompletion R649-8-17
UIC Form 1 Application for Injection Well R649-8-23
UIC Form 2 Monthly Report of Enhanced Recovery Project R649-8-24
UIC Form 3 Monthly Injection Report R649-8-25
UIC Form 4 Annual Fluid Injection Report R649-8-26
UIC Form 5 Transfer of Authority to Inject R649-8-27
UIC Form 6 Monthly Produced Water Disposition Report R649-8-28

2. Any permitted well which is referenced on a report form, correspondence, or well log should be identified by its assigned API number.

R649-8-2. Form 1, Application for Permit to Conduct Seismic Exploration.

At least seven days prior to commencing any type of seismic exploration operations, an Application for Permit to Conduct Seismic Exploration shall be submitted in duplicate to the division by the seismic contractor in accordance with R649-3-26.

R649-8-3. Form 2, Seismic Exploration Completion Report.

Within 60 days of the completion of each seismic exploration project, a Seismic Exploration Completion Report shall be submitted to the division by the seismic contractor in accordance with R649-3-26.

R649-8-4. Form 3, Application for Permit to Drill, Deepen, or Plug Back (APD).

Prior to the commencement of drilling, deepening, or plugging back any well or the commencement of exploratory drilling such as core holes and stratigraphic test holes, and prior to the commencement of any surface disturbance associated with such activity, the operator shall submit in duplicate an Application for Permit to Drill, Deepen, or Plug Back in accordance with R649-3-4.

R649-8-5. Form 4, Bond.

Except where a bond in satisfactory form has been filed by the operator in accordance with state, federal, or Indian lease requirements and evidence has been furnished to the division that such bond has been approved by the appropriate agency, the division shall require from the operator a good and sufficient bond in accordance with R649-3-1.

R649-8-6. Form 5, Designation of Agent or Operator.

Prior to the commencement of operations, a Designation of Agent or Operator shall be filed with the division in accordance with R649-2-4.

R649-8-7. Form 6, Entity Action Form.

1. For the purpose of accurately establishing the division's computerized oil and gas production accounting system and properly maintaining division of interest data for each well in the system, the operator shall file an Entity Action Form with the division within five working days of any of the following actions:

1.1. Spudding of a well, R649-3-6.

1.2. A change in operations which requires adding or removing a well from a group of wells that have identical division of interests, produce from the same formation, have product sales from a common tank, LACT meter, or gas meter, and have the same operator.

1.3. A change in operations when a service well is converted to a producing oil or gas well.

1.4. A change in operations when a well is recompleted and is capable of producing from another formation, R649-3-23.

1.5. A change in interest which requires adding or removing a well from a participating area of a properly designated unit.

2. Upon receipt of an Entity Action Form, the division will assign an entity number to a new well or change the entity number as needed for an existing well. This number identifies the well on the operator's monthly oil and gas production and disposition reports. Entity numbers are used by the State Tax Commission and the Division of State Lands and Forestry to properly account for all production taxes and the divisions of royalty interest on state leases.

3. This form does not take the place of Form 9, Sundry Notices and Reports on Wells, which is to be used to provide detailed accounts of physical operations on wells.

R649-8-8. Form 7, Report of Water Encountered During Drilling.

The operator shall report to the division all fresh water sands encountered during drilling in accordance with R649-3-6. The report shall be filed with the Well Completion or Recompletion Report and Log, Form 8.

R649-8-9. Form 8, Well Completion or Recompletion Report and Log.

In accordance with R649-3-11, R649-3-21, R649-3-23, and R649-3-24, the operator shall file a Well Completion or Recompletion Report and Log and a copy of the electric and radioactivity logs, if run, within 30 days after completing, recompleting, or plugging a well.

R649-8-10. Form 9, Sundry Notices and Reports on Wells.

1. This report form shall be used to notify the division of the intention to do miscellaneous work on any well for which a specific report form is not provided, and to report the subsequent results of that work. A notice of intention to do work on a well

located on lands with state, fee or privately owned minerals or to change plans previously approved shall be submitted in duplicate and must be received and approved by the division before the work is commenced. The operator is responsible for receipt of the notice by the division in ample time for proper consideration and action. In cases of emergency the operator may obtain verbal approval to commence work. Within five days after receiving verbal approval, the operator shall submit a Sundry Notice describing the work and acknowledging the verbal approval.

2. In addition to the types of work listed on the form, a Sundry Notice is required for the following:

2.1. Monthly status report for each drilling well in accordance with R649-3-6.

2.2. Application for permit to complete a well into more than one pool in accordance with R649-3-22.

2.3. Notice of intent to plug and abandon a well in accordance with R649-3-24.

2.4. Notice of intent to pull casing in accordance with R649-3-24.

2.5. Notice of change of operator. The report form should be submitted by both the previous operator and the new operator.

R649-8-11. Form 10, Monthly Oil and Gas Production Report.

1. The division will provide this report monthly to operators of all oil and gas wells within the state. Each operator shall complete the form to properly account for all oil, gas, and water produced from each well.

2. This report shall be submitted in conjunction with Form 11, Monthly Oil and Gas Disposition Report before the fifteenth day of the second calendar month following the month of production.

R649-8-12. Form 11, Monthly Oil and Gas Disposition Report.

1. All oil and gas well operators shall complete this form monthly to account for all oil and gas dispositions from each entity.

1.1. The report should account for the physical dispositions of all oil and gas produced during the report month from each well or group of wells (entity). Only the initial disposition of each product as it leaves the well site or is used at the well site should be reported. Residue gas and/or load oil received from another well, plant, or field should not be shown on this report.

2. This report shall be submitted in conjunction with Form 10, Monthly Oil and Gas Production Report and Form 12, Report of Transferred Oil on or before the fifteenth day of the second calendar month following the month of production.

R649-8-13. Form 12, Report of Transferred Oil.

1. This report is to be used only in accounting for oil that is transferred from one entity to another entity or oil that is acquired and used during remedial operations on a well. This includes situations such as (1) oil that is produced at one entity or is acquired from another company, is then used as load oil at a "second" entity, and is then recovered and sold, or (2) oil that

is produced and then transferred to a "second" entity for treatment and sale due to mechanical problems at the producing entity.

1.1. Load oil that is recovered at the "second" entity and non-load oil that is transferred to the "second" entity should be excluded from all reported production, dispositions, and stocks of the "second" entity on Form 11, Monthly Oil and Gas Disposition Report. This allows the reporting of the "second" entity's true production and sales on Form 11, while the remainder of any sales is accounted for on this form. The transported volumes reported on this form plus the transported volume for the "second" entity on Form 11 should equal the total run ticket volume as reported by the trucking or pipeline company serving this entity.

2. This report is to be filed as an attachment to Form 11, Monthly Oil and Gas Disposition Report during the month in which recovered load oil or any other transferred oil (non-load oil) is sold from the "second" entity.

R649-8-14. Form 13-A, Monthly Summary Report of Gas Processing Plant Operations.

1. Gas processing plant operators shall complete and submit a monthly report in accordance with R649-6-1, to account for the receipt, processing and disposition of all gas by the plant.

2. The report is due on or before the fifteenth day of the second calendar month following the operations month covered by the report.

R649-8-15. Form 13-B, Monthly Report of Gas Processing Plant Product Allocations.

1. Gas processing plant operators that are required by contractual arrangements to allocate residue gas and extracted liquids to the individual producing wells must complete and submit this form monthly in accordance with R649-6-1.

2. The report is to be filed as an attachment to Form 13-A, Monthly Summary Report of Gas Processing Plant Operations on or before the fifteenth day of the second calendar month following the operations month covered by the report.

R649-8-16. Form 14, Monthly Report of Waste Crude Oil Treatment Facility Operations.

1. Each operator of treatment or reclaiming facilities handling tank bottoms, oil from pits or ponds, or any other waste crude oil, shall complete and submit this report monthly in accordance with R649-6-2 to account for stocks, receipts, and deliveries of processed and unprocessed waste crude oil.

2. The report is due on or before the fifteenth day of the second calendar month following the operations month covered by the report.

R649-8-17. Form 15, Designation of Workover or Recompletion.

1. In accordance with Rule R649-3-23, each operator desiring to claim a tax credit for workover or recompletion work performed must submit this report within 90 days after the workover or recompletion work is completed. Upon determination and

notification by the division that the described work qualifies for a tax credit under this rule, the operator may claim the tax credit on reports submitted to the Tax Commission during the third quarter after completion of the work.

2. The following workover and recompletion operations qualify for a tax credit: perforating, stimulation (e.g., acid jobs, frac jobs, solvent treatments, nitrogen cleanouts), sand control, water control or shut-off, wellbore cleanout, casing or liner repair, well deepening, initiation of enhanced recovery (excluding surface equipment and associated costs), change of lift system (excluding surface equipment and associated costs), gas well tubing changes (i.e., down-sizing), thief zone identification and elimination. The following workover and recompletion operations do not qualify for a tax credit: pump changes, rod string fishing and repair/replacement, tubing repair/replacement, surface equipment installation and repair, operations generally classified as routine maintenance or repair. Division approval is conditional subject to audit, and actual final expenses may be disallowed if they are not appropriate workover or recompletion expenses.

R649-8-18. UIC Form 1, Application for Injection Well.

Prior to the commencement of operations for injecting any fluid into a well for the purpose of enhanced recovery, disposal, or storage, the operator shall submit an Application for Injection Well and obtain division approval in accordance with R649-5-2.

R649-8-19. UIC Form 2, Monthly Report of Enhanced Recovery Project.

1. The operator shall submit this report monthly to report the injection pressure, rate, and volume for each enhanced recovery injection well or project.

2. The report is due within 30 days following the end of the month of operations.

R649-8-20. UIC Form 3, Monthly Injection Report.

1. The operator shall submit this report monthly to report the daily injection pressure, rate, and volume for each disposal well and/or storage well.

2. The report is due within 30 days following the end of the month of operations.

R649-8-21. UIC Form 4, Annual Fluid Injection Report.

1. The operator of disposal wells, storage wells, or enhanced recovery projects shall file an annual report with the division using this form.

2. The report is due within 60 days following the end of the year.

R649-8-22. UIC Form 5, Transfer of Authority to Inject.

1. The authority to inject for any injection well shall not be transferred from one operator to another without the approval of the division. The transfer of authority to inject for any injection well from one operator to another shall be submitted to

the division on this form prior to the date of the proposed transfer.

2. The division shall, within 30 days after receipt of a properly completed form, return a copy of the form to each operator indicating approval or denial of the transfer of authority to inject. If approved, a copy of the order authorizing injection shall be attached to the form returned to the new operator.

KEY: oil and gas conservation, reporting
June 2, 1998 **40-6-1 et seq.**
Notice of Continuation March 26, 2002

R649. Natural Resources; Oil, Gas and Mining; Oil and Gas.
R649-9. Waste Management and Disposal.
R649-9-1. Introduction.

1. Section 40-6-5 UCA authorizes the board to regulate the disposal of salt water and oil-field wastes. It is the intent of the Board and Division to regulate E and P Wastes and facilities for the disposal of these wastes in a manner which protects the environment, limits liability to producers, and minimizes the volume of waste.

2. These rules specify the informational and procedural requirements for waste management and disposal, the permitting of disposal facilities, and cleanup requirements for E and P related sites.

R649-9-2. General Waste Management.

1. Wastes addressed by these rules are E and P Wastes which are exempt from the RCRA hazardous waste management requirements.

2. Reduction of the amount of material generated which must be disposed of is the preferred practice. Recycling should be used whenever possible and practical. In general, good housekeeping practices shall be used. Operators shall catch leaks and drips, contain spills, and cleanup promptly.

3. The method of disposal used shall be compatible with the waste which is the subject of disposal. RCRA exempt waste shall not be mixed with nonexempt waste. Before using a commercial disposal facility the Division may be contacted to verify the status of the facility.

4. The operator shall file an Annual Waste Management Plan by January 15 of each year to account for the proper disposition of produced water and other E and P Wastes. If changes are made to the plan during the year, then the operator shall notify the division in writing of this change. This plan will include the type and estimated volume of wastes to be generated, the disposal facilities (central and commercial) to be used for disposal, and the description of any waste reduction or minimization procedures and any onsite disposal/treatment to be implemented by the operator. Each site and/or facility used for disposal must be permitted and in good standing with the division.

R649-9-3. Permitting of Disposal Pits.

1. All commercial disposal pits and disposal pits located off of an existing mineral lease shall be bonded in accordance with R649-9-9, Bonding of Disposal Facilities to assure proper operation, maintenance, and closure of the pits.

2. Application shall be made to the Division for approval of any disposal pit. The pit shall be designed appropriately for the intended purpose. Commercial disposal pits shall be designed and constructed under the supervision of a registered professional engineer. The application and site shall meet the following requirements:

2.1 The pit shall be located on level, stable ground, and an acceptable distance away from any established or intermittent drainage.

2.2. The pit shall not be located in a geologically and hydrologically unsuitable area, such as aquifer recharge areas, flood plains, drainage bottoms, and areas near faults.

2.3. The pit shall have adequate storage capacity to safely contain all produced water even during those periods when evaporation rates are at a minimum.

2.4. The pit shall be designed and constructed so as to prevent the entrance of surface water.

2.5. The pit shall be designed, maintained and operated to prevent unauthorized surface or subsurface discharge of water.

2.6. The pit shall be fenced and maintained to prevent access by livestock, wildlife and unauthorized personnel and if required, equipped with flagging or netting to deter entry by birds and waterfowl.

2.7. The pit levees for produced water pits receiving volumes in excess of five barrels per day, shall be constructed so that the inside grade of the levee is no steeper than 3:1 and the outside grade no steeper than 2:1. The top of the levee shall be level and of sufficient width to allow for adequate compaction.

2.8 All approved produced water pits not located at a well site shall be identified with a suitable sign.

2.9. The artificial materials used in lining pits shall be impervious and resistant to weather, sunlight, hydrocarbons, aqueous acids, alkalies, salt, fungi, or other substances which might be contained in the produced water.

3. If rigid materials are used, leak proof expansion joints shall be provided, or the material shall be of sufficient thickness and strength to withstand, without cracking, expansion, contraction and settling movements in the underlying earth.

3.1. If flexible materials are used, they shall be of sufficient thickness and strength to be resistant to tears and punctures. Commercial disposal pits shall be lined with a minimum liner thickness of 40 mils or as approved by the Division.

3.2. Lined pits constructed in relatively impermeable soils shall have an underlaying gravel filled sump and lateral system or suitable leak detection system.

3.3 Lined pits constructed in relatively permeable soils shall have a secondary liner underlaying the leak detection system, which is graded so as to direct leakages to the observation sump.

3.4. Test borings shall be taken in sufficient quantity and to an adequate depth to satisfactorily define subsurface conditions and assure that the liner will be placed on a firm stable base and to determine the appropriate leak detection system.

4. Requirements for Unlined Disposal Pits.

4.1 An application for disposal of produced water into an unlined pit will be considered if such disposal does not demonstrate significant pollution potential to surface or ground water and meets at least one of the following criteria:

4.2. The water to be disposed of does not have a higher total dissolved solids "TDS" content than ground water that could be affected and provided that the water does not contain objectionable levels of constituents and characteristics including chlorides, sulfates, pH, oil, grease, heavy metals and aromatic hydrocarbons.

4.3. That all, or a substantial part of the produced water is being used for beneficial purposes such as irrigation and livestock or wildlife watering and a water analysis indicates that the water is acceptable for the intended use.

4.4. The volume of water to be disposed of does not exceed five barrels per day on a monthly basis.

5. Application Requirements for Produced Water Pits.

5.1. Applications for disposal of produced water into lined pits shall include the following information:

5.2. A topographic map and drawing of the site on a suitable scale that indicate the pit dimensions, cross section, side slopes, leak detection system and location relative to other site facilities. The drawings shall be of professional quality.

5.3. The maximum daily quantity of water to be disposed of and a representative water analysis of such water that includes the concentrations of chlorides and sulfates, pH, total dissolved solids "TDS", and information regarding any other significant constituents if requested.

5.4. Climatological data indicating the average annual evaporation and precipitation for the area.

5.5. The method and schedule for disposal of precipitated solids.

5.6. Drawings of unloading facilities and explanation of the method for controlling and disposing of any liquid hydrocarbon accumulation so that the evaporation process is not hampered.

5.7. The engineering data and design criteria used to determine the pit size which includes a 2-foot free-board.

5.8. The type, thickness, strength, and life span of material to be used for lining the pit and the method of installation.

5.9. A description of the leak detection method to be utilized and the proposed inspection frequency of the detection system. Also the proposed procedures for repair of the liner should leakage occur.

6. Applications for disposal of produced water into unlined pits shall include the following information:

6.1. A topographic map and drawing of the site on a suitable scale that indicate the pit dimensions, cross section, side slopes, size and location relative to other site facilities.

6.2. The daily quantity of water to be disposed of and a representative water analysis of such water that includes the total dissolved solids "TDS", pH, oil and grease content, the concentrations of chlorides and sulfates, and information regarding any other significant constituents if required.

6.3. Climatological data indicating the average annual evaporation and precipitation for the area.

6.4. The estimated percolation rate based on soil characteristics under and adjacent to the pit.

6.5. Estimated depth and areal extent of any USDW in the area and an indication of any effect or interaction of the produced water with any such water resources present at or near the surface.

6.6. If beneficial use is the basis for the application, written confirmation from the user should be submitted.

6.7. If the application is made on the basis that surface and subsurface waters will not be adversely affected by disposal in an unlined pit, the following additional information is required:

6.7.1. A map showing the location of surface waters, water wells, and existing water disposal facilities within a one mile radius of the proposed disposal facility.

6.7.2. The weighted average concentration of total dissolved solids "TDS" of all surface and subsurface waters within a one mile radius that might be affected by the proposed disposal.

6.7.3. Any reasonable geological and hydrological evidence showing that the proposed disposal method will not adversely affect existing water quality or major uses of such waters.

7. Within 30 days of the submission of an application for disposal of produced water into a commercial disposal pit, the division shall review the application as to its completeness and adequacy for the intended purpose and shall require such changes that are found necessary to assure compliance with the applicable rules. If the application is in order, the Division shall provide for a public notice to be published in a newspaper of general circulation in the county where the pit is to be located.

R649-9-4. Permitting of Other Disposal Facilities.

1. Facilities used for the treatment and disposal of E and P wastes other than evaporation pits shall be permitted by the Division. This would include such activities as landfarming, composting, solidifying, bioremediation, and others.

2. All commercial treatment and disposal facilities must be bonded in accordance with R649-9-9, Bonding of Disposal Facilities, to assure proper operation, maintenance, and closure of the facility.

3. Application Requirements for Treatment and Disposal Facilities. The application shall contain the following:

3.1 A complete description of the proposed facility and processes involved including a complete list of all wastes to be accepted at the facility and products generated.

3.2 Maps and drawings of suitable scale showing all facilities and equipment.

3.3 Materials or products to be applied to the land surface or subsurface shall meet the Division's cleanup levels for contaminated soil and other wastes. If leachability and/or toxicity is of concern due to the type or source(s) of wastes, tests will be required and may utilize the Toxicity Characteristic Leaching Procedure (TCLP).

3.4 The submission of an application to the Division of Water Quality, Department of Environmental Quality, for a discharge permit may be required if it is determined that the facility and associated activity will not have a de minimus actual or potential effect on ground water quality. If the Division determines there is potential for discharge, or if the proposal involves a commercial disposal operation it will be forwarded to the Division of Water Quality for their review.

R649-9-5. Construction and Inspection Requirements for Disposal Facilities.

1. Division personnel shall be afforded a reasonable opportunity for inspection of any proposed disposal facility during the construction and operation of the facility.
2. The division shall be notified at least two working days prior to the installation of a pit liner so that an inspection of the leak detection system can be conducted.
3. In any case, the division shall be notified after completion of facility construction, at least two working days prior to its use, so that an inspection can be conducted to verify that the facility has been constructed in accordance with the approved application.
4. Disposal facilities shall be operated in accordance with an approved application and in a manner which does not cause pollution or safety and health hazards.
5. Failure to meet the requirements and standards for construction and operation of a disposal facility shall be considered as noncompliance and will result in the imposition of corrective actions and compliance schedules or a cessation of operations order.

R649-9-6. Reporting and Recordkeeping Requirements for Disposal Facilities.

1. All unauthorized discharges or spills from disposal facilities including water observed in a leak detection system shall be promptly reported to the division.
2. Each producer who utilizes any approved produced water disposal facility shall comply with the reporting requirements of R649-8-10.
3. Each operator of a disposal facility, excluding disposal wells, shall report to the Division on a quarterly basis. This report shall include the volume and type of wastes received at the facility during the quarter and results of the leak detection system inspections.
4. The occurrence of water in a leak detection system during operation of a pit constitutes liner failure and requires immediate action. The Division has the option of allowing the operator a short period of time to take corrective action. Further utilization of the pit will be allowed only after liner

repairs and an inspection by the Division.

5. Each owner/operator of a commercial disposal facility shall keep records showing at a minimum the following: date and time waste was received, origin, volume, type, transporter, and generator of the waste. These records shall be available for inspection by the Division for at least six years.

R649-9-7. Final Closure and Cleanup of Disposal Facilities.

1. A plan for final closure of a disposal facility shall be submitted to the Division for approval. The closure plan shall include the following:

1.1 Provisions for removal of all equipment at the site.

1.2 Proposed plans and procedures for sampling and testing soils and ground water at the site. Soils will need to meet the Division's Cleanup Levels for Contaminated Soils or background levels whichever is less stringent.

1.3 Provisions for a monitoring plan if required by the Division, and

1.4 A consideration of post disposal land use and landowner requests when the closure plan is developed.

2. A bond for a disposal facility will be released when the requirements of a closure plan approved by the Division has been met as determined by the Division.

R649-9-8. Variances from Requirements and Standards.

Requests for approval of a variance from any of the requirements or standards of these rules shall be submitted to the director in writing and provide information as to the circumstances which warrant approval of the requested variance and the proposed alternative means by which the requirements or standards will be satisfied. Variances may be approved only after proper notice and public hearing before the board.

R649-9-9. Bonding of Disposal Facilities.

1. Disposal facilities, other than injection wells, shall be bonded according to this rule in order to protect the State and oil and gas producers from unnecessary liabilities and cleanup costs in the future. The objectives are to provide the State with adequate security to allow rehabilitation of a site to the point of preventing further or future pollution, and health and safety hazards should a facility owner default.

1.1. The parameters used to calculate the proper bond amount are: pit area, storage capacity, and volume of waste stored.

1.2. Bonds accepted shall be of the same type as those accepted for wells i.e. surety, collateral, or a combination of the two as described in the R649-3-1. In order to assist facility owners in providing bonding, the total bond amount provided may consist of an initial amount as determined by the division and an additional amount collected at a price per barrel and/or price per cubic yard of waste collected until the total bond amount is reached. The total bond will be held by the division or financial institution until the facility has been closed and inspected by the division in accordance with a division approved closure plan.

1.3. Total bond amount is calculated using values for pit area, pit storage capacity, and volume of stock piled waste material. No salvage value of equipment or removal cost is used. This bond will only be used by the State to treat or remove waste from the site and secure the facility to prevent any future contamination should the facility owner default on cleanup responsibilities. Bond amounts will be calculated as follows, and the per volume or per acre figures may be adjusted periodically to compensate for change in cost to perform the necessary cleanup work:

$14,000 per acre of pit, partial acres will be calculated at the rate of $14,000 per acre; plus

$1.00 per barrel of produced water for one-quarter of the total storage capacity of the facility; plus

$30 per cubic yard of solid or semi-solid waste material stockpiled at the facility.

$10,000 Minimum bond amount.

1.4 All commercial disposal facilities (except injection wells covered by R649-3-1) will be covered by an adequate and acceptable bond before being permitted to accept any exploration and production waste. The initial and minimum bond payment will be at least $10,000. The total bond amount will be calculated as described in Subsection R649-9-9(1.3). If requested by the disposal facility owner, the bond beyond the initial amount may be posted at a rate of two cents per barrel of liquid or sixty cents per cubic yard of solid/semi-solid waste material accepted for disposal at the facility.

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Notice of Continuation March 26, 2002

R649. Natural Resources; Oil, Gas and Mining; Oil and Gas.
R649-10. Administrative Procedures.
R649-10-1. Designation of Informal Adjudicative Proceedings.

1. Adjudicative proceedings which shall be conducted informally before the division in accordance with these rules are all actions prescribed by the Oil and Gas Conservation General Rules as being specifically under the division's authority and jurisdiction including: R649-2 General Rules; R649-3 Drilling and Operating Practices; R649-5 Underground Injection Control of Recovery Operations and Class II Injection Wells; R649-6 Gas Processing and Waste Crude Oil Treatment; R649-8 Reporting and Report Forms; R649-9 Disposal of Produced Water.

2. Prior to the issuance of a final order in any adjudicative proceeding, the presiding officer may convert an informal proceeding to a formal adjudicative proceeding if:

2.1. Conversion of the proceeding is in the public interest.

2.2. Conversion of the proceeding does not unfairly prejudice the rights of any party.

3. Informal adjudicative proceedings shall be commenced and conducted in accordance with these rules and the provisions of the applicable Oil and Gas Conservation General Rules. In case of conflict between these rules and the Oil and Gas Conservation

General Rules, these rules shall govern the informal adjudicative proceedings.

R649-10-2. Definitions.

As used in these rules:

1. "Adjudicative proceeding" means an agency action or proceeding that determines the legal rights, duties, privileges, immunities, or other legal interests of one or more identifiable persons, including all agency actions to grant, deny, revoke, suspend, modify, annul, withdraw, or amend an authority, right, or license; and judicial review of all of such actions.

2. "Agency" means the Board of Oil, Gas and Mining and the Division of Oil, Gas and Mining including the director or division employees acting on behalf of or under the authority of the director or board.

3. "Agency head" means an individual or body of individuals in whom the ultimate legal authority of the agency is vested by statute.

4. "Board" means the Board of Oil, Gas and Mining.

5. "Division" means the Division of Oil, Gas and Mining.

6. "License" means a franchise, permit, certification, approval, registration, charter, or similar form of authorization required by statute.

7. "Party" means the board, division, or other person commencing an adjudicative proceeding, all respondents, all persons permitted by the board to intervene in the proceeding, and all persons authorized by statute or agency rule to participate as parties in an adjudicative proceeding.

8. "Person" means an individual, group of individuals, partnership, corporation, association, political subdivision or its units, governmental subdivision or its units, public or private organization or entity of any character, or another agency.

9. "Presiding Officer" means an agency head, or an individual or body of individuals designated by the agency head, by the agency's rules, or by statute to conduct an adjudicative proceeding. For the purpose of these rules, the board, or its appointed hearing examiner, shall be considered the presiding officer of all appeals or informal adjudicative proceedings which commence before the division as well as all adjudicative proceedings which commence before the board. The director or his designated agent shall be considered a presiding officer for all informal adjudicative proceedings which commence before the division. If fairness to the parties is not compromised, an agency may substitute one presiding officer for another during any proceeding.

10. "Respondent" means any person against whom an adjudicative proceeding is initiated whether by an agency or any other person.

R649-10-3. Commencement of Informal Adjudicative Proceedings.

1. Except for emergency orders, all informal adjudicative proceedings shall be commenced by:

1.1. A Notice of Agency Action, if proceedings are commenced by the board or division; or

1.2. A Request for Agency Action, if proceedings are commenced by persons other than the board or division.

2. A Notice of Agency Action shall be filed and served according to the following requirements:

2.1. The Notice of Agency Action shall be in writing and shall be signed by a presiding officer and shall include:

2.1.1. The names and mailing addresses of all persons to whom notice is being given by the presiding officer, and the name, title, and mailing address of any attorney or employee who has been designated to appear for the agency.

2.1.2. The division's file number or other reference number.

2.1.3. The name of the adjudicative proceeding.

2.1.4. The date that the Notice of Agency Action was mailed.

2.1.5. A statement that the adjudicative proceeding is to be conducted informally according to the provision of these rules and Sections 63-46b-4 and 63-46b-5 if applicable.

2.1.6. A statement that the parties may request an informal hearing before the division within ten days, or such later period as may be provided for in the Oil and Gas Conservation General Rules, of the date of mailing or publication.

2.1.7. A statement of the legal authority and jurisdiction under which the adjudicative proceeding is to be maintained.

2.1.8. The name, title, mailing address, and telephone number of the presiding officer.

2.1.9. A statement of the purpose of the adjudicative proceeding and, to the extent known by the presiding officer, the questions to be decided.

2.2. The Division shall:

2.2.1. Mail the Notice of Agency Action to each party and any other person who has a right to notice under statute or rule.

2.2.2. Publish the Notice of Agency Action as required by statute or by the Oil and Gas Conservation General Rules.

2.2.3 Post a copy of the notice in a public area in the main office of the division at least 24 hours in advance of the scheduled agency proceeding.

2.3. A Request for Agency Action initiated by a person other than the board or the division shall be in writing and signed by the person seeking action by the the agency or by his representative, and shall include:

2.3.1. The names and addresses of all persons to whom a copy of the request for agency action is being sent.

2.3.2. The agency's file number or other reference number, if known.

2.3.3. The date that the request for agency action was mailed.

2.3.4. A statement of the legal authority and jurisdiction under which the agency action is requested.

2.3.5. A statement of the relief or action sought from the division.

2.3.6. A statement of the facts and reasons forming the basis for relief or action.

2.4. The person requesting agency action shall file the request with the division and shall send a copy by mail to each person known to have a direct interest in the requested agency action unless previously waived in writing by each person entitled to receive notice of the requested agency action.

2.5. The person requesting the agency action may use the division forms as specified in the Oil and Gas Conservation General Rules as a request for agency action.

2.6. The presiding officer shall promptly review a Request for Agency Action and shall:

2.6.1. Notify the requesting party in writing whether the request is granted and when the adjudicative proceeding is completed;

2.6.2. Notify the requesting party in writing that the request is denied; or

2.6.3. Notify the requesting party that further proceedings are required to determine the agency's response to the request.

2.7. The division shall mail any required notice to all parties, except that any notice required by R649-10-3-2.6 may be published when publication is required by statute.

2.7.1. Give the division's file number or other reference number.

2.7.2. Give the name of the proceeding.

2.7.3. Designate that the proceeding is to be conducted informally according to the provisions of these rules and Sections 63-46b-4 and 63-46b-5 if applicable.

2.7.4. If a hearing is to be held in an informal adjudicative proceeding, state the time and place of any scheduled hearing, the purpose for which the hearing is to be held, and that a party who fails to attend or participate in a scheduled and noticed hearing may be held in default.

2.7.5. If the adjudicative proceeding is to be informal, and a hearing is required by statute or rule, or if a hearing is permitted by rule and may be requested by a party with the time prescribed by rule, state the parties' right to request a hearing and the time within which a hearing may be requested under the agency's rules.

2.7.6. Give the name, title, mailing address, and telephone number of the presiding officer.

R649-10-4. Procedures for Informal Adjudicative Proceedings.

1. Procedures for informal adjudicative proceedings should include the following:

1.1. Unless the agency by rule provides for and requires a response, no answer or other pleading responsive to the allegations contained in the notice of agency action or the request for agency action need be filed.

1.2. The agency shall hold a hearing if a hearing is requested within ten days or such later period as may be provided for in the Oil and Gas Conservation General Rules.

1.3. In any hearing, the parties named in the Notice of Agency Action or in the Request for Agency Action shall be permitted to testify, present evidence, and comment on the issues.

1.4. Hearings will be held only after timely notice to all parties.

1.5. Discovery is prohibited, but the agency may issue subpoenas or other orders to compel production of necessary evidence.

1.6. All parties shall have access to information contained in the agency's files and to all materials and information gathered in any investigation, to the extent permitted by law.

1.7. Intervention is prohibited, except where a federal statute or rule requires that a state permit intervention.

1.8. All hearings shall be open to all parties.

1.9. Within a reasonable time after the close of an informal adjudicative proceeding, the presiding officer shall issue a signed order in writing that states the following:

1.9.1. The decision.

1.9.2. The reasons for the decision.

1.9.3. A notice of any right of administrative or judicial review available to the parties.

1.9.4. A statement that the filing of an appeal or the requesting of a review shall be accomplished within 30 days of the issuance of the order.

1.10. The presiding officer's order shall be based on the facts appearing in the agency's files and on the facts presented in evidence at any hearings.

1.11. A copy of the presiding officer's order shall be promptly mailed to each of the parties and to all persons who request a copy.

2.1. The agency may record any hearing.

2.2. Any party, at his own expense, may have a reporter, approved by the agency, prepare a transcript from the agency's record of the hearing.

3.0. Nothing in this section restricts or precludes any investigative right or power given to an agency by another statute.

R649-10-5. Default In An Informal Proceeding.

1. The presiding officer may enter an order of default against:

1.1. A party in an informal adjudicative proceeding if after proper notice the party fails to participate in the informal adjudicative proceeding.

2.0. An order of default shall include a statement of the grounds for default and shall be mailed to all parties.

3.1. A defaulted party may seek to have the agency set aside the default order, and any order in the adjudicative proceeding issued subsequent to the default order, by following the procedures outlined in the Utah Rules of Civil Procedure.

3.2. A motion to set aside a default and any subsequent order shall be made to the presiding officer.

3.3. A defaulted party may seek board review under R649-10-6 only on the decision of the presiding officer on the motion to set aside the default.

4.0. In an adjudicative proceeding commenced by the agency, or in an adjudicative proceeding commenced by a party that has other parties besides the party in default, the presiding officer shall, after issuing the order of default, conduct any further proceeding without the participation of the party in default and shall determine all issues in the adjudicative proceeding, including those affecting the defaulting party.

5.0. In an adjudicative proceeding that has no parties other than the agency and the party(ies) in default, the presiding officer may, after issuing the order(s) of default, dismiss the proceeding.

R649-10-6. Appeal of Division Order.

1. A request for review of an order issued by the division shall be filed with the secretary to the Board within 30 days of issuance of the order and:

1.1. Be signed by the party seeking review.

1.2. State the grounds for review and the relief requested.

1.3. State the date upon which it was mailed.

1.4. Be sent by mail to the presiding officer and to each party.

2. Within 15 days of the mailing date of request for review, or within the time period provided by agency rule, whichever is longer, any party may file a response with the board. One copy of the response shall be sent by mail to each of the parties and to the presiding officer.

3. The board shall review the order within a reasonable time or within the time required by statute or the agency's rules.

4. To assist in review, the board may by order or rule permit the parties to file briefs or other papers, or to conduct oral argument.

5. Notice of hearings on review shall be mailed to all parties.

6.1. Within a reasonable time after the filing of any response, other filings, or oral argument, or within the time required by statute or applicable rules, the board shall issue a written order on review.

6.2. The order on review shall be signed by the board chairman or by a person designated by the board for that purpose and shall be mailed to each party.

6.3. The order on review shall contain:

6.3.1. A designation of the statute or rule permitting or requiring review.

6.3.2. A statement of the issues reviewed.

6.3.3. Findings of fact as to each of the issues reviewed.

6.3.4. Conclusions of law as to each of the issues reviewed.

6.3.5. The reasons for the disposition.

6.3.6. Whether the decision of the presiding officer or agency is to be affirmed, reversed, or modified, and whether all or any portion of the adjudicative proceeding is to be remanded.

6.3.7. A notice of any right of further administrative reconsideration or judicial review available to aggrieved parties.

6.3.8. The time limits applicable to any appeal or review.

R649-10-7. Emergency Orders.

Notwithstanding the other provisions of these rules, the director or any member of the board is authorized to issue an emergency order without notice and hearing in accordance with Section 40-6-10. The emergency order shall remain in effect no longer than until the next regular meeting of the board, or such shorter period of time as shall be prescribed by statute.

1. An emergency order may be issued if:

1.1. The facts known by or presented to the director or board member are supported by affidavit to show that an immediate and significant danger of waste or other danger to the public health, safety, or welfare exists; and

1.2. The threat requires immediate action by the director or board member,

2. Limitations. In issuing its emergency order, the director or board member shall:

2.1. Limit its order to require only the action necessary to prevent or avoid the danger to the public health, safety, or welfare;

2.2. Issue promptly a written order, effective immediately, that includes a brief statement of findings of fact, conclusions of law, and reasons for the agency's utilization of emergency adjudicative proceedings;

2.3. Give immediate notice to the persons who are required to comply with the order; and

2.4. If the emergency order issued under this section will result in the continued infringement or impairment of any legal right or interest of any party, the division shall commence a formal adjudicative proceeding in accordance with the procedural rules of the board.

R649-10-8. Exhaustion of Administrative Remedies.

A person aggrieved by a division order in an adjudicative proceeding must seek review of that order by the board as provided in R649-10-6.

R649-10-9. Waivers.

Notwithstanding any other provision of these rules, any procedural matter, including any right to notice or hearing, may be waived by the affected person(s) by a signed, written waiver in a form acceptable to the division.

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December 18, 1996 **40-6-1 et seq.**
Notice of Continuation July 19, 2001 **63-46b**

Appendix G— Source Location Data for Southwestern U.S.

GASIFICATION AND GAS PROCESSING CENTER

GTI PROJECT 15369.1.01

Source Location Data for SW Regional Carbon Sequestration Partnership - Phase I

TOPICAL REPORT

November 4, 2004

Submitted To:
Prof. B. J. McPherson
New Mexico Institute of Mining and Technology
Petroleum Recovery Research Center
801 Leroy Place
Socorro, NM 87801

GTI Technical Contacts:
Howard S. Meyer
Manager, Gas Processing, 847/768/0955
howard.meyer@gastechnology.org

Dennis Leppin
Associate Director, Gas Processing, 847/768-0521
dennis.leppin@gastechnology.org

Gas Technology Institute
1700 S. Mount Prospect Rd.
Des Plaines, Illinois 60018
www.gastechnology.org

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Introduction:

The Regional Partnerships for Carbon Sequestration programs funded by DOE are ultimately required to identify the best carbon sequestration options in their respective regions, consisting of a CO_2 source, applicable CO_2 capture technology, transportation logistics (if applicable) and destination formation for non-terrestial sequestration approaches. In most cases the carbon capture step is the most costly, and selecting the appropriate least-cost options will be of particular importance. GTI was selected to provide advice and consultation on capture technologies for the Southwest Partnership.

This report consists of a summary of various databases assembled to help locate and quantify the CO_2 emissions in the Southwest Region. These point sources in the southwest region are mainly coal-fired power plants. Other sources include natural gas processing plants, refineries, ammonia/fertilizer production, ethylene and ethanol plants, and cement plants.

This information will assist in identifying candidate projects for Phase II.

Scope of Work:

The objective of this project is to delineate technologies applicable to capturing carbon dioxide from point sources and to provide estimates from various sources of the specific costs of such technologies. Research and Development on new technologies will be reviewed and a listing of those that appear promising and are sufficiently in the development cycle will be presented.

Databases:

GTI was requested to assemble a listing of gas treating plants in the Southwest Partnership Region (SW). These are plants that remove CO_2 from natural gas and generally emit the CO_2 at low pressure into the atmosphere. These were assembled and transmitted. However, the original data did not contain any location beyond the state in which the plant was located. GTI was requested to provide any and all location data as well as emission data in addition to facility data required to estimate the cost of capture.

Table 1 provides an index of the various databases assembled to meet the source data needs of the partnership. Some of the databases exist as Microsoft® Access™ databases, but they have all been assembled into Microsoft® Excel™ files to ease transfer. Table 2 is an extended table of the fields contained on each of the worksheets. The Appendices are a partial listing of the complete files. Where the database could be contained in a reasonable number of pages, it has been included in full within the Appendix. Where the worksheets would take hundreds or thousands of pages, a partial listing has been included to indicate the scope of the data.

Data by source

The overwhelming CO_2 emissions in the region are from coal-based power plants. Information on electrical generation plants can be found in the following workbooks/worksheets:

1. Sources in SW_By SIC/SW
2. SW_NATCARB_Data/Emissions and Facilities with RBLCID
3. SW_ElectricPlants_CO_2_Tons_%/ SW_ElectricPlants_CO_2_Tons_%
4. SW_99AirDataFacilitiesFile/RBLC_SW and RBLC_SW_ElectGen
5. SW_Coorid_fromEPA_HAP/SW

6. RACT_BACT_laer/SW
7. SW_NATCARB_Data_Facilities with Match to RACT_BACT_laer/Facilities 1030617920
8. SW_ElectricPlants_eGRID/all

Information on natural gas production and sources of emissions can be found in the following:
1. Sources in SW_BySIC/SW
2. SW_RegionalGasPlants/All
3. RACT_BACT-laer_NonPower/NonPower
4. SW_SubqualityGas Composition/SW_Subquality
5. SW_99AirDataFacilitiesFile/RBLC_SW and RBLC_SW_ElectGen
6. SW_Coorid_fromEPA_HAP/SW
7. RACT_BACT_laer/SW

Information on other CO_2 emitting industries can be found in the following:
1. Sources in SW_BySIC/SW
2. RACT_BACT-laer_NonPower/Portland Cement, Fertilizer, and NonPower
3. SW_NonFuelPlants/CementInRegion, AmmoniaInRegion, ChlorinePlants, EthlyenePlants, and Refineries (to be completed)
4. SW_99AirDataFacilitiesFile/RBLC_SW and RBLC_SW_ElectGen
5. SW_Coorid_fromEPA_HAP/SW
6. RACT_BACT_laer/SW
7. SW_minerals_usgs_gov/SW
8. SW_EthanolPlants/SW_EthanolProduction

Data with Location Information

It is difficult to locate each point source of CO_2. Some data sources will identify the location by latitude and longitude, some by physical address, county map coordinates, or by driving instructions from the red barn with blue shutters. In addition, there is not a consistent identified across the various data sources. Plant names may be the most consistent, but owners change on a regular basis. In some databases, GTI has included cross references to identifiers in other databases. GTI has suggested to the partnership several means to obtain latitude and longitude data where it is not given. Information with latitude and longitude (or x and y coordinate) data can be found in the following:
1. Sources in SW_BySIC/SW
2. SW_RegionalGasPlants/SW_RegionalTreatingPlants
3. SW_NATCARB_Data/FacilitiesWithRBLCID
4. RACT_BACT-laer_NonPower/PortlandCement, Fertilizer, and NonPower
5. SW_99v3AirDataFacilitiesFile/RBLC_SW, RBLC_SW_ElectGen/ORIS_Facility_Code
6. SW_CooridFromEPA_HAP
7. RACT_BACT_laer/SW
8. SW_ElectricPlants_eGRID/EGRDPLNT00

Information with other location data can be found in the following:

1. SW_RegionalGasPlants/H_2S>5% and AcidGas>20%
2. SW_NonFuelPlants/CementInRegion, AmmoniaInRegion, ChlorinePlants, EthylenePlants, and EOR
3. SW_99v3AirDataFacilitesFile/NH_3Releases
4. SW_EthanolPlants/SW_EthanolProduction

Data with CO_2 Emissions
Several data sources provide CO_2 emissions data in various forms. Some are as detailed as monthly emissions on specific units within a facility while some are provided on the facility or even state basis. Several databases contain emission data on other components, such as CO, NO_x, NH_3, and VOC. Information on CO_2 emissions can be found in the following:

1. SW_NATCARB_Data/Emissions
2. SW_NonFuelPlants/EIASummary
3. SW_ElectricPlants_CO_2_Tons_%/ SW_ElectricPlants_CO_2_Tons_%
4. SW_ElectricPlants_eGRID/EGRDBLR00

Data with Process Criteria
In order to estimate CO_2 capture costs from the various sources in the region, certain process criteria must be know. This can vary among the various technologies from simple capacity to specific emission-producing and emission-mitigating equipment. These data are part of the input to GTI's costing protocol. Process criteria information are contained in the following:

1. SW_RegionalGasPlants/SW_RegionalTreatingPlants
2. SW_NATCARB_Data/Emissions, Fuels, and FacilitiesWithRBLCID
3. RACT_BACT-laer_NonPower/PortlandCement, Fertilizer, and NonPower
4. SW_NonFuelPlants/CementInRegion, AmmoniaInRegion, ChlorinePlants, EthylenePlants
5. SW_99v3AirDataFacilitiesFile/ORIS_Facility_Code
6. RACT_BACT-laer/SW
7. SW_ElectricPlants_eGRID/EGRDPLNT00, EGRDBLR00, EGRDPLCH, EGRDPRCH, and EGRDPCCH
8. SW_EthanolPlants/SW_EthanolProduction

Table 1 Index of Data Tables

Workbook	Worksheet	List of Fields
Sources in SW_BySIC	SW	B1
SW_RegionalGasPlants	SW_RegionalTreatingPlants	B2
	H_2S>5%	B3
	Acid Gas >20%	B4
SW_NATCARB_Data	Emissions Fuels	B5 B6
	FacilitiesWithRBLCID	B7
RACT_BACT-laer_NonPower	Portland Cement	B8
	Fertilizer	B9
	NonPower	B10
SW_SubqualityGasComposition	SW_Subquality	B11
SW_NonFuelPlants	EIA Summary	B12
	CementInRegion	B13
	CementManufactors	B14
	Anhydrous Ammonia 96	B15
	AmmoniaInRegion	B16
	Chlorine Plants	B17
	EthylenePlants	B18
	EOR	B19
	Refineries	B20
SW_ElectricPlants_CO2_Tons_%	SW_ElectricPlants_CO_2_Tons_%	B21
SW_99v3AirDataFacilitiesFile	RBLC_SW	B22
	RBLC_SW_ElectGen	B23
	NH3Release	B24
	ORIS_Facility_Code	B25
SW_Coorid_fromEPA_HAP	SW	B26
RACT_BACT_laer	SW	B27
SW_NATCARB_Data_Facilities with Match to RACT_BACT_laer	Facilities1030617920	B28
SW_minerals_usgs_gov	SW	B29
SW_ElectricPlants_eGRID	Contents	B30
	EGRDPLNT00	B31
	EGRDBLR00	B32
	EGRDGEN00	B33
	EGRDPLCH	B34
	EGRDEGCH	B35
	EGRDPRCH	B36
	EGRDPCCH	B37
SW_EthanolPlants	EthanolProduction	B38
	SW_EthanolProduction	B39

Table 2 Table Fields

Sources in SW_BySIC
B1. SW
strStateFacilityIdentifier
strSICPrimary
strNAICSPrimary
strFacilityName
strSiteDescription
strLocationAddress
strCity
srtState
strZipCode
strCountry
dblXCoordinate
dblYCoordinate
intUTMZone
strXYCoordinateType

SW_RegionalGasPlants		
B2. SW_RegionalTreating Plants	***B3. H2S>5%***	***B4. Acid Gas >20%***
Operator	STATE	STATE
State	COUNTY	COUNTY
County	BASIN CODE	BASIN
Plantname	FIELD	FIELD
EPA ID	WELL NAME/PLANT	WELL NAME/PLANT
Lat	LOCATION/PIPELINE	LOCATION/PIPELINE
Long	OWNER	OWNER
dblXCoordinate	H2S	H2S
dblYCoordinate	CO2	CO2
Installed Capacity MMcf/d		SUM
Design Inlet CO2 Mol%		
Inlet CO2 Mol%		
Design Inlet H2S Mol%		
Inlet H2S Mol%		

SW_NATCARB_Data		
B5. Emissions	***B6. Fuels***	***B7. FacilitiesWithRBLCID***
ORIS_CODE	ID	RBLCID
UNIT_ID	EGRID_CODE	ORIS_CODE
YEAR	EPA_CODE	FACILITY_NAME
MONTH	DESCRIPTION_SPECIFIC	FACILITY_TYPE
CO2_TONS	DESCRIPTION_GENERIC	OWNER_NAME
CO2_CONCENTRATION	CO2_CONCENTRATION	OWNER_TYPE
SO2_TONS		OPERATOR_NAME
NOX_TONS		COMPANY_NAME
MERCURY_LBS		STREET_ADDRESS
HEAT_INPUT		CITY
TOTAL_OPERATING_HOURS		COUNTY_NAME
FUEL_TYPE_COMBUSTED		COUNTY_CODE_FIPS
		STATE
		ZIP_PLUS_4
		LATITUDE
		LONGITUDE
		LAT_LONG_DATUM
		LAT_LONG_SOURCE
		POWER_CAPACITY_MW

RACT_BACT-laer_NonPower		
B8. Portland Cement	***B9. Fertilizer***	***B10. NonPower***
RBLCID	RBLCID	RBLCID
FACILITY	FACILITY	FACILITY
COMPANY	COMPANY	COMPANY
COUNTY	COUNTY	COUNTY
CONTACT	CONTACT	CONTACT
ADDRESS	ADDRESS	ADDRESS
CITY	CITY	CITY
STATE	STATE	STATE
ZIP	ZIP	ZIP
PHONE	PHONE	PHONE
EMAIL	EMAIL	EMAIL
REGION	REGION	REGION
AGENCYCODE	AGENCYCODE	AGENCYCODE
AGENCYNAME	AGENCYNAME	AGENCYNAME
AGENCYCONTACT	AGENCYCONTACT	AGENCYCONTACT
AGENCYPHONE	AGENCYPHONE	AGENCYPHONE
AGENCYEMAIL	AGENCYEMAIL	AGENCYEMAIL
PERMITNUM	PERMITNUM	PERMITNUM
SIC	SIC	SIC
NAICS	NAICS	NAICS
AIRSID	AIRSID	AIRSID
EPAID	EPAID	EPAID
UTMZONE	UTMZONE	UTMZONE
XCOORD	XCOORD	XCOORD
YCOORD	YCOORD	YCOORD
RCVDDATE	RCVDDATE	RCVDDATE
PERMITDATE	PERMITDATE	PERMITDATE
STARTUPDATE	STARTUPDATE	STARTUPDATE
VERIFYDATE	EMISLIMIT2UNIT	VERIFYDATE
ENTRYDATE	STOTHERCONDITIONS	ENTRYDATE
LASTUPDATE	CAPCOST	LASTUPDATE
NEW_MOD	OMCOST	NEW_MOD
PUBLICHEAR	COSTEFFECT	PUBLICHEAR
FUEL	COSTVERIFY	FUEL
EMISSSOURCES	DOLLARYEAR	EMISSSOURCES
ABATEMENT	POLNOTES	ABATEMENT
NARRATIVE		NARRATIVE
NOTES		NOTES
PROCESS		PROCESS
PROCTYPE		PROCTYPE
SCC		SCC
FUEL		FUEL
THRUPUT		THRUPUT
THRUPUTUNIT		THRUPUTUNIT
COMPVERIFY		COMPVERIFY
STACKTEST		STACKTEST

INSPECTION	INSPECTION
CALCULATED	CALCULATED
OTHERTEST	OTHERTEST
OTHERMETHD	OTHERMETHD
PRNOTES	PRNOTES
POLLUTANT	POLLUTANT
CAS	CAS
CONTROLCOD	CONTROLCOD
CTRLDESC	CTRLDESC
RANKOPTS	RANKOPTS
RANKSEL	RANKSEL
EMISLIMIT1	EMISLIMIT1
EMISLIMIT1UNIT	EMISLIMIT1UNIT
EMISLIMIT1CONDITION	EMISLIMIT1CONDITION
BASIS	BASIS
PCTEFFIC	PCTEFFIC
EMISLIMIT2	EMISLIMIT2
EMISLIMIT2UNIT	EMISLIMIT2UNIT
EMISLIMIT2CONDITION	EMISLIMIT2CONDITION
STDEMISS	STDEMISS
STDUNIT	STDUNIT
STOTHERCONDITIONS	STOTHERCONDITIONS
EMISSTYPE	EMISSTYPE
CAPCOST	CAPCOST
ANNUALCOST	ANNUALCOST
OMCOST	OMCOST
COSTEFFECT	COSTEFFECT
COSTVERIFY	COSTVERIFY
DOLLARYEAR	DOLLARYEAR
POLNOTES	POLNOTES

SW_SubqualityGasComposition	
B11. SW_Subquality	
HCMREG	Hydrocarbon Supply Model Region (see map)
BASCODE	AAPG Basin Code
BASIN	Basin name
FORMATION	Formation name
NRES	Number of reservoirs
NCOMP	Number of gas well completions
ULT_COMP	Average recovery per completion
AVDEPTH	Average depth
CO2AV	Carbon dioxide average
CO2MIN	Carbon dioxide minimum
CO2MAX	Carbon dioxide maximum
CO2STD	Carbon dioxide standard deviation
RAW_RUR	Heating value standard deviation
R_SAMP	Proven raw gas reserves as of 12/32/99
GASAN	Fraction of raw gas reserves sampled
CONVGROW	1999 raw gas production
CONVNEWF	Reserve growth in existing conventional fields
UNCONV	Conventional new field potential
TYPUNCNV	Type of unconventional gas: TIGHT, COAL, SHALE, LOW_Btu, CoProduction
PRD	1999 production CO2>2%
RUR	1999 reserves of CO2>2%
UND	Undiscovered resources of CO2>2%

SW_NonFuelPlants								
B12. EIA Summary	***B13. Cement In Region***	***B14. Cement Manufactors***	***B15. Anhydrous Ammonia 96***	***B16. Ammonia In Region***	***B17. Chlorine Plants***	***B18. Ethylene Plants***	***B19. EOR***	***B20. Refineries***
CO2 Emissions	Company	Company	Licensor/ Construction	Company	Company	Company	Type	
States	Plant Name	Website	City	City	City	Location	Operator	
Energy - Residential	address	US?	State	State	State	State	Field	
Energy - commercial	City		Tonnes/year	k METRIC TONS/YEAR	Capacity (Kt/year)	Year of start up	State	
Energy - Industrial	State		Feedstock		Age of Process in 1994	Ethylene Capacity (ktonne/a)	County	
Energy - Transport	Zip				Process	Ethane	Pay zone	
Energy- Utility	Phone					Propane	Formation	
Energy - Exported Electricity	PhoneFree					Butane	Project Maturity	
Energy - Other	Fax					Naphtha	Proj. Eval	
Total Energy	NoKilms					Gas oil	Profit	
Waste	K ton/y					Other	Project Scope	
Agriculture						Licensor, Remarks		
Industry								
Land Use								
Total								

SW_ElectricPlants_CO_2_Tons_%	
B21.	***SW_ElectricPlants_CO2_Tons_%***

STATE
ORIS_CODE
FACILITY_NAME
UNIT_ID
YEAR
SumOfCO2_TONS
SumOfSO2_TONS

SumOfNOX_TONS
SumOfHEAT_INPUT
SumOfTOTAL_OPERATING_HOURS
DESCRIPTION_SPECIFIC
DESCRIPTION_GENERIC
CO2_CONCENTRATION

SW_99v3AirDataFacilitiesFile				
***B22.* BLC_SW**	***B23.* RBLC_SW_ElectGen**	***B24.* NH3 Release**	***B25.* ORIS_Facility_Code**	
STATE FIPS	STATE FIPS	P200_STATE_FIPS	ORISPL	ORIS Plant Code in eGRID 1999
COUNTY FIPS	COUNTY FIPS	P200_COUNTY_FIPS	FIPST	State FIPS code (text field for matching to NEI)
STATE ABBREV	STATE ABBREV	P200_SITE_ID	FIPSCNY	County FIPS code
COUNTY NAME	COUNTY NAME	P200_ORIS_FACILITY_CODE	ORISPL_In_NEI_V300_Draft	Identifies the codes that have been entered in the ORIS facility Code field in the Site table of draft Version 3 of the 1999 NEI
FACILITY ID	FACILITY ID	P200_SIC_PRIMARY	SiteID_In_NEI_V300_Draft	Identifies the site ID associated with the ORIS Facility Code in the Site table of draft Version 3 of the 1999 NEI
FACILITY NAME	FACILITY NAME	P200_FACILITY_NAME	FIPST_NUM	State FIPS code (text field for matching to NEI)
STREET	STREET	P200_SITE_DESCRIPTION	FIPSCNY_NUM	County FIPS code
CITY	CITY	P200_STREET_LINE_1	PSTATABB	Postal code abbreviation of the State where the plant is located
STATE	STATE	P200_STREET_LINE_2	CNTYNAME	County name
ZIP	ZIP	P200_STREET_LINE_3	PNAME	Plant name
FACILITY ADDRESS	FACILITY ADDRESS	P200_CITY	OPRNAME	Plant operator name
EPAREGION	EPA REGION	P200_STATE	OPPRNAME	Operator parent company name
INVENTORY YEAR	INVENTORY YEAR	P200_ZIP_CODE	PCANAME	Physical (operator) based power control area name
SIC	SIC	P200_NH3_EMISSION_TON_SUM	PLTYPE	Plant type (utility or nonutility)
LATITUDE	LATITUDE	MATCH_TYPE	PREVUTIL	Previously a utility plant flag (this field has a value of 1 if the plant has been sold by a utility to a nonutility; it has a value of 0 otherwise)
LONGITUDE	LONGITUDE	MATCH_MULTIPLE	LAT	Plant latitude
CO	CO	MATCH_RATIO	LON	Plant longitude

NH3	NH3	NH3_TO_APPLY_ EMISSION_TON_ SUM	NUMBLR	Number of utility boilers within a plant
NOX	NOX	P300_STATE_ FIPS	NUMGEN	Number of generators within a plant
PMCON	PMCON	P300_COUNTY_ FIPS	SOURCEM	The source(s) of emissions data for the plant. The choices are: T- ETS/CEM Knox, SO2, and CO2 emissions reported to EPA; E=Emissions estimated by applying EPA AP-42 emission factors to fuel data from EIA-767, EIA-759/FERC-423, EIA-860B, r default values: and Z=Plant utilizes energy resources with zero emissions.
PMFIL	PMFIL	P300_SITE_ID	PLPRIMFL	Plant's primary fuel based on maximum heat input or assignment (if plant is solar, wind, nuclear, geothermal, or hydro) (see eGRID technical support document for definition of codes used in this field).
PMPRI	PMPRI	P300_ORIS_ FACILITY_CODE	PLFFLCTG	Plant Fossil Fuel Category (field contains a "C" if PLPRIMPL is derived from coal, "O" if it derived from oil, or "G" if it is derived from gas. The value is blank otherwise. Fossil Fuel refers to any naturally occurring organic fuel, such as petroleum, coal, and natural gas)
PM10FIL	PM10FIL	P300_SIC_PRIMARY	CAPFAC	Plant capacity factor
PM10PRI	PM10PRI	P300_FACILITY_ NAME	BOILCAP	Utility plant boiler capacity (MW)
PM25FIL	PM25FIL	P300_SITE_ DESCRIPTION	NAMEPCAP	Plant Generator capacity (MW)
PM25PRI	PM25PRI	P300_STREET_ LINE_1	CHPFLAG	Combined heat and power (CHP) (cogenerator) 1998 plant flag
SO2	SO2	P300_STREET_ LINE_2	USETHRMO	CHP plant 1998 useful thermal output (MMBtu)
VOC	VOC	P300_STREET_ LINE_3	PWRTOHT	CHP plant 1998 power to heat ratio
		P300_CITY	ELCALLOC	CHP plant 1998 electric allocation factor
		P300_STATE	PLNUCONN	Nonutility plant connected to grid flag (Y=yes, N=no)
		P300_ZIP_CODE		
		P300_NH3_ EMISSION _TON_SUM		

SW_Coorid fromEPA_HAP
B26. SW
strState Facility Identifier
strSICPrimary
strNAICSPrimary
strFacilityName
strSite Description
strLocation Address
strCity
srtState
strZipCode
strCountry
dblXCoordinate
dblYCoordinate
intUTMZone
strXY Coordinate Type

RACT_BACT_laer	SW_NATCARB_Data_Facilities with Match to RACT_BACT_laer	SW_minerals_usgs_gov
B27. SW	***B28. Facilities1030617920***	***B29. SW***
ORIS_CODE	RBLCID	Mineral
RBLCID	ORIS_CODE	Beryllium concentrates
FACILITY	FACILITY_NAME	Cement:
COMPANY		Masonry
COUNTY		Portland
CONTACT		Clays:
ADDRESS		Bentonite
CITY		Common
STATE		Fuller's earth
ZIP		Kaolin
PHONE		Copper[3]
EMAIL		Gemstones
REGION		Gold[3]
AGENCYCODE		Gypsum, crude
AGENCYNAME		Helium, crude
AGENCYCONTACT		Grade-A
AGENCYPHONE		Iodine, crude
AGENCYEMAIL		Lime
PERMITNUM		Salt
SIC		Sand and gravel:
NAICS		Construction
AIRSID		Industrial
EPAID		Silver[3]
UTMZONE		Stone:
XCOORD		Crushed
YCOORD		Dimension
RCVDDATE		Talc, crude
PERMITDATE		Tripoli
STARTUPDATE		
VERIFYDATE		
ENTRYDATE		
LASTUPDATE		
NEW_MOD		
PUBLICHEAR		
FUEL		
EMISSSOURCES		
ABATEMENT		
NARRATIVE		
NOTES		
PROCESS		
PROCTYPE		

SCC
FUEL
THRUPUT
THRUPUTUNIT
COMPVERIFY
STACKTEST
INSPECTION
CALCULATED
OTHERTEST
OTHERMETHD
PRNOTES
POLLUTANT
CAS
CONTROLCOD
CTRLDESC
RANKOPTS
RANKSEL
EMISLIMIT1
EMISLIMIT1UNIT
EMISLIMIT1CONDITION
BASIS
PCTEFFIC
EMISLIMIT2
EMISLIMIT2UNIT
EMISLIMIT2CONDITION
STDEMISS
STDUNIT
STOTHERCONDITIONS
EMISSTYPE
CAPCOST
ANNUALCOST
OMCOST
COSTEFFECT
COSTVERIFY
DOLLARYEAR
POLNOTES

B30. Contents	B31. EGRDPLNT00	B32. EGRDBLR00	B33. EGRDGEN00	B34. EGRDPLCH	B35. EGRDEGCH	B36. EGRDPRCH	B37. EGRDPCCH
	SEQPLT00 eGRID2002 2000 file plant sequence number	**SEQBLR00** eGRID2002 2000 file boiler sequence number	**SEQGEN00** eGRID2002 2000 file generator sequence number	**SEQPLCH** eGRID2002 plant change sequence number	**SEQEGCH** eGRID2002 EGC change sequence number	**SEQPRCH** eGRID2002 parent company change sequence number	**SEQPCCH** eGRID2002 PCA change sequence number
	SEQPLT99 eGRID2002 1999 file plant sequence number	**SEQBLR99** eGRID2002 1999 file boiler sequence number	**SEQGEN99** eGRID2002 1999 file generator sequence number	**SEQPLT00** eGRID2002 2000 file plant sequence number	**SEQEGO00** eGRID2002 2000 file owner-based EGC sequence number	**SEQPRO00** eGRID2002 2000 file owner-based parent company sequence number	**SEQPCO00** eGRID2002 2000 file owner-based PCA sequence number
	PSTATABB State abbreviation	**PSTATABB** State abbreviation	**PSTATABB** State abbreviation	**SEQPLT98** eGRID2002 1998 file plant sequence number	**SEQEGP00** eGRID2002 2000 file location (operator)-based EGC sequence number	**SEQPRP00** eGRID2002 2000 file location (operator)-based parent company sequence number	**SEQPCP00** eGRID2002 2000 file location (operator)-based PCA sequence number
	PNAME Plant name	**PNAME** Plant name	**PNAME** Plant name	**PNAME** Plant name	**SEQEGO98** eGRID2002 1998 file owner-based EGC sequence number	**SEQPRO98** eGRID2002 1998 file owner-based parent company sequence number	**SEQPCO98** eGRID2002 1998 file owner-based PCA sequence number
	ORISPL DOE/EIA ORIS plant or facility code	**ORISPL** DOE/EIA ORIS plant or facility code	**ORISPL** DOE/EIA ORIS plant or facility code	**ORISPL** DOE/EIA ORIS plant or facility code	**SEQEGP98** eGRID2002 1998 file location (operator)-based EGC sequence number	**SEQPRP98** eGRID2002 1998 file location (operator)-based parent company sequence	**SEQPCP98** eGRID2002 1998 file location (operator)-based PCA sequence number

SW_ElectricPlants_eGRID

number

PLTYPE Plant type

PREVUTIL Previously a utility plant flag

CHANGE Change? – If Y, go to EGRDPLCH file

OPRNAME Plant operator name

OPRCODE Plant operator ID

UTLSRVNM Nonutility's service area name

UTLSRVID Nonutility's service area ID

OPPRNUM Location (operator)-based parent company ID

BLRID Boiler ID

AFFECTED Affected flag

BOTFIRTY Boiler bottom and firing types

BOILCAP Boiler capacity (MMBtu/hr)

NUMGEN Number of associated generators

FUELB1 Primary boiler fuel

LOADHRS Hours connected to load

HTIEAN Boiler 2000 annual ETS/CEM heat input (MMBtu)

GENID Generator ID or grouped identifier

GENTYPE Generator type

NUMBLR Number of associated boilers

GENSTAT Generator 2000 status

PRMVR Prime mover type

FUELG1 Primary generator fuel

NAMEPCAP Generator nameplate capacity (MW)

CFACT Generator 2000 capacity factor

CHTYPE Type of note

CHDATE Change date (yymm)

OLDNAME Old name

OLDID Old ID

NEWNAME New name

NEWID New ID

PRVOWNTY Previous owner type, if CHTYPE= OWN or OPR

OLDPERC Old percent, if CHTYPE=OWN

EGCNAME EGC name

EGCID EGC ID

CHTYPE Type of note

CHDATE Change year

CHDESC Note text

OLDNAME Old name

OLDID Old ID

NEWNAME New name

PRNAME Parent company name

PRNUM Parent company ID

CHTYPE Type of note

CHDATE Change year

CHDESC Note text

OLDNAME Old name

OLDID Old ID

NEWNAME New name

PCANAME PCA name

PCAID PCA ID

CHTYPE Type of note

CHDATE Change year

CHDESC Note text

OLDNAME Old name

OLDID Old ID

NEWNAME New name

OPPRNAME
Location (operator)-based parent company name

PCANAME
Location (operator)-based power control area name

PCAID
Location (operator)-based power control area ID

NERC
Location (operator)-based NERC region acronym

NERCNUM
NERC number associated with NERC region

SUBRGN
eGRID subregion acronym

HTIEOZ
Boiler 2000 ozone season ETS/CEM heat input (MMBtu)

HTIFAN
Boiler 2000 annual total EIA-based calculated heat input (MMBtu)

HTIFOZ
Boiler 2000 ozone season EIA-based calculated heat input (MMBtu)

HTICL
Boiler 2000 annual EIA-based calculated coal heat input (MMBtu)

HTIOL
Boiler 2000 annual EIA-based calculated oil heat input (MMBtu)

HTIGS
Boiler 2000 annual EIA-based calculated gas heat input (MMBtu)

GENNTAN
Generator 2000 annual net generation (MWh)

GENNTOZ
Generator 2000 ozone season net generation (MWh)

GENYRONL
Generator year on-line

SEQGEN
eGRID96 1996 file generator sequence number

SEQGEN97
eGRID97 1997 file generator sequence number

SEQGEN98
eGRID2000 1998 file generator sequence number

NEWPERC
New percent, if CHTYPE=OWN

NEWID
New ID

NEWID
New ID

NEWID
New ID

SRNAME eGRID subregion name	**HTIBM** Boiler 2000 annual EIA-based calculated biomass/ wood heat input (MMBtu)
FIPST Plant FIPS State code	**HTISW** Boiler 2000 annual EIA-based calculated solid waste heat input (MMBtu)
FIPSCNY Plant FIPS county code	**HTIOT** Boiler 2000 annual EIA-based calculated other fuel heat input (MMBtu)
CNTYNAME Plant county name	**HTIBAN** Boiler 2000 annual best heat input (MMBtu)
LAT Plant latitude	**HTIBOZ** Boiler 2000 ozone season best heat input (MMBtu)
LON Plant longitude	**NOXEAN** Boiler 2000 annual ETS/CEM NOx emissions (tons)

NUMBLR
Number of utility boilers

NUMGEN
Number of generators

SOURCEM
Plant emissions source(s)

PLPRIMFL
Plant primary fuel

PLFFLCTG
Plant fossil fuel category

CAPFAC
Plant capacity factor

NOXEOZ
Boiler 2000 ozone season ETS/CEM NOx emissions (tons)

NOXFAN
Boiler 2000 annual EIA-based calculated NOx emissions (tons)

NOXFOZ
Boiler 2000 ozone season EIA-based calculated NOx emissions (tons)

SO2EAN
Boiler 2000 annual ETS/CEM SO2 emissions (tons)

SO2FAN
Boiler 2000 annual EIA-based calculated SO2 emissions (tons)

CO2EAN
Boiler 2000 annual ETS/CEM CO2 emissions (tons)

BOILCAP
Utility plant boiler capacity (MMBtu/hr)

NAMEPCAP
Plant generator capacity (MW)

CHPFLAG
Combined heat and power (CHP) (cogenerator) 2000 plant flag

USETHRMO
CHP plant 2000 useful thermal output (MMBtu)

PWRTOHT
CHP plant 2000 power to heat ratio

ELCALLOC
CHP plant 2000 electric allocation factor

PLNUCONN
Nonutility plant connected to grid flag

CO2FAN
Boiler 2000 annual EIA-based calculated CO2 emissions (tons)

SRCBEST
Source of "best" 2000 heat input, NOx, SO2, and CO2 data

NOXBAN
Boiler 2000 annual best NOx emissions (tons)

NOXBOZ
Boiler 2000 ozone season best NOx emissions (tons)

SO2BAN
Boiler 2000 annual best SO2 emissions (tons)

CO2BAN
Boiler 2000 annual best CO2 emissions (tons)

SO2CTLDV
2000 SO2 (scrubber) control device for utilities

PSFLG
Plant pumped storage flag

ARDBNU
ARD nonutility flag

LMSWFLG
Nonutility plant landfill methane or solid waste flag

PLNUCMBS
Plant nonutility combustion flag

PLNUCOAL
Plant nonutility coal flag

UTNOWNU
Now nonutility flag

GENERVAL
Generation value source

NOXCTLDV
2000 NOx control device for utilities

T4A00
Year 2000 Title IV SO2 1998 reallocation plus repowering allowance (tons)

T4A10
Year 2010 Title IV SO2 1998 reallocation plus repowering allowance (tons)

BLRYRONL
Boiler year on-line

BLRSEQ
Unique boiler identifier originating in NADB, and continuing in ARDB and IMDB data files

SEQBLR
eGRID96 1996 file boiler sequence number

SEQBLR97
eGRID97 1997 file boiler sequence number

	SEQBLR98 **eGRID2000 1998 file boiler sequence number**
EMISVAL **Emission value source**	
RESMXVAL **Resource mix value source**	
PLHTIAN **Plant 2000 annual heat input (MMBtu)**	
PLHTIOZ **Plant 2000 ozone season heat input (MMBtu)**	
PLGGENAN **Plant 2000 annual gross generation (MWh)**	
PLNGENAN **Plant 2000 annual net generation (MWh)**	
PLNGENOZ **Plant 2000 ozone season net generation (MWh)**	
PLNOXAN **Plant 2000 annual NOx emissions (tons)**	
PLNOXOZ **Plant 2000 ozone season NOx emissions (tons)**	

PLSO2AN
Plant 2000 annual SO2 emissions (tons)
PLCO2AN
Plant 2000 annual CO2 emissions (tons)

PLHGAN
Plant 2000 annual mercury emissions (lbs)
PLNOXRTA
Plant 2000 annual NOx output emission rate (lbs/MWh)
PLNOXRTO
Plant 2000 ozone season NOx output emission rate (lbs/MWh)
PLSO2RTA
Plant 2000 annual SO2 output emission rate (lbs/MWh)
PLCO2RTA
Plant 2000 annual CO2 output emission rate (lbs/MWh)

PLHGRTA
Plant 2000 annual mercury output emission rate (lbs/GWh)
PLNOXRA
Plant 2000 annual NOx input emission rate (lbs/MMBtu)
PLNOXRO
Plant 2000 ozone season NOx input emission rate (lbs/MMBtu)
PLSO2RA
Plant 2000 annual SO2 input emission rate (lbs/MMBtu)
PLCO2RA
Plant 2000 annual CO2 input emission rate (lbs/MMBtu)

PLHGRA
Plant 2000 annual mercury input emission rate (lbs/BBtu)
PLHTRT
Plant 2000 nominal heat rate (Btu/kWh)

PLGENACL
Plant 2000 annual coal net generation (MWh)
PLGENAOL
Plant 2000 annual oil net generation (MWh)
PLGENAGS
Plant 2000 annual gas net generation (MWh)
PLGENANC
Plant 2000 annual nuclear net generation (MWh)
PLGENAHY
Plant 2000 annual hydro net generation (MWh)
PLGENABM
Plant 2000 annual biomass/ wood net generation (MWh)
PLGENAWI
Plant 2000 annual wind net generation (MWh)
PLGENASO
Plant 2000 annual solar net generation (MWh)

PLGENAGT
Plant 2000 annual geothermal net generation (MWh)
PLGENAOF
Plant 2000 annual other fossil (tires, batteries, chemicals, etc.) net generation (MWh)
PLGENASW
Plant 2000 annual solid waste net generation (MWh)
PLGENATN
Plant 2000 annual total nonrenewables net generation (MWh)
PLGENATR
Plant 2000 annual total renewables net generation (MWh)
PLGENATH
Plant 2000 annual total nonhydro renewables net generation (MWh)

PLCLPR
Plant 2000 coal generation percent (resource mix)
PLOLPR
Plant 2000 oil generation percent (resource mix)
PLGSPR
Plant 2000 gas generation percent (resource mix)
PLNCPR
Plant 2000 nuclear generation percent (resource mix)
PLHYPR
Plant 2000 hydro generation percent (resource mix)
PLBMPR
Plant 2000 biomass/ wood generation percent (resource mix)
PLWIPR
Plant 2000 wind generation percent (resource mix)
PLSOPR
Plant 2000 solar generation percent

(resource mix)

PLGTPR
Plant 2000 geothermal generation percent (resource mix)

PLOFPR
Plant 2000 other fossil (tires, batteries, chemicals, etc.) generation percent (resource mix)

PLSWPR
Plant 2000 solid waste generation percent (resource mix)

PLTNPR
Plant 2000 total nonrenewables generation percent (resource mix)

PLTRPR
Plant 2000 total renewables generation percent (resource mix)

PLTHPR
Plant 2000 total nonhydro renewables generation percent

(resource mix)

OWNRNM01
Plant 2000 owner name (first)
OWNRUC01
Plant 2000 owner code (first)
OWNRPR01
Plant 2000 owner percent (first)
OWNRTY01
Plant 2000 owner type (first)
OWNRNM02
Plant 2000 owner name (second)
OWNRUC02
Plant 2000 owner code (second)
OWNRPR02
Plant 2000 owner percent (second)
OWNRTY02
Plant 2000 owner type (second)
OWNRNM03
Plant 2000 owner name (third)

OWNRUC03
Plant 2000 owner code (third)
OWNRPR03
Plant 2000 owner percent (third)
OWNRTY03
Plant 2000 owner type (third)
OWNRNM04
Plant 2000 owner name (fourth)
OWNRUC04
Plant 2000 owner code (fourth)
OWNRPR04
Plant 2000 owner percent (fourth)
OWNRTY04
Plant 2000 owner type (fourth)
OWNRNM05
Plant 2000 owner name (fifth)
OWNRUC05
Plant 2000 owner code (fifth)
OWNRPR05
Plant 2000 owner percent (fifth)

OWNRTY05
Plant 2000 owner type (fifth)
OWNRNM06
Plant 2000 owner name (sixth)
OWNRUC06
Plant 2000 owner code (sixth)
OWNRPR06
Plant 2000 owner percent (sixth)
OWNRTY06
Plant 2000 owner type (sixth)
OWNRNM07
Plant 2000 owner name (seventh)
OWNRUC07
Plant 2000 owner code (seventh)
OWNRPR07
Plant 2000 owner percent (seventh)
OWNRTY07
Plant 2000 owner type (seventh)
OWNRNM08
Plant 2000 owner name (eighth)

OWNRUC08
Plant 2000 owner code (eighth)
OWNRPR08
Plant 2000 owner percent (eighth)
OWNRTY08
Plant 2000 owner type (eighth)
OWNRNM09
Plant 2000 owner name (ninth)
OWNRUC09
Plant 2000 owner code (ninth)
OWNRPR09
Plant 2000 owner percent (ninth)
OWNRTY09
Plant 2000 owner type (ninth)
OWNRNM10
Plant 2000 owner name (tenth)
OWNRUC10
Plant 2000 owner code (tenth)
OWNRPR10
Plant 2000 owner percent (tenth)

OWNRTY10
Plant 2000 owner type (tenth)
OWNRNM11
Plant 2000 owner name (eleventh)
OWNRUC11
Plant 2000 owner code (eleventh)
OWNRPR11
Plant 2000 owner percent (eleventh)
OWNRTY11
Plant 2000 owner type (eleventh)
OWNRNM12
Plant 2000 owner name (twelfth)
OWNRUC12
Plant 2000 owner code (twelfth)
OWNRPR12
Plant 2000 owner percent (twelfth)
OWNRTY12
Plant 2000 owner type (twelfth)
OWNRNM13
Plant 2000 owner name (thirteenth)

OWNRUC13
Plant 2000 owner code (thirteenth)
OWNRPR13
Plant 2000 owner percent (thirteenth)
OWNRTY13
Plant 2000 owner type (thirteenth)
OWNRNM14
Plant 2000 owner name (fourteenth)
OWNRUC14
Plant 2000 owner code (fourteenth)
OWNRPR14
Plant 2000 owner percent (fourteenth)
OWNRTY14
Plant 2000 owner type (fourteenth)
SEQPLT
eGRID96 1996 file plant sequence number
SEQPLT97
eGRID97 1997 file plant sequence number
SEQPLT98
eGRID2000 1998 file plant sequence number

SW_EthanolPlants	
*B38. **Ethanol Production***	*B39. **SW_Ethanol Production***
COMPANY	**COMPANY**
LOCATION	**LOCATION**
STATE	**STATE**
FEEDSTOCK	**FEEDSTOCK**
Current Capacity (mmgy)	**Current Capacity (mmgy)**
Under Construction/ Expansion (mmgy)	**Under Construction/ Expansions (mmgy)**
	Address
Ethanol Plants Currently Operating	**City/State/Zip**
City	
State	
MGY	

SUB-APPENDICES – WORKSHEETS

strStateFacilit	strSIC	strNAICS	strFacilityName	srtState	dblXCoord	dblYCoord	intUTMZo	strXYCoor
T$12468	1061	2122	AMERICAN MINERALS INC.	NM	-107.7336	32.27778		LATLON
T$12022	1061	2122	AMERICAN MINERALS INC.	TX	-106.5518	31.8093		LATLON
0278	1311	211111	AMOCO PROD. CO. - J.B. GARDNER A #1	CO	-107.9203	37.005	13	LATLON
0280	1311	211111	AMOCO PRODUCTION - EVELYN PAYNE GU #1	CO	-107.5511	37.258	13	LATLON
0083	1311	211111	AMOCO PRODUCTION CO PICNIC FLATS	CO	-107.9898	37.0732	13	LATLON
0279	1311	211111	AMOCO PRODUCTION CO - ROBERT DULIN D #1	CO	-107.6046	37.2725	13	LATLON
0273	1311	211111	AMOCO PRODUCTION CO GEARHART WELL #1-6	CO	-107.6778	37.244	13	LATLON
0274	1311	211111	AMOCO PRODUCTION CO LORETT FEDERAL GU #1	CO	-107.6679	37.1913	13	LATLON
0025	1311	211111	AMOCO PRODUCTION CO WATTENBERG PLT	CO	-104.6779	39.7448	13	LATLON
0277	1311	211111	AMOCO PRODUCTION CO.- ROBIN FRAZIER A	CO	-107.9027	37.005	13	LATLON
0444	1311	211111	ANTELOPE ENERGY COMPANY-TERANCE PLANT	CO	-103.8969	40.8454	13	LATLON
081230099	1311	211111	ASSOCIATED NATURAL GAS GREELEY PLT	CO	-104.8525	40.49639		LATLON
081230074	1311	211111	ASSOCIATED NATURAL GAS INC SINGLETREE	CO	-104.8122	40.14556		LATLON
081230015	1311	211111	ASSOCIATED NATURAL GAS INC SPINDLE PLT	CO	-104.8825	40.08917		LATLON
081230075	1311	211111	ASSOCIATED NATURAL GAS INC SURREY PLT	CO	-104.8864	40.01583		LATLON
081230076	1311	211111	ASSOCIATED NATURAL GAS INC WEST SPINDLE	CO	-104.8858	40.0875		LATLON
081230125	1311	211111	ASSOCIATED NATURAL GAS SPINDLE AIR PLT	CO	-104.885	40.0875		LATLON
081230068	1311	211111	ASSOCIATED NATURAL GAS WATTENBERG	CO	-104.8944	40.12111		LATLON
0145	1311	211111	BARGARTH INC GRAND VALLEY GAS PROC	CO	-108.1116	39.3219	12	LATLON
0089	1311	211111	BARRETT RESOURCES CORP RULISON ANVIL PTS	CO	-107.9096	39.4961	13	LATLON
0029	1311	211111	BITTER CREEK PIPELINES - YENTER C.S.	CO	-103.3965	40.6909	13	LATLON
0016	1311	211111	BURR OIL & GAS INC. - CROSS CANYON #1	CO	-108.9854	37.566	12	LATLON
1189	1311	211111	CASCADE OIL & GAS INC	CO	-104.5176	39.9776	13	LATLON
080330012	1311	211111	CELSIUS ENERGY CO DOVE CREEK PLT	CO	-108.87	37.76		LATLON
080810066	1311	211111	CELSIUS ENERGY CO HIAWATHA CO2 EXTR FAC	CO	-108.6247	40.99028		LATLON
0153	1311	211111	CER CORP MWX-1 GAS WELL	CO	-107.8811	39.4833	13	LATLON
0034	1311	211111	CHEVRON USA PRODUCTION CO RANGELY FIELD	CO	-108.9281	40.1042	12	LATLON
081030055	1311	211111	COLORADO INTERSTATE GAS CO GREASEWOOD	CO	-108.1906	39.89694		LATLON
0001	1311	211111	COLORADO INTERSTATE GAS CO KIT CARSON	CO	-102.6206	38.673	13	LATLON
0007	1311	211111	COLORADO INTERSTATE GAS CO VILAS C S	CO	-102.472	37.3237	13	LATLON
081030036	1311	211111	CONOCO INC DRAGON TRAIL GAS PROC PLT	CO	-108.8089	39.83139		LATLON
081030032	1311	211111	CONOCO INC NATURAL GAS WEST DOUGLAS	CO	-108.7567	39.81111		LATLON
0103	1311	211111	CUSTOM ENERGY CONSTRUCTION INC BUCK PEAK	CO	-107.4977	40.4858	13	LATLON
0099	1311	211111	DUKE ENERGY FIELD SERVICES - GREELEY	CO	-104.8525	40.4965	13	LATLON
0049	1311	211111	DUKE ENERGY FIELD SERVICES - ROGGEN	CO	-104.3898	40.1193	13	LATLON
0015	1311	211111	DUKE ENERGY FIELD SERVICES - SPINDLE	CO	-104.8827	40.0893	13	LATLON
0036	1311	211111	EL PASO CORPORATION - DRAGON TRAIL GAS	CO	-108.809	39.8308	12	LATLON
0016	1311	211111	EL PASO CORPORATION - EAST DRAGON TRAIL	CO	-108.7904	39.8296	12	LATLON
081010098	1311	211111	FUEL RESOURCES DEV SYNHYTEC	CO	-104.7144	38.21917		LATLON
0333	1311	211111	GATEWAY PROCESSING CO	CO	-108.22	38.931		LATLON
080810124	1311	211111	GRYNBERG PETROLEUM COMPANY SUGAR LOAF	CO	-108.6833	40.94472		LATLON
080810123	1311	211111	GRYNBERG PETROLEUM COMPANY BLUE GRAVEL	CO	-107.6508	40.69417		LATLON
0019	1311	211111	HORSESHOE OPERATING INC LA DRY CREEK	CO	-102.8027	37.8602	13	LATLON
080110018	1311	211111	HORSESHOE OPERATING INC WAGON TRAIL	CO	-102.8211	38.06417		LATLON
080010501	1311	211111	IRONDALE GAS PROCESSING CO IRONDALE CS2	CO	-104.3803	39.86694		LATLON
0082	1311	211111	KN GAS GATHERING BLACK SULPHUR LIQUIDS	CO	-108.3053	39.8625	12	LATLON
081030083	1311	211111	KN GAS GATHERING PICEANCE CREEK	CO	-108.2661	40.04056		LATLON
080050519	1311	211111	KOCH HYDROCARBON CO DENVER CTL PLT	CO	-104.3544	39.64139		LATLON

strStateFacilit	strSIC	strNAICS	strFacilityName	srtState	dblXCoord	dblYCoord	intUTMZo	strXYCoor
080010628	1311	211111	KOCH HYDROCARBON CO KALLSEN PLT	CO	-104.3333	39.87861		LATLON
080010629	1311	211111	KOCH HYDROCARBON CO LINNEBURG PLT	CO	-103.9558	39.94056		LATLON
080010627	1311	211111	KOCH HYDROCARBON CO STATE PLT	CO	-104.6767	39.96222		LATLON
080310950	1311	211111	KOCH HYDROCARBON CO THIRD CREEK PLT	CO	-104.6969	39.88472		LATLON
080990057	1311	211111	MARATHON OIL CO SNIFF E1	CO	-102.7844	38.04944		LATLON
080830033	1311	211111	MID AMERICA PIPELINE CO DOLORES STA	CO	-108.4328	37.41444		LATLON
0031	1311	211111	MITCHELL ENERGY CORP HELLS HOLE CANYON	CO	-109.005	39.9236	12	LATLON
0005	1311	211111	MULL DRILLING CO INC SORRENTO FIELD	CO	-102.6025	38.8709	13	LATLON
080770180	1311	211111	NATL FUEL CORP	CO	-108	39.26583		LATLON
081230127	1311	211111	NORTH AMERICAN RESOURCES CO ARISTOCRAT	CO	-104.6167	40.25		LATLON
0319	1311	211111	NORTH AMERICAN RESOURCES CO FT LUPTON	CO	-104.7394	40.1486	13	LATLON
0950	1311	211111	NORTH AMERICAN RESOURCES CO THIRD CREEK	CO	-104.7487	39.78118	13	LATLON
0628	1311	211111	NORTH AMERICAN RESOURCES CO_ KALLSEN	CO	-104.3311	39.8811	13	LATLON
081070047	1311	211111	NORTHERN NATURAL GAS CO ENRON ROUTT NO 1	CO	-107.3942	40.29889		LATLON
080770183	1311	211111	PUBLIC SERVICE CO ASBURY	CO	-108.6472	39.23028		LATLON
0121	1311	211111	PUBLIC SERVICE CO BAXTER STATION	CO	-108.8633	39.3958	12	LATLON
081030016	1311	211111	PUBLIC SERVICE CO DRAGON TRAIL	CO	-108.79	39.82972		LATLON
0086	1311	211111	PUBLIC SERVICE CO GREASEWOOD STATION	CO	-108.1925	39.9058	12	LATLON
080770182	1311	211111	PUBLIC SERVICE CO HUNTER CANYON	CO	-108.5914	39.33139		LATLON
081030056	1311	211111	PUBLIC SERVICE CO INDIAN VALLEY	CO	-108.1928	40.10139		LATLON
0087	1311	211111	PUBLIC SERVICE CO NORTH DOUGLAS STATION	CO	-108.7745	39.9599	12	LATLON
0122	1311	211111	PUBLIC SERVICE CO RIFLE COMP STA	CO	-107.8166	39.5254	13	LATLON
081030048	1311	211111	PUBLIC SERVICE CO WHITE RIVER DOME	CO	-108.1908	40.09861		LATLON
0024	1311	211111	PUBLIC SERVICE CO WILLIAMS FORK STATION	CO	-106.0896	39.8626	13	LATLON
081230141	1311	211111	PUBLIC SERVICE CO YOSEMITE	CO	-104.8856	40.01472		LATLON
0024	1311	211111	QUESTAR EXPLORATION & PROD -CUTTHROAT A	CO	-108.9272	37.4723	12	LATLON
0132	1311	211111	QUESTAR GAS MANAGEMENT - AVALANCHE	CO	-107.6493	40.993	13	LATLON
0135	1311	211111	QUESTAR GAS MANAGEMENT CO E.HIAWATHA	CO	-108.1817	40.6116	13	LATLON
0131	1311	211111	QUESTAR GAS MANAGEMENT CO SAND HILL	CO	-107.6209	40.9514	13	LATLON
0006	1311	211111	QUESTAR GAS MANAGEMENT DOVE CREEK PLT	CO	-108.8651	37.7857	12	LATLON
080330006	1311	211111	QUESTAR PIPELINE CO DOVE CREEK PLT	CO	-108.8647	37.78556		LATLON
081030037	1311	211111	ROCKY MOUNTAIN NATURAL GAS CO PICEANCE	CO	-108.2628	40.04333		LATLON
081130007	1311	211111	ROCKY MOUNTAIN NATURAL GAS CO SLICK ROCK	CO	-108.8925	38.02056		LATLON
081130016	1311	211111	ROCKY MOUNTAIN NATURAL GAS NICHOLAS DRAW	CO	-108.8192	38.03083		LATLON
0068	1311	211111	ROCKY MTN NATURAL GAS CO BLACK SULPHUR	CO	-107.8557	40.03395	13	LATLON
0108	1311	211111	ROCKY MTN NATURAL GAS CO DEBEQUE C S	CO	-108.2598	39.3885	12	LATLON
0037	1311	211111	ROCKY MTN NATURAL GAS CO PICEANCE	CO	-108.263	40.0435	12	LATLON
0018	1311	211111	ROCKY MTN NATURAL GAS CO WOLF CREEK	CO	-107.407	39.3202	13	LATLON
080870034	1311	211111	ROGGEN GAS PROCESSING CO SITE NAME UNK	CO	-104.0503	40.46861		LATLON
0018	1311	211111	SHELL CO2 COMPANY - YELLOW JACKET	CO	-108.787	37.4715	12	LATLON
0020	1311	211111	SHELL CO2 COMPANY, LTD. - HOVENWEEP CO2 SOURCE	CO	-108.8623	37.49	12	LATLON
081230422	1311	211111	SNYDER OIL CO WEST GAS PLT	CO	-104.7967	40.23361		LATLON
081230049	1311	211111	SNYDER OIL CORP ROGGEN GAS PLT	CO	-104.3897	40.11944		LATLON
081230111	1311	211111	SNYDER OIL CORP THOMPSON VALLEY GAS PLA	CO	-104.9414	40.31472		LATLON
080870012	1311	211111	SNYDER OIL CORP VALLERY GAS PLT	CO	-103.9658	40.22278		LATLON
0098	1311	211111	SOUTHWESTERN PRODUCTION - GILCREST GAS	CO	-104.8059	40.2739	13	LATLON
0018	1311	211111	TBI FIELD SERVICES, INC- N DOUGLAS CREEK	CO	-108.6761	40.1336	12	LATLON
0077	1311	211111	TBI FIELD SERVICES, INC. - CLOUGH COMP.	CO	-107.862	39.527	13	LATLON

strStateFacilit	strSIC	strNAICS	strFacilityName	srtState	dblXCoord	dblYCoord	intUTMZo	strXYCoor
0020	1311	211111	TBI FIELD SERVICES, INC. - FOUNDATION CR	CO	-108.8035	39.6731	12	LATLON
0004	1311	211111	TBI FIELD SERVICES, INC. - GREASEWOOD	CO	-108.1891	39.9021	12	LATLON
0010	1311	211111	TEXACO E&P INC WILSON CREEK GAS PLT	CO	-107.9169	40.194	13	LATLON
0120	1311	211111	TEXACO EXPLOR & PROD - VAN SCHAIK B-3	CO	-108.696	40.9852	12	LATLON
0015	1311	211111	TOM BROWN INC - ANDY'S MESA	CO	-108.6398	38.0441	12	LATLON
0065	1311	211111	TOM BROWN INC TAIGA MTN 1-29	CO	-108.9809	40.0258	12	LATLON
0015	1311	211111	UNION PACIFIC RES CO ARAPAHOE PLT	CO	-102.7948	38.76645	13	LATLON
0010	1311	211111	UNION PACIFIC RES CO BLEDSOE RANCH	CO	-103.059	38.9541	13	LATLON
0008	1311	211111	UNION PACIFIC RES CO MT PEARL PLT	CO	-102.7523	38.8738	13	LATLON
080170014	1311	211111	UNION PACIFIC RESOURCES FRONTERA PLT	CO	-102.0406	38.795		LATLON
1274	1311	211111	UNITED STATES EXPLOR.-CARLSON 2 32-33	CO	-104.5546	39.8329	13	LATLON
081230119	1311	211111	VESSELS GAS PROC LTD FT LUPTON PROC PLT	CO	-104.8883	40.01639		LATLON
081230367	1311	211111	VESSELS GAS PROCESSING INC	CO	-104.995	40.00056		LATLON
081230148	1311	211111	VESSELS GAS PROCESSING LTD SPACE CITY	CO	-104.6317	40.08139		LATLON
081230132	1311	211111	VESSELS OIL &GAS FT LUPTON FRACTIONATION	CO	-104.8872	40.01583		LATLON
0468	1311	211111	WALSH PRODUCTION INC - LILLI GAS PROC.	CO	-103.8876	40.6922	13	LATLON
0128	1311	211111	WEST TEXAS GAS dba DAVIS GAS PROCESSING-	CO	-108.1542	39.8985	12	LATLON
080010228	1311	211111	WESTERN GAS RESOURCES INC CABIN CREEK	CO	-104.0392	39.75222		LATLON
0115	1311	211111	WILDHORSE ENERGY RIFLE BOULTON COMP	CO	-107.6159	39.4166	13	LATLON
081030020	1311	211111	WILLIAMS FIELD SVCS FOUNDATION CREEK	CO	-108.8033	39.67306		LATLON
081030018	1311	211111	WILLIAMS FIELD SVCS N DOUGLAS SITE	CO	-108.72	39.86		LATLON
0011	1311	211111	WILLIFORD ENERGY CO	CO	-102.8214	38.8752	13	LATLON
081230098	1311	211111	WINDSOR GAS PROCESSING INC	CO	-104.8056	40.27389		LATLON
00099	1311	211111	AMOCO PRODUCTION ULYSSES DEHY	KS	-101.3507	37.57915		LATLON
350150024	1311	211111	AGAVE ENERGY/YATES PLANT_____________1M3	NM	-104.4442	32.71222		LATLON
350150002	1311	211111	AMOCO PROD/EMPIRE ABO GAS PLNT_____126M3	NM	-104.2633	32.77167		LATLON
350250001	1311	211111	AMOCO PROD/S HOBBS CO2 INJECT STA___79M3	NM	-103.1553	32.66056		LATLON
350390028	1311	211111	APACHE CORP/BEAR CANYON______________814	NM	-107.0203	36.49		LATLON
350150101	1311	211111	ARCO PERMIAN/EMPIRE ABO INJECTION___12M1	NM	-104.2586	32.77306		LATLON
350450068	1311	211111	BURLINGTON RES/VALVERDE_______PSDNM728M6	NM	-107.9564	36.73139		LATLON
350150045	1311	211111	CONOCO/TURKEY TRACK GAS PLANT______457M1	NM	-104.04	32.65278		LATLON
350310004	1311	211111	CONOCO/WINGATE FRACTION PLANT_____1313R2	NM	-108.6392	35.54278		LATLON
350150102	1311	211111	EL PASO NATL GAS/BURTON FLATS______157M2	NM	-104.1486	32.56861		LATLON
350250006	1311	211111	EL PASO NATL GAS/JAL #1_____________0007	NM	-103.2097	32.06611		LATLON
350450042	1311	211111	FIVE OAKS/GALLEGOS CANYON__________131M1	NM	-107.8431	36.40111		LATLON
350450045	1311	211111	GULF ENERGY PROCESSING/GALLUP PLANT__458	NM	-108.3869	36.7475		LATLON
350410003	1311	211111	H.L.BROWN JR/BLUITT PLANT____________567	NM	-103.1833	33.635		LATLON
350250007	1311	211111	J.L.DAVIS GAS PROCESS/DENTON________65M2	NM	-103.1697	33.04611		LATLON
350390071	1311	211111	NIJECT/SAN JUAN 28-7 UNIT NITRO_____1495	NM	-107.5317	36.65611		LATLON
350150172	1311	211111	PARKER & PARSLEY/LOVING GAS PLNT____1172	NM	-104.0753	32.24028		LATLON
350250052	1311	211111	TEXACO/EUNICE NORTH GAS PLANT_______57M3	NM	-103.1628	32.44972		LATLON
350250051	1311	211111	TEXACO/EUNICE SOUTH GAS PLANT______278M4	NM	-103.1581	32.36139		LATLON
350410001	1311	211111	WARREN PETROLEUM/BLUITT GAS PLANT____563	NM	-103.2375	33.62056		LATLON
350150043	1311	211111	WARREN PETROLEUM/SNYDER RANCH FACIL__228	NM	-103.8694	32.65139		LATLON
350450247	1311	211111	WESTERN GAS RESOURCES/SAN JUAN RVR____GF	NM	-108.3675	36.75694		LATLON
0004	1311	211111	Wingate Fraction Plant	NM	-108.6394	35.5427	12	LATLON
350050050	1311	211111	YATES PETROLEUM/PATHFINDER AMINE___848M1	NM	-104.1983	33.42861		LATLON
401370203	1311	211111	MOBIL/SHOLEM ALECHEM GAS PLANT	OK	-97.605	34.4225		LATLON

strStateFacilit	strSIC	strNAICS	strFacilityName	srtState	dblXCoord	dblYCoord	intUTMZo	strXYCoor
2482	1311	211111	Swift Energy Company Weatherford Facility	OK	-98.728	35.4851	14	LATLON
483230006	1311	211111	ALKEK GAS PLANT	TX	-100.3891	28.64302		LATLON
481690005	1311	211111	CEDAR HILL GAS PLANT	TX	-101.2328	33.09556		LATLON
483230002	1311	211111	CRUDE OIL PRODUCTION	TX	-100.3891	28.64302		LATLON
48320	1311	211111	DAVIS GAS PROCESSING	TX	-101.3964	33.1635	14	LATLON
AG0002Q	1311	211111	EOG RESOURCES INC JOURDANTON GAS SWEETENING	TX	-98.59443	28.87301	14	LATLON
483230003	1311	211111	FESSMAN PLANT	TX	-100.3891	28.64302		LATLON
482250002	1311	211111	LAURA LAVELLE SOUTH	TX	-95.3658	31.25965		LATLON
481590004	1311	211111	NEW HOPE GAS PLANT	TX	-95.07278	33.23194		LATLON
BI0009J	1311	211111	WEST TEXAS GAS PROCESSING LP	TX	-101.2602	32.57091	14	LATLON
BI0011W	1311	211111	WEST TEXAS GAS PROCESSING LP	TX	-101.6003	32.61674	14	LATLON
HT0016G	1311	211111	WEST TEXAS GAS PROCESSING LP	TX	-101.3526	32.49712	14	LATLON
HT0059L	1311	211111	WEST TEXAS GAS PROCESSING LP	TX	-101.5234	32.51563	14	LATLON
484930005	1311	211111	WILSON COUNTY PLANT	TX	-98.06785	29.1603		LATLON
490139013	1311	211111	ALTONAH GAS PLANT	UT	-110.4395	40.3199		LATLON
55529	1311	211111	COASTAL FIELD ALTAMONT EAST	UT	-110.4395	40.3199	12	LATLON
55530	1311	211111	COASTAL FIELD ALTAMONT SOUTH	UT	-110.4395	40.3199	12	LATLON
55531	1311	211111	COASTAL FIELD ALTAMONT WEST	UT	-110.4395	40.3199	12	LATLON
490079095	1311	211111	DEW POINT PLANT	UT	-110.5648	39.64065		LATLON
490070013	1311	211111	DRUNKARDS WASH	UT	-110.86	39.58944		LATLON
55552	1311	211111	GARY-WILLIAMS BLUEBELL GAS PLANT	UT	-110.4395	40.3199	12	LATLON
10034	1311	211111	Lisbon Plant-Hook & Ladder	UT	-110.2266	37.7491		LATLON
560070006	1311	211111	AMOCO BAIROIL CO2	WY	-107.5142	42.22917		LATLON
560130008	1311	211111	AMOCO BEAVER CREEK	WY	-108.3139	42.84778		LATLON
560290012	1311	211111	AMOCO PROD CO.-ELK BASIN GAS PLANT	WY	-108.8539	44.52944		LATLON
560410006	1311	211111	AMOCO PRODUCTION COMPANY - ANSCHUTZ	WY	-111.0406	41.07528		LATLON
560070017	1311	211111	AMOCO PRODUCTION COMPANY - WERTZ PL	WY	-106.9999	41.71695		LATLON
5604100006	1311	211111	AMOCO PRODUCTION COMPANY _ ANSCHUTZ	WY	-111.0404	41.0755	12	LATLON
560410012	1311	211111	AMOCO WHITNEY CANYON	WY	-110.8897	41.45444		LATLON
5600300012	1311	22121	BIG HORN GAS PROCESSING-BYRON GAS PLANT	WY	-108.5534	44.8022	12	LATLON
5601300028	1311	211111	BURLINGTON RESOURCES_LOST CABIN	WY	-107.6327	43.28651		LATLON
5604100009	1311	211111	CHEVRON CARTER CREEK	WY	-110.9123	41.5735	12	LATLON
560410030	1311	211111	CHEVRON USA - PAINTER RESERVOIR EAST	WY	-110.8675	41.31194		LATLON
5604100030	1311	211111	CHEVRON USA _ PAINTER RESERVOIR EAST	WY	-110.8675	41.3116	12	LATLON
560070019	1311	211111	CIG RAWLINS COMP	WY	-107.0578	41.75667		LATLON
5603700014	1311	211111	COLORADO INTER GAS_TABLE ROCK GAS PLANT	WY	-108.4176	41.6074	12	LATLON
560290006	1311	211111	COLORADO INTERSTATE GAS - ELK BASIN	WY	-109.8025	44.40953		LATLON
58193	1311	211111	CONOCO - SHERIDAN	WY	-106.9753	44.6637	13	LATLON
560250011	1311	211111	EREC-BALCRON OIL DIV -NORTH GRIEVE	WY	-106.8064	42.96618		LATLON
560350001	1311	211111	EXXON -LABARGE DEHYDRATION FACILITY	WY	-110.3489	42.3725		LATLON
560230013	1311	211111	EXXON SHUTE CREEK I	WY	-110.0873	41.8838	12	LATLON
5602900012	1311	211111	HOWELL PET CORP_ELK BASIN GAS PLANT	WY	-108.8539	44.5292	12	LATLON
560430003	1311	211111	INTERENERGY CORP.- HILAND GAS PLANT	WY	-107.8511	44.03056		LATLON
560090021	1311	211111	INTERLINE GAS (LIGHTNING CREEK)	WY	-105.2111	43.0392	13	LATLON
560090019	1311	211111	INTERLINE GAS (SOUTH WELL DRAW)	WY	-111.0368	42.9178	12	LATLON
560410022	1311	211111	KERN RIVER GAS - PAINTER RESERVIOR	WY	-110.5468	41.28735		LATLON
560230025	1311	211111	KERN RIVER GAS TRANS. - MUDDY CREEK	WY	-110.3619	41.69111		LATLON
560410001	1311	211111	KERN RIVER GTC-ANSCHUTZ (CT-742)	WY	-111.0272	41.06278		LATLON

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560130027	1311	211111	KN GAS GATHERING - PAVILLION STATION	WY	-108.7768	43.1348		LATLON
560070026	1311	211111	NORTHERN GAS CO. - OIL SPRINGS	WY	-106.9999	41.71695		LATLON
560230023	1311	211111	NORTHWEST PIPELINE-MUDDY CREEK COMP STN	WY	-110.546	42.44677		LATLON
560290007	1311	211111	OREGON BASIN GAS PLANT OP-184	WY	-108.9033	44.35278		LATLON
560090026	1311	211111	PHILLIPS PETROLEUM (YOSS)	WY	-105.2586	43.01		LATLON
560350006	1311	211111	QUESTAR PIPELINE - DRY PINEY	WY	-109.8339	42.86412		LATLON
5603500006	1311	211111	QUESTAR PIPELINE _ DRY PINEY	WY	-110.3439	42.3492	12	LATLON
560410023	1311	211111	QUESTAR PIPELINE-LEROY STORAGE COMP STN	WY	-110.6161	41.32972		LATLON
560290005	1311	211111	RALSTON PROCESSING ASSOCIATES	WY	-108.8986	44.40917		LATLON
5601300008	1311	211111	SANTA FE SNYDER_BEAVER CREEK	WY	-108.3139	42.8474	12	LATLON
560130011	1311	211111	SNYDER OIL CORP.-RIVERTON PLANT	WY	-108.3428	42.94111		LATLON
T$12143	1311	211111	U.S. DOE NAVAL PETROLEUM RESERVE NO. 3	WY	-106.25	43.31667		LATLON
560410040	1311	211111	UNIVERSAL RESOURCES CORP - CLEAR CREEK	WY	-110.8394	41.38028		LATLON
560090039	1311	211111	WESTERN GAS RESOURCES - SPEARHEAD	WY	-105.4846	42.89442		LATLON
560090033	1311	211111	WESTERN GAS RESOURCES-SOUTH SAND DUNES	WY	-105.4846	42.89442		LATLON
5603700052	1311	22121	WEXPRO CANYON CREEK/VERMILLION	WY	-108.7785	41.634		LATLON
0069	1321	211112	BEAR PAW ENERGY - WIGGINS GAS PLANT	CO	-103.9709	40.2542	13	LATLON
0183	1321	211112	CALPINE NATURAL GAS (WAS VESSELS OIL & G	CO	-107.53	39.727		LATLON
0107	1321	211112	DUKE ENERGY FIELD SERVICES - LUCERNE	CO	-104.658	40.4502	13	LATLON
0189	1321	211112	DUKE ENERGY FIELD SERVICES - N ARROWHEAD	CO	-102.515	38.6699	13	LATLON
080690274	1321	211112	INDUSTRIAL GAS SERVICES INC WELLINGTON	CO	-105.0472	40.77639		LATLON
0473	1321	211112	SW PRODUCTION CO (WAS COSTILLA PETRO)	CO	-104.3121	40.50103	13	LATLON
0006	1321	211112	WILLIAMS FIELD SERVICES IGNACIO B PLT	CO	-107.7844	37.1449	13	LATLON
080670006	1321	211112	WILLIAMS FIELD SVCS IGNACIO B PLT	CO	-107.7858	37.13889		LATLON
201750038	1321	211112	ANADARKO PETROLEUM CORP.	KS	-101.0131	37.15528		LATLON
201710011	1321	211112	KN ENERGY, INC. SUNFLOWER HELIUM PLANT	KS	-100.9819	38.48306		LATLON
00011	1321	211112	ONEOK FIELD SERVICES COMPANY	KS	-100.9897	38.48944		LATLON
200070022	1321	211112	TEXACO PRODUCING, INC.	KS	-98.57333	37.25528		LATLON
200770017	1321	211112	TRIDENT NGL, INC.	KS	-98.21278	37.37667		LATLON
200950002	1321	211112	TRIDENT NGL, INC.	KS	-97.84583	37.65		LATLON
350250018	1321	211112	AMERICAN PROCESSING/HOBBS PLANT____320M3	NM	-103.3578	32.71306		LATLON
0072	1321	211112	Antelope Ridge Gas Plant	NM	-103.4537	32.2996	13	LATLON
350390027	1321	211112	BENSON-MONTIN-GREER/CANADA OJITOS__914M1	NM	-106.9008	36.39639		LATLON
0140	1321	211112	Carlsbad Gas Plant	NM	-104.0769	32.3184	13	LATLON
350250004	1321	211112	CONOCO/MALJAMAR GAS PLANT__________319M3	NM	-103.7683	32.8125		LATLON
350450062	1321	211112	CONOCO/SAN JUAN PLANT______________613M2	NM	-107.9594	36.73167		LATLON
0285	1321	211112	Dagger Draw Gas Plant	NM	-104.4452	32.7183	13	LATLON
350450009	1321	211112	EL PASO NATL GAS/CHACO GAS PLANT__1555M1	NM	-108.12	36.48833		LATLON
350150011	1321	211112	GPM GAS/ARTESIA GAS PLANT__________434M5	NM	-104.2308	32.7625		LATLON
350150169	1321	211112	GPM GAS/AVALON GASOLINE PLNT______1148M1	NM	-104.2092	32.5025		LATLON
350250044	1321	211112	GPM GAS/EUNICE GAS PLANT____________44M6	NM	-103.2994	32.52056		LATLON
350250046	1321	211112	GPM GAS/LEE GAS PLANT______________276M1	NM	-103.5136	32.80528		LATLON
350250035	1321	211112	GPM GAS/LINAM RANCH GAS PLANT_______39M2	NM	-103.3022	32.69833		LATLON
350150140	1321	211112	HIGHLANDS GATHERING/CARLSBAD PLT___927M3	NM	-104.0767	32.31806		LATLON
350250072	1321	211112	LG&E/HADSON/ANTELOPE RDG GAS PLNT__401M4	NM	-103.4503	32.29639		LATLON
350250122	1321	211112	LG&E/HADSON/MINERALS PLANT_________166M1	NM	-103.3247	32.70806		LATLON
350050014	1321	211112	LIQUID ENERGY/WHITE RANCH_______PSD356M1	NM	-103.9456	33.46361		LATLON
0004	1321	211112	Maljamar Gas Plant	NM	-103.7685	32.8125	13	LATLON

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350150008	1321	211112	MARATHON OIL/INDIAN BSN GAS PLT_PSD295M3	NM	-104.5742	32.46639		LATLON
350310023	1321	211112	MERRION OIL & GAS/OJO ENCINO_________936	NM	-107.3272	35.92556		LATLON
350450196	1321	211112	MERRION OIL & GAS/SNAKE EYES PLANT___950	NM	-107.6311	36.05417		LATLON
350150035	1321	211112	OXY USA/ABO GAS PROCESSING____G__102,256	NM	-104.2525	32.78472		LATLON
350150138	1321	211112	PAN ENERGY/BURTON FLATS GAS PLT____913M1	NM	-103.7206	32.40111		LATLON
350150285	1321	211112	PAN ENERGY/DAGGER DRAW GAS PLT__PSD753M2	NM	-104.4447	32.71833		LATLON
350150095	1321	211112	PAN ENERGY/PECOS DIAMND GAS PLT___PSD389	NM	-104.2736	32.76861		LATLON
0062	1321	211112	San Juan Gas Plant	NM	-107.9644	36.7398	13	LATLON
350250008	1321	211112	SID RICHARDSON GASOLINE/JAL #3______1092	NM	-103.1756	32.17417		LATLON
350250009	1321	211112	SID RICHARDSON GASOLINE/JAL #4______70M1	NM	-103.195	32.25528		LATLON
350250055	1321	211112	TEXACO/BUCKEYE GASOLINE PLANT_________60	NM	-103.5081	32.78444		LATLON
350250060	1321	211112	WARREN PETROLEUM/EUNICE GAS PLANT___67M3	NM	-103.1439	32.42583		LATLON
350250061	1321	211112	WARREN PETROLEUM/MONUMENT PLANT____110M3	NM	-103.3075	32.61056		LATLON
350250063	1321	211112	WARREN PETROLEUM/SAUNDERS PLANT____315M1	NM	-103.6097	33.05694		LATLON
350250064	1321	211112	WARREN PETROLEUM/VADA GAS PLANT____203M1	NM	-103.5442	33.43417		LATLON
350450026	1321	211112	WILLIAMS FIELD SERV/KUTZ GAS PLANT_301M	NM	-107.9536	36.66833		LATLON
350390010	1321	211112	WILLIAMS FIELD SERV/LYBROOK PLANT___81M2	NM	-107.5453	36.23194		LATLON
1055	1321	211112	Anadarko Gathering Company-Panther Creek Gas Plant	OK	-97.4716	34.7079	14	LATLON
400390351	1321	211112	ANR PRODUCTION CO.	OK	-99.01417	35.63556		LATLON
400370204	1321	211112	ASSOCIATED NATURAL GAS/MILFAY GAS PLANT	OK	-96.33	35.9		LATLON
2089	1321	211112	Carrera Gas Compranies, LLC Madill Gas Plant	OK	-96.5918	34.0858	14	LATLON
400070231	1321	211112	CIMARRON GAS HOLDING COMPANY	OK	-100.9433	36.50167		LATLON
400070385	1321	211112	COLORADO INTERSTATE GAS	OK	-100.3969	36.89889		LATLON
400510363	1321	211112	CONOCO INC.	OK	-97.76333	35.305		LATLON
400870201	1321	211112	CONOCO/GOLDSBY CONTRAL GAS PLANT	OK	-97.50667	35.10167		LATLON
2843	1321	211112	Continental Gas, Inc.Eagle Chief Gas Plant	OK	-98.5111	36.6109	14	LATLON
1310	1321	211112	Continental Laverne Gas Processing, LLC Laverne Gas Plant	OK	-99.9263	36.7117	14	LATLON
400070361	1321	211112	CONTINENTAL NATURAL GAS INC.(NICOL	OK	-100.2931	36.72583		LATLON
1308	1321	211112	Duke Energy Goldsby Gas Plant	OK	-97.507	35.1032	14	LATLON
2299	1321	211112	Duke Energy Hillsboro Gas Plant	OK	-98.0801	34.9567	14	LATLON
2315	1321	211112	Duke Energy Milfay Gas Plant	OK	-96.5674	35.7695	14	LATLON
2365	1321	211112	Duke Energy West Edmond Gas Plant	OK	-97.622	35.7535	14	LATLON
2366	1321	211112	Duke Energy West Guthrie	OK	-97.4529	35.747	14	LATLON
1481	1321	211112	Enerfin Resources Co. Tecumseh Gas Plant	OK	-96.9447	35.2088	14	LATLON
401090130	1321	211112	ENOGEX, INC	OK	-97.245	35.43556		LATLON
1488	1321	211112	Enogex, Inc. Calumet Gas Processing Plant	OK	-98.1549	35.6665	14	LATLON
2565	1321	211112	Enogex, Inc. Cox City Processing Plant	OK	-97.7923	34.7933	14	LATLON
1079	1321	211112	Enogex, Inc. Custer Gas Plant	OK	-99.0144	35.6369	14	LATLON
400730203	1321	211112	EXXON/DOVER-HENNESSEY	OK	-97.90278	36.07194		LATLON
1531	1321	211112	ExxonMobile Production Company Dover Hennessey Gas Plant	OK	-97.904	36.0729	14	LATLON
1042	1321	211112	GPM Gas Company LLC. Mooreland Plant	OK	-99.1574	36.4408	14	LATLON
400730220	1321	211112	GPM GAS CORP. KINGFISHER PLANT	OK	-97.73278	35.79083		LATLON
400730224	1321	211112	GPM GAS CORP. OKARCHE PLANT	OK	-98.08556	35.73639		LATLON
400030202	1321	211112	GPM/ALINE BOOSTER	OK	-98.38917	36.51444		LATLON
400930218	1321	211112	GPM/CEDAR BOOSTER	OK	-98.82139	36.31611		LATLON
400070208	1321	211112	MAPLE GAS CORP.	OK	-100.5156	36.87306		LATLON
400390358	1321	211112	MOBIL EXPLORATION & PRODUCING U.S.	OK	-98.87944	35.82806		LATLON
400190205	1321	211112	MOBIL OIL CO - FOX	OK	-97.50944	34.34833		LATLON

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401390212	1321	211112	MOBIL OIL CORPORATION WEST HOUGH	OK	-101.6406	36.90139		LATLON
400030200	1321	211112	NGC ENERGY RESOURCES LIMITED PARTNE	OK	-98.26194	36.58194		LATLON
400150205	1321	211112	NGC ENERGY RESOURCES LIMITED PARTNE	OK	-98.32667	35.3175		LATLON
400950201	1321	211112	NGC ENERGY RESOURCES LIMITED PARTNE	OK	-96.76056	34.11917		LATLON
400470203	1321	211112	NGC ENERGY RESOURCES, L.P.	OK	-97.81944	36.42694		LATLON
400950200	1321	211112	NGC ENERGY RESOURCES/MADILL GAS PLANT	OK	-96.59028	34.08583		LATLON
400930203	1321	211112	NGC ENERGY, INC/RINGWOOD PLANT	OK	-98.24167	36.36556		LATLON
400450201	1321	211112	NORTHERN NATURAL GAS CO.	OK	-99.85556	36.45222		LATLON
400070212	1321	211112	NORTHERN NATURAL GAS ELMWOOD	OK	-100.5228	36.61417		LATLON
401390206	1321	211112	OKLAHOMA GAS PIPELINE CO/TYRONE	OK	-101.0878	36.99472		LATLON
2523	1321	211112	ONEOK Field Services Co. Antelope Hills Plant	OK	-99.7841	35.8307	14	LATLON
2524	1321	211112	ONEOK Field Services Co. Beaver Gas Plant	OK	-100.1466	36.5718	14	LATLON
2525	1321	211112	ONEOK Field Services Co. Cimarron Gas Plant	OK	-98.5417	36.0247	14	LATLON
2526	1321	211112	ONEOK Field Services Co. Custer Gas Plant	OK	-98.8918	35.6496	14	LATLON
2527	1321	211112	ONEOK Field Services Co. El Reno Gas Facility	OK	-97.9522	35.6302	14	LATLON
2074	1321	211112	ONEOK Field Services Co. Enid Plant	OK	-97.8188	36.4263	14	LATLON
2679	1321	211112	ONEOK Field Services Co. Leedey Plant	OK	-99.4659	35.8092	14	LATLON
2092	1321	211112	ONEOK Field Services Co. Ringwood Gas Plant	OK	-98.2421	36.3658	14	LATLON
2531	1321	211112	ONEOK Field Services Co. Stephens Plant	OK	-97.7011	34.47	14	LATLON
400530205	1321	211112	ORYX ENERGY	OK	-97.90417	36.84639		LATLON
400590200	1321	211112	ORYX ENERGY COMPANY	OK	-99.92556	36.70889		LATLON
401390200	1321	211112	PARKER & PARSLEY	OK	-101.2558	36.83417		LATLON
2658	1321	211112	Questar Gas Management Company Beaver Gas Plant	OK	-100.9533	36.7783	14	LATLON
2509	1321	211112	Spectrum Field Services Velma Gas Plant	OK	-97.6919	34.4617	14	LATLON
3082	1321	211112	Superior Pipeline Co. Butler Gas Plant	OK	-99.1997	35.6246	14	LATLON
400490219	1321	211112	TEXACO EXPLORATION & PRODUCTION, IN	OK	-97.44417	34.81417		LATLON
400850201	1321	211112	TEXACO EXPLORATION & PRODUCTION, IN	OK	-97.02806	33.96333		LATLON
2508	1321	211112	Texaco Exploration & Production, Inc. Maysville Gas Plant	OK	-97.4456	34.815	14	LATLON
401370200	1321	211112	TEXACO PRODUCTS - VELMA GAS PLANT	OK	-97.67806	34.46083		LATLON
2517	1321	211112	Timberland Gathering & Processing Company Tyrone	OK	-101.0892	36.9973	14	LATLON
400170203	1321	211112	TONKAWA GAS PROCESSING CO.	OK	-97.95167	35.63056		LATLON
401290203	1321	211112	TONKAWA GAS PROCESSING CO.	OK	-99.78333	35.83056		LATLON
401370208	1321	211112	TONKAWA GAS PROCESSING CO.	OK	-97.70083	34.46917		LATLON
400390205	1321	211112	TRANSOK, INC.	OK	-98.7975	35.73833		LATLON
400630200	1321	211112	TRANSOK, INC.	OK	-96.16917	35.1375		LATLON
400830200	1321	211112	TRANSOK, INC.	OK	-97.61667	35.89917		LATLON
401290202	1321	211112	TRANSOK, INC.	OK	-99.48306	35.74778		LATLON
400470218	1321	211112	TRIDENT NGL, INC.	OK	-98.0325	36.17806		LATLON
400470358	1321	211112	TRIDENT NGL, INC.	OK	-97.56306	36.36556		LATLON
400730236	1321	211112	TRIDENT NGL, INC.	OK	-98.12417	35.79667		LATLON
400710204	1321	211112	TRIDENT NGL, INC/AMBROSE	OK	-97.31333	36.82667		LATLON
2946	1321	211112	Tri-Star Energy, LLC Braman Gas Processing Plant	OK	-97.2406	36.9863	14	LATLON
400070214	1321	211112	WARREN PERTOLEUM COMPANY MOCANE	OK	-100.3958	36.89889		LATLON
401290204	1321	211112	WARREN PETROLEUM CO., DIVISION CHEV	OK	-99.46556	35.80917		LATLON
2683	1321	211112	Westana Gathering Company Chester Gas Plant	OK	-98.9789	36.2474	14	LATLON
400930222	1321	211112	WESTERN GAS RESOURCES/CHANEY DELL	OK	-98.24444	36.43222		LATLON
2928	1321	211112	Williams Field Services Co.Dry Trails Gas Plant	OK	-101.6162	36.9058	14	LATLON
400530211	1321	211112	WILLIAMS NATURAL GAS CO.	OK	-97.47778	36.85306		LATLON

strStateFacilit	strSIC	strNAICS	strFacilityName	srtState	dblXCoord	dblYCoord	intUTMZo	strXYCoor
SD0048I	1321	211112	ABRAXAS PETROLEUM CORP	TX	-97.12951	28.18036	14	LATLON
MQ0303C	1321	211112	ACACIA NATURAL GAS CORP	TX	-95.09162	30.02799	15	LATLON
EA0085H	1321	211112	ALLIANT ENERGY DESDEMONA LP	TX	-98.51673	32.30843	14	LATLON
CF0017D	1321	211112	AMERICAN GATHERING LP	TX	-101.121	35.56446	14	LATLON
CF0005K	1321	211112	AMERICAN PROCESSING	TX	-101.1363	35.52877	14	LATLON
HL0019O	1321	211112	AMERICAN PROCESSING LP	TX	-100.4764	35.73454	14	LATLON
PG0036K	1321	211112	AMERICAN PROCESSING LP	TX	-101.639	35.5433	14	LATLON
MR0026R	1321	211112	ANADARKO GATHERING CO	TX	-101.6296	35.80891	14	LATLON
WF0098I	1321	211112	APACHE CORPORATION	TX	-96.07695	29.14636	14	LATLON
480090001	1321	211112	ARCHER CITY PLT	TX	-98.6871	33.6156		LATLON
HL0101F	1321	211112	BP AMOCO	TX	-100.27	35.84	10	LATLON
EA0007E	1321	211112	CANTERA RESOURCES INC	TX	-99.09271	32.50563	14	LATLON
EA0008C	1321	211112	CANTERA RESOURCES INC	TX	-98.79008	32.46883	14	LATLON
PA0009K	1321	211112	CANTERA RESOURCES INC	TX	-98.33891	32.53763	14	LATLON
PC0140M	1321	211112	CANTERA RESOURCES INC	TX	-97.68349	32.98432	14	LATLON
481010001	1321	211112	CHALK PLANT	TX	-100.2576	34.07462		LATLON
480210001	1321	211112	CHEROKEE GATHERING COMPAN	TX	-97.33635	30.1029		LATLON
WJ0002I	1321	211112	CITATION OIL & GAS CORP WILLAMAR PLANT	TX	-97.57094	26.40943	14	LATLON
CC0005U	1321	211112	CMS TAURUS FIELD SERVICES LP	TX	-99.18664	32.27621	14	LATLON
FD0003I	1321	211112	CMS TAURUS FIELD SERVICES LP	TX	-100.6624	32.96172	14	LATLON
CI0042R	1321	211112	CONOCO INC	TX	-94.91884	29.85177	15	LATLON
IA0001R	1321	211112	CONOCO INCORPORATED	TX	-100.9076	31.18384	14	LATLON
SF0008V	1321	211112	CONOCO INCORPORATED	TX	-100.6829	30.9914	14	LATLON
SD0022D	1321	211112	CORPUS CHRISTI NAT GAS GPLP	TX	-97.26329	27.93952	14	LATLON
CZ0011M	1321	211112	CROCKETT GAS PROCESSING CO	TX	-101.237	30.73371	14	LATLON
484510003	1321	211112	DOUBLE A GAS PLANT	TX	-100.4097	31.35		LATLON
481770001	1321	211112	DUBOSE PLANT	TX	-97.33472	29.09194		LATLON
ML0024S	1321	211112	DUKE ENERGY	TX	-101.7939	31.85784	14	LATLON
MF0012R	1321	211112	DUKE ENERGY	TX	-101.9683	32.26804	14	LATLON
PB0067I	1321	211112	DUKE ENERGYFIELD SERVICES	TX	-94.34317	32.24294	15	LATLON
PB0002N	1321	211112	DUKE ENERGYFIELD SERVICES INC	TX	-94.26366	32.18816	15	LATLON
SF0001M	1321	211112	DUKE ENERGYFIELD SERVICES INC	TX	-100.5191	31.00091	14	LATLON
SQ0006B	1321	211112	DUKE ENERGYFIELD SERVICES INC	TX	-100.5893	30.50798	14	LATLON
LE0012W	1321	211112	DUKE ENERGYFIELD SERVICES INC	TX	-96.95005	29.50857	14	LATLON
NE0028T	1321	211112	DUKE ENERGYFIELD SERVICES INC	TX	-97.90158	27.68646	14	LATLON
ML0020D	1321	211112	DUKE ENERGYFIELD SERVICES INC	TX	-102.1332	31.66262	13	LATLON
PE0024Q	1321	211112	DUKE ENERGYFIELD SERVICES INC	TX	-103.0865	31.26842	13	LATLON
PE0025O	1321	211112	DUKE ENERGYFIELD SERVICES INC	TX	-103.0373	31.18308	13	LATLON
WF0095O	1321	211112	DUKE ENERGYFIELD SERVICES LLC	TX	-96.20963	29.2059	14	LATLON
HW0020F	1321	211112	DUKE ENERGYFIELD SERVICES LLC	TX	-101.411	35.67427	14	LATLON
HD0055B	1321	211112	DUKE ENERGYFIELD SERVICES LLC	TX	-101.3883	36.19576	14	LATLON
CI0022A	1321	211112	DYNEGY MIDSTREAM SERVICES LP	TX	-94.90304	29.84173	15	LATLON
CY0018J	1321	211112	DYNEGY MIDSTREAM SERVICES LP	TX	-102.6406	31.50153	13	LATLON
GA0011C	1321	211112	DYNEGY MIDSTREAM SERVICES LP	TX	-102.7998	32.76063	13	LATLON
GH0007I	1321	211112	DYNEGY MIDSTREAM SERVICES LP	TX	-100.7625	35.43211	14	LATLON
GI0012E	1321	211112	DYNEGY MIDSTREAM SERVICES LP	TX	-96.6344	33.68186	14	LATLON
HH0005S	1321	211112	DYNEGY MIDSTREAM SERVICES LP	TX	-94.07232	32.46927	15	LATLON
HL0008T	1321	211112	DYNEGY MIDSTREAM SERVICES LP	TX	-100.4021	35.86848	14	LATLON

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SH0003J	1321	211112	DYNEGY MIDSTREAM SERVICES LP	TX	-99.21747	32.85847	14	LATLON
WG0011M	1321	211112	DYNEGY MIDSTREAM SERVICES LP	TX	-100.5002	35.34575	14	LATLON
WN0005E	1321	211112	DYNEGY MIDSTREAM SERVICES LP	TX	-97.87754	33.31185	14	LATLON
WN0045P	1321	211112	DYNEGY MIDSTREAM SERVICES LP	TX	-97.39594	32.98941	14	LATLON
HE0012I	1321	211112	ECHO PRODUCTION INC	TX	-99.64688	34.25581	14	LATLON
MC0006W	1321	211112	EGS HYDROCARBONS INC	TX	-98.45715	28.44476	14	LATLON
CB0063R	1321	211112	EL PASO FIELD SERVICES	TX	-96.63	28.4	14	LATLON
MH0039V	1321	211112	EL PASO FIELD SERVICES	TX	-96.18275	28.80017	14	LATLON
MH0057T	1321	211112	EL PASO FIELD SERVICES	TX	-96.13367	28.61693	14	LATLON
LK0044R	1321	211112	ENRON PROCESSING PROPERTIES INC	TX	-98.1206	28.36758	14	LATLON
WB0003U	1321	211112	EXXON COMPANY	TX	-95.87722	29.81367	15	LATLON
WC0010M	1321	211112	EXXON COMPANY USA	TX	-103.107	31.4882	13	LATLON
WO0009I	1321	211112	EXXON COMPANY USA	TX	-95.19792	32.61159	15	LATLON
HG0234M	1321	211112	EXXON CORPORATION	TX	-95.12229	29.63141	15	LATLON
RL0007C	1321	211112	EXXON CORPORATION	TX	-94.92893	32.27045	15	LATLON
KJ0003N	1321	211112	EXXON USA INC KING RANCH	TX	-98.05826	27.46553	14	LATLON
CB0053U	1321	211112	FORMOSA HYDROCARBONS CO INC	TX	-96.55861	28.66372	14	LATLON
GJ0003W	1321	211112	GAS SOLUTIONS	TX	-94.86644	32.50383	15	LATLON
HD0014P	1321	211112	GPM GAS CORPORATION	TX	-101.35	36.28	14	LATLON
MR0030D	1321	211112	GPM GAS CORPORATION	TX	-102.0277	35.82075	13	LATLON
FC0033K	1321	211112	GPM GAS SERVICES CO	TX	-96.98674	30.03686	14	LATLON
FC0049S	1321	211112	GPM GAS SERVICES CO	TX	-96.89193	29.99269	14	LATLON
LF0019U	1321	211112	GPM GAS SERVICES CO	TX	-96.80767	30.29071	14	LATLON
LF0022I	1321	211112	GPM GAS SERVICES CO	TX	-96.77428	30.26542	14	LATLON
LF0024E	1321	211112	GPM GAS SERVICES CO	TX	-96.86028	30.20506	14	LATLON
482250005	1321	211112	GRAPELAND PLANT	TX	-95.31444	31.30278		LATLON
KA0013M	1321	211112	GULF ENERGYGATHERING PROCESSING	TX	-97.6316	28.79102	14	LATLON
RG0069H	1321	211112	H & D OPERATING CO	TX	-97.38844	28.20168	14	LATLON
BL0005M	1321	211112	HILCORP ENERGY CO SWEENY	TX	-95.75015	29.0415	15	LATLON
HM0010V	1321	211112	HUNT OIL CO	TX	-95.58218	32.08478	15	LATLON
CA0011B	1321	211112	JL DAVIS	TX	-97.72817	29.73106	14	LATLON
FJ0045A	1321	211112	JL DAVIS GAS PROC INC	TX	-99.03089	28.81301	14	LATLON
IA0009B	1321	211112	JL DAVIS GAS PROCESSING INC	TX	-101.1616	31.28765	14	LATLON
RC0001Q	1321	211112	JL DAVIS GAS PROCESSING INC	TX	-101.3422	31.16433	14	LATLON
CI0005A	1321	211112	KOCH HYDROCARBON CO	TX	-94.90867	29.85413	15	LATLON
480710032	1321	211112	KOCH HYDROCARBON COMPANY	TX	-94.54278	29.51167		LATLON
482490001	1321	211112	LA GLORIA GAS PLANT	TX	-98.09139	27.16278		LATLON
483130003	1321	211112	MADISONVILLE GAS PROCESSI	TX	-95.92925	30.958		LATLON
484030001	1321	211112	MAGASCO COMPRESSOR STN.	TX	-93.58306	31.17139		LATLON
35868	1321	211112	MARATHON OIL COMPANY	TX	-100.301	31.2625	14	LATLON
JE0746E	1321	211112	MARINER ENERGY INC	TX	-94.17923	30.16773	15	LATLON
LK0001M	1321	211112	MERIT ENERGY CO	TX	-98.01317	28.48416	14	LATLON
483630008	1321	211112	MINERAL WELLS PLANT	TX	-98.31573	32.7596		LATLON
MQ0335M	1321	211112	MITCHELL ENERGY CORP	TX	-95.64011	30.23659	15	LATLON
WN0021G	1321	211112	MITCHELL GAS SERVCS LMTD PARTNERSHIP	TX	-97.80758	33.19607	14	LATLON
CN0003A	1321	211112	MITCHELL GAS SERVICES LP	TX	-100.6798	32.04785	14	LATLON
JA0026U	1321	211112	MITCHELL GAS SERVICES LP	TX	-98.18834	33.07295	14	LATLON
PA0015P	1321	211112	MITCHELL GAS SERVICES LP	TX	-98.31161	32.66187	14	LATLON

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36659	1321	211112	MOBIL EXPLORATION AND PRODUCING US I	TX	-100.8673	33.235	14	LATLON
483390032	1321	211112	N.G.P.L.C.O.A. STN. 302	TX	-95.15083	30.12028		LATLON
MQ0064U	1321	211112	NATURAL GASPIPELINE CO OF AMERICA	TX	-95.25138	30.20271	15	LATLON
CZ0024D	1321	211112	NELEH GAS SYSTEMS	TX	-102.2207	31.03878	13	LATLON
HW0035P	1321	211112	NORTHERN NATURAL GAS CO	TX	-101.5136	36.02208	14	LATLON
HP0005E	1321	211112	OCCIDENTAL PERMIAN LTD	TX	-102.5589	33.4678	13	LATLON
TC0002Q	1321	211112	OCCIDENTAL PERMIAN LTD	TX	-101.8435	30.37381	14	LATLON
GH0001U	1321	211112	ONEOK FIELDSERVICES CO	TX	-101.0346	35.52066	14	LATLON
MR0023A	1321	211112	ONEOK FIELDSERVICES CO	TX	-101.6964	35.78764	14	LATLON
38108	1321	211112	ORYX ENERGYCOMPANY	TX	-98.06	27.3285	14	LATLON
38517	1321	211112	PANENERGY FIELDS SERVICES INC	TX	-98.1532	27.2766	14	LATLON
PG0035M	1321	211112	PIONEER NATRESOURCES CO	TX	-101.8941	35.53807	14	LATLON
BE0013Q	1321	211112	PIONEER NATURAL RESOURCES USA INC	TX	-97.99291	28.62278	14	LATLON
481690006	1321	211112	PLEASANT VALLEY PLANT	TX	-101.0214	33.23444		LATLON
AG0024G	1321	211112	PUEBLO MIDSTREAM GAS CORP	TX	-98.18026	28.79523	14	LATLON
MF0001W	1321	211112	RAPTOR FACILITIES INC	TX	-101.9322	32.21152	14	LATLON
39833	1321	211112	ROCKLAND PIPELINE COMPANY	TX	-100.693	31.5918	14	LATLON
482630002	1321	211112	SALT CREEK FIELD GAS PLT	TX	-100.5208	33.13972		LATLON
482490006	1321	211112	SEELIGSON GAS PLANT	TX	-98.08278	27.24139		LATLON
PE0009M	1321	211112	SID RICHARDSON GASOLINE CO	TX	-102.888	31.23951	13	LATLON
PE0042O	1321	211112	SID RICHARDSON GASOLINE COMPANY	TX	-102.9862	31.18636	13	LATLON
484510011	1321	211112	STRAWN GAS PLANT	TX	-100.689	31.3958		LATLON
CG0012C	1321	211112	SULPHUR RIVER GATHERING LP	TX	-94.45978	33.2238	15	LATLON
GJ0005S	1321	211112	SULPHUR RIVER GATHERING LP	TX	-94.82991	32.53675	15	LATLON
HM0014N	1321	211112	SULPHUR RIVER GATHERING LP	TX	-96.03903	32.26805	14	LATLON
VB0004M	1321	211112	SULPHUR RIVER GATHERING LP	TX	-95.8981	32.62733	15	LATLON
484510008	1321	211112	SUSAN PEAK GAS PLANT	TX	-100.689	31.3958		LATLON
RG0054U	1321	211112	TC OIL COMPANY	TX	-97.04596	28.50943	14	LATLON
RG0053W	1321	211112	T-C OIL COMPANY	TX	-97.0589	28.40712	14	LATLON
PF0049M	1321	211112	TECO GAS PROCESSING CO	TX	-94.70117	30.75699	15	LATLON
SD0072L	1321	211112	TEJAS CORPUS CHRISTI PROCESSING LP	TX	-97.41038	27.88751	14	LATLON
CZ0027U	1321	211112	TEXACO E &P INC	TX	-101.0706	30.63449	14	LATLON
ML0048E	1321	211112	TEXACO EXPLORATION & PRDCTN INC	TX	-102.0159	31.84817	13	LATLON
CZ0014G	1321	211112	TEXACO EXPLORATION & PRODUCTION	TX	-101.2058	30.67269	14	LATLON
SO0003G	1321	211112	TEXACO EXPLORATION & PRODUCTION INC	TX	-101.1956	31.74186	14	LATLON
EB0069R	1321	211112	TEXACO EXPLORATION AND PRODUCTION IN	TX	-102.313	31.86012	13	LATLON
NE0062T	1321	211112	TEXAS CRUDEENERGY INC	TX	-97.27911	27.65474	14	LATLON
44263	1321	211112	THE WISER OIL COMPANY	TX	-103.5085	31.8293	13	LATLON
482490007	1321	211112	TIJERINA, CANALES,BLUCHER	TX	-97.47139	28.03194		LATLON
44278	1321	211112	TONKAWA GASPROCESSING	TX	-95.5285	31.5084	15	LATLON
LK0027R	1321	211112	TONKAWA GASPROCESSING CO	TX	-98.1351	28.40499	14	LATLON
BL0004O	1321	211112	TRI-UNION DEVELOPMENT CORP	TX	-95.24388	29.50191	15	LATLON
HM0011T	1321	211112	TXU PROCESSING CO	TX	-96.08541	32.12701	14	LATLON
483390020	1321	211112	U.P. RESOURCES CONROE	TX	-95.4633	30.33665		LATLON
VB0011P	1321	211112	UNION OIL COMPANY OF CALIFORNIA	TX	-95.64252	32.59353	15	LATLON
PB0003L	1321	211112	UNION PACIFIC RESOURCES	TX	-94.40084	32.16103	15	LATLON
MQ0002T	1321	211112	UNION PACIFIC RESOURCES CO	TX	-95.36587	30.27968	15	LATLON
HR0018T	1321	211112	VALENCE OPERATING CO	TX	-95.49708	32.98774	15	LATLON

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OC0151B	1321	211112	VASTAR RESOURCES INC	TX	-94.0024	30.19632	15	LATLON
484510004	1321	211112	Veribest Gas Plant	TX	-100.689	31.3958		LATLON
SG0031P	1321	211112	WEST TEXAS GAS PROCESSING LP	TX	-100.9308	32.85534	14	LATLON
RC0018W	1321	211112	WESTERN GASRESOURCES INC	TX	-101.6471	31.48897	14	LATLON
UB0009T	1321	211112	WESTERN GASRESOURCES INC	TX	-101.7967	31.3399	14	LATLON
481590003	1321	211112	WESTLAND OIL DEVELOPMENT	TX	-95.21683	33.1757		LATLON
WI0016D	1321	211112	WG OPERATING INC	TX	-98.96862	34.0436	14	LATLON
HL0076C	1321	211112	WILLIAMS FIELD SERVICES CO	TX	-100.3887	35.7466	14	LATLON
10679	1321	211112	Bridger Lake Plant	UT	-110.82	40.91557		LATLON
490131003	1321	211112	KOCH HYDROCARBONS - CEDAR RIM PLANT	UT	-110.3653	40.20028		LATLON
10683	1321	211112	Pineview Gas Plant	UT	-111.1629	40.94026		LATLON
10268	1321	211112	San Arroyo Plant	UT	-109.6337	39.0414		LATLON
5603700036	1321	211112	DUKE ENERGY FLD SVCS _ PATRICK DRAW	WY	-108.5023	41.5899	12	LATLON
5604100015	1321	211112	DUKE ENERGY FLD SVCS_EMIGRANT TRAIL	WY	-110.0909	41.3991	12	LATLON
5604300003	1321	48621	HILAND PARTNERS, LLC_HILAND GAS PLANT	WY	-107.8515	44.0302	13	LATLON
5602500020	1321	211112	KINDER MORGAN, INC _ CASPER EXTRACTION	WY	-106.3223	42.84456		LATLON
5600900015	1321	211112	KN GAS GATHERING_DOUGLAS GAS PLANT	WY	-105.3595	42.7902	13	LATLON
5602900007	1321	211112	MARATHON OIL CO _ OREGON BASIN GAS PLANT	WY	-108.9034	44.3524	12	LATLON
5603700006	1321	211112	MOUNTAIN GAS RESOURCES_GRANGER GAS PLANT	WY	-109.9535	41.5385	12	LATLON
560430004	1321	211112	UNION OIL COMPANY-WORLAND PLANT #60	WY	-107.9061	44.13222		LATLON
560370008	1321	211112	UNION PAC BRADY	WY	-108.7456	41.38806		LATLON
560410015	1321	211112	UNION PAC EMIGRANT	WY	-110.0908	41.39944		LATLON
560370026	1321	211112	UNION PAC RESCRS - NORTH BAXTER COMP STN	WY	-108.7785	41.634		LATLON
5603700008	1321	211112	UNION PAC_BRADY	WY	-108.7457	41.388	12	LATLON
560410018	1321	211112	UPRC - LUCKY DITCH GAS PLANT	WY	-110.2708	41.01944		LATLON
560370006	1321	211112	WESTERN GAS PROCESSORS-GRANGER GAS PLNT	WY	-109.9531	41.53861		LATLON
560370011	1321	211112	WESTERN GAS RESOURCES - FONTENELLE	WY	-109.9753	42.05417		LATLON
560050006	1321	211112	WESTERN GAS RESOURCES - KITTY PLANT	WY	-105.5462	44.24773		LATLON
560090036	1321	211112	WESTERN GAS RESOURCES - SAND DUNES	WY	-105.9006	43.09083		LATLON
5600500006	1321	211112	WESTERN GAS RESOURCES _ KITTY PLANT	WY	-105.4858	44.29511		LATLON
5600500003	1321	211112	WESTERN GAS RESOURCES_AMOS DRAW PLANT	WY	-105.8998	44.3558	13	LATLON
5600500049	1321	211112	WESTERN GAS_HILIGHT (MD_124)	WY	-105.357	43.8411	13	LATLON
560050049	1321	211112	WESTERN GAS-HILIGHT (MD-124)	WY	-105.5462	44.24773		LATLON
560070005	1321	211112	WILLIAMS FIELD SERVICES - ECHO SPRINGS	WY	-106.9999	41.71695		LATLON
560230014	1321	211112	WILLIAMS FIELD SVCS-OPAL PLANT	WY	-110.3417	41.76778		LATLON
490390007	1411	212311	BENTONITE PRODUCTION	UT	-111.8667	39.055		LATLON
00034	1422	212312	ALLEN COUNTY PUBLIC WORKS	KS	-95.29785	37.91552		LATLON
00045	1422	212312	APAC KANSAS, INC., SHEARS DIV DODGE CITY	KS	-100.0207	37.75704		LATLON
00009	1422	212312	APAC-KANSAS, INC., RENO CONST DIVISION	KS	-94.66778	38.82556		LATLON
00130	1422	212312	APAC-KANSAS, INC., RENO CONST DIVISION	KS	-94.65286	38.79999		LATLON
00131	1422	212312	APAC-KANSAS, INC., RENO CONST DIVISION	KS	-94.92956	38.81565		LATLON
00023	1422	212312	APAC-KANSAS, INC., RENO CONST. DIVISION	KS	-94.68745	38.67893		LATLON
00016	1422	212312	APAC-KANSAS, INC., SHEARS DIVISION	KS	-98.2089	39.0451		LATLON
00016	1422	212312	APAC-KANSAS, INC., SHEARS DIVISION	KS	-96.02793	37.60846		LATLON
00030	1422	212312	APAC-KANSAS, INC., SHEARS DIVISION	KS	-95.97929	38.27441		LATLON
00019	1422	212312	ASH GROVE AGGREGATES, INC.	KS	-94.73301	38.40049		LATLON
00019	1422	212312	ASH GROVE AGGREGATES, INC.	KS	-94.85085	37.8554		LATLON
00120	1422	212312	ASH GROVE AGGREGATES, INC.	KS	-94.83175	38.8978		LATLON

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00020	1422	212312	BAYER CONSTRUCTION CO., INC.	KS	-96.75208	39.29102		LATLON
00022	1422	212312	BAYER CONSTRUCTION CO., INC.	KS	-96.36603	39.3463		LATLON
00024	1422	212312	BAYER CONSTRUCTION CO., INC.	KS	-97.13476	39.37493		LATLON
00030	1422	212312	BAYER CONSTRUCTION CO., INC.	KS	-96.41752	39.8704		LATLON
00007	1422	212312	BYERS & SONS, INC. (HARRY)	KS	-95.47056	37.68913		LATLON
00043	1422	212312	HARSHMAN CONSTRUCTION L.L.C.	KS	-96.97079	37.67964		LATLON
00121	1422	212312	HOLLAND CORPORATION, INC.	KS	-94.8608	38.83988		LATLON
00011	1422	212312	HUNT MIDWEST MINING, INC.	KS	-96.47571	37.12088		LATLON
00020	1422	212312	HUNT MIDWEST MINING, INC.	KS	-94.80322	38.60663		LATLON
00020	1422	212312	HUNT MIDWEST MINING, INC.	KS	-95.37099	38.07939		LATLON
00021	1422	212312	HUNT MIDWEST MINING, INC.	KS	-95.12696	38.36686		LATLON
00022	1422	212312	HUNT MIDWEST MINING, INC.	KS	-95.35272	38.1768		LATLON
00023	1422	212312	HUNT MIDWEST MINING, INC.	KS	-94.81396	38.14271		LATLON
00024	1422	212312	HUNT MIDWEST MINING, INC.	KS	-94.70152	37.83246		LATLON
00025	1422	212312	HUNT MIDWEST MINING, INC.	KS	-95.67518	38.61903		LATLON
00025	1422	212312	HUNT MIDWEST MINING, INC.	KS	-94.70152	37.83246		LATLON
00029	1422	212312	HUNT MIDWEST MINING, INC.	KS	-95.26768	38.48788		LATLON
00039	1422	212312	HUNT MIDWEST MINING, INC.	KS	-95.37209	38.9446		LATLON
00040	1422	212312	HUNT MIDWEST MINING, INC.	KS	-95.39895	38.75095		LATLON
00123	1422	212312	HUNT MIDWEST MINING, INC.	KS	-94.9804	38.95647		LATLON
00124	1422	212312	JOHNSON COUNTY AGGREGATES	KS	-94.86205	38.85451		LATLON
00011	1422	212312	LABETTE COUNTY HIGHWAY DEPT.	KS	-95.11569	37.17144		LATLON
00017	1422	212312	MARTIN MARIETTA MATERIALS, INC	KS	-95.63743	38.51323		LATLON
00032	1422	212312	MARTIN MARIETTA MATERIALS, INC	KS	-97.01424	38.34863		LATLON
00017	1422	212312	MARTIN MARIETTA MATERIALS, INC.	KS	-96.22739	37.62547		LATLON
00023	1422	212312	MARTIN MARIETTA MATERIALS, INC.	KS	-96.42787	39.1195		LATLON
00023	1422	212312	MARTIN MARIETTA MATERIALS, INC.	KS	-95.2825	38.56432		LATLON
00031	1422	212312	MARTIN MARIETTA MATERIALS, INC.	KS	-95.48214	38.98573		LATLON
00044	1422	212312	MARTIN MARIETTA MATERIALS, INC.	KS	-96.83875	37.23763		LATLON
00061	1422	212312	MARTIN MARIETTA MATERIALS, INC.	KS	-96.96398	38.84736		LATLON
00029	1422	212312	MIDWEST MINERALS, INC.	KS	-95.59026	37.55881		LATLON
00037	1422	212312	MIDWEST MINERALS, INC.	KS	-94.70107	37.40638		LATLON
00049	1422	212312	MIDWEST MINERALS, INC.	KS	-95.26893	37.34054		LATLON
00071	1422	212312	MIDWEST MINERALS, INC.	KS	-95.62528	37.03866		LATLON
00073	1422	212312	MIDWEST MINERALS, INC.	KS	-95.74103	37.19285		LATLON
00042	1422	212312	MULBERRY LIMESTONE QUARRY CO.	KS	-94.64191	37.55744		LATLON
00043	1422	212312	MULBERRY LIMESTONE QUARRY CO.	KS	-94.85248	37.5065		LATLON
00014	1422	212312	N.R. HAMM QUARRY, INC.	KS	-95.73137	39.4627		LATLON
00020	1422	212312	N.R. HAMM QUARRY, INC.	KS	-95.3884	39.2321		LATLON
00022	1422	212312	N.R. HAMM QUARRY, INC.	KS	-95.3884	39.2321		LATLON
00024	1422	212312	N.R. HAMM QUARRY, INC.	KS	-96.18241	39.47825		LATLON
00027	1422	212312	N.R. HAMM QUARRY, INC.	KS	-96.06495	39.83569		LATLON
00028	1422	212312	N.R. HAMM QUARRY, INC.	KS	-96.0703	39.65311		LATLON
00037	1422	212312	N.R. HAMM QUARRY, INC.	KS	-95.08509	38.92783		LATLON
00065	1422	212312	N.R. HAMM QUARRY, INC.	KS	-97.0164	38.96732		LATLON
00034	1422	212312	NELSON QUARRIES, INC.	KS	-95.74676	38.19927		LATLON
00041	1422	212312	NELSON QUARRIES, INC.	KS	-94.85248	37.5065		LATLON
00078	1422	212312	NELSON QUARRIES, INC.	KS	-95.54378	37.26724		LATLON

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00044	1422	212312	NEOSHO COUNTY PUBLIC WORKS DEPT.	KS	-95.30663	37.55883		LATLON
00033	1422	212312	SCOTT ROCK COMPANY	KS	-95.7325	37.33		LATLON
00114	1422	212312	SHAWNEE ROCK COMPANY (PLANT #1)	KS	-94.82972	38.89127		LATLON
00231	1422	212312	SHAWNEE ROCK COMPANY (PLANT #3)	KS	-94.9075	39.07226		LATLON
00115	1422	212312	SHAWNEE ROCK COMPANY (PLANT #4)	KS	-94.70771	39.02012		LATLON
00020	1422	212312	WADE QUARRIES	KS	-94.73301	38.40049		LATLON
00021	1422	212312	WADE QUARRIES	KS	-94.67612	38.60332		LATLON
00021	1422	212312	WADE QUARRIES	KS	-94.86305	38.41787		LATLON
490270005	1422	212312	CONTINENTAL LIME	UT	-112.8169	38.93972		LATLON
10313	1422	212312	Cricket Mountain Plant	UT	-112.5857	39.36197		LATLON
0118	1474	212391	AMERICAN SODA LLP - PICEANCE FACILITY	CO	-107.8557	40.03395	13	LATLON
58196	1474	212391	FMC TRONA	WY	-109.8241	41.6013	12	LATLON
5603700010	1474	212391	FMC WYOMING CORP _ SODA ASH PLANT	WY	-109.8987	41.6744	12	LATLON
5603700049	1474	212391	FMC WYOMING CORPORATION-WESTVACO TRONA	WY	-109.4661	41.51425		LATLON
5603700002	1474	212391	GENERAL CHEMICAL	WY	-109.7534	41.5933	12	LATLON
5603700001	1474	212391	OCI (RHONE_POULENC) WYOMING	WY	-109.6898	41.7141	12	LATLON
5603700005	1474	212391	SOLVAY MINERALS, INC.	WY	-109.7524	41.531	12	LATLON
490470003	1475	212392	S.F. PHOSPHATES	UT	-109.4831	40.59972		LATLON
490570032	1479	212393	GREAT SALT LAKE MINERAL	UT	-112.2289	41.23333		LATLON
040250698	1499	2123	CHEMICAL LIME, NELSON PLANT	AZ	-113.3108	35.51639		LATLON
0209	2813	325120	DUKE ENERGY - LADDER CREEK HELIUM PLANT	CO	-102.3921	38.7943	13	LATLON
00031	2813	325120	ATOFINA CHEMICALS, INC.	KS	-97.42516	37.58492		LATLON
201650004	2813	325120	KANSAS REFINED HELIUM COMPANY	KS	-99.10667	38.56917		LATLON
200670008	2813	325120	MOBIL EXPLORATION & PRODUCING U.S. INC	KS	-101.1867	37.57194		LATLON
200670050	2813	325120	PRAXAIR, INC.	KS	-101.0889	37.64056		LATLON
T$11640	2813	325120	AIR LIQUIDE AMERICA CORP.	TX	-95.05	29.62111		LATLON
T$11721	2813	325120	AIR LIQUIDE AMERICA CORP.	TX	-95.33334	28.99167		LATLON
HG0010N	2813	325120	AIR PRODUCTS INC	TX	-95.06703	29.70155	15	LATLON
MONC4	2813	325120	AIR PRODUCTS, INCORPORATED/HARRIS/HG0011L	TX	-95.44	29.83	0	LATLON
HG1223K	2813	325120	BOC GASES	TX	-94.99216	29.74134	15	LATLON
JE0052V	2813	325120	HUNTSMAN CORPORATION	TX	-93.95389	29.84996	15	LATLON
HX2302N	2813	325120	LA PORTE MENTHANOL	TX	-95.06194	29.70682	15	LATLON
HX2334A	2813	325120	LINDE GAS INC.	TX	-95.05745	29.70675	15	LATLON
T$11739	2813	325120	MATHESON TRI-GAS	TX	-95.03806	29.65333		LATLON
238	2873	325311	KERLEY AG INC.	AZ	-112.1069	33.4228	12	LATLON
T$10213	2873	325311	FARMLAND INDS. INC. - LAWRENCE NITROGEN PLANT	KS	-95.19972	38.95583		LATLON
T$10374	2873	325311	FARMLAND INDS. INC. DODGE CITY NITROGEN PLANT	KS	-99.92917	37.77667		LATLON
00003	2873	325311	FARMLAND INDUSTRIES, INC. (FERTILIZER)	KS	-99.92722	37.74111		LATLON
350430021	2873	325311	AGRONICS, INC/HUMATES PLANT_______1127M1	NM	-106.9475	35.89806		LATLON
T$11018	2873	325311	FARMLAND INDS. INC.	OK	-97.76278	36.37972		LATLON
1635	2873	325311	Farmland Industries, Inc.-Enid Nitrogen Plant	OK	-97.7657	36.3751	14	LATLON
401310704	2873	325311	TERRA NITROGEN	OK	-95.71972	36.21972		LATLON
T$11021	2873	325311	TERRA NITROGEN CORP. WOODWARD COMPLEX	OK	-99.46889	36.43528		LATLON
2495	2873	325311	Terra Nitrogen, Limited Partnership Verdigris Plant	OK	-95.7201	36.2203	15	LATLON
HW0004D	2873	325311	AGRIUM US INC	TX	-101.4249	35.64532	14	LATLON
T$11681	2873	325311	EL DORADO NITROGEN CO.	TX	-94.92528	29.75583		LATLON
T$12138	2873	325311	COASTAL CHEM INC.	WY	-104.9042	41.09583		LATLON
560210002	2873	325311	COASTAL CHEMICAL	WY	-104.9128	41.09306		LATLON

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HG0534U	2874	325312	AGRIFOS FERTILIZER LP	TX	-95.25713	29.73725	15	LATLON
T$12154	2874	325312	SF PHOSPHATES LTD. CO.	WY	-109.2354	41.59491		LATLON
5603700022	2874	325312	SF PHOSPHATES, INC	WY	-109.1275	41.538	12	LATLON
0032	2911	324110	BARTKUS OIL CO	CO	-105.2461	40.0243	13	LATLON
0520	2911	324110	CHIEF PETROLEUM	CO	-104.8422	38.8332	13	LATLON
23-E	2911	324110	Colorado Refining Company	CO	-104.9422	39.80481	0	LATLON
55	2911	324110	Conoco Denver Products Terminal	CO	-104.9456	39.80333	0	LATLON
ESD035	2911	324110	Conoco Inc.	CO	-104.9411	39.80384	13	LATLON
080770001	2911	324110	LANDMARK PETROLEUM INC	CO	-108.7575	39.16833		LATLON
0063	2911	324110	REX OIL CO	CO	-105.021	39.7308	13	LATLON
0035	2911	324110	REX OIL CO INC	CO	-105.2484	40.0234	13	LATLON
0065	2911	324110	SIEGEL OIL CO	CO	-105.0152	39.7371	13	LATLON
ESD036	2911	324110	Ultramar Diamond Shamrock (formerly Total Petroleu	CO	-104.946	39.80495	13	LATLON
201730020	2911	324110	COASTAL DERBY REFINING CO.	KS	-97.31472	37.72556		LATLON
200150001	2911	324110	COASTAL DERBY REFINING CO.	KS	-96.85917	37.8325		LATLON
ESD050	2911	324110	Cooperative Refining (formerly Farmland Industries	KS	-95.60525	37.04822	15	LATLON
ESD051	2911	324110	Cooperative Refining (formerly National Cooperativ	KS	-97.66704	38.34928	14	LATLON
201470001	2911	324110	FARMLAND INDUSTRIES, INC.-REFINERY DIV.	KS	-99.37139	39.78694		LATLON
ESD052	2911	324110	Frontier Oil Corp. (formerly El Dorado Refining, f	KS	-96.87958	37.79681	14	LATLON
200150004	2911	324110	TEXACO REFINING & MARKETING, INC.	KS	-96.86667	37.79917		LATLON
200350004	2911	324110	TOTAL PETROLEUM, INC.	KS	-97.13139	37.075		LATLON
0008	2911	324110	Ciniza Refinery	NM	-108.425	35.4887	12	LATLON
ESD091	2911	324110	Giant Refining Co.	NM	-107.9755	36.70039	13	LATLON
ESD092	2911	324110	Giant Refining Co.	NM	-108.425	35.50724	12	LATLON
T$12478	2911	324110	LEA REFINING CO.	NM	-103.3003	32.87944		LATLON
T$12476	2911	324110	NAVAJO REFINING CO.	NM	-104.3961	32.85139		LATLON
T$12459	2911	324110	SAN JUAN REFINING CO.	NM	-107.9722	36.69722		LATLON
T$12490	2911	324110	FORELAND REFINING- TONOPAH REFY.	NV	-117.1	38.06667		LATLON
400810001	2911	324110	ALLIED MATLS-REFINER	OK	-97.0725	35.635		LATLON
T$11123	2911	324110	CONOCO INC. - PONCA CITY REFY.	OK	-97.08694	36.69305		LATLON
2477	2911	324110	Sun Company Inc.	OK	-96.0249	36.14	14	LATLON
23-D	2911	324110	TRI Petroleum, Inc. Ardmore Refinery	OK	-97.13592	34.17472	0	LATLON
ESD103	2911	324110	Ultramar/Diamond Shamrock (formerly Total Petroleu	OK	-97.10337	34.20234	14	LATLON
2782	2911	324110	Wynnewood Refining Company	OK	-97.1673	34.635	14	LATLON
ESD110	2911	324110	AGE Refining & Manufacturing	TX	-98.46007	29.34916	14	LATLON
ESD111	2911	324110	Alon Israel (formerly Fina Oil & Chemical Co.)	TX	-101.47	32.24	14	LATLON
HT0011Q	2911	324110	ALON USA LP	TX	-101.4237	32.27038	14	LATLON
JE0005H	2911	324110	ATOFINA PETROCHEMICALS INC	TX	-93.8954	29.95857	15	LATLON
HG0130C	2911	324110	BASIS PETROLEUM INC	TX	-95.26208	29.72616	15	LATLON
481670050	2911	324110	BASIS PETROLEUM, INC.	TX	-94.54389	29.22083		LATLON
10-C	2911	324110	Big Spring Refinery	TX	-101.4147	32.28444	0	LATLON
T$11755	2911	324110	BP AMOCO TEXAS CITY BUSINESS UNIT	TX	-94.925	29.37444		LATLON
27-H	2911	324110	Chevron El Paso Refinery (North Facility)	TX	-106.4024	31.77099	0	LATLON
ESD115	2911	324110	Citgo	TX	-97.48822	27.81323	14	LATLON
T$11904	2911	324110	CITGO REFINING & CHEMICALS CO. L.P. - EAST PLANT	TX	-97.42778	27.80917		LATLON
ESD116	2911	324110	Coastal Refining & Marketing Inc.	TX	-97.44322	27.81263	14	LATLON
24-C	2911	324110	Corpus Christi East Refinery	TX	-97.42223	27.80611	0	LATLON
24-B	2911	324110	Corpus Christi West Refinery	TX	-97.52778	27.83055	0	LATLON

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ESD117	2911	324110	Crown Central Petroleum Corp.	TX	-95.20725	29.72599	15	LATLON
T$11702	2911	324110	DEER PARK REFINING L.P.	TX	-95.12917	29.72139		LATLON
MR0008T	2911	324110	DIAMOND SHAMROCK REFINING CO LP	TX	-101.8905	35.95423	14	LATLON
LK0009T	2911	324110	DIAMOND SHAMROCK REFINING CO LP	TX	-98.18428	28.45563	14	LATLON
20-A	2911	324110	Exxon Baytown Refinery	TX	-94.99269	29.75505	0	LATLON
ESD119	2911	324110	ExxonMobil Corp. (formerly Mobil)	TX	-94.0716	30.07583	15	LATLON
26-A	2911	324110	Houston Refinery	TX	-95.25305	29.72333	0	LATLON
NE0122D	2911	324110	KOCH PETROLEUM GROUP LP	TX	-97.44185	27.80693	14	LATLON
SK0022A	2911	324110	LA GLORIA OIL AND GAS CO	TX	-95.26928	32.36675	15	LATLON
ESD121	2911	324110	LaGloria Oil & Gas Co.	TX	-95.27276	32.36735	15	LATLON
HG0048L	2911	324110	LYONDELL-CITGO REFINING LP	TX	-95.25121	29.70939	15	LATLON
ESD123	2911	324110	Marathon Ashland Petrol. LCC	TX	-94.90659	29.37657	15	LATLON
23-F	2911	324110	McKee Plants	TX	-101.8733	35.95167	0	LATLON
12-D	2911	324110	Mobil Beaumont Refinery	TX	-94.07027	30.06389	0	LATLON
ESD124	2911	324110	Motiva Enterprises (formerly Star)	TX	-93.95823	29.87322	15	LATLON
JE0095D	2911	324110	MOTIVA ENTERPRISES LLC	TX	-93.95268	29.88934	15	LATLON
BL0042G	2911	324110	PHILLIPS 66CO	TX	-95.76373	29.07126	15	LATLON
16-D	2911	324110	Phillips Borger Refinery & NGL Center	TX	-101.3678	35.69722	0	LATLON
JE0042B	2911	324110	PREMCOR REFINING GROUP	TX	-93.95519	29.85866	15	LATLON
ESD127.5	2911	324110	Pride Refining Inc.	TX	-99.76712	32.54485	14	LATLON
27-G	2911	324110	Refinery Holding Co. Refinery (South Facility)	TX	-106.4019	31.7703	0	LATLON
ESD128	2911	324110	Shell -Deer Park Refining Limited Partnership	TX	-95.11635	29.72406	15	LATLON
HG0659W	2911	324110	SHELL OIL CO	TX	-95.11546	29.72356	15	LATLON
ESD128.5	2911	324110	Specified Fuels & Chemicals (formerly Howell Hydro	TX	-95.09996	29.76851	15	LATLON
16-A	2911	324110	Sweeny Refinery and Petrochemical Complex	TX	-95.74667	29.06889	0	LATLON
21-G	2911	324110	Texas City Refinery	TX	-94.91142	29.40593	0	LATLON
T$11850	2911	324110	THREE RIVERS REFY.	TX	-98.19028	28.45667		LATLON
ESD129	2911	324110	Trifinery Petrol. Srvc. (formerly Neste Trifinery)	TX	-97.49272	27.81925	14	LATLON
ESD131	2911	324110	Ultramar/Diamond Shamrock Corp.	TX	-101.8825	35.96259	14	LATLON
ESD130	2911	324110	Ultramar/Diamond Shamrock Corp.	TX	-98.18844	28.45739	14	LATLON
ESD133	2911	324110	Valero (formerly Basis Petroleum, Inc.)	TX	-95.23721	29.57851	15	LATLON
GB0073P	2911	324110	VALERO REFINING CO - TEXAS	TX	-94.89437	29.3733	15	LATLON
ESD132	2911	324110	Valero Refining Co.	TX	-97.52651	27.89656	14	LATLON
T$12204	2911	324110	BIGWEST OIL L.L.C.	UT	-111.9056	40.86667		LATLON
ESD135	2911	324110	BP (formerly Amoco Oil Co.)	UT	-111.9032	40.79073	12	LATLON
ESD136	2911	324110	Chevron USA	UT	-111.9244	40.82801	12	LATLON
490470053	2911	324110	CHEVRON USA PRODUCING CO	UT	-109.3019	40.20306		LATLON
490470007	2911	324110	CITATION OIL AND GAS (PREV. EXXON)	UT	-109.3714	40.30417		LATLON
10122	2911	324110	Flying J Refinery (Big West Oil Co.)	UT	-111.9239	40.84199		LATLON
490130100	2911	324110	GARY REFINERY	UT	-110.22	40.36056		LATLON
490430004	2911	324110	NGC ENERGY RESOURCES	UT	-111.3681	40.90889		LATLON
490470017	2911	324110	NORTHWEST PIPELINE	UT	-109.3331	40.56889		LATLON
490130027	2911	324110	PENNZOIL	UT	-110.0183	40.28		LATLON
490130053	2911	324110	PG & E RESOURCES COMPANY	UT	-110.0197	40.04472		LATLON
490110013	2911	324110	PHILLIPS PETROLEUM	UT	-111.9081	40.8925		LATLON
ESD139	2911	324110	Phillips Petroleum Co.	UT	-111.9006	40.88746	12	LATLON
490439078	2911	324110	PINEVIEW FIELD	UT	-110.82	40.91557		LATLON
490430010	2911	324110	PINEVIEW GAS PLANT	UT	-110.82	40.91557		LATLON

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10335	2911	324110	Salt Lake City Refinery	UT	-111.9038	40.78906		LATLON
10119	2911	324110	Salt Lake Refinery	UT	-111.921	40.81955		LATLON
ESD137	2911	324110	Silver Eagle Refining Inc. (formerly Inland Refini	UT	-111.9102	40.86698	12	LATLON
490431001	2911	324110	UNION PACIFIC RESOURCES-YELLOW CREEK	UT	-111.1542	40.94528		LATLON
490070034	2911	324110	US FUEL CO	UT	-111.0106	39.49139		LATLON
5602100001	2911	324110	FRONTIER REFINING, INC.	WY	-104.7868	41.128	13	LATLON
ESD150	2911	324110	Little America Refining Co.	WY	-106.2645	42.85974	13	LATLON
T$12156	2911	324110	SILVER EAGLE REFINING	WY	-110.8069	41.26056		LATLON
60-C	2911	324110	Sinclair, Little America Refinery	WY	-106.2799	42.83902	0	LATLON
60-A	2911	324110	Sinclair, Wyoming Refinery	WY	-107.056	41.78889	0	LATLON
T$12150	2911	324110	WYOMING REFINING CO.	WY	-104.2158	43.84972		LATLON
080011182	3211	327211	CAPITOL GLASS & ALUMINUM CORP	CO	-104.8483	39.76389		LATLON
0008	3221	327213	ROCKY MOUNTAIN BOTTLE CO	CO	-105.1156	39.7857	13	LATLON
0326	3229	327212	FIBERON INC	CO	-105.083	40.603	13	LATLON
080311259	3229	327212	ROCKY MOUNTAIN SCIENTIFIC GLASS BLOWING	CO	-104.9286	39.68028		LATLON
0401900310	3241	32731	ARIZONA PORTLAND CEMENT COMPANY	AZ	-111.1492	32.40915	12	LATLON
0003	3241	327310	CEMEX, INC. - LYONS CEMENT PLANT	CO	-105.2291	40.209	13	LATLON
0001	3241	327310	HOLNAM INC PORTLAND PLANT	CO	-105.0172	38.3872	13	LATLON
0002	3241	327310	HOLNAM INC_FORT COLLINS PLANT	CO	-105.1407	40.6524	13	LATLON
T$10266	3241	327310	ASH GROVE CEMENT CO.	KS	-95.46306	37.69778		LATLON
T$10268	3241	327310	LAFARGE CORP. (INCLD SYSTECH ENVIRONMENTAL)	KS	-95.82167	37.50945		LATLON
T$10273	3241	327310	MONARCH CEMENT CO.	KS	-95.44167	37.80056		LATLON
T$12442	3241	327310	RIO GRANDE PORTLAND CEMENT CORP.	NM	-106.3897	35.07222		LATLON
BG0259G	3241	327310	ALAMO CEMENT CO II LTD	TX	-98.37563	29.61184	14	LATLON
BG0045E	3241	327310	CAPITOL CEMENT DIV CAPITOL AGGREGATE	TX	-98.42069	29.54637	14	LATLON
T$11980	3241	327310	LONE STAR IND. INC. MARYNEAL PLANT	TX	-100.4583	32.25		LATLON
ND0014S	3241	327310	LONE STAR INDUSTRIES INC	TX	-100.4593	32.25113	14	LATLON
T$11385	3241	327310	NORTH TEXAS CEMENT CO. LLP.	TX	-97.00833	32.52083		LATLON
EB0121R	3241	327310	SOUTHDOWN INC	TX	-102.5445	31.74667	13	LATLON
T$12011	3241	327310	SOUTHWESTERN PORTLAND CEMENT	TX	-102.5406	31.75111		LATLON
CS0022K	3241	327310	SUNBELT CEMENT OF TEXAS LP	TX	-98.25237	29.69211	14	LATLON
318	3241	327310	Texas Industries, Inc.	TX	-97.02847	32.46378	0	LATLON
T$11924	3241	327310	TEXAS-LEHIGH CEMENT CO.	TX	-97.85333	30.07111		LATLON
ED0066B	3241	327310	TXI OPERATIONS LIMITED PARTNERSHIP	TX	-97.02549	32.46194	14	LATLON
CS0018B	3241	327310	TXI OPERATIONS LP	TX	-98.04115	29.80478	14	LATLON
5600100002	3241	327310	MOUNTAIN CEMENT CO	WY	-105.6028	41.2689	13	LATLON
BSCP20	3251	327121	Clinton-Campbell Contractor, Inc	AZ	-112.0839	33.42083		LATLON
0043	3251	327	DENVER BRICK CO	CO	-104.8665	39.3757	13	LATLON
T$12069	3251	327	ROBINSON BRICK CO.	CO	-105.0067	39.6625		LATLON
BSCP116	3251	327121	Summit Pressed Brick and Tile Co	CO	-104.595	38.28083		LATLON
BSCP39	3251	327121	Summit Pressed Brick and Tile Co	CO	-105.0644	39.7375		LATLON
BSCP155	3251	327121	The Denver Brick Co	CO	-104.8561	39.37889		LATLON
00004	3251	327	ACME BRICK COMPANY	KS	-98.14778	38.71083		LATLON
00009	3251	327	CLOUD CERAMICS (DIV. GENERAL FINANCE)	KS	-97.68417	39.59167		LATLON
BSCP158	3251	327121	General Finance, Inc	KS	-97.65803	39.56749		LATLON
BSCP92	3251	327121	Justin Industries	KS	-98.15056	38.71222		LATLON
BSCP93	3251	327121	Justin Industries	KS	-94.72861	37.28556		LATLON
BSCP175NR	3251	327121	Kansas Brick and Tile Co	KS	-98.78416	38.53603		LATLON

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BSCP2	3251	327121	American Eagle Brick Co	NM	-106.5417	31.78889		LATLON
BSCP38	3251	327121	Hoffman Enterprises, Inc	NM	-106.6594	35.01473		LATLON
PC0001E	3251	327	ACME BRICK COMPANY	TX	-98.05362	32.715	14	LATLON
T$11307	3251	327	BORAL BRICKS INC. HENDERSON PLANT	TX	-94.80333	32.18083		LATLON
T$11314	3251	327	BORAL BRICKS INC. MARSHALL PLANT	TX	-94.36777	32.555		LATLON
BSCP21	3251	327121	D'Hanis Clay Products, Inc	TX	-99.27944	29.33028		LATLON
BSCP153	3251	327121	Elgin-Butler Brick Co	TX	-97.28944	30.32167		LATLON
BSCP70	3251	327121	Hanson, PLC	TX	-98.12583	32.81556		LATLON
BSCP77	3251	327121	Hanson, PLC	TX	-97.33972	30.31643		LATLON
BSCP118	3251	327121	Justin Industries	TX	-96.02084	32.16555		LATLON
BSCP125	3251	327121	Justin Industries	TX	-97.77444	33.20945		LATLON
BSCP126	3251	327121	Justin Industries	TX	-94.50889	31.83917		LATLON
BSCP128	3251	327121	Justin Industries	TX	-96.13972	29.82889		LATLON
BSCP151	3251	327121	Justin Industries	TX	-98.05167	32.68333		LATLON
BSCP97	3251	327121	Justin Industries	TX	-97.13472	33.18639		LATLON
BSCP98	3251	327121	Justin Industries	TX	-97.29333	30.31917		LATLON
BSCP99	3251	327121	Justin Industries	TX	-98.03972	29.5725		LATLON
BSCP160NR	3251	327121	Snyder Brick and Tile	TX	-100.9062	32.71685		LATLON
BSCP121	3251	327121	Texas Industries	TX	-97.35018	32.61335		LATLON
HM0003S	3251	327	TEXAS INDUSTRIES INC	TX	-95.82237	32.20379	15	LATLON
46461	3251	327	WILLIAMSBURG BRICK COMPANY	TX	-95.1039	32.9806	15	LATLON
DB1073N	3253	327122	AMERICAN MARAZZI TILE INC	TX	-96.56251	32.76681	14	LATLON
CC48	3253	327122	Dal-Tile Corporation	TX	-95.46722	30.39083		LATLON
CC50	3253	327122	Dal-Tile Corporation	TX	-106.3553	31.95278		LATLON
DB0242V	3253	327122	DAL-TILE CORPORATION	TX	-96.68785	32.71733	14	LATLON
CC72	3253	327122	Huntington/Pacfic Ceramics, Inc.	TX	-97.2954	32.76771		LATLON
CC73	3253	327122	Huntington/Pacific Ceramics, Inc.	TX	-95.24333	33.18528		LATLON
CC205	3253	327122	Lone Star Ceramics Mfg. Co.	TX	-96.90916	32.93528		LATLON
9611	3255	327124	ADIENCE INC	CO	-105.2303	38.442	13	LATLON
0459	3255	327124	COORSTEK, INC	CO	-105.1775	39.7829	13	LATLON
0017	3255	327124	DFC CERAMICS	CO	-105.2314	38.4393	13	LATLON
0012	3255	327124	VESUVIUS USA	CO	-105.2303	38.442	13	LATLON
BSCP106	3259	327123	MCP Industries, Inc	AZ	-112.1631	33.43684		LATLON
BSCP108	3259	327123	MCP Industries, Inc	KS	-94.69167	37.35833		LATLON
BSCP109	3259	327123	MCP Industries, Inc	TX	-98.3	29.2375		LATLON
CC15	3261	327111	American Standard, Inc.	AZ	-111.9569	33.30245		LATLON
CC92	3261	327111	Falcon Building Products, Inc. (Mansfield)	TX	-94.84861	32.40333		LATLON
CC203	3261	327111	Kohler Co	TX	-98.99722	31.66389		LATLON
CC38	3262	327112	CR/PL, L.L.C.	TX	-96.59428	30.87724		LATLON
0007	3264	327113	COORS CERAMICS CO ELECTRONICS DIV	CO	-105.2008	39.7649	13	LATLON
0024	3264	327113	COORSTEK GRAND JUNCTION	CO	-108.5964	39.0852	12	LATLON
0437	3264	327113	COORSTEK, INC.	CO	-105.174	39.7694	13	LATLON
308	3271	327331	QUALITY BLOCK INC	AZ	-112.225	33.68333		LATLON
490350200	3271	327331	BRICK MANUFACTURING PLANT	UT	-112.0136	40.59389		LATLON
490439045	3271	327331	HENIFER MINE	UT	-111.4719	41.025		LATLON
490499046	3271	327331	POWELL MINE (UTAH SITE #1)	UT	-111.9272	40.33		LATLON
490459043	3271	327331	SMILE MINE	UT	-112.1914	40.08889		LATLON
T$12328	3272	327	MONIERLIFETILE L.L.C.	AZ	-112.1692	33.43528		LATLON

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0411	3272	327	DENVER ARCHITECHURAL PRECAST INC	CO	-104.8913	39.8704	13	LATLON
0053	3272	327	ROCKY MOUNTAIN PRESTRESS ARCHITECTURAL	CO	-104.9825	39.8047	13	LATLON
0081	3272	327	STRESSCON CORP	CO	-104.7721	38.7808	13	LATLON
00097	3272	327	RICH MIX PRODUCTS, INC.- KANSAS DIVISION	KS	-97.41805	37.72333		LATLON
DB0374D	3272	327	FRITZ INDUSTRIES INC	TX	-96.67501	32.75562	14	LATLON
T$11169	3272	327	GIFFORD-HILL AMERICAN	TX	-96.95583	32.76639		LATLON
490410012	3272	327	COX ROCK PRODUCTS - AURORA PLANT	UT	-111.9076	38.7739		LATLON
490390001	3272	327	COX ROCK PRODUCTS - MT PLEASANT CONCRETE	UT	-111.6307	39.42275		LATLON
490350088	3272	327	HOBUSCH PIT	UT	-111.8614	40.58111		LATLON
490110049	3272	327	WEBER SAND AND GRAVEL L-6	UT	-112.1154	40.9611		LATLON
400	3273	327320	CALMAT OF ARIZONA	AZ	-112.25	33.85556		LATLON
401	3273	327320	CALMAT OF ARIZONA	AZ	-112.0722	33.70833		LATLON
403	3273	327320	CALMAT OF AZ PLANT #3	AZ	-112.4472	33.78889		LATLON
404	3273	327320	CALMAT OF AZ/SUN CITY PLANT	AZ	-112.5167	34.02778		LATLON
411	3273	327320	CENTURY MATERIALS, INC.	AZ	-112.4917	33.725		LATLON
413	3273	327320	CHANDLER READY MIX	AZ	-112.3806	33.68611		LATLON
304	3273	327320	PHOENIX REDI MIX	AZ	-112.2528	33.69167		LATLON
339	3273	327320	SUNWARD MATERIALS	AZ	-112.5222	33.82222		LATLON
340	3273	327320	SUNWARD MATERIALS (BCW CEMENT CO.)	AZ	-112.4389	33.55556		LATLON
367	3273	327320	UNITED METRO (TANNER)	AZ	-112.6611	33.70833		LATLON
0672	3273	327320	KIEWIT WESTERN CO	CO	-104.7339	39.7521	13	LATLON
0103	3273	327320	QUIKRETE OF DENVER HOLDINGS INC	CO	-105.0187	39.811	13	LATLON
0010	3273	327320	TRANSIT MIX CONCRETE	CO	-104.8168	38.8278	13	LATLON
0400300176	3274	32741	CHEMICAL LINE COMPANY - DOUGLAS FACILITY	AZ	-109.7347	31.36357	12	LATLON
0261	3274	327410	PILOT PEAK	NV	-114.2202	40.82477	11	LATLON
BJ0001T	3274	327410	CHEMICAL LIME LTD	TX	-97.59734	31.70845	14	LATLON
490450005	3274	327410	GRANTSVILLE PLANT	UT	-112.55	40.685		LATLON
490350373	3274	327410	HERCULES COMPOSITE MATERIALS	UT	-111.906	40.6737		LATLON
490450035	3274	327410	USPCI - MERR	UT	-113.0903	40.93056		LATLON
080370029	3275	327420	EAGLE GYPSUM PRODUCTS WALLBOARD PLT	CO	-106.8994	39.64583		LATLON
00021	3275	327420	G-P GYPSUM CORPORATION	KS	-96.645	39.70444		LATLON
T$10977	3275	327420	UNITED DESIGN CORP. NOBLE FAC.	OK	-97.40556	35.15694		LATLON
10654	3275	327420	Sigurd Plant	UT	-111.9668	38.83921		LATLON
5600300001	3275	327420	GEORGIA PACIFIC_GYPSUM PLANT	WY	-108.0004	44.7529	13	LATLON
T$12314	3281	327991	AVONTI MFG. INC.	AZ	-112.1264	33.85083		LATLON
T$12342	3281	327991	MESA FULLY FORMED INC.	AZ	-111.8306	33.39389		LATLON
T$12434	3281	327991	MOUNTAIN MARBLE MFG. INC.	AZ	-112.3175	34.58556		LATLON
0131	3281	327991	MANSTONE	CO	-104.8236	38.8792	13	LATLON
0286	3281	327991	ROCKY MOUNTAIN CULTURED MARBLE INC	CO	-105.0555	40.5885	13	LATLON
T$11300	3281	327991	ALDON MARBLE MFG. CO.	TX	-94.75667	32.40417		LATLON
T$11438	3291		NORTON CO.	TX	-98.23611	32.20278		LATLON
T$11914	3291		NORTON CO.	TX	-97.4399	25.90414		LATLON
455	3295	2123	HARBORLITE CORP, SUPERIOR PLANT	AZ	-111.128	33.2833	12	LATLON
040271006	3295	2123	YUMA COUNTY DEPT PUBLIC WORKS C&S PLANT	AZ	-114.4942	32.75833		LATLON
0004	3295	2123	MWCA INC	CO	-105.5746	37.1907	13	LATLON
00015	3295	2123	MICRO-LITE, L.L.C.	KS	-95.6971	37.70861		LATLON
NB0037F	3295	2123	TXI OPERATIONS LP	TX	-96.3488	31.91539	14	LATLON
T$12365	3296	327993	OWENS-CORNING ELOY PLANT	AZ	-111.6283	32.66833		LATLON

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0168	3296	327993	MESA FIBERGLASS INC	CO	-104.9136	39.7857	13	LATLON
00001	3296	327993	CERTAIN TEED CORPORATION	KS	-94.61139	39.14305		LATLON
00036	3296	327993	JOHNS MANVILLE	KS	-97.61166	38.38583		LATLON
00010	3296	327993	OWENS CORNING	KS	-94.61555	39.14667		LATLON
34651	3296	327993	SCHULLER INTL. INC.	KS	-97.615	38.38639		LATLON
T$11455	3296	327993	AMERICAN ROCKWOOL INC.	TX	-97.56861	31.075		LATLON
JH0025O	3296	327993	JOHNS MANVILLE INTERNATIONAL INC	TX	-97.397	32.38778	14	LATLON
AA0044U	3296	327993	OWEN CORNING	TX	-95.76103	31.65535	15	LATLON
ED0051O	3296	327993	OWENS-CORNING	TX	-96.85005	32.43925	14	LATLON
T$11220	3296	327993	OWENS-CORNING	TX	-96.85	32.43917		LATLON
HG1766N	3296	327993	ROCK WOOL MANUFACTURING CO	TX	-95.31723	29.69829	15	LATLON
BF0107S	3296	327993	THERMAFIBER LLC	TX	-97.56948	31.07524	14	LATLON
0106	3299	327	VISICOM LABORATORIES DBA MICROLITHICS CO	CO	-105.1657	39.7316	13	LATLON
T$11847	3299	327	KAMAL INC. VENETIAN MARBLE (DBA)	TX	-98.66194	29.56556		LATLON
BM0026Q	3299	327	NORTON CHEMICAL PROCESS PRODUCTS COR	TX	-96.40858	30.66233	14	LATLON
MQ0106G	3299	327	SCAN-PAC MFG INC	TX	-95.46	30.34	15	LATLON
RL0086D	3299	327	TROY MFG TEXAS INC	TX	-94.81824	32.19677	15	LATLON
0401501232	3312	331111	NORTH STAR STEEL ARIZONA	AZ	-114.0914	35.13795	11	LATLON
0048	3312	331	CF&I STEEL L P DBA ROCKY MTN STEEL MILLS	CO	-104.6127	38.237	13	LATLON
1144	3312	331	CONSOLIDATED STEEL SVC	CO	-105.0023	39.6479	13	LATLON
T$11138	3312	331	ACKER INDS. INC.	OK	-96.49111	35.16028		LATLON
2453	3312	331	Sheffield Steel	OK	-96.1185	36.1324	14	LATLON
T$11048	3312	331	SHEFFIELD STEEL CORP.	OK	-96.11861	36.11861		LATLON
EE0011P	3312	331	BORDER STEEL INC	TX	-106.5841	31.96589	13	LATLON
T$11384	3312	331	CHAPARRAL STEEL MIDLOTHIAN L.P.	TX	-97.04166	32.46389		LATLON
ED0011D	3312	331	CHAPARRAL STEEL MIDLOTHIAN LP	TX	-97.0375	32.45792	14	LATLON
CI0170H	3312	331	JINDAL UNITED STEEL CORP	TX	-94.89564	29.68826	15	LATLON
MS0008I	3312	331	LONE STAR STEEL CO	TX	-94.74	33.12	15	LATLON
T$11311	3312	331	LONE STAR STEEL CO.	TX	-94.71667	32.9		LATLON
55404	3312	331	LONE STAR STEEL COMPANY	TX	-94.718	32.9142	15	LATLON
OC0011S	3312	331	NORTH STAR STEEL OF TEXAS	TX	-94.0786	30.08556	15	LATLON
GL0028H	3312	331	STRUCTURAL METALS INC	TX	-98.03277	29.57685	14	LATLON
T$12209	3312	331	GENEVA STEEL	UT	-111.7403	40.29639		LATLON
T$12268	3312	331	NUCOR STEEL - A DIV. OF NUCOR CORP.	UT	-112.1894	41.87695		LATLON
5603700003	3312	331	P4 PRODUCTION_ROCK SPRINGS FACILITY	WY	-109.2204	41.5241	12	LATLON
T$12467	3331	331411	PHELPS DODGE HIDALGO INC.	NM	-108.5425	31.77111		LATLON
350230003	3331	331411	PHELPS DODGE/HIDALGO SMELTER________59M1	NM	-108.5292	31.77528		LATLON
T$11966	3331	331411	ASARCO INC. AMARILLO COPPER REFY.	TX	-101.7342	35.28528		LATLON
EE0007G	3331	331411	ASARCO INCORPORATED	TX	-106.5232	31.78263	13	LATLON
PG0005V	3331	331411	ASARCO INCORPORATED	TX	-101.733	35.28257	14	LATLON
EE0067L	3331	331411	PHELPS DODGE EL PASO OPERATIONS	TX	-106.3923	31.76683	13	LATLON
15076	3331	331411	KENNECOTT - UTAH POWER PLANT AND	UT	-112.1167	40.7		LATLON
T$12197	3331	331411	KENNECOTT UTAH COPPER SMELTER & REFY.	UT	-112.1969	40.72167		LATLON
10346	3331	331411	Smelter, Refinery	UT	-112.0833	40.70026		LATLON
T$11456	3334	331312	ALCOA	TX	-97.08861	30.63417		LATLON
MM0001T	3334	331312	ALUMINUM COMPANY OF AMERICA	TX	-97.07285	30.56841	14	LATLON
00002	3341	331	TOWER METAL PRODUCTS	KS	-94.69882	37.8389		LATLON
T$11049	3341	331	IMCO RECYCLING INC.	OK	-96.13167	36.01694		LATLON

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T$11114	3341	331	WABASH ALLOYS L.L.C.	OK	-95.54166	35.4		LATLON
T$11028	3341	331	ZINC CORP. OF AMERICA	OK	-95.99361	36.74167		LATLON
T$11852	3341	331	ALCOA INC. SAN ANTONIO WORKS	TX	-98.37889	29.2775		LATLON
T$11283	3341	331	ALUMAX MILL PRODS. INC.	TX	-94.14222	33.45139		LATLON
47835	3341	331	COLUMBIA ALUMINUM PROCESSORS	TX	-96.4494	32.925	14	LATLON
T$11212	3341	331	ECS REFINING TEXAS L.L.C.	TX	-96.31332	32.72585		LATLON
CP0029G	3341	331	EXIDE CORPORATION	TX	-96.83353	33.13477	14	LATLON
T$11520	3341	331	FABRICATED PRODS./LONE STAR	TX	-95.26367	29.76901		LATLON
BL0029V	3341	331	GULF CHEMICAL & METALLURGICAL CORP	TX	-95.33824	28.95808	15	LATLON
T$11469	3341	331	GULF REDUCTION CORP. - ESPERSON DIV. OF U.S. ZINC	TX	-95.3125	29.74333		LATLON
T$11478	3341	331	GULF REDUCTION CORP. - GREENWOOD METAL DIV. OF	TX	-95.3125	29.74694		LATLON
490350006	3341	331	UTAH METAL WORKS	UT	-111.7694	40.79944		LATLON
13374	4911	2211	AGUA FRIA	AZ	-112.2175	33.55667		LATLON
13068-A	4911	2211	Apache Station	AZ	-109.9265	32.03034		LATLON
040131025	4911	2211	APS-CC PLANT PHOENIX	AZ	-112.1572	33.44444		LATLON
040131507	4911	2211	APS-OCOTILLO POWER PLANT	AZ	-111.9119	33.42222		LATLON
313	4911	2211	APS-OCOTILLO POWER PLANT	AZ	-111.9119	33.4225	12	LATLON
324	4911	2211	APS-WEST PHOENIX POWER PLANT	AZ	-112.1579	33.4447	12	LATLON
T$12400	4911	2211	ARIZONA ELECTRIC POWER COOPERATIVE INC.	AZ	-109.8917	32.06167		LATLON
040030037	4911	2211	ARIZONA ELECTRIC POWER COOPERATIVE, INC.	AZ	-109.8931	32.06167		LATLON
040131009	4911	2211	ARIZONA NUCLEAR POWER PROJECT	AZ	-113.4333	33.65		LATLON
040030123	4911	2211	ARIZONA PUBLIC SERVICE COMPANY (APS)	AZ	-109.5519	31.36333		LATLON
040270331	4911	2211	ARIZONA PUBLIC SERVICE COMPANY (APS)	AZ	-114.7094	32.72139		LATLON
040210033	4911	2211	ARIZONA PUBLIC SERVICE, SAGUARO PLANT	AZ	-111.2997	32.55167		LATLON
0400300037	4911	221112	AZ ELECTRIC POWER COOPERATIVE INC	AZ	-109.8896	32.06176	12	LATLON
13700-A	4911	2211	Cholla Power Plant	AZ	-110.3638	35.1869		LATLON
13712	4911	2211	CORONADO	AZ	-109.2717	34.57778		LATLON
13712-A	4911	2211	Coronado	AZ	-109.377	34.50642		LATLON
040131007	4911	2211	GROVE COGENERATION PROJECT	AZ	-112.1158	33.58389		LATLON
13135	4911	2211	IRVINGTON	AZ	-110.9042	32.15972		LATLON
13135-A	4911	2211	Irvington	AZ	-110.9065	32.16294		LATLON
13160	4911	2211	KYRENE	AZ	-111.9364	33.35444		LATLON
13568	4911	2211	NAVAJO	AZ	-111.3917	37.52361		LATLON
13568-A	4911	2211	Navajo	AZ	-111.4602	36.91629		LATLON
13248	4911	2211	OCOTILLO	AZ	-111.9417	33.44667		LATLON
98	4911	221113	PALO VERDE NUCLEAR GENERATING STATION	AZ	-112.8749	33.39567	12	LATLON
040190076	4911	2211	PIMA CO. WASTE WATER	AZ	-110.8694	32.15111		LATLON
13308	4911	2211	SAGUARO	AZ	-111.2992	32.55194		LATLON
040131500	4911	2211	SANTAN GENERATING PLANT_(SRP)	AZ	-111.7478	33.33028		LATLON
318	4911	2211	SANTAN GENERATING PLANT_(SRP)	AZ	-111.748	33.3306	12	LATLON
040131006	4911	2211	SCOTTSDALE PRINCESS RESORT HOTEL	AZ	-111.9083	33.64806		LATLON
322	4911	2211	SCOTTSDALE PRINCESS RESORT HOTEL	AZ	-112.5222	34.08889		LATLON
13638	4911	2211	SPRINGERVILLE	AZ	-109.1633	34.31833		LATLON
13638-A	4911	2211	Springerville	AZ	-109.5223	35.24095		LATLON
3316	4911	221112	SRP AGUA FRIA	AZ	-112.216	33.55593	12	LATLON
040131215	4911	2211	SRP-AGUA FRIA PWR PL	AZ	-112.2158	33.55389		LATLON
0400100060	4911	22111	TUCSON ELECTRIC POWER CO-SPRINGERVILLE	AZ	-109.1636	34.31857	12	LATLON
13387	4911	2211	YUMA AXIS	AZ	-113.9397	33.21972		LATLON

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080450057	4911	2211	AMERICAN ATLAS NO 1	CO	-107.7083	39.51917		LATLON
13079	4911	2211	Arapahoe	CO	-105.0007	39.66833		LATLON
13391	4911	2211	Cameo	CO	-108.3167	39.13306		LATLON
13400	4911	2211	CHEROKEE	CO	-105.9664	39.80806		LATLON
080410030	4911	2211	COLORADO SPRINGS NIXON	CO	-104.7092	38.63306		LATLON
0030	4911	2211	COLORADO SPRINGS UTILITIES - NIXON PLT	CO	-104.7059	38.6329	13	LATLON
0004	4911	2211	COLORADO SPRINGS UTILITIES-DRAKE PLT	CO	-104.8307	38.8242	13	LATLON
13410	4911	2211	Comanche	CO	-104.5744	38.20806		LATLON
13418-A	4911	2211	Craig	CO	-107.7723	40.6362		LATLON
13091	4911	2211	GEORGE BIRDSALL	CO	-104.5197	38.82972		LATLON
13112	4911	2211	Hayden	CO	-107.2582	40.49484		LATLON
1238	4911	2211	KN SERVICES - LAKEWOOD GENERATION FACILI	CO	-105.1327	39.7154	13	LATLON
13168	4911	2211	LAMAR	CO	-102.4006	37.95028		LATLON
080990006	4911	2211	LAMAR UTILITIES BOARD	CO	-102.6147	38.09028		LATLON
13194	4911	2211	Martin Drake	CO	-104.8331	38.82417		LATLON
11589-A	4911	2211	Nucla	CO	-108.5064	38.24238		LATLON
13259	4911	2211	Pawnee	CO	-103.6931	40.26917		LATLON
081230321	4911	2211	PHOENIX POWER PARTNERS	CO	-104.6864	40.40972		LATLON
11170	4911	2211	PLATTE RIVER POWER AUTH RAWHIDE	CO	-105.0474	40.8408	13	LATLON
0053	4911	2211	PLATTE RIVER POWER AUTHORITY - RAWHIDE	CO	-105.0474	40.8408	13	LATLON
0008	4911	2211	PUBLIC SERVICE CO - ARAPAHOE	CO	-105	39.6695	13	LATLON
0001	4911	2211	PUBLIC SERVICE CO - VALMONT	CO	-105.2062	40.0162	13	LATLON
0007	4911	2211	PUBLIC SERVICE CO ALAMOSA PLT	CO	-105.8831	37.4655	13	LATLON
080030007	4911	2211	PUBLIC SERVICE CO ALAMOSA STA	CO	-105.8831	37.46556		LATLON
080310008	4911	2211	PUBLIC SERVICE CO ARAPAHOE	CO	-104.9992	39.66972		LATLON
080770002	4911	2211	PUBLIC SERVICE CO CAMEO	CO	-108.315	39.14861		LATLON
0002	4911	2211	PUBLIC SERVICE CO CAMEO PLT	CO	-108.3154	39.1484	12	LATLON
8653	4911	2211	PUBLIC SERVICE CO CHEROKEE PLANT	CO	-104.9685	39.8056	13	LATLON
0001	4911	2211	PUBLIC SERVICE CO CHEROKEE PLT	CO	-104.9685	39.8056	13	LATLON
081010003	4911	2211	PUBLIC SERVICE CO COMANCHE	CO	-104.5706	38.21111		LATLON
0003	4911	2211	PUBLIC SERVICE CO COMANCHE PLT	CO	-104.5706	38.2107	13	LATLON
0023	4911	2211	PUBLIC SERVICE CO FORT SAINT VRAIN PLT	CO	-104.8742	40.2434	13	LATLON
080770035	4911	2211	PUBLIC SERVICE CO FRUITA	CO	-108.7325	39.15972		LATLON
0035	4911	2211	PUBLIC SERVICE CO FRUITA STA	CO	-108.7328	39.16	12	LATLON
081230014	4911	2211	PUBLIC SERVICE CO FT LUPTON	CO	-104.7722	40.10028		LATLON
0014	4911	2211	PUBLIC SERVICE CO FT LUPTON STATION	CO	-104.7724	40.1	13	LATLON
081230023	4911	2211	PUBLIC SERVICE CO FT ST VRAIN	CO	-104.8742	40.24333		LATLON
11193	4911	2211	PUBLIC SERVICE CO HAYDEN	CO	-107.185	40.4858	13	LATLON
0001	4911	2211	PUBLIC SERVICE CO HAYDEN PLT	CO	-107.185	40.4858	13	LATLON
080590059	4911	2211	PUBLIC SERVICE CO LOOKOUT CTR	CO	-105.2017	39.73361		LATLON
080870011	4911	2211	PUBLIC SERVICE CO PAWNEE	CO	-103.6833	40.21889		LATLON
0011	4911	2211	PUBLIC SERVICE CO PAWNEE PLT	CO	-103.6838	40.2189	13	LATLON
8661	4911	2211	PUBLIC SERVICE CO VALMONT	CO	-105.2062	40.0162	13	LATLON
8662	4911	2211	PUBLIC SERVICE CO ZUNI	CO	-105.0152	39.7362	13	LATLON
T$12092	4911	2211	RAWHIDE ENERGY STATION	CO	-105.0239	40.85944		LATLON
9748-A	4911	2211	Ray D. Nixon	CO	-104.6908	38.64485		LATLON
0250	4911	2211	THERMO COGEN PARTNERSHIP FT LUPTON	CO	-104.7724	40.1063	13	LATLON
0412	4911	2211	THERMO GREELEY INC	CO	-104.6864	40.443	13	LATLON

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0126	4911	2211	THERMO POWER & ELEC INC	CO	-104.6865	40.4097	13	LATLON
081250001	4911	2211	TRI STATE GENERATION & TRANSMISSION ASSN	CO	-102.2417	40.07917		LATLON
0003	4911	2211	TRI STATE GENERATION BURLINGTON	CO	-102.2412	39.3286	13	LATLON
0018	4911	2211	TRI STATE GENERATION CRAIG	CO	-107.5912	40.4639	13	LATLON
0001	4911	2211	TRI STATE GENERATION NUCLA	CO	-108.5169	38.2474	12	LATLON
T$12135	4911	2211	TRI-STATE GENERATION & TRANSMISSION - CRAIG	CO	-107.5903	40.46444		LATLON
T$12125	4911	2211	TRI-STATE GENERATION & TRANSMISSION - NUCLA	CO	-108.5064	38.24238		LATLON
13363	4911	2211	Valmont	CO	-105.206	40.01735		LATLON
081010008	4911	2211	WEST PLAINS ENERGY PUEBLO	CO	-104.6139	38.26528		LATLON
0003	4911	2211	WEST PLAINS ENERGY - W.N. CLARK STATION	CO	-105.2383	38.4393	13	LATLON
080890004	4911	2211	WEST PLAINS ENERGY ROCKY FORD PLT	CO	-103.7133	38.04917		LATLON
13388	4911	2211	ZUNI	CO	-105.0181	39.73722		LATLON
200330001	4911	2211	ANR PIPELINE CO.	KS	-99.37722	37.47806		LATLON
200770002	4911	2211	ANTHONY-MUNICIPAL POWER PLANT	KS	-98.08944	37.17306		LATLON
13110	4911	2211	ARTHUR MULLERGREN	KS	-98.86917	38.40528		LATLON
200250001	4911	2211	ASHLAND-MUNICIPAL POWER PLANT	KS	-99.81139	37.21722		LATLON
200770013	4911	2211	ATTICA-MUNICIPAL POWER PLANT	KS	-98.28806	37.27667		LATLON
200150009	4911	2211	AUGUSTA-MUNICIPAL POWER PLANT (#1)	KS	-97.04194	37.69694		LATLON
200150010	4911	2211	AUGUSTA-MUNICIPAL POWER PLANT (#2)	KS	-97.04194	37.69667		LATLON
200450011	4911	2211	BALDWIN-MUNICIPAL POWER PLANT	KS	-95.17833	38.79556		LATLON
201570016	4911	2211	BELLEVILLE-MUNICIPAL POWER PLANT	KS	-97.66028	39.85167		LATLON
201230012	4911	2211	BELOIT-MUNICIPAL POWER PLANT	KS	-98.15306	39.49444		LATLON
00008	4911	2211	BOARD OF PUBLIC UTILITIES - NEARMAN	KS	-94.70556	39.15639		LATLON
00048	4911	2211	BOARD OF PUBLIC UTILITIES - QUINDARO	KS	-94.64139	39.14833		LATLON
202090048	4911	2211	BOARD OF PUBLIC UTILITIES - QUINDARO	KS	-94.64056	39.14972		LATLON
201390012	4911	2211	BURLINGAME-MUNICIPAL POWER PLANT	KS	-95.80639	38.75222		LATLON
200310006	4911	2211	BURLINGTON-MUNICIPAL POWER PLANT	KS	-95.71167	38.18972		LATLON
13404	4911	2211	CIMARRON RIVER	KS	-100.9319	37.05917		LATLON
201330030	4911	2211	CITY OF CHANUTE ELEC. DEPT.- N. GARFIELD	KS	-95.45083	37.67389		LATLON
201330028	4911	2211	CITY OF CHANUTE ELEC. DEPT.- S. PLUMMER	KS	-95.40056	37.68833		LATLON
201330002	4911	2211	CITY OF CHANUTE ELEC. DEPT.-S. SANTA FE	KS	-95.40056	37.68833		LATLON
200930019	4911	2211	CITY OF LAKIN	KS	-101.2853	37.95222		LATLON
201910055	4911	2211	CITY OF OXFORD, MUNICIPAL POWER PLANT	KS	-97.17306	37.26806		LATLON
200270007	4911	2211	CLAY CENTER-MUNICIPAL POWER PLANT	KS	-97.14556	39.39556		LATLON
13406	4911	2211	COFFEYVILLE	KS	-95.54333	37.04722		LATLON
201930007	4911	2211	COLBY-MUNICIPAL POWER PLANT	KS	-101.1267	39.40583		LATLON
13446	4911	2211	EAST 12TH STREET PLA	KS	-97.07167	37.26306		LATLON
200090025	4911	2211	ELLINWOOD-MUNICIPAL POWER PLANT	KS	-98.62778	38.39528		LATLON
00002	4911	2211	EMPIRE DISTRICT ELECTRIC COMPANY (THE)	KS	-94.69861	37.07167		LATLON
202050018	4911	2211	FREDONIA-MUNICIPAL POWER PLANT	KS	-95.76	37.53556		LATLON
200910065	4911	2211	GARDNER ENERGY CENTER	KS	-94.92556	38.80833		LATLON
200030001	4911	2211	GARNETT-MUNICIPAL POWER PLANT	KS	-95.24806	38.26917		LATLON
200370006	4911	2211	GIRARD-MUNICIPAL POWER PLANT	KS	-94.79472	37.52528		LATLON
201810005	4911	2211	GOODLAND-MUNICIPAL POWER PLANT	KS	-101.7967	39.34778		LATLON
13098	4911	2211	GORDON EVANS	KS	-97.52167	37.79028		LATLON
200970007	4911	2211	GREENSBURG-MUNICIPAL POWER PLANT	KS	-99.32417	37.64056		LATLON
200410034	4911	2211	HERINGTON-MUNICIPAL POWER PLANT	KS	-96.99694	38.68306		LATLON
201530011	4911	2211	HERNDON-MUNICIPAL POWER PLANT	KS	-100.8708	39.91667		LATLON

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200650009	4911	2211	HILL CITY-MUNICIPAL POWER PLANT	KS	-99.91167	39.39194		LATLON
200090026	4911	2211	HOISINGTON-MUNICIPAL POWER PLANT	KS	-98.77639	38.51528		LATLON
13121	4911	2211	HOLCOMB	KS	-100.9717	37.93167		LATLON
13121-A	4911	2211	Holcomb	KS	-100.9921	37.92702		LATLON
200850011	4911	2211	HOLTON-MUNICIPAL POWER PLANT	KS	-95.74167	39.465		LATLON
201890020	4911	2211	HUGOTON-MUNICIPAL POWER PLANT (#1)	KS	-101.3519	37.18194		LATLON
201890021	4911	2211	HUGOTON-MUNICIPAL POWER PLANT (#2)	KS	-101.3519	37.18194		LATLON
13132	4911	2211	HUTCHINSON	KS	-97.86944	38.09417		LATLON
13134	4911	2211	IOLA	KS	-95.35417	37.93667		LATLON
200010011	4911	2211	IOLA-MUNICIPAL POWER PLANT (#1)	KS	-95.35417	37.93639		LATLON
200010019	4911	2211	IOLA-MUNICIPAL POWER PLANT (#2)	KS	-95.4225	37.93056		LATLON
13509	4911	2211	JEFFREY ENERGY CENTE	KS	-96.10833	39.28528		LATLON
13509-A	4911	2211	Jeffrey Energy Center	KS	-96.11281	39.28223		LATLON
200830005	4911	2211	JETMORE-MUNICIPAL POWER PLANT	KS	-99.93167	38.11583		LATLON
201870009	4911	2211	JOHNSON CITY MUN. POWER PLANT	KS	-101.7644	37.56556		LATLON
13153	4911	2211	JUDSON LARGE	KS	-99.94917	37.73278		LATLON
201070005	4911	2211	KANSAS CITY POWER & LIGHT CO.	KS	-94.64306	38.34667		LATLON
201730079	4911	2211	KANSAS GAS AND ELECTRIC CO.-WICHITA STA.	KS	-97.28083	37.66389		LATLON
00007	4911	2211	KANSAS STATE UNIVERSITY	KS	-96.5825	39.19417		LATLON
13154	4911	2211	KAW	KS	-94.65167	39.08639		LATLON
200950004	4911	2211	KINGMAN-MUNICIPAL POWER PLANT	KS	-98.17417	37.68139		LATLON
200410017	4911	2211	KPL GAS SERVICE (AEC)	KS	-97.24944	38.93306		LATLON
201550033	4911	2211	KPL GAS SERVICE (HEC)	KS	-97.86944	38.09417		LATLON
201770030	4911	2211	KPL GAS SERVICE (TEC)	KS	-95.56889	39.05444		LATLON
13526	4911	2211	LA CYGNE	KS	-94.64556	38.34806		LATLON
13526-A	4911	2211	La Cygne	KS	-94.84505	38.2133		LATLON
201650001	4911	2211	LACROSSE MUNICIPAL POWER PLANT	KS	-99.36472	38.56889		LATLON
13172	4911	2211	LARNED	KS	-99.14278	38.20694		LATLON
201450010	4911	2211	LARNED-MUNICIPAL POWER PLANT	KS	-99.14278	38.20694		LATLON
13174	4911	2211	LAWRENCE	KS	-95.26806	39.00778		LATLON
13174-A	4911	2211	Lawrence	KS	-95.27081	39.00079		LATLON
201050013	4911	2211	LINCOLN-MUNICIPAL POWER PLANT	KS	-98.19528	39.07417		LATLON
13198	4911	2211	MCPHERSON 2	KS	-97.68667	38.37167		LATLON
201130014	4911	2211	MCPHERSON BOARD OF PUBLIC UTILITIES #2	KS	-97.68667	38.37167		LATLON
201190013	4911	2211	MEADE-MUNICIPAL POWER PLANT	KS	-100.3589	37.38639		LATLON
200090001	4911	2211	MIDWEST ENERGY, INC.	KS	-98.81083	38.39556		LATLON
200230008	4911	2211	MIDWEST ENERGY, INC.	KS	-101.6439	39.75722		LATLON
200510012	4911	2211	MIDWEST ENERGY, INC.	KS	-99.31806	38.86694		LATLON
201930001	4911	2211	MIDWEST ENERGY, INC.	KS	-101.1267	39.40583		LATLON
201430013	4911	2211	MINNEAPOLIS-MUNICIPAL POWER PLANT	KS	-97.74778	39.1575		LATLON
201910025	4911	2211	MULVANE-MUNICIPAL POWER PLANT	KS	-97.23694	37.45917		LATLON
13563	4911	2211	MURRAY GILL	KS	-97.41333	37.42806		LATLON
23422-A	4911	2211	Nearman Creek	KS	-94.70565	39.15488		LATLON
202050014	4911	2211	NEODESHA-MUNICIPAL POWER PLANT	KS	-95.61028	37.42333		LATLON
201370005	4911	2211	NORTON-MUNICIPAL POWER PLANT	KS	-99.955	39.85556		LATLON
201090009	4911	2211	OAKLEY-MUNICIPAL POWER PLANT	KS	-100.9422	39.11917		LATLON
200390009	4911	2211	OBERLIN-MUNICIPAL POWER PLANT	KS	-100.6125	39.83417		LATLON
201390014	4911	2211	OSAGE CITY-MUNICIPAL POWER PLANT	KS	-95.80194	38.6375		LATLON

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201210001	4911	2211	OSAWATOMIE-MUNICIPAL POWER PLANT	KS	-94.91167	38.52444		LATLON
201410009	4911	2211	OSBORNE-MUNICIPAL POWER PLANT	KS	-98.7525	39.46833		LATLON
200590006	4911	2211	OTTAWA-MUNICIPAL POWER PLANT	KS	-95.24806	38.63833		LATLON
13276	4911	2211	PRATT	KS	-98.79444	37.68417		LATLON
201510005	4911	2211	PRATT-MUNICIPAL POWER PLANT	KS	-98.79444	37.68417		LATLON
13278-A	4911	2211	Quindaro	KS	-94.64111	39.14855		LATLON
201730128	4911	2211	RITCHIE SAND, INC.	KS	-97.46139	37.77528		LATLON
13299	4911	2211	RIVERTON	KS	-94.69833	37.07167		LATLON
13299-A	4911	2211	Riverton	KS	-94.73527	37.02401		LATLON
201670005	4911	2211	RUSSELL-MUNICIPAL POWER PLANT	KS	-98.90306	38.91722		LATLON
201310009	4911	2211	SABETHA-MUNICIPAL POWER PLANT	KS	-95.83417	39.89778		LATLON
201990005	4911	2211	SHARON SPRINGS-MUNICIPAL POWER PLANT	KS	-101.8153	38.88306		LATLON
200230009	4911	2211	ST. FRANCIS-MUNICIPAL POWER PLANT	KS	-101.9081	39.76556		LATLON
201850015	4911	2211	ST. JOHN-MUNICIPAL POWER PLANT	KS	-98.81167	38.03194		LATLON
201850017	4911	2211	STAFFORD-MUNICIPAL POWER PLANT	KS	-98.64667	38.00306		LATLON
201590024	4911	2211	STERLING MUNICIPAL POWER PLANT	KS	-98.25917	38.24806		LATLON
201630014	4911	2211	STOCKTON-MUNICIPAL POWER PLANT	KS	-99.33222	39.46806		LATLON
200550026	4911	2211	SUNFLOWER ELECTRIC POWER CORPORATION	KS	-100.8942	37.96917		LATLON
13347	4911	2211	TECUMSEH	KS	-95.56889	39.05444		LATLON
13347-A	4911	2211	Tecumseh	KS	-95.5663	39.0516		LATLON
201490012	4911	2211	WAMEGO-MUNICIPAL POWER PLANT	KS	-96.30694	39.19722		LATLON
202010024	4911	2211	WASHINGTON-MUNICIPAL POWER PLANT	KS	-97.07778	39.82917		LATLON
13376	4911	2211	WELLINGTON	KS	-97.47028	37.28306		LATLON
201910056	4911	2211	WELLINGTON CITY POWER PLANT, GAS TURBINE	KS	-97.36444	37.27139		LATLON
201910019	4911	2211	WELLINGTON-MUNICIPAL POWER PLANT	KS	-97.47028	37.28306		LATLON
201750001	4911	2211	WEST PLAINS ENERGY	KS	-100.9319	37.05917		LATLON
202010012	4911	2211	WEST PLAINS ENERGY	KS	-97.30917	39.58694		LATLON
23413	4911	2211	WEST PLAINS ENERGY	KS	-98.8694	38.4052	14	LATLON
00014	4911	2211	WESTERN RESOURCES, INC.	KS	-95.28361	39.00056		LATLON
00033	4911	2211	WESTERN RESOURCES, INC. (HEC)	KS	-97.87639	38.08639		LATLON
200350006	4911	2211	WINFIELD MUNICIPAL POWER PLANT (OLD)	KS	-97.07167	37.26306		LATLON
13438	4911	2211	ANIMAS	NM	-108.3297	36.50972		LATLON
350450029	4911	2211	CITY OF FARMINGTON/ANIMAS PLANT___1061R1	NM	-108.1928	36.72806		LATLON
13423	4911	2211	CUNNINGHAM	NM	-103.3531	32.71306		LATLON
0032	4911	2211	Escalante	NM	-108.0815	35.416	12	LATLON
13086	4911	2211	FOUR CORNERS	NM	-108.4819	36.69056		LATLON
13086-A	4911	2211	Four Corners	NM	-108.4362	36.75341		LATLON
T$12460	4911	2211	FOUR CORNERS STEAM ELECTRIC STATION	NM	-108.4819	36.69139		LATLON
350250028	4911	2211	LEA COUNTY ELEC COOP/CUNNINGHAM_______GF	NM	-103.3197	32.97833		LATLON
350230001	4911	2211	LORDSBURG LTD/REPOWERING PRJCT___PSD90M1	NM	-108.6942	32.33778		LATLON
13189	4911	2211	MADDOX	NM	-103.3017	32.71306		LATLON
350310027	4911	2211	MERRION OIL & GAS/PAPERS WASH ELEC_949M1	NM	-107.3253	35.85333		LATLON
350130025	4911	2211	NMSU/PHYSICAL PLANT BOILERS_________1640	NM	-106.7531	32.27944		LATLON
0025	4911	2211	Physical Plant Boilers	NM	-106.753	32.2798	13	LATLON
350470004	4911	2211	PUBLIC SERV CO NM/LAS VEGAS GEN STA___GF	NM	-105.2317	35.60528		LATLON
12917	4911	2211	RATON	NM	-104.6506	36.60139		LATLON
13288	4911	2211	REEVES	NM	-106.5	36.33306		LATLON
13603	4911	2211	RIO GRANDE	NM	-106.5469	31.80444		LATLON

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0002	4911	2211	Rio Grande Generating Station	NM	-106.5464	31.8017	13	LATLON
13618	4911	2211	SAN JUAN	NM	-108.4831	36.88306		LATLON
13618-A	4911	2211	San Juan	NM	-108.4821	36.7616		LATLON
350490017	4911	2211	SANTA FE COGEN ASSOC_________________620	NM	-106.0481	35.55583		LATLON
350250054	4911	2211	SOUTHWESTERN PUBL SERV/CUNNINGH PSD622M1	NM	-103.3564	32.7175		LATLON
350250034	4911	2211	SOUTHWESTERN PUBL SERV/MADDOX STN____747	NM	-103.3031	32.71694		LATLON
350370002	4911	2211	SOUTHWESTERN PUBL SERV/TUCUMCARI___586M1	NM	-103.7369	35.175		LATLON
1011	4911	2211	AES Shady Point, Inc.	OK	-94.6466	35.1972	15	LATLON
13427	4911	2211	ANADARKO	OK	-98.22556	35.08417		LATLON
13313	4911	2211	BOOMER LAKE	OK	-96.98722	36.09389		LATLON
400310703	4911	2211	CENTRAL AND SOUTH WEST SERVICES, IN	OK	-98.32417	34.54306		LATLON
1211	4911	2211	Central and South West Services, Inc. - Comanche Power	OK	-98.3246	34.5435	14	LATLON
1212	4911	2211	Central and South West Services, Inc. - Northeastern Power	OK	-95.6992	36.426	15	LATLON
1213	4911	2211	Central and South West Services, Inc. - Riverside/Jenks Power	OK	-95.9566	35.9995	15	LATLON
1214	4911	2211	Central and South West Services, Inc. - Southwestern Power	OK	-98.3523	35.1009	14	LATLON
1215	4911	2211	Central and South West Services, Inc. - Tulsa Power Station	OK	-95.9903	36.1159	15	LATLON
1216	4911	2211	Central and South West Services, Inc. - Weleetka Power	OK	-96.1357	35.3261	14	LATLON
13411	4911	2211	COMANCHE	OK	-98.32417	34.54306		LATLON
1799	4911	2211	Grand River Dam Authority	OK	-95.2898	36.1913	15	LATLON
13103	4911	2211	GRDA	OK	-95.28917	36.18889		LATLON
13103-A	4911	2211	GRDA	OK	-95.33031	36.19272		LATLON
13488	4911	2211	HORSESHOE LAKE	OK	-97.17944	35.50222		LATLON
13492-A	4911	2211	Hugo	OK	-95.3167	34.0292		LATLON
13213	4911	2211	MOORELAND	OK	-99.22056	36.7375		LATLON
13224	4911	2211	MUSKOGEE	OK	-95.29528	35.76722		LATLON
13566-A	4911	2211	Muskogee	OK	-95.29613	35.7713		LATLON
13225	4911	2211	MUSTANG	OK	-97.67472	35.48139		LATLON
13241	4911	2211	NORTHEASTERN	OK	-95.69806	36.43194		LATLON
13241-A	4911	2211	Northeastern	OK	-95.71181	36.43913		LATLON
T$11045	4911	2211	NORTHEASTERN STATION	OK	-95.70084	36.43167		LATLON
401090052	4911	2211	OG & E TINKER	OK	-97.90056	35.24		LATLON
400470702	4911	2211	OG&E	OK	-97.87417	36.36917		LATLON
401090010	4911	2211	OG&E-HORSESHOE PLANT	OK	-97.17917	35.50833		LATLON
401330702	4911	2211	OG&E-SEMINOLE POWER PLANT	OK	-96.72472	34.96556		LATLON
2209	4911	2211	Oklahoma Gas & Electric	OK	-95.2869	35.7619	15	LATLON
2211	4911	2211	Oklahoma Gas & Electric	OK	-97.0517	36.4542	14	LATLON
13269	4911	2211	PONCA	OK	-97.15056	36.82		LATLON
401070700	4911	2211	PUBLIC SERVICE CO.	OK	-96.13083	35.32583		LATLON
13297	4911	2211	RIVERSIDE	OK	-95.95167	35.98556		LATLON
13624	4911	2211	SEMINOLE	OK	-96.72556	34.96639		LATLON
13637	4911	2211	SOONER	OK	-97.04972	36.45417		LATLON
13637-A	4911	2211	Sooner	OK	-97.12142	36.46992		LATLON
13331	4911	2211	SOUTHWESTERN	OK	-98.35306	35.10139		LATLON
13356	4911	2211	TULSA	OK	-95.99056	36.11639		LATLON
2700	4911	2211	Western Farmers Electric Coop Hugo	OK	-95.3197	34.0136	15	LATLON
13244-A	4911	2211	Big Brown	TX	-96.14939	31.72349		LATLON
481610004	4911	2211	BIG BROWN STATION	TX	-96.1418	31.712		LATLON
T$11331	4911	2211	BIG BROWN STEAM ELECTRIC STATION & LIGNITE MINE	TX	-96.05611	31.82056		LATLON

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PA0003W	4911	2211	BRAZOS ELECTRIC POWER COOPERATIVE IN	TX	-98.30854	32.65814	14	LATLON
HG1169O	4911	2211	CALPINE CORPORATION	TX	-95.06532	29.62571	15	LATLON
GF0002R	4911	2211	CENTRAL SOUTH WEST SERVICES INC	TX	-97.21423	28.7129	14	LATLON
480830002	4911	2211	CITY OF COLEMAN	TX	-99.4588	31.76063		LATLON
BG0057U	4911	2211	CITY PUBLICSERVICE	TX	-98.32026	29.30802	14	LATLON
13705	4911	2211	COLETO CREEK	TX	-97.21417	28.71278		LATLON
13705-A	4911	2211	Coleto Creek	TX	-97.21632	28.73652		LATLON
484250001	4911	2211	COMANCHE PEAK POWER PLANT	TX	-97.47139	32.17528		LATLON
13456	4911	2211	GIBBONS CREEK	TX	-96.1375	30.61667		LATLON
13456-A	4911	2211	Gibbons Creek	TX	-96.0778	30.6167		LATLON
T$11304	4911	2211	H.W. PIRKEY POWER PLANT	TX	-94.48278	32.4625		LATLON
13157	4911	2211	KNOX LEE	TX	-94.64306	32.37417		LATLON
T$11951	4911	2211	L.C.R.A. FAYETTE POWER PROJECT	TX	-96.75306	29.91917		LATLON
13178	4911	2211	LIMESTONE	TX	-96.25528	31.42306		LATLON
T$11333	4911	2211	LIMESTONE ELECTRIC GENERATING STATION	TX	-96.26167	31.41083		LATLON
55505	4911	2211	LOWER COLORADO RIVER AUTHORITY	TX	-97.2723	30.0616	14	LATLON
FC0018G	4911	2211	LOWER COLORADO RIVER AUTHORITY	TX	-96.75057	29.91745	14	LATLON
T$11320	4911	2211	MARTIN LAKE STEAM ELECTRIC STATION & LIGNITE	TX	-94.57584	32.26111		LATLON
484490004	4911	2211	MONTICELLO STATION	TX	-95.02	33.05444		LATLON
T$11277	4911	2211	MONTICELLO STEAM ELECTRIC STATION & LIGNITE MINE	TX	-95.04166	33.09167		LATLON
13232	4911	2211	NEWMAN	TX	-106.4314	31.98306		LATLON
T$12027	4911	2211	NEWMAN POWER STATION	TX	-106.395	31.93399		LATLON
481410028	4911	2211	NEWMAN STATION	TX	-106.2228	31.45306		LATLON
T$11892	4911	2211	O.W. SOMMERS/J.T. DEELY/J.K. SPRUCE GENERATING	TX	-98.33583	29.32028		LATLON
13580	4911	2211	OKLAUNION	TX	-99.17528	34.14028		LATLON
13580-A	4911	2211	Oklaunion	TX	-99.30041	34.15378		LATLON
T$11436	4911	2211	OKLAUNION POWER STATION	TX	-99.17694	34.08333		LATLON
13257	4911	2211	PAINT CREEK	TX	-99.57778	33.08083		LATLON
13265	4911	2211	PIRKEY	TX	-94.46778	32.44556		LATLON
13265-A	4911	2211	Pirkey	TX	-94.58171	32.53524		LATLON
HT0065Q	4911	2211	POWER RESOURCES LTD	TX	-101.4222	32.27277	14	LATLON
FG0020V	4911	2211	RELIANT ENERGY INC	TX	-95.63411	29.47652	15	LATLON
LI0027L	4911	2211	RELIANT ENERGY INC	TX	-96.25341	31.42341	14	LATLON
13616	4911	2211	SAM SEYMOUR	TX	-96.75417	29.925		LATLON
13616-A	4911	2211	Sam Seymour	TX	-96.87554	29.91007		LATLON
13617	4911	2211	SAN ANGELO	TX	-100.4919	31.39306		LATLON
484510007	4911	2211	SAN ANGELO POWER STATION	TX	-100.0644	31.42167		LATLON
13619	4911	2211	SAN MIGUEL	TX	-98.47194	28.70889		LATLON
13619-A	4911	2211	San Miguel	TX	-98.4722	28.7089		LATLON
AG0007G	4911	2211	SAN MIGUEL ELCTRC COOPERATIVE INC	TX	-98.47229	28.70915	14	LATLON
483310002	4911	2211	SANDOW STATION	TX	-96.96548	30.78385		LATLON
T$11457	4911	2211	SANDOW STEAM ELECTRIC STATION	TX	-97.01197	30.65274		LATLON
13325	4911	2211	SIM GIDEON	TX	-97.27083	30.06056		LATLON
VC0026O	4911	2211	SOUTH TEXASELECTRIC COOPERATIVE INC	TX	-97.13592	28.89386	14	LATLON
GJ0043K	4911	2211	SOUTHWESTERN ELECTRIC POWER CO	TX	-94.64216	32.37419	15	LATLON
HH0037F	4911	2211	SOUTHWESTERN ELECTRIC POWER CO	TX	-94.46794	32.44564	15	LATLON
ME0006A	4911	2211	SOUTHWESTERN ELECTRIC POWER CO	TX	-94.54684	32.84868	15	LATLON
TF0012D	4911	2211	SOUTHWESTERN ELECTRIC POWER CO	TX	-94.84575	33.05838	15	LATLON

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LB0047N	4911	2211	SOUTHWESTERN PUBLIC SERVICE CO	TX	-102.575	34.18164	13	LATLON
PG0041R	4911	2211	SOUTHWESTERN PUBLIC SERVICE CO	TX	-101.7462	35.29962	14	LATLON
T$11964	4911	2211	SOUTHWESTERN PUBLIC SERVICE CO. HARRINGTON	TX	-101.7467	35.29944		LATLON
T$11974	4911	2211	SOUTHWESTERN PUBLIC SERVICE CO. - TOLK STATION	TX	-102.5686	34.18472		LATLON
13343	4911	2211	T C FERGUSON	TX	-98.36917	30.55639		LATLON
GB0153Q	4911	2211	TEXAS CITY COGENERATION LP	TX	-94.9416	29.37886	15	LATLON
RI0035C	4911	2211	TEXAS NEW MEXICO POWER CO	TX	-96.69556	31.09322	14	LATLON
13351	4911	2211	TOLK STATION	TX	-102.5744	34.18139		LATLON
FB0025U	4911	2211	TX UTILITIES ELECTRIC CO	TX	-96.36733	33.63033	14	LATLON
HQ0012T	4911	2211	TXU ELECTRIC CO	TX	-97.68801	32.40537	14	LATLON
CP0065C	4911	2211	TXU ELECTRIC CO	TX	-96.81328	33.19956	14	LATLON
DB0249H	4911	2211	TXU ELECTRIC CO	TX	-96.54544	32.83763	14	LATLON
HM0017H	4911	2211	TXU ELECTRIC CO	TX	-96.10114	32.12639	14	LATLON
DB0251U	4911	2211	TXU ELECTRIC CO	TX	-96.97458	32.95025	14	LATLON
DB0252S	4911	2211	TXU ELECTRIC CO	TX	-96.93597	32.72499	14	LATLON
DB0253Q	4911	2211	TXU ELECTRIC CO	TX	-96.72273	32.77844	14	LATLON
CJ0026J	4911	2211	TXU ELECTRIC CO	TX	-94.98954	31.94187	15	LATLON
RE0012M	4911	2211	TXU ELECTRIC CO	TX	-95.15492	33.40181	15	LATLON
TF0013B	4911	2211	TXU ELECTRIC CO	TX	-95.03736	33.09243	15	LATLON
RL0020K	4911	2211	TXU ELECTRIC CO	TX	-94.57022	32.26071	15	LATLON
FI0020W	4911	2211	TXU ELECTRIC CO	TX	-96.0549	31.82158	14	LATLON
TA0352I	4911	2211	TXU ELECTRIC CO	TX	-97.47945	32.90547	14	LATLON
TA0354E	4911	2211	TXU ELECTRIC CO	TX	-97.33653	32.76111	14	LATLON
TA0353G	4911	2211	TXU ELECTRIC CO	TX	-97.22197	32.72918	14	LATLON
YB0017V	4911	2211	TXU ELECTRIC CO	TX	-98.61226	33.13643	14	LATLON
MM0023J	4911	2211	TXU ELECTRIC CO	TX	-97.05813	30.5681	14	LATLON
MB0117A	4911	2211	TXU ELECTRIC CO	TX	-96.98526	31.46673	14	LATLON
MO0014L	4911	2211	TXU ELECTRIC CO	TX	-100.916	32.3346	14	LATLON
WC0028Q	4911	2211	TXU ELECTRIC CO	TX	-102.9574	31.58346	13	LATLON
13368	4911	2211	W A PARISH	TX	-95.63167	29.48389		LATLON
13368-A	4911	2211	W A Parish	TX	-95.7641	29.5695		LATLON
481570011	4911	2211	W. A. PARISH STATION	TX	-95.25139	29.47167		LATLON
T$11617	4911	2211	W.A. PARISH ELECTRIC GENERATING STATION	TX	-95.63417	29.47528		LATLON
13675	4911	2211	WELSH	TX	-94.84556	33.05806		LATLON
WI0025C	4911	2211	WEST TEXAS UTILITIES CO	TX	-99.18023	34.083	14	LATLON
13379	4911	2211	WILKES	TX	-94.54667	32.84833		LATLON
12922	4911	2211	Bonanza	UT	-109.2831	40.08306		LATLON
T$12223	4911	2211	BONANZA POWER PLANT	UT	-109.2844	40.08639		LATLON
12997	4911	2211	Carbon	UT	-110.8639	39.72639		LATLON
10081	4911	2211	Carbon Power Plant	UT	-110.8524	39.66883		LATLON
490470001	4911	2211	DESERET - BONANZA	UT	-109.3173	40.1177	0	LATLON
490350044	4911	2211	ELECTRICAL GENERATION PLANT	UT	-111.906	40.6737		LATLON
10355	4911	2211	Gadsby Power Plant	UT	-111.93	40.77138		LATLON
11539	4911	2211	Hildale City Cogeneration Facility	UT	-113.1402	37.2278		LATLON
12799	4911	2211	Hunter	UT	-111.0188	39.21085		LATLON
10237	4911	2211	Hunter Power Plant	UT	-111.0188	39.21085		LATLON
12800	4911	2211	Huntington	UT	-111.075	39.37917		LATLON
10238	4911	2211	Huntington Power Plant	UT	-110.963	39.32856		LATLON

strStateFacilit	strSIC	strNAICS	strFacilityName	srtState	dblXCoord	dblYCoord	intUTMZo	strXYCoor
10327	4911	2211	Intermountain Generation Station	UT	-112.5681	39.49323		LATLON
490579088	4911	2211	LITTLE MOUNTAIN COGENERATION FACILITY	UT	-111.9563	41.24985		LATLON
13088	4911	2211	PACIFCORP GADSBY	UT	-111.9292	40.76667		LATLON
10120	4911	2211	Power Plant	UT	-111.8847	40.88658		LATLON
490490018	4911	2211	PROVO CITY POWER CO.	UT	-111.6664	40.2625		LATLON
490530011	4911	2211	ST GEORGE POWER	UT	-113.66	37.12861		LATLON
10892	4911	2211	St. George City Power Plant	UT	-113.5655	37.11274		LATLON
T$12281	4911	2211	SUNNYSIDE COGENERATION ASSOCIATES	UT	-110.3917	39.54722		LATLON
490490072	4911	2211	WHITEHEAD POWER PLANT	UT	-111.6186	40.17611		LATLON
5603100001	4911	2211	BASIN ELECTRIC_LARAMIE RIVER STATION	WY	-104.8768	42.1119	13	LATLON
T$12151	4911	2211	BHPL-OSAGE POWER PLANT	WY	-104.4097	43.97167		LATLON
5604500005	4911	2211	BLACK HILLS OSAGE	WY	-104.4081	43.9672	13	LATLON
5600500002	4911	2211	BLACK HILLS POWER & LGHT SIMPSON 1	WY	-105.387	44.2867	13	LATLON
58184-A	4911	2211	BLACK HILLS POWER & LGT-SIMPSON 2	WY	-105.4991	44.25329		LATLON
13722	4911	2211	DAVE JOHNSTON	WY	-105.7667	42.83306		LATLON
13722-A	4911	2211	Dave Johnston	WY	-105.8477	42.87368		LATLON
T$12140	4911	2211	LARAMIE RIVER STATION	WY	-104.8806	42.10833		LATLON
58145-A	4911	2211	Laramie River Station	WY	-104.8819	42.10436		LATLON
13228	4911	2211	Naughton	WY	-110.5425	41.79367		LATLON
T$12159	4911	2211	PACIFICORP, NAUGHTON POWER PLANT	WY	-110.5986	41.75722		LATLON
5600900001	4911	2211	PACIFICORP_DAVE JOHNSTON	WY	-105.7747	42.843	13	LATLON
5603701002	4911	2211	PACIFICORP_JIM BRIDGER	WY	-108.7948	41.7375	12	LATLON
5602300004	4911	221112	PACIFICORP_NAUGHTON POWER PLANT	WY	-110.5961	42.8489	12	LATLON
5600500046	4911	2211	PACIFICORP_WYODAK	WY	-105.3862	44.2903	13	LATLON
58233-A	4911	2211	PACIFICORP-JIM BRIDGER	WY	-108.9567	41.6029	12	LATLON
58137-A	4911	2211	Wyodak	WY	-105.3848	44.28926		LATLON
T$12153	4911	2211	WYODAK PLANT	WY	-105.3848	44.28926		LATLON
1639	3211	327211	Visteon	OK	-95.8318	36.0835	15	LATLON
1057	3221	327213	Anchor Glass Container Corporation	OK	-95.9694	35.4476	15	LATLON
1144	3221	327213	Bartlett-Collins Glass Company	OK	-96.1037	35.9929	14	LATLON
1826	3241	327310	Holnam, Inc.	OK	-96.6933	34.773	14	LATLON
401310703	3241	327310	BLUE CIRCLE CEMENT (LaFarge?)	OK	-95.81306	36.19417		LATLON
T$11100	3241	327310	LONE STAR IND. INC. PRYOR CEMENT PLANT	OK	-95.22166	36.27194		LATLON
BSCP134	3251	327121	Commercial Brick Corp	OK	-96.54583	35.175		LATLON
BSCP76	3251	327121	Scott Jewett Truck Line, Inc	OK	-99.5	34.9		LATLON
BSCP95	3251	327121	Justin Industries	OK	-97.63361	35.6025		LATLON
BSCP96	3251	327121	Justin Industries	OK	-95.93	36.18		LATLON
T$11108	3251	327	BORAL BRICKS INC. - MUSKOGEE PLANT	OK	-95.4	35.69167		LATLON
CC87	3253	327122	Laufen International	OK	-95.92182	36.24933		LATLON
T$10977	3275	327420	UNITED DESIGN CORP. NOBLE FAC.	OK	-97.40556	35.15694		LATLON
1219	3295	2123	Chandler Materials Co.	OK	-95.8206	36.1853	15	LATLON
10303	3241	327310	Ash Grove Leamington Cement Plant	UT	-112.8154	39.6627		LATLON
490290001	3241	327310	HOLNAM INC.-Devil Slide Plant	UT	-111.5142	41.06778		LATLON
BSCP154	3251	327121	Pacific Coast Building Products	UT	-112.0611	40.59444		LATLON
BSCP71	3251	327121	Interpace Industries Inc	UT	-111.9942	41.28388		LATLON
490450051	3255	327124	A.P.GREEN REFRACTORIES - SILICA STONE QU	UT	-113.1058	40.49005		LATLON
490490007	3255	327124	A.P.GREEN REFRACTORIES - LEHI PLANT	UT	-111.5237	40.1895		LATLON

U.S. GAS TREATING PLANTS (By State & Operator)

Prepared by GTI

Operator	State	Plantname	EPA ID	Lat	Long	IXCoordina	IYCoordina	Installed Capacity MMcf/d	Design Inlet CO2 Mol%	Inlet CO2 Mol%	Design Inlet H2S Mol%	Inlet H2S Mol%
AMOCO PROD. CO.	CO	WATTENBERG	http://maps.epa.go	39.7453	104.6781	-104.678	39.7448	175	Unknown	2.99	Unknown	0
AMOCO PROD. CO.	CO	FLORIDA RIVER COMPRESSION	http://maps.epa.go	37.1564	107.7792			250	3.50	3	0.00	0
CHEVRON USA	CO	RANGELY	http://maps.epa.go	40.1044	108.9286	-108.928	40.1042	6				
CONOCO	CO	DRAGON TAIL	http://maps.epa.go	39.8297	108.7903			20	0.60	0.72	0.00	0
GRACE PETROLEUM CORP.	CO	COLORADO						5				
KOCH HYDROCARBON CO.	CO	COLORADO						0				
NORTHWEST PIPELINE CO	CO	PICEANCE CREEK	http://maps.epa.go	40.0408	108.2664	-108.266	40.0406	15	Unknown	Unknown	Unknown	Unknown
NORTHWEST PIPELINE CORP.	CO	IGNACIO	http://maps.epa.go	37.1456	107.7839	-107.784	37.1449	347	1.57	Unknown	0.00	Unknown
NORTHWEST PIPELINE CORP.	CO	NORTH DOUGLAS CREEK	http://maps.epa.go	39.9606	108.7742	-108.676	40.1336	20	Unknown	0.42	Unknown	Unknown
NORTHWEST PIPELINE CORP.	CO	FOUNDATION CREEK				-108.803	39.6731	20	6.98	2.733	Unknown	Unknown
POLUMBUS	CO	UNKNOWN (KLINE)							Unknown		Unknown	
QUESTAR PIPELINE	CO	SKULL CREEK						40	Unknown		Unknown	
RKY. MT. NATURAL GAS	CO	SLICK ROCK				-108.893	38.0206	25				
UNION PACIFIC RESOURCES	CO	BLEDSOE RANCH	http://maps.epa.go	38.9544	103.0589	-103.059	38.9541	2	Unknown	1.25	Unknown	0
UNION PACIFIC RESOURCES	CO	MT. PEARL	http://maps.epa.go	38.8739	102.7522	-102.752	38.8738	2	0.87	0.93	0.00	0
UNION PACIFIC RESOURCES	CO	ARAPAHOE	http://maps.epa.go	38.8300	102.6100	-102.795	38.7664	8	3.75	Unknown	0.00	Unknown
UNKNOWN	CO	HANCOCK						40				
AMOCO PROD. CO.	KS	ULYSSES				-101.351	37.5792	400	Unknown	0.02	Unknown	0
ANADARKO PETROLEUM CORP.	KS	CIMARRON RIVER				-100.932	37.0592	15	0.18	0.12	0.00	0
ANADARKO PETROLEUM CORP.	KS	WOODS						10	0.08	0.15	0.00	0
COLORADO INTERST. GAS CO.	KS	LAKIN						216	0.02	0.02	0.00	0
COLORADO INTERST. GAS CO.	KS	MORTON COUNTY						25	0.60	0.15	0.00	0
INTERNORTH	KS	BUSHTON						130				
KAN-NEB NAT. GAS	KS	PAWNEE						20				
MESA LIMITED PARTNERSHIP	KS	ULYSSES				-101.351	37.5792	251	0.01	0.025	0.00	0
NATIIONAL HELIUM	KS	NATIONAL HELIUM PLANT						850	0.60	0.31	Unknown	Unknown
TEXACO INC.	KS	MINNEOLA						25	0.20	0.2	0.00	0
AMOCO PROD. CO.	NM	EMPIRE ABO				-104.263	32.7717	20	Unknown	0.8	Unknown	2.09
CHEVRON USA (WARREN)	NM	VADA				-103.544	33.4342	40				
CHEVRON USA (WARREN)	NM	EUNICE				-103.144	32.4258	70	Unknown	Unknown	Unknown	Unknown
CHEVRON USA (WARREN)	NM	MONUMENT				-103.144	32.4258	77	Unknown		Unknown	
CHEVRON USA (WARREN)	NM	SAUNDERS				-103.308	32.6106	26				
CITIES SERVICE OIL & GAS CO.	NM	EMPIRE ABO				-103.61	33.0569	4				
CONOCO	NM	MALJAMAR				-103.768	32.8125	200	0.49	1.64	0.00	0.1
CONOCO	NM	SAN JUAN				-107.959	36.7317	500	1.13	1.5	0.00	0
EL PASO NATURAL GAS CO.	NM	EUNICE				-103.454	32.2996	152				
EL PASO NATURAL GAS CO.	NM	JAL				-103.21	32.0661	76				
EL PASO NATURAL GAS CO.	NM	JAL 1				-103.21	32.0661	120				
EL PASO NATURAL GAS CO.	NM	JAL 3				-103.176	32.1742	100				
EL PASO NATURAL GAS CO.	NM	JAL 4				-103.195	32.2553	185				
EL PASO NATURAL GAS CO.	NM	MONUMENT				-103.308	32.6106	180				
GAS CO. OF NEW MEXICO	NM	AVALON				-104.209	32.5025	30	1.00	Unknown	0.00	Unknown
GAS CO. OF NEW MEXICO (SUNTERRA)	NM	LYBROOK PLANT				-107.545	36.2319	70	0.71	0.65	0.00	Unknown
GAS CO. OF NEW MEXICO (SUNTERRA)	NM	KUTZ II PLANT				-107.954	36.6683	80	1.16	1.24	0.00	Unknown
GETTY OIL	NM	NEW MEXICO						100				
GMP GAS CORP.	NM	ARTESIA				-104.231	32.7625	54	Unknown	Unknown	Unknown	Unknown
GPM GAS CORP.	NM	EUNICE				-103.299	32.5206	100	Unknown	Unknown	Unknown	Unknown

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Operator	State	Plantname	EPA ID	Lat	Long	IXCoordina	IYCoordina	Installed Capacity MMcf/d	Design Inlet CO2 Mol%	Inlet CO2 Mol%	Design Inlet H2S Mol%	Inlet H2S Mol%
GPM GAS CORP.	NM	LEE				-103.514	32.8053	42	Unknown	Unknown	Unknown	Unknown
INTERNORTH	NM	HOBBS				-103.358	32.7131	220	Unknown		Unknown	
MARATHON OIL CO.	NM	INDIAN BASIN				-104.574	32.4664	130	Unknown		Unknown	
NORTHWEST PIPELINE CO. (WILLIAMS)	NM	MILAGRO						320	10.00	10	Unknown	Unknown
OXY NGL, INC.	NM	BLUITT				-103.238	33.6206	37	Unknown	Unknown	Unknown	Unknown
PERRY GAS	NM	ANTELOPE RIDGE				-103.454	32.2996	20				
RICHARDSON, SID CARBON & GASOLINE	NM	JAL #3				-103.176	32.1742	200	Unknown	1.57	Unknown	0.56
SO. UNION	NM	KUTZ CANYON				-107.954	36.6683	82				
SO. UNION	NM	LYBROOK				-107.545	36.2319	72				
SUNTERRA GAS PROCESSING CO.	NM	KUTZ CANYON				-107.954	36.6683	70	0.36	1.41	0.00	Unknown
TEXACO INC.	NM	EUNICE COMPLEX				-103.158	32.3614	140	Unknown	1.5	Unknown	0.34
TEXACO, MIDLAND	NM	BUCKEYE				-103.508	32.7844	23	Unknown	3.4	Unknown	1.4
TRANSWESTERN	NM	BELL LAKE						30				
TRANSWESTERN	NM	YATES				-104.198	33.4286	10				
AMOCO PROD. CO.	OK	HITCHCOCK						55	0.45	Unknown	0.00	0
AMOCO PROD. CO.	OK	WILBURTON TREATING						24	3.95	Unknown	0.00	Unknown
AMOCO PROD. CO.	OK	MOORELAND				-99.1574	36.4408	130	Unknown	0.6	Unknown	0
ANADARKO PETROLEUM CORP.	OK	PANTHER CREEK				-97.4716	34.7079	15	0.23	0.36	0.00	0
ANADARKO PETROLEUM CORP.	OK	NORTH RICHLAND CTR						25	Unknown	0.22	Unknown	0
ANDARKO GATHERING SYSTEM	OK	BURNS FLAT						15	0.49	1.18	Unknown	Unknown
AQUILLA ENERGY CORP	OK	ELK CITY						100	0.50	0.85	0.00	0
CENTANA ENERGY CORP.	OK	SEILING GAS PLANT						75	0.60	0.92	Unknown	Unknown
CHEVRON USA (WARREN)	OK	MOCANE				-100.396	36.8989	175				
CHEVRON USA (WARREN)	OK	KINGFISHER				-97.7328	35.7908	15				
CHEVRON USA (WARREN)	OK	KNOX						50				
CHEVRON USA (WARREN)	OK	LEEDEY				-99.4659	35.8092	50				
COASTAL OIL & GAS CO.	OK	STURGIS						30	0.01	1.2	0.00	0
COASTAL OIL & GAS CO.	OK	CUSTER				-98.8918	35.6496	200	Unknown	Unknown	Unknown	Unknown
CONOCO	OK	MUSTANG				-97.6747	35.4814	30	0.35	0.61	0.00	0
CONOCO	OK	CASHION						30	0.35	0.48	0.00	0
CONOCO	OK	HENNESSEY				-97.9028	36.0719	30	0.21	0.32	0.00	0
DELHI GAS PIPELINE CORP.	OK	BEAVER				-100.147	36.5718	55	Unknown	Unknown	Unknown	Unknown
DELHI GAS PIPELINE CORP.	OK	EL RENO				-97.9522	35.6302	75	Unknown	Unknown	Unknown	Unknown
DELHI GAS PIPELINE CORP.	OK	CUSTER				-98.8918	35.6496	25	Unknown	Unknown	Unknown	Unknown
DELHI GAS PIPELINE CORP.	OK	ANTELOPE HILLS				-99.7841	35.8307	20	Unknown	Unknown	Unknown	Unknown
DELHI GAS PIPELINE CORP.	OK	WOODWARD						45	Unknown	Unknown	Unknown	Unknown
DIAMOND SHAMROCK R&M CO.	OK	ROGER MILLS						50				
EXXON COMPANY, U.S.A.	OK	DOVER-HENNESSEY				-97.904	36.0729	80				
FREEPORT-MCMORAN INC	OK	TYRONE				-101.088	36.9947	36				
GETTY OIL	OK	OKLAHOMA						100				
GETTY OIL	OK	OKLAHOMA UNIT 1						5				
GETTY OIL	OK	OKLAHOMA UNIT 4						5				
GETTY OIL	OK	OKLAHOMA UNIT 5						5				
GETTY OIL	OK	OKLAHOMA UNIT 2						5				
GETTY OIL	OK	OKLAHOMA UNIT 3						5				
GPM GAS CORP.	OK	KINGFISHER				-97.7328	35.7908	165	Unknown	Unknown	Unknown	Unknown
GPM GAS CORP.	OK	OKARCHE				-98.0856	35.7364	142	Unknown	Unknown	Unknown	Unknown

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Operator	State	Plantname	EPA ID	Lat	Long	IXCoordina	IYCoordina	Installed Capacity MMcf/d	Design Inlet CO2 Mol%	Inlet CO2 Mol%	Design Inlet H2S Mol%	Inlet H2S Mol%
GPM GAS CORP.	OK	LUCIEN						10	Unknown	Unknown	Unknown	Unknown
GPM GAS CORP.	OK	CIMARRON				-98.5417	36.0247	56	Unknown	Unknown	Unknown	Unknown
LIBERTY ENERGY	OK	OKLAHOMA						0				
MAXUS EXPLORATION CO.	OK	ROGER MILLS						50				
MOBIL	OK	BRADLEY						140				
MOBIL E & P U.S.	OK	CHITWOOD						50	0.50	0.46	0.00	0
MOBIL E & P U.S.	OK	SHOLEM ALECHEM				-97.605	34.4225	60	Unknown	0.75	Unknown	0
MOBIL E & P U.S.	OK	POSTLE HOUGH				-101.641	36.9014	20	Unknown	0.1	Unknown	Unknown
NGC ENERGY, INC	OK	BINGER						15	0.74	0.09	Unknown	Unknown
NGC ENERGY, INC	OK	RINGWOOD				-98.2417	36.3656	65	Unknown	0.3	Unknown	Unknown
NGC ENERGY, INC	OK	MADILL				-96.5903	34.0858	25	Unknown	0.68	Unknown	Unknown
ORYX ENERGY	OK	LAVERNE				-99.9263	36.7117	200	Unknown	0.5	Unknown	0
ORYX ENERGY	OK	CARNEY				-97.5067	35.1017	15	Unknown	Unknown	Unknown	Unknown
ORYX ENERGY	OK	GOLDSBY						40	0.47	0.44	0.00	0
PG&E RESOURCES COMPANY	OK	ELMORE CITY						24	0.02	0.02	0.00	0
TEXACO E & P INC	OK	CAMRICK						35	0.45	0.46	0.00	0
TEXACO E & P INC	OK	MAYSVILLE				-97.4456	34.815	500	0.50	Unknown	0.00	Unknown
TEXACO E & P INC	OK	ENVILLE						15	Unknown	Unknown	Unknown	Unknown
TEXACO E & P INC	OK	VELMA				-97.6781	34.4608	100	0.07	0.7	0.00	0.23
TONKAWA GAS PROCESSING CO.	OK	CIMARRON				-98.5417	36.0247	90	Unknown	Unknown	Unknown	Unknown
TONKAWA GAS PROCESSING CO.	OK	WATONGA						30	Unknown	Unknown	Unknown	Unknown
TRANSOK, INC.	OK	THOMAS						150	0.77	0.91	0.00	0
TRANSOK, INC.	OK	CLINTON						75	0.70	0.87	0.00	0
TRANSOK, INC.	OK	LINE CREEK						27	0.50	0.5	0.00	0
TRANSOK, INC.	OK	COMANCHE TAP				-98.3246	34.5435	30	0.50	0.5	0.00	0
TRANSOK, INC.	OK	GREASY CREEK						30	0.40	Unknown	0.00	Unknown
TRANSOK, INC.	OK	CRESCENT						45	0.28	0.28	0.00	0
TRANSOK, INC.	OK	CRYSTAL LAKE						7	Unknown	Unknown	Unknown	Unknown
TRANSOK, INC.	OK	RED FORK						30	1.28	1.34	0.00	0
UNION PACIFIC RESOURCES	OK	ENID				-97.8188	36.4263	36	0.50	0.5	0.00	0
VICKERS PETROLEUM	OK	UNKNOWN							Unknown		Unknown	
WARREN PETROLEUM COMPANY	OK	WAYSVILLE						40				
ADOBE RESOURCES CORP.	TX	APPLE CREEK						28	0.51	0.7	0.00	0
ADOBE RESOURCES CORP.	TX	SALE RANCH						16	0.29	0.28	0.00	0.004
AMERADA HESS CORP.	TX	VIDOR				-94.0024	30.1963					
AMERICAN CENTRAL	TX	SAND HILLS						15				
AMERICAN CENTRAL GAS COMPANIES	TX	LIVE OAK				-98.0132	28.4842	18				
AMOCO PROD. CO.	TX	MIDLAND FARMS						30	Unknown	1.69	Unknown	2.58
AMOCO PROD. CO.	TX	OLD OCEAN				-95.7467	29.0689	175	Unknown	1.73	Unknown	0
AMOCO PROD. CO.	TX	NORTH COWDEN						25	Unknown	3.5	Unknown	4.55
AMOCO PROD. CO.	TX	CEDAR LAKE						3	Unknown	5.71	Unknown	8.34
AMOCO PROD. CO.	TX	TEXAS CITY				-94.925	29.3744	70	Unknown	0.81	Unknown	0
AMOCO PROD. CO.	TX	ANTON IRISH						4	Unknown	9.3	Unknown	2.87
AMOCO PROD. CO.	TX	LEVELLAND						40	Unknown	Unknown	Unknown	Unknown
AMOCO PROD. CO.	TX	SLAUGHTER						62	Unknown	9.29	Unknown	3.01
AMOCO PROD. CO.	TX	MALLET CO2 REMOVAL PLANT						100	82.00	84	0.50	0.6
AMOCO PROD. CO.	TX	SOLD->BURNELL-N. PETTUS						35	Unknown	Unknown	Unknown	Unknown

U.S. GAS TREATING PLANTS (By State & Operator)

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Operator	State	Plantname	EPA ID	Lat	Long	IXCoordina	IYCoordina	Installed Capacity MMcf/d	Design Inlet CO2 Mol%	Inlet CO2 Mol%	Design Inlet H2S Mol%	Inlet H2S Mol%
AMOCO PROD. CO.	TX	WEST YANTIS						45	Unknown	Unknown	Unknown	Unknown
AMOCO PROD. CO.	TX	WASSON CO2						80	Unknown	78.28	Unknown	0.35
ANADARKO PETROLEUM CORP.	TX	SNEED						150	0.27	0.56	0.00	0
ARCO OIL & GAS CO.	TX	BLOCK 31						75				
ARCO OIL & GAS CO.	TX	FREER						0				
ARCO OIL & GAS CO.	TX	GORMAN						100				
ARCO OIL & GAS CO.	TX	GORMAN						200				
ARCO OIL & GAS CO.	TX	GORMAN						40				
ARCO OIL & GAS CO.	TX	LONGVIEW						27				
ARCO OIL & GAS CO.	TX	ELDORADO				-100.683	30.9914	15				
ARCO OIL & GAS CO.	TX	FASHING				-98.1803	28.7952	20				
ARKLA	TX	WASKOM				-94.0723	32.4693	32	1.25	1.25	0.00	0
ARKLA	TX	WILLOW SPRINGS						10	1.29	Unknown	0.00	Unknown
ARKLA	TX	JEFFERSON						2	Unknown	1.04	Unknown	0
ARKLA	TX	GILMER						15	2.64	Unknown	0.26	Unknown
CABOT CORP.	TX	ESTES						13				
CABOT CORP.	TX	BRYAN						2				
CABOT CORP.	TX	YAKE-MERCHANT						7				
CABOT CORP.	TX	WALTON						25				
CHEVRON USA	TX	TAFT ONE						16				
CHEVRON USA	TX	THREE P.						12				
CHEVRON USA	TX	KSBHUGU #3						330				
CHEVRON USA	TX	N. WARD ESTES						63				
CHEVRON/WARREN	TX	PUCKETT						40				
CITIES SERVICE OIL & GAS CO.	TX	MONT BELVIEU				-94.9188	29.8518	57				
CITIES SERVICE OIL & GAS CO.	TX	WELCH						3				
CITIES SERVICE OIL & GAS CO.	TX	EAST TEXAS						19				
CITIES SERVICE OIL & GAS CO.	TX	DUNBAR						11				
CITIES SERVICE OIL & GAS CO.	TX	ROBERTS RANCH						85				
CITIES SERVICE OIL & GAS CO.	TX	PANTHER CREEK						15				
CITIES SERVICE OIL & GAS CO.	TX	CANTON						5				
CLAJON GAS CO., L.P.	TX	LAGRANGE						200				
CONOCO	TX	HAMLIN						20	1.19	1.26	0.03	0.06
CONOCO	TX	MC ALLEN RANCH						21	0.23	0.11	0.00	0
CONOCO	TX	BAILY						15	0.17	0.52	0.00	0
CONOCO	TX	MERTZON						25	0.40	0.62	0.00	0
CONOCO	TX	RAMSEY						5	0.27	0.52	0.00	0.01
CONOCO	TX	CHITTIM RANCH						3	0.29	0.25	0.00	0
CONOCO	TX	ELDORADO						30	0.17	0.71	0.00	0
CONOCO	TX	STERLING						60	0.50	0.5	0.00	0
CRYSTAL OIL	TX	UNKNOWN						0				
DELHI	TX	AKER						16	Unknown	Unknown	Unknown	Unknown
DELHI	TX	TEAS						12	Unknown	Unknown	Unknown	Unknown
DELHI GAS PIPELINE CORP.	TX	DENTON						30	Unknown	Unknown	Unknown	Unknown
DELHI GAS PIPELINE CORP.	TX	GRAPELAND						165	Unknown	Unknown	Unknown	Unknown
DELHI GAS PIPELINE CORP.	TX	THREE RIVERS						25	Unknown	Unknown	Unknown	Unknown
DELHI GAS PIPELINE CORP.	TX	EAST TEXAS						90	Unknown	Unknown	Unknown	Unknown

Prepared by GTI

Operator	State	Plantname	EPA ID	Lat	Long	IXCoordina	IYCoordina	Installed Capacity MMcf/d	Design Inlet CO2 Mol%	Inlet CO2 Mol%	Design Inlet H2S Mol%	Inlet H2S Mol%
DELHI GAS PIPELINE CORP.	TX	COYANOSA						100	Unknown	Unknown	Unknown	Unknown
DELHI GAS PIPELINE CORP.	TX	LAREDO						25	Unknown	Unknown	Unknown	Unknown
DIAMOND SHAMROCK R&M CO.	TX	MCKEE						300	Unknown		Unknown	
EL PASO NATURAL GAS CO.	TX	MCELROY CRANE						54				
EL PASO NATURAL GAS CO.	TX	GOLDSMITH						211				
EL PASO NATURAL GAS CO.	TX	WASSON						145				
EL PASO NATURAL GAS CO.	TX	PUCKETT						80				
EL PASO NATURAL GAS CO.	TX	TERRELL						271				
EL PASO NATURAL GAS CO.	TX	KEYSTONE						187				
EL PASO NATURAL GAS CO.	TX	MIDWAY LANE						90				
EL PASO NATURAL GAS CO.	TX	PANOMA						176				
EL PASO NATURAL GAS CO.	TX	WAHA						285				
EL PASO NATURAL GAS CO.	TX	UPTON CO.						18				
EL PASO NATURAL GAS CO.	TX	DENVER CITY						168				
ENSERCH PROCESSING, INC.	TX	NOVICE						5	Unknown	Unknown	Unknown	Unknown
ENSERCH PROCESSING, INC.	TX	SANTA ANNA						5	Unknown	Unknown	Unknown	Unknown
ENSERCH PROCESSING, INC.	TX	RANGER						10	Unknown	Unknown	Unknown	Unknown
ENSERCH PROCESSING, INC.	TX	PUEBLO						20	0.26	Unknown	Unknown	Unknown
ENSERCH PROCESSING, INC.	TX	REPRIEVE						3	Unknown	Unknown	Unknown	Unknown
ENSERCH PROCESSING, INC.	TX	TRINIDAD						65	1.45	1.45	Unknown	Unknown
ENSERCH PROCESSING, INC.	TX	CHICO						30	38.00	Unknown	Unknown	Unknown
ENSERCH PROCESSING, INC.	TX	GILLILAND						12	Unknown	Unknown	Unknown	Unknown
ENSERCH PROCESSING, INC.	TX	GORDON						48	0.43	Unknown	Unknown	Unknown
ENSERCH PROCESSING, INC.	TX	SPRINGTOWN						65	0.57	Unknown	Unknown	Unknown
EXXON COMPANY, U.S.A.	TX	CORDONA LAKE RYAN HOLMES						8	78.00	40	0.04	0.03
EXXON COMPANY, U.S.A.	TX	FT. STOCKTON						100				
EXXON COMPANY, U.S.A.	TX	TEXAS						125				
EXXON COMPANY, U.S.A.	TX	PYOTE						100	Unknown	0.175	Unknown	Unknown
FORMOSA HYDROCARBONS CO.	TX	POINT COMFORT						100	0.98	1.23	0.00	0
FOUR STAR OIL & GAS CO.	TX	HEADLEE DEVONIAN						200	0.74	0.526	0.01	0.004
GENERAL CRUDE	TX	SALT CREEK						28				
GETTY OIL	TX	TEXAS PANHANDLE						30				
GETTY OIL	TX	NEW HOPE						50	Unknown		Unknown	
GETTY OIL	TX	REVCO						50				
GPM	TX	SHERMAN						340				
GPM GAS CORP.	TX	FULLERTON						65	Unknown	Unknown	Unknown	Unknown
GPM GAS CORP.	TX	GIDDINGS						90	Unknown	Unknown	Unknown	Unknown
GPM GAS CORP.	TX	GRAY						70	Unknown	Unknown	Unknown	Unknown
GPM GAS CORP.	TX	ROCK CREEK						180	Unknown	Unknown	Unknown	Unknown
GPM GAS CORP.	TX	SPRAYBERRY TIDEWATER						12	Unknown	Unknown	Unknown	Unknown
GPM GAS CORP.	TX	SPRABERRY						41	Unknown	Unknown	Unknown	Unknown
GPM GAS CORP.	TX	DUMAS	http://maps.epa.g	35.8275	101.6308			120	Unknown	Unknown	Unknown	Unknown
GULF ENERGY	TX	CRANE						60				
HNG	TX	GOMEZ						280				
HNG	TX	DUBOSE						30				
HNG	TX	MI VIDA						400	Unknown		Unknown	
HUNT PETROLEUM	TX	NORDHEIM						10				

Prepared by GTI

Operator	State	Plantname	EPA ID	Lat	Long	IXCoordina	IYCoordina	Installed Capacity MMcf/d	Design Inlet CO2 Mol%	Inlet CO2 Mol%	Design Inlet H2S Mol%	Inlet H2S Mol%
HUNT PETROLEUM	TX	NORTH PUCKETT						10				
HUNT PETROLEUM	TX	YUCCA BUTTE						20				
INTERNORTH	TX	JASPER						10				
INTERNORTH	TX	MITCHELL						140				
INTERNORTH	TX	LOCKRIDGE						25				
INTERNORTH	TX	DATES						130				
INTERNORTH	TX	NORTH HUTCH						10				
INTERNORTH	TX	PIKES PEAK						75				
INTERNORTH	TX	KERMIT						60				
KERR-MCGEE CORP.	TX	PAMPA						11				
LIQUID ENERGY CORP.	TX	LIVE OAK COUNTY						15				
LIQUID ENERGY CORP.	TX	BRENT RANCH						20				
LIQUID ENERGY CORP.	TX	CANADIAN RIVER						20				
LIQUID ENERGY CORP.	TX	WHITE RANCH						6				
LONE STAR	TX	TEAGUE						15				
LONE STAR	TX	TEAGUE						25				
LONE STAR	TX	BOX CHURCH						15				
LONE STAR	TX	PIKES PEAK (A)						75				
LONE STAR	TX	PIKES PEAK (B)						75				
LONE STAR	TX	WARWINK						100				
MAPCO GAS PRODUCTS, INC.	TX	WESTPAN 950						52	0.18	0.54	0.00	0.0003
MAPCO WESTPAN, INC.	TX	BIVINS						120	0.07	0.41	Unknown	0.004
MAPLE GAS CORP, THE	TX	GRAY COUNTY						20				
MARATHON OIL CO.	TX	YATES						40	Unknown		Unknown	
MARATHON OIL CO.	TX	IRAAN						10				
MARATHON OIL CO.	TX	SUSAN PEAK						3				
MARATHON OIL CO.	TX	SCIPIO						30				
MEPUS	TX	NORTH WORD						33	Unknown	Unknown	Unknown	Unknown
MERIDIAN OIL	TX	VANDERBILT GAS PLANT						120	1.20	Unknown	Unknown	Unknown
MESA LIMITED PARTNERSHIP	TX	FAIN						80		0.5		0.004
MOBIL E & P U.S.	TX	FELDMAN						3	0.68	Unknown	0.00	Unknown
MOBIL E & P U.S.	TX	LA GLORIA						265	0.15	0.526	0.00	0
MOBIL E & P U.S.	TX	SALT CREEK						26	0.58	0.89	0.01	0.5
MOBIL E & P U.S.	TX	PEGASUS						60	2.00	2	0.00	0.003
MOBIL E & P U.S.	TX	LAKE CREEK						6	Unknown	Unknown	Unknown	Unknown
MOBIL E & P U.S.	TX	COYANOSA						50	0.16	0.1714	0.00	0
MOBIL E & P U.S.	TX	WAHA						125	Unknown	1	0.00	0.03
MOBIL E & P U.S.	TX	EAST WHITE POINT						25	1.00	Unknown	0.00	Unknown
MOBIL E & P U.S.	TX	PORTILLA						15	Unknown	0.391	Unknown	Unknown
MOBIL E & P U.S.	TX	WILL-O-MILLS						28	15.00	14	0.02	0.02
MONSANTO	TX	CHOCOLATE BAYOU						110				
MOORE-MCCORMACK	TX	GEORGEWEST						2				
NATURAL GAS P/L CO. AMERICA	TX	KERMIT						30				
OCCIDENTAL PETROLEUM CORP	TX	EUSTACE						51				
ODESSA NATURAL	TX	FOSTER						15				
ORYX ENERGY	TX	DIAMOND M-SHARON RDG						50				
ORYX ENERGY	TX	SNYDER						75				

Operator	State	Plantname	EPA ID	Lat	Long	IXCoordina	IYCoordina	Installed Capacity MMcf/d	Design Inlet CO2 Mol%	Inlet CO2 Mol%	Design Inlet H2S Mol%	Inlet H2S Mol%
OXY NGL, INC.	TX	WELCH						3				
OXY NGL, INC.	TX	WEST SEMINOLE						35				
OXY NGL, INC.	TX	MYRTLE SPRINGS						48				
OXY, USA	TX	WELCH PLANT						2				
PANHANDLE EASTERN	TX	CABOT						10				
PARKER & PARSLEY	TX	KARNES						10				
PENNZOIL PRODUCING CO.	TX	MCFADDIN EAST						5	Unknown	0.523	Unknown	0
PERRY GAS	TX	DEWITT						10				
PERRY GAS	TX	ROSITA						20				
PERRY GAS	TX	LA GRANGE						90				
PERRY GAS	TX	ROSITA						20				
PERRY GAS	TX	ROSITA						20				
PERRY GAS	TX	PYOTE FIELD						300				
PHILLIPS 66 NATURAL GAS CO.	TX	LULING						12				
PHILLIPS 66 NATURAL GAS CO.	TX	GOLDSMITH						120	Unknown	Unknown	Unknown	Unknown
PHILLIPS 66 NATURAL GAS CO.	TX	SHERMAN						250	Unknown	Unknown	Unknown	Unknown
PHILLIPS 66 NATURAL GAS CO.	TX	BURGER						52				
PHILLIPS 66 NATURAL GAS CO.	TX	BURGER						52				
PHILLIPS 66 NATURAL GAS CO.	TX	SNEED						250				
PHILLIPS 66 NATURAL GAS CO.	TX	SPRABERRY						25				
PHILLIPS 66 NATURAL GAS CO.	TX	FULLERTON						59				
POGO PRODUCING	TX	TEXAS						0				
REEF CORP.	TX	BIG SPRING						30				
RICHARDSON, SID CARBON & GASOLINE	TX	CHALK						15	Unknown	2.37	Unknown	0
RICHARDSON, SID CARBON & GASOLINE	TX	ESKOTA						12	Unknown	1.11	Unknown	0
RICHARDSON, SID CARBON & GASOLINE	TX	HALLEY						60	Unknown	0	Unknown	0
RICHARDSON, SID CARBON & GASOLINE	TX	KEYSTONE						120	Unknown	1.07	Unknown	0.32
SHELL WESTERN E & P, INC.	TX	PAWNEE						45				
SHELL WESTERN E & P, INC.	TX	BRYANS MILL						66	Unknown	Unknown	Unknown	Unknown
SHELL WESTERN E & P, INC.	TX	HOUSTON CENTRAL						550	Unknown	Unknown	Unknown	Unknown
SHELL WESTERN E & P, INC.	TX	PERSONS						38				
SOUTH TEXAS GAS TREATERS	TX	LIVE OAK						50	8.00	Unknown	0.12	Unknown
SUN GAS	TX	BIG WELLS						8				
SUN GAS	TX	CARRIZO SPRINGS						5				
SUN GAS	TX	JAMESON						50				
SUN GAS	TX	STRAIGHT GAS UNIT						8				
SUN GAS	TX	SACROC CO2 REMOVAL FAC.						110				
SUN GAS	TX	ROCKY FIELD						5				
SUPERIOR OIL	TX	SWEET HOME						28				
TENNECO OIL CO.	TX	TEXAS						0				
TEXACO E & P INC	TX	CHOCOLATE BAYOU GAS PLANT						20	Unknown	Unknown	Unknown	Unknown
TEXACO E & P INC	TX	BROOKELAND GAS PLANT						30	Unknown	Unknown	Unknown	Unknown
TEXACO INC.	TX	OZONA						25	Unknown	0.6	Unknown	0
TEXACO INC.	TX	STREETMAN						15	Unknown	Unknown	Unknown	Unknown
TEXACO INC.	TX	MCLEAN						25	Unknown	0.04	Unknown	0
TEXACO INC.	TX	EAST VEALMOOR						50	Unknown	1.03	Unknown	0.16
TEXACO INC.	TX	GEORGE WEST						20	0.00	Unknown	0.00	Unknown

Operator	State	Plantname	EPA ID	Lat	Long	IXCoordinaIYCoordina	Installed Capacity MMcf/d	Design Inlet CO2 Mol%	Inlet CO2 Mol%	Design Inlet H2S Mol%	Inlet H2S Mol%
TEXACO INC.	TX	GAS TREATING					10	Unknown	Unknown	Unknown	Unknown
TEXACO INC.	TX	BRADFORD RANCH					12	Unknown	0.5	Unknown	0.0015
TEXACO INC.	TX	PECOS					30				
TEXACO INC.	TX	FULLER					5	Unknown	1.2	Unknown	0.4
TEXACO INC.	TX	SOUTH KERMIT COMPLEX					24	Unknown	0.9	Unknown	0.2
TEXACO, MIDLAND	TX	REEVES					50				
TEXACO, MIDLAND	TX	MABEE					6	Unknown	Unknown	Unknown	Unknown
TEXACO, MIDLAND	TX	KNIGHT					90				
TEXACO, MIDLAND	TX	KERMIT					7				
TEXAS OIL & GAS CO	TX	TEAGUE					100	Unknown	Unknown	Unknown	Unknown
TEXAS OIL & GAS CO	TX	GILMER B					80	Unknown	Unknown	Unknown	Unknown
TONKAWA GAS PROCESSING CO.	TX	LONGVIEW					100	Unknown	Unknown	Unknown	Unknown
TONKAWA GAS PROCESSING CO.	TX	BOOKER					6	Unknown	Unknown	Unknown	Unknown
TRANSCO	TX	MCMULLEN					106	Unknown		Unknown	
TRANSCO	TX	TILDEN					96				
TRANSWESTERN	TX	ESTES					18				
TRANSWESTERN	TX	CHENOT PUTNAM					18				
TRANSWESTERN	TX	HALLEY					135				
TRANSWESTERN	TX	HUBER					3				
TRANSWESTERN	TX	KEYSTONE					78				
TRANSWESTERN	TX	WALTON					33				
TRANSWESTERN	TX	PYOTE					450				
TRANSWESTERN	TX	KERMIT					35				
UNION PACIFIC RESOURCES	TX	BRYAN					35	2.60	2.599	0.00	0
UNION PACIFIC RESOURCES	TX	A & M					50	Unknown	3.399	Unknown	0
UNION PACIFIC RESOURCES	TX	CONROE					70	1.57	1.242	Unknown	Unknown
UNION PACIFIC RESOURCES	TX	GULF PLAINS					135	0.37	0.275	Unknown	Unknown
UNION PACIFIC RESOURCES	TX	EAST TEXAS					220	1.41	Unknown	0.00	Unknown
UNION TEXAS	TX	BRAYSON					10				
UNITED TRANS.	TX	FANDANGO					20				
USAGAS PIPELINE CO.	TX	MCLEOD I					15	Unknown	Unknown	Unknown	Unknown
USAGAS PIPELINE CO.	TX	MCLEOD II					10	Unknown	Unknown	Unknown	Unknown
VALERO HYDROCARBONS CO.	TX	ARMSTRONG					50				
VALERO HYDROCARBONS CO.	TX	GOMEZ					250				
VALERO HYDROCARBONS CO.	TX	WEST GOMEZ					180				
VALERO HYDROCARBONS CO.	TX	BLOCK 21					100				
VALERO HYDROCARBONS CO.	TX	GREASEWOOD					100				
VALERO HYDROCARBONS CO.	TX	HOLESON					30				
VALERO HYDROCARBONS CO.	TX	MI VIDA					80				
VALERO HYDROCARBONS CO.	TX	GREY RANCH					275				
VALERO HYDROCARBONS CO.	TX	PYOTE					100				
VENTECH	TX	CARRIZO SPRINGS					17				
VENTECH	TX	POST					2				
WARREN PETROLEUM COMPANY	TX	FASHING					100	Unknown		Unknown	
WARREN PETROLEUM COMPANY	TX	SAND HILLS					150	Unknown		Unknown	
WARREN PETROLEUM COMPANY	TX	MOORES ORCHARD					10				
WARREN PETROLEUM COMPANY	TX	SHERMAN NORTH					33				

U.S. GAS TREATING PLANTS (By State & Operator)

Prepared by GTI

Operator	State	Plantname	EPA ID	Lat	Long	IXCoordina	IYCoordina	Installed Capacity MMcf/d	Design Inlet CO2 Mol%	Inlet CO2 Mol%	Design Inlet H2S Mol%	Inlet H2S Mol%
WARREN PETROLEUM COMPANY	TX	CANADIAN						25				
WARREN PETROLEUM COMPANY	TX	TONKAWA						4				
WARREN PETROLEUM COMPANY	TX	COMO						21	Unknown		Unknown	
WARREN PETROLEUM COMPANY	TX	FANNETT						33				
WARREN PETROLEUM COMPANY	TX	WORSHAM						30				
WARREN PETROLEUM COMPANY	TX	MONAHANS						45				
WESTERN GAS PROC., LTD.	TX	EDGEWOOD						60	Unknown	Unknown	Unknown	Unknown
CHEVRON USA	UT	RED WASH						22				
COASTAL OIL & GAS CO.	UT	ALTAMONT						40	Unknown	Unknown	Unknown	Unknown
ELKHORN OPERATING CO.	UT	ANETH						14	Unknown	Unknown	Unknown	Unknown
MOBIL E & P U.S.	UT	MCELMD CREEK						20	Unknown	65.66	Unknown	0.06
UNION PACIFIC RESOURCES	UT	YELLOW CREEK						80	0.03	0.3	0.00	0
UNION PACIFIC RESOURCES	UT	PINEVIEW						10	Unknown	2.04	Unknown	0.0025
AMOCO PROD. CO.	WY	BAIROIL CO2						150	Unknown	96.65	Unknown	0.34
AMOCO PROD. CO.	WY	BEAVER CREEK - J.I.						30	Unknown	0.34	Unknown	0
AMOCO PROD. CO.	WY	BEAVER CRK PHOSPHORIA						17	Unknown	1.26	Unknown	8.62
AMOCO PROD. CO.	WY	SALT CREEK						2	Unknown	9.75	Unknown	0.58
AMOCO PROD. CO.	WY	ELK BASIN						21	Unknown	8.63	Unknown	14.73
AMOCO PROD. CO.	WY	ANSCHUTZ RANCH EAST						700	Unknown	0.2	Unknown	0
AMOCO PROD. CO.	WY	WHITNEY CANYON						275	Unknown	4.67	Unknown	15.2
AMOCO PROD. CO.	WY	PAINTER COMPLEX						240	Unknown	0.1	Unknown	0
ARCO OIL & GAS CO.	WY	RIVERTON DOME						16				
CHEVRON USA (WARREN)	WY	CARTER CREEK						155	Unknown		Unknown	
COLORADO INTERST. GAS CO.	WY	RAWLINS						220	1.50	1.3	0.00	0
COLORADO INTERST. GAS CO.	WY	TABLE ROCK						60	17.51	11.5	3.75	4.5
EXXON COMPANY, U.S.A.	WY	SHUTE CREEK						480	65.00	65	5.00	5
GULF ENERGY	WY	POWELL						12				
KERR-MCGEE CORP.	WY	BOXCAR-BUTTE						5				
KN GAS GATHERING	WY	DOUGLAS						25	0.00	2.3	0.00	0
MARATHON OIL CO.	WY	OREGON BASIN						7	Unknown		Unknown	
MONTANA DAKOTA	WY	RIVERTON						20				
NORTHWEST PIPELINE CORP.	WY	OPAL						250	0.20	0.5	0.00	0
UNION PACIFIC RESOURCES	WY	BRADY						65	29.34	38.24	1.25	1.4
UNION PACIFIC RESOURCES	WY	PATRICK DRAW						20	3.40	1.86	0.00	0
UNION PACIFIC RESOURCES	WY	EMIGRANT TRAIL						60	0.79	1.07	0.00	0
UNION PACIFIC RESOURCES	WY	SILO						2	2.49	Unknown	0.00	Unknown

U.S. NATURAL GAS FIELDS WITH GREATER THAN 5% HYDROGEN SULFIDE (Sorted by Basin Code)

Prepared by GTI

High H2S (> 5%)

STATE	COUNTY	BASIN CODE	FIELD	WELL NAME/PLANT	LOCATION/PIPELINE	OWNER	H2S	CO2
TEXAS	FREESTONE	260	NEAL	GLAYDENE NEAL NO. 1	JOHN BRADLEY SUR. A-53	GETTY OIL CO.	44.4%	4.3%
TEXAS	FREESTONE	260	NEAL	GLAYDENE NEAL NO. 1	JOHN BRADLEY SUR. A-53	GETTY OIL CO.	28.9%	5.0%
TEXAS	VAN ZANDT	260	EDGEWOOD	PARKER G.U. A NO. 1	J. H. PARKER TRACT	PAN AMERICAN PETROLEUM CORP.	24.0%	3.0%
TEXAS	VAN ZANDT	260	EDGEWOOD NE	PARKER G.U. B NO. 1	I. R. CHISUM A-157 SUR.	PAN AMERICAN PETROLEUM CORP.	21.6%	2.7%
WYOMING	NIOBRARA	515	ANT HILLS N	FED. NO. 32-12	SEC. 12, T37N, R63W	MILESTONE PETROLEUM, INC.	6.3%	4.7%
WYOMING	BIG HORN	520	TORCHLIGHT W	TORCHLIGHT UNIT WELL NO. 2	SEC. 14, T51N, R93W	STANOLIND OIL & GAS CO.	9.3%	0.3%
WYOMING	PARK	520	SILVERTIP	NO. 31-33	SEC. 33, T58N, R100W	TEXACO INC.	16.2%	4.3%
WYOMING	PARK	520	ELK BASIN	UNIT NO. 153	SEC. 25, T58N, R100W	PAN AMERICAN PETROLEUM CORP.	11.7%	4.2%
WYOMING	WASHAKIE	520	WORLAND	NO. 5E	SEC. 21, T48N, R92W	PURE OIL CO.	6.4%	2.5%
WYOMING	FREMONT	530	RIVERTON E	TRIBAL 32 NO. 6	SEC. 32, T1N, R6E	CONTINENTAL OIL CO.	5.4%	0.5%
WYOMING	FREMONT	530	BEAVER CREEK	BEAVER CREEK NO. 10	SEC. 16, T33N, R96W	PAN AMERICAN PETROLEUM CORP.	5.1%	1.0%

U.S. NATURAL GAS FIELDS WITH GREATER THAN 20% ACID GAS (Sorted by Basin Code)

Prepared by GTI

HIGH ACID GAS (HIGH TOTAL H2S+CO2)

STATE	COUNTY	BASIN	FIELD	WELL NAME/PLANT	LOCATION/PIPELINE	OWNER	H2S	CO2	SUM
COLORADO	BACA	360	NOT GIVEN	BORE HOLE NO. F614	SEC. 20, T29S, R50W	SKELLY OIL CO.	0.0%	99.4%	99.4%
COLORADO	BACA	360	NOT GIVEN	INGLE NO. 1	SEC. 27, T29S, R50W	SHARPLES OIL CORP.	0.0%	97.3%	97.3%
COLORADO	BACA	360	NOT GIVEN	INGLE NO. 1	SEC. 27, T29S, R50W	J. M. HUBER CORP.	0.0%	91.0%	91.0%
COLORADO	BACA	360	NOT GIVEN	JACOBSON NO. 1	NOT GIVEN	SHARPLES OIL CORP.	0.0%	90.0%	90.0%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	KOSCOVE NO. 1	SEC. 15, T27S, R70W	ATLANTIC RICHFIELD CO.	0.0%	97.3%	97.3%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	METER STA.	GATHERING SYSTEM	ARCO OIL & GAS CO.	0.0%	96.5%	96.5%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	NO. 1-15-C	SEC. 15, T27S, R70W	ARCO OIL & GAS CO.	0.0%	97.0%	97.0%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	NO. 1-22-H	SEC. 22, T27S, R70W	ARCO OIL & GAS CO.	0.0%	96.6%	96.6%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	NO. 2-10-0	SEC. 15, T27S, R70W	ARCO OIL & GAS CO.	0.0%	96.7%	96.7%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	NO. 3-15-B	SEC. 15, T27S, R70W	ARCO OIL & GAS CO.	0.0%	96.6%	96.6%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	NO. 3-4-O	SEC. 9, T27S, R70W	ARCO OIL & GAS CO.	0.0%	96.8%	96.8%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	NO. 4-4-P	SEC. 9, T27S, R70W	ARCO OIL & GAS CO.	0.0%	96.6%	96.6%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	NO. 5-15-F	SEC. 15, T27S, R70W	ARCO OIL & GAS CO.	0.0%	97.0%	97.0%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	NO. 5-9-A	SEC. 9, T27S, R70W	ARCO OIL & GAS CO.	0.0%	96.9%	96.9%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	NO. 6-15-I	SEC. 15, T27S, R70W	ARCO OIL & GAS CO.	0.0%	96.9%	96.9%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	SHEEP MOUNTAIN NO. 12	SEC. 15, T27S, R70W	ATLANTIC RICHFIELD CO.	0.0%	97.7%	97.7%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	SHEEP MOUNTAIN NO. 7	SEC. 9, T27S, R70W	ATLANTIC RICHFIELD CO.	0.0%	95.0%	95.0%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	SHEEP MOUNTAIN NO. 7	SEC. 9, T27S, R70W	ATLANTIC RICHFIELD CO.	0.0%	91.1%	91.1%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	SHEEP MOUNTAIN UNIT NO. 7	SEC. 9, T27S, R70W	ATLANTIC RICHFIELD CO.	0.0%	74.8%	74.8%
COLORADO	HUERFANO	455	SHEEP MOUNTAIN	SHEEP MOUNTAIN UNIT NO. 7-9	SEC. 9, T27S, R70W	ATLANTIC RICHFIELD CO.	0.0%	62.9%	62.9%
COLORADO	LAS ANIMAS	455	NOT GIVEN	BRUMLEY NO. 1	SEC. 6, T29S, R51W	BRUMLEY, C. W.	0.0%	98.8%	98.8%
COLORADO	LAS ANIMAS	455	NOT GIVEN	KING NO. 1	SEC. 1, T28S, R53W	NOT GIVEN	0.0%	95.9%	95.9%
COLORADO	LAS ANIMAS	455	NINA VIEW	WELL NO. 2	SEC. 7, T28S, R52W	NELSON-MOORE DEVELOPMENT CO.	0.0%	96.6%	96.6%
COLORADO	LAS ANIMAS	455	NINA VIEW	WELL NO. 3	SEC. 7, T28S, R52W	NELSON-MOORE DEVELOPMENT CO.	0.0%	96.7%	96.7%
COLORADO	LAS ANIMAS	455	NINA VIEW	WELL NO. 4	SEC. 7, T28S, R52W	NELSON-MOORE DEVELOPMENT CO.	0.0%	97.6%	97.6%
COLORADO	MOFFAT	535	MOFFAT	WICK NO. 13	SEC. 10, T4N, R91W	TEXACO INC.	0.0%	98.4%	98.4%
COLORADO	JACKSON	545	NOT GIVEN	BALLINGER FED. NO. 1	SEC. 8, T9N, R78W	GULF OIL CORP.	0.0%	90.4%	90.4%
COLORADO	JACKSON	545	MCCALLUM S	CONOCO FED. 8-3 UNIT NO. 1	SEC. 8, T9N, R78W	CONOCO, INC.	0.0%	70.2%	70.2%
COLORADO	JACKSON	545	MCCALLUM S	CONOCO-FEDERAL NO. 21-6	SEC. 21, T9N, R78W	CONOCO, INC.	0.0%	91.8%	91.8%
COLORADO	JACKSON	545	MCCALLUM N	GLENWOOD SPRINGS NO. 1	SEC. 12, T9N, R79W	CONTINENTAL OIL CO.	0.0%	91.8%	91.8%
COLORADO	JACKSON	545	CANADIAN RIVER	GOVT. LANMON NO. 1-A	SEC. 7, T9N, R80W	TEXACO INC.	0.0%	96.3%	96.3%
COLORADO	JACKSON	545	MCCALLUM S	HOYE NO. 1	SEC. 34, T9N, R76S	CONTINENTAL OIL CO.	0.0%	97.5%	97.5%
COLORADO	JACKSON	545	MCCALLUM S	HOYE NO. 3	SEC. 34, T9N, R78W	CONTINENTAL OIL CO.	0.0%	91.3%	91.3%
COLORADO	JACKSON	545	MCCALLUM UNIT	SEPERATOR AT PLANT	DAKOTA-LAKOTA RESERVOIR	CONTINENTAL OIL CO.	0.0%	92.3%	92.3%
COLORADO	JACKSON	545	MCCALLUM	SEPERATOR AT PLANT	MORRISON POOL	CONTINENTAL OIL CO.	0.0%	91.7%	91.7%
COLORADO	JACKSON	545	MCCALLUM N	SHERMAN NO. 1	SEC. 12, T9N, R79W	CONTINENTAL OIL CO.	0.0%	92.1%	92.1%
COLORADO	DOLORES	585	DOE CANYON	DOE CANYON NO. 1	SEC. 13, T40N, R18W	HUMBLE OIL & REFINING CO.	0.0%	92.6%	92.6%
COLORADO	DOLORES	585	DOE CANYON	DOE CANYON NO. 1	SEC. 13, T40N, R18W	HUMBLE OIL & REFINING CO.	0.0%	90.4%	90.4%
COLORADO	DOLORES	585	GLADE CANYON	GLADE CANYON UNIT NO. 1	SEC. 13, T40N, R17W	SINCLAIR OIL & GAS CO.	0.0%	95.8%	95.8%
COLORADO	MONTEZUMA	585	MCELMO DOME UNIT	DEAN DUDLEY NO. 2	SEC. 13, T36N, R18W	DELHI-TAYLOR OIL CORP.	0.0%	96.2%	96.2%
COLORADO	MONTEZUMA	585	MCELMO DOME UNIT	DEAN DUDLEY NO. 3	SEC. 13, T36N, R28W	AMERIGAS, INC.	0.0%	97.5%	97.5%
COLORADO	MONTEZUMA	585	MCELMO DOME UNIT	DUDLEY NO. 2	SEC. 13, T36N, R18W	TENNECO OIL CO.	0.0%	96.0%	96.0%
COLORADO	MONTEZUMA	585	MCELMO DOME UNIT	HOVENWEEP FED. NO. 1	SEC. 19, T38N, R18W	MOBIL RESEARCH & DEVELOPMENT	0.0%	98.6%	98.6%
COLORADO	MONTEZUMA	585	MCELMO DOME UNIT	HOVENWEEP FED. NO. 1	SEC. 19, T38N, R18W	MOBIL OIL CORP.	0.0%	98.5%	98.5%
COLORADO	MONTEZUMA	585	MCELMO DOME UNIT	J. A. FULKS NO. 1	SEC. 27, T37N, R17W	GULF OIL CORP.	0.0%	97.8%	97.8%
COLORADO	MONTEZUMA	585	MCELMO DOME UNIT	J. A. FULKS NO. 1	SEC. 27, T37N, R17W	GULF OIL CORP.	0.0%	97.7%	97.7%
COLORADO	MONTEZUMA	585	MCELMO DOME UNIT	J. A. FULKS NO. 1	SEC. 27, T37N, R17W	GULF OIL CORP.	0.0%	97.5%	97.5%
COLORADO	MONTEZUMA	585	MCELMO DOME UNIT	J. A. FULKS NO. 1	SEC. 27, T37N, R17W	GULF OIL CORP.	0.0%	97.5%	97.5%
COLORADO	MONTEZUMA	585	MCELMO DOME UNIT	MOQUI UNIT NO. 2	SEC. 12, T37N, R19W	MOBIL OIL CORP.	0.0%	97.9%	97.9%

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COLORADO	MONTEZUMA	585	MCELMO	SCHMIDT NO. 1	SEC. 24, T36N, R18W	BYRD-FROST, INC.	0.0%	81.9%	81.9%
COLORADO	MONTEZUMA	585	MCELMO DOME UNIT	SCHMIDT NO. 2	SEC. 24, T36N, R18W	AMERIGAS, INC.	0.0%	97.6%	97.6%
COLORADO	DELTA	595	BLACK CANYON	NO. 1	SEC. 6, T15S, R94W	BILLSTROM BROTHERS	0.0%	82.3%	82.3%
COLORADO	GARFIELD	595	GARMESA	GARMESA NO. 1	SEC. 5, T8S, R102W	GYPSY OIL CO.	0.0%	61.1%	61.1%
COLORADO	GARFIELD	595	GARMESA	GARMESA NO. 1	SEC. 8, T8S, R102W	FULTON PETROLEUM CO.	0.0%	35.6%	35.6%
COLORADO	GARFIELD	595	GARMESA	GARMESA NO. 1	SEC. 8, T8S, R102W	KERR-MCGEE OIL IND., INC.	0.0%	20.8%	20.8%
COLORADO	GARFIELD	595	GARMESA	NATIONAL NO. 1	SEC. 6, T8S, R102W	KERR-MCGEE OIL IND., INC.	0.0%	57.6%	57.6%
COLORADO	GARFIELD	595	GARMESA	NOT GIVEN	SEC. 5, T8S, R102W	GYPSY OIL CO.	0.0%	20.0%	20.0%
COLORADO	MESA	595	GARMESA	GARMESA NO. 1	SEC. 8, T8S, R102W	KERR-MCGEE OIL IND., INC.	0.0%	20.4%	20.4%
COLORADO	MESA	595	BRONCO FLATS	U.S.A. NO. 1-14 HC	SEC. 14, T9S, R98W	COORS ENERGY CO.	0.0%	53.7%	53.7%
COLORADO	RIO BLANCO	595	WHITE RIVER DOME	NO. 1	SEC. 30, T2N, R96W	TEXAS PRODUCTION CO.	0.0%	21.8%	21.8%
COLORADO	RIO BLANCO	595	FOUNDATION CREEK	STEELE NO. 1-35	SEC. 35, T4S, R102W	SWEET PEA OIL & GAS CO.	0.0%	37.5%	37.5%
COLORADO	RIO BLANCO	595	DOUGLAS CREEK S	UNIT NO. 7	SEC. 6, T4S, R101W	CITIES SERVICE OIL CO.	0.0%	21.4%	21.4%
NEW MEXICO	HARDING	445	BACA	BACA NO. 1	SEC. 19, T20N, R31E	WADDELL & MCFANN, ET AL.	0.0%	99.4%	99.4%
NEW MEXICO	HARDING	445	NOT GIVEN	DE BACA WELL NO. 2YB	SEC. 31, T20N, R31E	AMERIGAS, INC.	0.0%	99.6%	99.6%
NEW MEXICO	HARDING	445	BRAVO DOME	HEIMANN NO. 1 (1933-031M)	SEC. 3, T19N, R33E	AMOCO PRODUCTION CO. (USA)	0.0%	98.8%	98.8%
NEW MEXICO	HARDING	445	BACA	KERLIN NO. 1	SEC. 34, T21N, R30E	KUMMBACA OIL & GAS CO.	0.0%	98.2%	98.2%
NEW MEXICO	HARDING	445	NOT GIVEN	LIBBY WELL NO. 4K	SEC. 16, T20N, R31E	AMERIGAS, INC.	0.0%	99.1%	99.1%
NEW MEXICO	HARDING	445	NOT GIVEN	MITCHELL LEASE NO. 20K	SEC. 5, T18N, R30E	AMERIGAS, INC.	0.0%	99.6%	99.6%
NEW MEXICO	HARDING	445	NOT GIVEN	MITCHELL LEASE NO. 6M	SEC. 8, T19N, R30E	AMERIGAS, INC.	0.0%	98.4%	98.4%
NEW MEXICO	HARDING	445	BUEYEROS	POWERS-MARSHELL NO. 1	SEC. 34, T21N, R30E	POWERS-MARSHALL CO.	0.0%	99.7%	99.7%
NEW MEXICO	UNION	445	BRAVO DOME	CAIN NO. E-1 (1935-221G)	SEC. 22, T22N, R16W	AMOCO PRODUCTION CO. (USA)	0.0%	99.0%	99.0%
NEW MEXICO	UNION	445	SIERRA GRANDE	ROGERS NO. 1	SEC. 4, T29N, R29E	SIERRA GRANDE OIL CORP.	0.0%	98.4%	98.4%
NEW MEXICO	COLFAX	455	NOT GIVEN	ROBERTS NO. 1	SEC. 7, T28N, R27E	ROBERTS, W. C.	0.0%	89.1%	89.1%
NEW MEXICO	MORA	455	WAGON MOUND	C. F. CRUSE NO. 1	SEC. 11, T19N, R21E	ARKANSAS FUEL OIL CO.	0.0%	92.2%	92.2%
NEW MEXICO	MORA	455	WAGON MOUND	C. F. CRUSE NO. 1	SEC. 11, T19N, R21E	ARKANSAS FUEL OIL CO.	0.0%	90.0%	90.0%
NEW MEXICO	BERNALILLO	460	NOT GIVEN	WATER WELL	SEC. 36, T11N, R6E	CROSBY, JIM & U.S.G.S.	0.0%	78.7%	78.7%
NEW MEXICO	TORRANCE	460	TORRANCE	J. B. WITT TEXT	SEC. 12, T7N, R7E	SINOCO OIL CO.	0.0%	97.4%	97.4%
NEW MEXICO	TORRANCE	460	ESTANCIA VALLEY	PACE NO. 1	SEC. 12, T6N, R7E	NOT GIVEN	0.0%	99.0%	99.0%
NEW MEXICO	TORRANCE	460	ESTANCIA VALLEY	PACE NO. 1	NOT GIVEN	PACE, E., HEIRS	0.0%	98.4%	98.4%
NEW MEXICO	RIO ARRIBA	580	ABIQUIN	MORTEN NO. 1	SEC. 24, T24N, R5E	LOWRY, ET AL.	0.0%	96.5%	96.5%
NEW MEXICO	RIO ARRIBA	580	HAYSTACK DOME	NAVAJO C NO. 1	SEC. 8, T23N, R5W	HUMBLE OIL & REFINING CO.	0.0%	88.1%	88.1%
NEW MEXICO	SAN JUAN	580	WILDCAT	NAVAJO C NO. 1	SEC. 1, T29N, R17W	PAN AMERICAN PETROLEUM CORP.	0.0%	38.2%	38.2%
NEW MEXICO	SAN JUAN	580	HOGBACK N	NAVAJO K NO. 2	SEC. 31, T30N, R16W	HUMBLE OIL & REFINING CO.	0.0%	88.5%	88.5%
NEW MEXICO	SAN JUAN	580	NAVAJO	NAVAJO TRACT 27 NO. 1	SEC. 32, T26N, R15W	PURE OIL CO.	0.0%	96.2%	96.2%
NEW MEXICO	SAN JUAN	580	NAVAJO	NAVAJO TRACT 27 NO. 1	SEC. 32, T26N, R15W	PURE OIL CO.	0.0%	95.3%	95.3%
NEW MEXICO	SAN JUAN	580	UTE DOME	NOT GIVEN	NOT GIVEN	PAN AMERICAN PETROLEUM CORP.	1.1%	23.1%	24.2%
NEW MEXICO	SAN JUAN	580	HOGBACK	U.S.G. NO. 13	SEC. 19, T29N, R16W	STANOLIND OIL & GAS CO.	0.0%	20.3%	20.3%
NEW MEXICO	SAN JUAN	580	HOGBACK	U.S.G. NO. 13	SEC. 19, T29N, R16W	STANOLIND OIL & GAS CO.	0.0%	20.0%	20.0%
NEW MEXICO	SAN JUAN	580	UTE DOME	UTE MOUNTAIN TRIBAL D NO. 1	SEC. 10, T31N, R14W	PAN AMERICAN PETROLEUM CORP.	0.0%	88.0%	88.0%
NEW MEXICO	SAN JUAN	580	UTE DOME	UTE MOUNTAIN TRIBAL D NO. 1	SEC. 10, T31N, R14W	PAN AMERICAN PETROLEUM CORP.	0.0%	88.0%	88.0%
NEW MEXICO	SAN JUAN	580	UTE DOME	UTE MOUNTAIN TRIBAL D NO. 1	SEC. 10, T31N, R14W	PAN AMERICAN PETROLEUM CORP.	1.3%	31.2%	32.5%
NEW MEXICO	SAN JUAN	580	UTE DOME	UTE MOUNTAIN TRIBAL D NO. 1	SEC. 10, T31N, R14W	PAN AMERICAN PETROLEUM CORP.	1.3%	30.9%	32.2%
NEW MEXICO	SAN JUAN	580	UTE DOME	UTE MOUNTAIN TRIBAL D NO. 1	SEC. 10, T31N, R14W	PAN AMERICAN PETROLEUM CORP.	1.5%	28.5%	30.0%
NEW MEXICO	SAN JUAN	580	UTE DOME	UTE MOUNTAIN TRIBAL-K NO. 1	SEC. 33, T32N, R14W	PAN AMERICAN PETROLEUM CORP.	0.1%	33.7%	33.8%
NEW MEXICO	SANDOVAL	580	NACIMIENTO	OIL TEST	SEC. 1, T16N, R1W	ZIA PUEBLOS	0.0%	86.4%	86.4%
NEW MEXICO	VALENCIA	580	WATER WELL	ARTESIAN WATER WELL IN SEC12	SEC. 12, T9N, R5W	U.S. BUREAU OF INDIAN AFFAIRS	0.0%	42.7%	42.7%
NEW MEXICO	VALENCIA	580	WATER WELL	INDIAN WATER WELL OF MESITA	SEC. 12, T9N, R5W	U.S. BUREAU OF INDIAN AFFAIRS	0.0%	52.1%	52.1%
NEW MEXICO	VALENCIA	580	WATER WELL	NOT GIVEN	SEC. 12, T9N, R5W	U.S. BUREAU OF INDIAN AFFAIRS	0.0%	21.4%	21.4%
NEW MEXICO	VALENCIA	580	COMANCHE DRAW	SPRING	SEC. 35, T6N, R3W	USGS, QUALITY OF WATER BRANCH	0.0%	98.4%	98.4%
NEW MEXICO	VALENCIA	580	SPRING N OF MESA LUCERO	SPRING	SEC. 15, T8N, R3W	USGS, QUALITY OF WATER BRANCH	0.0%	92.1%	92.1%
TEXAS	FRANKLIN	260	NEW HOPE	DEEP UNIT NO. 2-1-D	C. F. MCKENZIE SUR.	TIDEWATER OIL CO.	14.0%	6.3%	20.3%

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TEXAS	FREESTONE	260	NEAL	GLAYDENE NEAL NO. 1	JOHN BRADLEY SUR. A-53	GETTY OIL CO.	44.4%	4.3%	48.7%
TEXAS	FREESTONE	260	NEAL	GLAYDENE NEAL NO. 1	JOHN BRADLEY SUR. A-53	GETTY OIL CO.	28.9%	5.0%	33.9%
TEXAS	FREESTONE	260	CARTER-BLOXOM	M. D. BLOXOM NO. 1	J. MATTHEWS SUR. A-418	GETTY OIL CO.	17.2%	5.5%	22.7%
TEXAS	RAINS	260	GINGER	JENKINS "C" NO. 1	A. WOODRING SUR., A-272	TXO PRODUCTION CORP.	28.4%	6.6%	35.0%
TEXAS	VAN ZANDT	260	EDGEWOOD	PARKER G.U. A NO. 1	J. H. PARKER TRACT	PAN AMERICAN PETROLEUM CORP.	24.0%	3.0%	27.0%
TEXAS	VAN ZANDT	260	EDGEWOOD NE	PARKER G.U. B NO. 1	I. R. CHISUM A-157 SUR.	PAN AMERICAN PETROLEUM CORP.	21.6%	2.7%	24.3%
TEXAS	MEDINA	400	WILDCAT	CARL EST BUSHWACK RANCH NO.1	NOT GIVEN	MONO CORP.	0.0%	74.2%	74.2%
TEXAS	CROCKETT	430	WILDCAT	M. MITCHELL NO. 1	BLK. 1, I&GN RR SUR.	SUN OIL CO.	0.0%	40.9%	40.9%
TEXAS	CROCKETT	430	J M	MITCHELL NO. 1	SEC. 3, BLK. Q-6, TCRR SUR.	SHELL OIL CO.	0.0%	20.3%	20.3%
TEXAS	IRION	430	BURNT ROCK	SHEEN "3061" NO. 1	SEC.3061,BLK.28,H&TCRR SUR.	UNION TEXAS PETROLEUM CORP.	0.0%	45.4%	45.4%
TEXAS	PECOS	430	GMW	ALLISON RANCH 3-170 NO. 1	SEC. 3, BLK. 170, TTRRCO.SUR	CONTINENTAL OIL CO.	0.0%	42.5%	42.5%
TEXAS	PECOS	430	GREY RANCH W	BLACKSTONE-SLAUGHTER NO. 1	SEC. 1, BLK. 131, T&STL SUR.	CHEVRON OIL CO.	0.0%	47.7%	47.7%
TEXAS	PECOS	430	OATES NE	C. E. MCINTYRE NO. 1	SEC. 139, BLK 3, T&PRR SUR.	HUMBLE OIL & REFINING CO.	0.0%	38.3%	38.3%
TEXAS	PECOS	430	PIKES PEAK E	EISINORE CATTLE CO. NO. 1	SEC. 25 BLK. C, GC&SF SUR.	TEXAS PACIFIC OIL CO., INC.	0.0%	41.6%	41.6%
TEXAS	PECOS	430	PUCKETT	GLENNA NO. 1	SEC. 28, BLK. 101, TCRR SUR.	PHILLIPS PETROLEUM CO.	0.0%	28.0%	28.0%
TEXAS	PECOS	430	GOMEZ & GRAY RANCH	GRAY RANCH	30 IN. LINE	COASTAL STATES GAS PROD. CO.	0.0%	47.2%	47.2%
TEXAS	PECOS	430	PUCKETT	MITCHELL-THOMAS 1 NO. 1	SEC. 23, BLK. 100, ELRR SUR.	CHEVRON OIL CO.	0.0%	26.7%	26.7%
TEXAS	PECOS	430	ELSINORE	MONTGOMERY-FULK NO. 11	SEC. 9, BLK. 170, TTRR CO.	TEXAS PACIFIC OIL CO., INC.	0.0%	46.6%	46.6%
TEXAS	PECOS	430	PUCKETT	PUCKETT K-1	SEC. 39, BLK. 101, TCRR SUR.	PHILLIPS PETROLEUM CO.	0.0%	26.9%	26.9%
TEXAS	REEVES	430	MI VIDA	CAMP UNIT NO. 1	SEC. 3, BLK. 4, H&GN SUR.	SUPERIOR OIL CO.	0.5%	52.0%	52.5%
TEXAS	TERRELL	430	BROWN-BASSETT	ALMA H. POULTER NO. 1	SEC. 21, BLK. 1, TC&RR SUR.	SINCLAIR OIL & GAS CO.	0.0%	47.5%	47.5%
TEXAS	TERRELL	430	BROWN-BASSETT	BROWN-BASSETT NO. 1-LT	SEC. 227, BLK. Y, TCRR SUR.	CONTINENTAL OIL CO.	0.0%	53.2%	53.2%
TEXAS	TERRELL	430	BROWN-BASSETT	GOODE ESTATE NO. 2	SEC. 1, BLK. R, TCRY SUR.	MAGNOLIA PETROLEUM CO.	0.0%	38.4%	38.4%
TEXAS	WARD	430	QUITO	SABINE G.U. NO. 1	SEC. 196, BLK. 34, H&TC SUR.	AMERICAN QUASAR PET. CO.	0.4%	37.7%	38.1%
TEXAS	WINKLER	430	O'BRIEN	PIPELINE SAMPLE	SEC. 27, BLK. B-12, P.S.L.	CONTINENTAL OIL CO.	0.0%	30.3%	30.3%
TEXAS	OLDHAM	435	WILDCAT	OLD HIGH NO. 1	SEC. 76, BLK GM-5 WMD LEE SR	BAKER & TAYLOR DRILLING CO.	0.0%	24.9%	24.9%
UTAH	CARBON	575	SEEP 30MMI. E. OF PRICE	GAS SEEP	SEC.--, T14, R15	LUNDY, G. E.	0.0%	97.2%	97.2%
UTAH	CARBON	575	FARNHAM DOME	NO. 1	SEC. 12, T15S, R11E	CARBON DIOXIDE & CHEMICAL CO.	0.0%	98.9%	98.9%
UTAH	CARBON	575	FARNHAM DOME	NO. 4	SEC. 12, T15S, R11E	CALIFORNIA OIL CO.	0.0%	98.3%	98.3%
UTAH	CARBON	575	GORDON CREEK UNIT	R. BRYNER NO. 1	SEC. 24, T14S, R7E	SKELLY OIL CO.	0.0%	99.5%	99.5%
UTAH	CARBON	575	GORDON CREEK UNIT	R. BRYNER NO. 2	SEC. 25, T14S, R7E	SKELLY OIL CO.	0.0%	89.3%	89.3%
UTAH	EMERY	585	WOODSIDE	FED. 44-12	SEC. 12, T19S, R13E	HOLLY RESOURCES CORP.	0.0%	33.2%	33.2%
UTAH	EMERY	585	FEDERAL MOUNDS	FED. MOUNDS NO. 1	SEC. 11, T16S, R11E	PAN AMERICAN PETROLEUM CORP.	0.0%	27.3%	27.3%
UTAH	EMERY	585	FEDERAL MOUNDS	FED. MOUNDS NO. 1	SEC. 11, T16S, R11E	PAN AMERICAN PETROLEUM CORP.	0.0%	26.8%	26.8%
UTAH	EMERY	585	FEDERAL MOUNDS	FED. MOUNDS NO. 1	SEC. 11, T16S, R11E	PAN AMERICAN PETROLEUM CORP.	0.0%	24.2%	24.2%
UTAH	EMERY	585	WOODSIDE	FED. NO. 44-12	SEC. 12, T19S, R13E	HOLLY RESOURCES CORP.	0.0%	33.0%	33.0%
UTAH	EMERY	585	FERRON UNIT	FERRON UNIT NO. 3	SEC. 21, T20S, R7E	PAN AMERICAN PETROLEUM CORP.	0.3%	52.4%	52.7%
UTAH	EMERY	585	FERRON UNIT	FERRON UNIT NO. 3	SEC. 21, T20S, R7E	PAN AMERICAN PETROLEUM CORP.	0.2%	51.4%	51.6%
UTAH	EMERY	585	FERRON UNIT	FERRON UNIT NO. 4	SEC. 2, T20S, R7E	PAN AMERICAN PETROLEUM CORP.	0.0%	79.0%	79.0%
UTAH	EMERY	585	WILDCAT	GOVT.-WHEATLEY NO. 1	SEC. 27, T16S, R12E	CARTER OIL CO.	0.0%	91.2%	91.2%
UTAH	EMERY	585	WILDCAT	PACKSADDLE NO. 1	SEC. 12, T18S, R12E	EL PASO NATURAL GAS CO.	0.0%	94.7%	94.7%
UTAH	EMERY	585	WOODSIDE	WOODSIDE	NOT GIVEN	UTAH OIL REFINING CO.	0.0%	28.4%	28.4%
UTAH	EMERY	585	WOODSIDE	WOODSIDE NO. 1	SEC. 12, T19S, R13E	UTAH OIL REFINING CO.	0.0%	31.7%	31.7%
UTAH	GARFIELD	585	ESCALANTE ANTICLINE	CHARGER NO. 2	SEC. 33, T32S, R3E	MID-CONTINENT OIL CO.	0.0%	98.8%	98.8%
UTAH	GARFIELD	585	ESCALANTE ANTICLINE	CHARGER NO. 4	SEC. 13, T33S, R2E	MID-CONTINENT OIL CORP.	0.0%	97.6%	97.6%
UTAH	GARFIELD	585	ESCALANTE	ESCALANTE NO. 2	SEC. 29, T32S, R3E	PHILLIPS PETROLEUM CO.	0.0%	96.1%	96.1%
UTAH	GARFIELD	585	ESCALANTE	ESCALANTE NO. 2	SEC. 29, T32S, R3E	PHILLIPS PETROLEUM CO.	0.0%	93.1%	93.1%
UTAH	GRAND	585	BAR X	BAR X UNIT NO. 4	SEC. 18, T17S, R26E	AMERICAN CLIMAX PETROLEUM CO.	0.0%	24.3%	24.3%
UTAH	GRAND	585	SAN ARROYO	NO. 6	SEC. 21, T16S, R25E	SINCLAIR OIL & GAS CO.	0.0%	23.9%	23.9%
UTAH	GRAND	585	SAN ARROYO	SAN ARROYO GOVT. NO. 1	SEC. 26, T16S, R25E	SINCLAIR OIL & GAS CO.	0.0%	26.1%	26.1%
UTAH	GRAND	585	SAN ARROYO	SAN ARROYO GOVT. NO. 2	SEC. 22, T16S, R25E	SINCLAIR OIL & GAS CO.	0.0%	24.5%	24.5%
UTAH	GRAND	585	SAN ARROYO	SAN ARROYO GOVT. NO. 3	SEC. 23, T16S, R25E	SINCLAIR OIL & GAS CO.	0.0%	23.4%	23.4%

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UTAH	GRAND	585	SAN ARROYO	SAN ARROYO GOVT. NO. 3	SEC. 23, T16S, R25E	SINCLAIR OIL & GAS CO.	0.0%	22.7%	22.7%
UTAH	SAN JUAN	585	LISBON	ARNOLD 21-15	SEC. 15, T30S, R24E	CALIFORNIA OIL CO.	0.0%	28.7%	28.7%
UTAH	SAN JUAN	585	LISBON	ARNOLD 21-15	SEC. 15, T30S, R24E	CALIFORNIA OIL CO.	0.3%	26.3%	26.6%
UTAH	SAN JUAN	585	LISBON	BELCO NO. 2	SEC. 16, T30S, R24E	BELCO PETROLEUM CORP.	0.0%	30.2%	30.2%
UTAH	SAN JUAN	585	BIG INDIAN	BIG INDIAN U.S.A. NO. 1	SEC. 33, T29S, R24E	PURE OIL CO.	0.7%	23.5%	24.2%
UTAH	SAN JUAN	585	BLUFF UNIT	BLUFF UNIT NO. 3	SEC. 4, T40S, R23E	SHELL OIL CO.	0.0%	86.6%	86.6%
UTAH	SAN JUAN	585	BLUFF UNIT	BLUFF UNIT NO. 3	SEC. 4, T40S, R23E	SHELL OIL CO.	0.0%	85.7%	85.7%
UTAH	SAN JUAN	585	BOUNDARY BUTTE N	BOUNDARY BUTTE N NO. 1	SEC. 33, T42S, R22E	SHELL OIL CO.	0.0%	56.8%	56.8%
UTAH	SAN JUAN	585	ANTICLINE E	CANYON NO. 1	SEC. 28, T14N, R19S	UTAH SOUTHERN OIL CO.	0.0%	97.3%	97.3%
UTAH	SAN JUAN	585	COALBED CANYON	COALBED CANYON UNIT NO. 2	SEC. 20, T35S, R26E	GULF OIL CORP.	0.0%	62.3%	62.3%
UTAH	SAN JUAN	585	NOT GIVEN	DEADMAN CANYON NO. 1	SEC. 20, T37S, R24E	PAN AMERICAN PETROLEUM CORP.	0.0%	93.6%	93.6%
UTAH	SAN JUAN	585	DESERT CREEK	DESERT CREEK NO. 1	SEC. 2, T42S, R23E	SHELL OIL CO.	0.0%	77.5%	77.5%
UTAH	SAN JUAN	585	ROLLING MESA	GOVT. FEHR-LYON NO. 1	SEC. 33, T40S, R21E	CARTER OIL CO.	0.0%	69.2%	69.2%
UTAH	SAN JUAN	585	LISBON	LISBON FED. NO. 1-12	SEC. 12, T30S, R24E	PUBCO PETROLEUM CORP.	0.0%	29.0%	29.0%
UTAH	SAN JUAN	585	LISBON	LISBON VALLEY NO. 1-C	SEC. 9, T30S, R24E	ELLIOTT PRODUCTION CO.	0.0%	31.3%	31.3%
UTAH	SAN JUAN	585	LISBON	N. W. E-1	SEC. 15, T30S, R24E	PURE OIL CO.	0.0%	27.5%	27.5%
UTAH	SAN JUAN	585	NOT GIVEN	NAVAJO "D" NO. 30	SEC. 20, T40S, R24E	TEXACO INC.	0.0%	69.9%	69.9%
UTAH	SAN JUAN	585	GOTHIC AREA	NAVAJO-GOTHIC NO. 2	SEC. 36, T40S, R21E	CARTER OIL CO.	0.0%	93.4%	93.4%
UTAH	SAN JUAN	585	LISBON	NO. 1-12	SEC. 12, T30S, R24E	PUBCO PETROLEUM CORP.	0.3%	27.9%	28.2%
UTAH	SAN JUAN	585	LISBON	NO. 1-C	SEC. 9, T30S, R24E	ELLIOTT PRODUCTION CO.	0.3%	31.9%	32.2%
UTAH	SAN JUAN	585	LISBON	NO. 1-C	SEC. 9, T30S, R24E	ELLIOTT PRODUCTION CO.	0.2%	29.6%	29.8%
UTAH	SAN JUAN	585	GOTHIC MESA	NO. 30-1	SEC. 7, T41S, R21E	CARTER OIL CO.	0.0%	73.2%	73.2%
UTAH	SAN JUAN	585	LISBON	NO. A-1	SEC. 10, T30S, R24E	PURE OIL CO.	0.2%	25.8%	26.0%
UTAH	SAN JUAN	585	LISBON	NO. C-1	SEC. 4, T30S, R24E	PURE OIL CO.	0.1%	28.3%	28.4%
UTAH	SAN JUAN	585	LISBON	NO. C-3	SEC. 3, T30S, R24E	PURE OIL CO.	0.3%	23.9%	24.2%
UTAH	SAN JUAN	585	LISBON	NW B-2	SEC. 14, T30S, R24E	PURE OIL CO.	0.1%	30.6%	30.7%
UTAH	SAN JUAN	585	LISBON	NW LISBON B NO. 1	SEC. 14, T30S, R24E	PURE OIL CO.	0.6%	32.2%	32.8%
UTAH	SAN JUAN	585	LISBON	NW LISBON B NO. 1	SEC. 14, T30S, R24E	PURE OIL CO.	0.0%	24.0%	24.0%
UTAH	SAN JUAN	585	LISBON	NW LISBON NO. 2	SEC. 14, T30S, R24E	PURE OIL CO.	0.0%	21.1%	21.1%
UTAH	SAN JUAN	585	LISBON	NW LISBON NO. 3	SEC. 3, T30S, R24E	PURE OIL CO.	0.0%	26.7%	26.7%
UTAH	SAN JUAN	585	LISBON	NW LISBON NO. B-1	SEC. 14, T30S, R24E	PURE OIL CO.	0.2%	25.5%	25.7%
UTAH	SAN JUAN	585	LISBON	NW LISBON NO. B-1	SEC. 14, T30S, R24E	PURE OIL CO.	0.0%	23.5%	23.5%
UTAH	SAN JUAN	585	LISBON	NW LISBON NO. B-1	SEC. 14, T30S, R24E	PURE OIL CO.	0.0%	22.3%	22.3%
UTAH	SAN JUAN	585	LISBON	NW LISBON NO. C-1	SEC. 4, T30S, R24E	PURE OIL CO.	0.6%	27.7%	28.3%
UTAH	SAN JUAN	585	LISBON	NW LISBON NO. C-1	SEC. 4, T30S, R24E	PURE OIL CO.	1.7%	24.9%	26.6%
UTAH	SAN JUAN	585	LISBON	NW LISBON U.S.A. NO. 1	SEC. 10, T30S, R24E	PURE OIL CO.	0.1%	23.0%	23.1%
UTAH	SAN JUAN	585	LISBON	NW LISBON U.S.A. NO. 1	SEC. 10, T30S, R24E	PURE OIL CO.	0.1%	22.9%	23.0%
UTAH	SAN JUAN	585	LISBON	NW LISBON U.S.A. NO. 1	SEC. 10, T30S, R24E	PURE OIL CO.	0.2%	22.5%	22.7%
UTAH	SAN JUAN	585	LISBON	NW LISBON U.S.A. NO. 1	SEC. 10, T30S, R24E	PURE OIL CO.	0.0%	21.6%	21.6%
UTAH	SAN JUAN	585	LISBON	PIPELINE SAMPLE	LISBON UNIT WELL NO. C-93	PURE OIL CO.	0.3%	27.8%	28.1%
UTAH	SAN JUAN	585	LISBON	PUBCO LISBON FED. NO. 1-12	SEC. 12, T30S, R24E	PUBCO PETROLEUM CORP.	0.0%	26.6%	26.6%
UTAH	SAN JUAN	585	BLUFF UNIT	SHELL BLUFF UNIT NO. 1	NOT GIVEN	SHELL OIL CO.	0.0%	92.5%	92.5%
UTAH	SAN JUAN	585	LISBON	STATE NO. 2	SEC. 16, T30S, R24E	BELCO PETROLEUM CORP.	0.1%	32.9%	33.0%
UTAH	SAN JUAN	585	LISBON	STATE NO. 2	SEC. 16, T30S, R24E	BELCO PETROLEUM CORP.	0.1%	29.9%	30.0%
UTAH	SAN JUAN	585	LIME RIDGE	U.S. LIME RIDGE NO. 1	SEC. 28, T40S, R20E	KINGWOOD OIL CO.	3.9%	17.9%	21.8%
UTAH	SAN JUAN	585	LISBON	U.S.A. A-1	SEC. 10, T30S, R24E	PURE OIL CO.	1.0%	35.6%	36.6%
UTAH	SAN JUAN	585	LISBON	U.S.A. A-1	SEC. 10, T30S, R24E	PURE OIL CO.	0.2%	26.6%	26.8%
UTAH	SAN JUAN	585	WILDCAT	U.S.A. B NO. 1	SEC. 9, T35S, R25E	TEXAS PACIFIC COAL & OIL CO.	0.0%	88.6%	88.6%
UTAH	WASHINGTON	625	VIRGIN	NO. 1	SEC. 31, T41S, R11W	BARR & CO.	0.0%	86.8%	86.8%
UTAH	SEVIER	630	EMERY UNIT	EMERY UNIT NO. 1	SEC. 34, T22S, R5E	SKELLY OIL CO.	0.0%	95.7%	95.7%
UTAH	SEVIER	630	EMERY UNIT	EMERY UNIT NO. 1	SEC. 34, T22S, R5E	SKELLY OIL CO.	0.0%	92.2%	92.2%
UTAH	SEVIER	630	EMERY UNIT	EMERY UNIT NO. 1	SEC. 34, T22S, R5E	SKELLY OIL CO.	0.0%	91.7%	91.7%

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WYOMING	HOT SPRINGS	520	HAMILTON DOME	NOT GIVEN	SEC. 13&14, T44N, R98W	ATLANTIC REFINING CO.	0.2%	96.4%	96.6%
WYOMING	PARK	520	HORSE CENTER	NO. 1	NOT GIVEN	NOT GIVEN	0.0%	98.0%	98.0%
WYOMING	PARK	520	SILVERTIP	NO. 31-33	SEC. 33, T58N, R100W	TEXACO INC.	16.2%	4.3%	20.5%
WYOMING	CARBON	535	WERTZ	PIPELINE SAMPLE	NOT GIVEN	SINCLAIR OIL & GAS CO.	0.0%	32.9%	32.9%
WYOMING	LINCOLN	535	WILDCAT	BROAD CANYON NO. 1	SEC. 28, T32N, R116W	ARCO OIL & GAS CO.	2.5%	80.4%	82.9%
WYOMING	LINCOLN	535	WILDCAT	BROAD CANYON NO. 1	SEC. 28, T32N, R116W	ARCO OIL & GAS CO.	34.9%	19.5%	54.4%
WYOMING	LINCOLN	535	BRUFF UNIT	BRUFF UNIT NO. 1	SEC. 22, T19N, R112W	MOUNTAIN FUEL SUPPLY CO.	0.0%	92.1%	92.1%
WYOMING	LINCOLN	535	BRUFF UNIT	BRUFF UNIT NO. 1	SEC. 22, T19N, R112W	MOUNTAIN FUEL SUPPLY CO.	0.0%	74.2%	74.2%
WYOMING	LINCOLN	535	CARTER CREEK	FEDERAL 1-30M	SEC. 30, T19N,R119W	CHEVRON U.S.A., INC.	21.3%	7.3%	28.6%
WYOMING	LINCOLN	535	FONTENELLE	FONTENELLE FED. NO. 35-22	SEC. 35, T26N, R112W	AMERICAN QUASAR PET. CO.	0.0%	95.9%	95.9%
WYOMING	SUBLETTE	535	RILEY RIDGE	FOGARTY CREEK UNIT NO. 11-24	SEC. 24, T28N, R115W	EXXON CO., U.S.A.	1.6%	87.2%	88.8%
WYOMING	SUBLETTE	535	RILEY RIDGE	HOBACK II UNIT, NO. 2	SEC. 15, T28N, R115W	HUMBLE OIL & REFINING CO.	3.9%	60.4%	64.3%
WYOMING	SUBLETTE	535	RILEY RIDGE	RILEY RIDGE N FED. NO. 33-24	SEC. 33, T30N, R114W	AMERICAN QUASAR PET. CO.	2.2%	76.2%	78.4%
WYOMING	SUBLETTE	535	RILEY RIDGE	RILEY RIDGE-FED. NO. 12-43	SEC. 12, T29N, R115W	AMERICAN QUASAR PET. CO.	0.1%	72.8%	72.9%
WYOMING	SUBLETTE	535	RILEY RIDGE	RILEY RIDGE-FED. NO. 8-24	SEC. 08, T29N, R114W	AMERICAN QUASAR PET. CO.	3.7%	69.4%	73.1%
WYOMING	SUBLETTE	535	RILEY RIDGE	RILEY RIDGE-FED. NO. 8-24	SEC. 08, T29N, R114W	AMERICAN QUASAR PET. CO.	4.2%	68.4%	72.6%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP 22-19G	SEC. 19, T28N, R113W	MOBIL OIL CO.	0.0%	85.5%	85.5%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP 22-19G	SEC. 19, T28N, R113W	MOBIL OIL CO.	0.0%	64.2%	64.2%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP T54-2G	SEC. 02, T28N, R114W	MOBIL OIL CORP.	3.5%	69.7%	73.2%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	1.6%	82.2%	83.8%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	1.2%	76.6%	77.8%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	4.5%	67.3%	71.8%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	4.6%	67.2%	71.8%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	6.8%	63.5%	70.3%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	6.4%	63.4%	69.8%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	5.9%	63.3%	69.2%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	5.8%	63.3%	69.1%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	6.7%	62.2%	68.9%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	6.6%	62.2%	68.8%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	6.0%	62.7%	68.7%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	6.4%	62.1%	68.5%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	6.3%	61.9%	68.2%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	6.2%	61.6%	67.8%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	2.0%	65.7%	67.7%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	5.7%	62.0%	67.7%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	5.2%	62.4%	67.6%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	6.2%	61.3%	67.5%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	6.1%	60.2%	66.3%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	5.9%	59.2%	65.1%
WYOMING	SUBLETTE	535	RILEY RIDGE	TIP TOP UNIT F14-13G	SEC. 13, T28N, R114W	MOBIL OIL CORP.	5.3%	64.5%	69.8%
WYOMING	SWEETWATER	535	BRADY DEEP UNIT	BRADY NO. 11W	NOT GIVEN	CHAMPLIN PETROLEUM CO.	1.1%	27.5%	28.6%
WYOMING	SWEETWATER	535	BRADY DEEP UNIT	BRADY NO. 13W	NOT GIVEN	CHAMPLIN PETROLEUM CO.	1.1%	24.7%	25.8%
WYOMING	SWEETWATER	535	BRADY DEEP UNIT	BRADY NO. 16W	NOT GIVEN	CHAMPLIN PETROLEUM CO.	0.5%	27.6%	28.1%
WYOMING	SWEETWATER	535	BRADY DEEP UNIT	BRADY NO. 1W	NOT GIVEN	CHAMPLIN PETROLEUM CO.	0.9%	25.8%	26.7%
WYOMING	SWEETWATER	535	BRADY DEEP UNIT	BRADY NO. 2W	NOT GIVEN	CHAMPLIN PETROLEUM CO.	1.5%	24.8%	26.3%
WYOMING	SWEETWATER	535	BRADY DEEP UNIT	BRADY NO. 31N	NOT GIVEN	CHAMPLIN PETROLEUM CO.	0.0%	69.6%	69.6%
WYOMING	SWEETWATER	535	BRADY DEEP UNIT	BRADY NO. 3W	NOT GIVEN	CHAMPLIN PETROLEUM CO.	0.0%	26.4%	26.4%
WYOMING	SWEETWATER	535	BRADY DEEP UNIT	BRADY NO. 5N	NOT GIVEN	CHAMPLIN PETROLEUM CO.	0.1%	73.9%	74.0%
WYOMING	SWEETWATER	535	BRADY DEEP UNIT	BRADY NO. 8N	NOT GIVEN	CHAMPLIN PETROLEUM CO.	0.1%	72.3%	72.4%
WYOMING	SWEETWATER	535	BRADY DEEP UNIT	BRADY NO. 9N	NOT GIVEN	CHAMPLIN PETROLEUM CO.	0.3%	74.2%	74.5%
WYOMING	SWEETWATER	535	PRETTY WATER CREEK	FED. NO. 1-2	SEC. 2, T15N, R104W	GREAT WESTERN DRILLING CO.	0.0%	28.2%	28.2%
WYOMING	SWEETWATER	535	LOST SOLDIER	PIPELINE SAMPLE	SEC. 7, T26N, R89W	SINCLAIR OIL & GAS CO.	0.0%	29.3%	29.3%

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WYOMING	SWEETWATER	535	BAXTER BASIN N	UNION PACIFIC 11-19-104 NO.4	SEC. 11, T19N, R104W	MOUNTAIN FUEL SUPPLY CO.	0.2%	72.1%	72.3%
WYOMING	SWEETWATER	535	BAXTER BASIN N	UNION PACIFIC NO. 4	SEC. 11, T19N, R104W	MOUNTAIN FUEL SUPPLY CO.	0.7%	82.0%	82.7%
WYOMING	SWEETWATER	535	CHURCH BUTTES	UNIT NO. 31	SEC. 21, T16N, R112W	WEXPRO CO.	6.2%	29.3%	35.5%
WYOMING	SWEETWATER	535	LOST SOLDIER	WEST WERTZ NO. 2	SEC. 2, T26N, R90W	SINCLAIR OIL & GAS CO.	0.0%	31.7%	31.7%
WYOMING	UINTA	535	BUTCHER KNIFE SPRINGS	BUTCHER KNIFE SPRINGS NO. 1	SEC. 29, T15N, R112W	MOUNTAIN FUEL SUPPLY CO.	11.8%	20.2%	32.0%
WYOMING	UINTA	535	BUTCHER KNIFE SPRINGS	BUTCHER KNIFE SPRINGS NO. 1	SEC. 29, T15N, R112W	MOUNTAIN FUEL SUPPLY CO.	6.4%	23.1%	29.5%
WYOMING	UINTA	535	BUTCHER KNIFE SPRINGS	BUTCHER KNIFE SPRINGS NO. 1	SEC. 29, T15N, R112W	MOUNTAIN FUEL SUPPLY CO.	4.6%	23.8%	28.4%
WYOMING	UINTA	535	CHURCH BUTTES	CHURCH BUTTES NO. 31	SEC. 9, T17N, R112W	MT. FUEL SUPPLY & CHAMPLIN PET.	0.9%	85.5%	86.4%
WYOMING	UINTA	535	CHURCH BUTTES	CHURCH BUTTES UNIT NO. 19	SEC. 8, T16N, R112W	MOUNTAIN FUEL SUPPLY CO.	0.1%	86.6%	86.7%
WYOMING	UINTA	535	CHURCH BUTTES	CHURCH BUTTES UNIT NO. 19	SEC. 8, T16N, R112W	MOUNTAIN FUEL SUPPLY CO.	0.0%	20.4%	20.4%
WYOMING	UINTA	535	WHITNEY CANYON-CARTER (	FED. NO. 2-6E	SEC. 6, T17N, R119W	CHEVRON U.S.A., INC..	0.7%	93.3%	94.0%
WYOMING	UINTA	535	WHITNEY CANYON-CARTER (	FED. NO. 2-6E	SEC. 6, T17N, R119W	CHEVRON U.S.A., INC.	12.9%	23.3%	36.2%
WYOMING	UINTA	535	CHURCH BUTTES	UNIT NO. 19	SEC. 8, T16N, R112W	MOUNTAIN FUEL SUPPLY CO.	3.7%	22.9%	26.6%

ORIS_CODE	UNIT_ID	YEAR	MONTH	CO2_TONS	CO2_CONCENTRATION	SO2_TONS	NOX_TONS	MERCURY_LBS	HEAT_INPUT	TOTAL_OPERATING_HOURS	FUEL_TYPE_COMBUSTED
1233	4	1980	0			31			3025789		
1233	4	1985	0			1			1605856		
1233	4	1990	0			1			2672220		
1233	4	1995	0	82736		1	145		1392189		
1233	4	1996	0	280307		115.6	454		4615376		
1233	4	1997	1	17191.2	0.045	0.1	22.1		289273	680	15
1233	4	1997	2	14863.7	0.045	0.1	19		250108	672	15
1233	4	1997	3	19060.7	0.045	0.1	25.3		320745	744	15
1233	4	1997	4	17829.5	0.045	0.1	32.3		300013	455	15
1233	4	1997	5	2208.4	0.045		3.1		37153	107	15
1233	4	1997	6	27053.7	0.045	0.1	52.4		455226	720	15
1233	4	1997	7	35441.3	0.045	0.2	76.5		596344	744	15
1233	4	1997	8	27853	0.045	0.1	48.9		468663	744	15
1233	4	1997	9	22031.9	0.045	0.1	41.9		370738	644	15
1233	4	1997	10	27683.8	0.045	0.1	44.7		465842	744	15
1233	4	1997	11	29728.2	0.045	0.1	53		500225	720	15
1233	4	1997	12	24836	0.045	0.1	38.8		417914	744	15
1233	4	1998	1	20438.3	0.045	0.1	28.7		343930	744	15
1233	4	1998	2	17697.2	0.045	0.1	23.8		297795	672	15
1233	4	1998	3	12238.8	0.045	0.1	22.4		205950	288	15
1233	4	1998	4		0.045						15
1233	4	1998	5	9683.3	0.045		19.7		162944	294	15
1233	4	1998	6	30693.9	0.045	0.2	64		516488	720	15
1233	4	1998	7	35574.4	0.045	0.2	69.6		598588	744	15
1233	4	1998	8	36804.5	0.045	0.2	79.5		619272	744	15
1233	4	1998	9	40651	0.045	0.2	94.6		684017	720	15
1233	4	1998	10	14484.2	0.045	0.1	24.9		243735	450	15
1233	4	1998	11	26046.2	0.045	0.1	51.7		438288	720	15
1233	4	1998	12	20807	0.045	0.1	31.6		350105	744	15
1233	4	1999	1	21338.5	0.045	0.1	35.9		359072	744	15
1233	4	1999	2	21522.5	0.045	0.1	42.4		362181	672	15
1233	4	1999	3	16878.8	0.045	0.1	38.6		284021	421	15
1233	4	1999	4	31698.8	0.045	0.2	82.7		533394	665	15
1233	4	1999	5	26409.8	0.045	0.1	56.9		444398	744	15
1233	4	1999	6	25290.2	0.045	0.1	50.7		425539	720	15
1233	4	1999	7	41694.7	0.045	0.2	114.1		701594	744	15
1233	4	1999	8	36477.2	0.045	0.2	64.3		613802	744	15
1233	4	1999	9	17226.7	0.045	0.1	33.4		289874	562	15
1233	4	1999	10	15738	0.045	0.1	20.3		264819	600	15

ORIS_CODE	UNIT_ ID	YEAR	MONTH	CO2_ TONS	CO2_ CONCENTR ATION	SO2_ TONS	NOX_ TONS	MERCURY_ LBS	HEAT_ INPUT	TOTAL_ OPERATING _HOURS	FUEL_ TYPE_ COMBUSTED
1233	4	1999	11	20510.3	0.045	0.1	36.8		345126	720	15
1233	4	1999	12	23131.9	0.045	0.1	47.4		389203	744	15
1233	4	2000	1	23652.1	0.045	0.1	42.9		397988	744	15
1233	4	2000	2	23380.9	0.045	0.1	48.8		393433	696	15
1233	4	2000	3	13299	0.045	0.1	26.6		223776	479	15
1233	4	2000	4	25761.3	0.045	0.1	63.9		433491	715	15
1233	4	2000	5	30858.3	0.045	0.2	78.1		519254	744	15
1233	4	2000	6	24799.3	0.045	0.1	48.7		417286	720	15
1233	4	2000	7	30418.3	0.045	0.2	73.1		511820	744	15
1233	4	2000	8	36241.2	0.045	0.2	105.5		609833	744	15
1233	4	2000	9	23717.7	0.045	0.1	56.6		399090	705	15
1233	4	2000	10	15988.4	0.045	0.1	33		269019	513	15
1233	4	2000	11	21916	0.045	0.1	49		368774	720	15
1233	4	2000	12	28759.5	0.045	0.1	70.4		483942	744	15
1233	4	2001	1	18746.8	0.045	0.1	27.9		315468	744	15
1233	4	2001	2	17194.7	0.045	0.1	27.3		289322	672	15
1233	4	2001	3	20551.1	0.045	0.1	42.6		345797	744	15
1233	4	2001	4	9647.6	0.045		20.7		162333	300	15
1233	4	2001	5	18897.3	0.045	0.1	38.7		317993	657	15
1233	4	2001	6	18118.6	0.045	0.1	28.9		304892	720	15
1233	4	2001	7	27743.4	0.045	0.1	61.6		466829	744	15
1233	4	2001	8	32576.9	0.045	0.2	79.8		548173	743	15
1233	4	2001	9	20393.7	0.045	0.1	33.6		343177	720	15
1233	4	2001	10	8424.4	0.045		14.6		141754	304	15
1233	4	2001	11	18823.1	0.045	0.1	30.5		316747	720	15
1233	4	2001	12	18644	0.045	0.1	28.3		313711	743	15
1233	4	2002	1	19756.7	0.045	0.1	32.6		332450	744	15
1233	4	2002	2	18809.2	0.045	0.1	32.3		316519	672	15
1233	4	2002	3	23903.1	0.045	0.1	43.2		402216	744	15
1233	4	2002	4	3342.1	0.045		4.4		56222	120	15
1233	4	2002	5		0.045						15
1233	4	2002	6	10976.4	0.045	0.1	13.8		184695	446	15
1233	4	2002	7	33404.9	0.045	0.2	89.5		562084	744	15
1233	4	2002	8	31563.4	0.045	0.2	73.5		531108	744	15
1233	4	2002	9	24972.8	0.045	0.1	50.7		420208	720	15
1233	4	2002	10	10030.6	0.045		12.5		168779	408	15
1233	4	2002	11	18948.8	0.045	0.1	25.3		318853	720	15
1233	4	2002	12	20546	0.045	0.1	30		345717	744	15
1328	ALL	1996	0	1440		0.495	33				

ORIS_CODE	UNIT_ID	YEAR	MONTH	CO2_TONS	CO2_CONCENTRATION	SO2_TONS	NOX_TONS	MERCURY_LBS	HEAT_INPUT	TOTAL_OPERATING_HOURS	FUEL_TYPE_COMBUSTED
1328	ALL	1997	0	3216.73		0.15	78.02				
1328	ALL	1998	0	4073.05	0.045	0.21	100.85				15
1328	ALL	1999	0	3735.93	0.045	0.79	88.8				15
1328	ALL	2000	0	3099.87	0.045	0.37	73.7				15
1319	ALL	1996	0	28220		7	660				
1319	ALL	1997	0	18895.98		1.18	459.76				
1319	ALL	1998	0	25219.07	0.045	1.68	626.94				15
1319	ALL	1999	0	33963.88	0.045	7.87	805.89				15
1319	ALL	2000	0	24137.59	0.045	3.37	571.56				15
1225	ALL	1998	0	516.24	0.045	0.35	2.04				15
1225	ALL	1999	0	1170.84	0.045	0.1	3.36				15
1225	ALL	2000	0	1326.33	0.045	0.04	3.68				15
1251	ALL	1996	0	2753		0.239	11				
1251	ALL	1997	0	2861.74		0.02	11.2				
1251	ALL	1998	0	7495.43	0.045	0.22	21.08				15
1251	ALL	1999	0	4981.66	0.045	0.15	13.84				15
1251	ALL	2000	0	5893.58	0.045	1.31	20				15
1267	ALL	1996	0	8							
1267	ALL	1997	0	40.75		0.02	1.07				
1267	ALL	1998	0	5.57	0		0.15				26
1270	ALL	1996	0	648382		4	1543				
1270	ALL	1997	0	572384.2		10.4	1381.86				
1270	ALL	1998	0	16886.41	0.045	0.4	113.62				15
1270	ALL	1999	0	17639.5	0.045	1.21	87.48				15
1270	ALL	2000	0	20396.87	0.045	1.16	152.76				15
1299	ALL	1996	0	11477		0.383	77				
1299	ALL	1997	0	11844.57		0.08	33.6				
1299	ALL	1998	0	13640.87	0.045	0.13	38.16				15
1299	ALL	1999	0	11970.64	0.045	0.27	43.52				15
1299	ALL	2000	0	8378.12	0.045	0.46	64.07				15
1316	ALL	1996	0	3263		1	54				
1316	ALL	1997	0	4189.32		0.52	96.74				
1316	ALL	1998	0	6993.23	0.045	0.78	128.39				15
1316	ALL	2000	0	10992.2	0.045	1.58	115.54				15
1330	ALL	1996	0	13986		0.072	64				
1330	ALL	1997	0	12384.53		0.06	29.15				

ID	EGRID_CODE	EPA_CODE	DESCRIPTION_SPECIFIC	DESCRIPTION_ GENERIC	CO2_ CONCENTRATION
1	AB		Agricultural Byproduct	Biomass	0
2	AC		Anthracite Coal	Coal	0.12
3	BFG	PRG	Blast Furnace Gas	Other Gas	0
4	BG		Bituminous Gob	Coal	0.12
5	BIOMASS		Biomass	Biomass	0
6	BIT		Bituminous Coal	Coal	0.12
7	BL		Black Liquor	Biomass	0
8	CB		Cell Burner	Coal	0.12
9	COL	C	Coal	Coal	0.12
10		CRF	Coal Refuse	Coal	0.12
11	DFO	DSL	Diesel Fuel Oil	Diesel Oil	0
12	DG		Digester Gas	Other Gas	0
13	DI		Diesel	Diesel Oil	0
14	FO1		Fuel Oil	Diesel Oil	0
15	GAS	PNG	Natural Gas	Natural Gas	0.045
16	GE		Geothermal	Geothermal	0
17	HY		Hydro	Hydro	0
18	KE		Kerosene	Other Oil	0.06
20	LF		Landfill Gas	Other Gas	0
21		LPG	Liquid Petroleum Gas	Other Gas	0
22	LW		Lignite Waste	Coal	0.12
23	MW	R	Municipal Waste	Other	0
24	NG	NNG	Natural Gas	Natural Gas	0.045
25	OG	OGS	Other Gas	Other Gas	0
26	OIL	OIL	Residual Oil	Other Oil	0
27		OSF	Other Solid Fuel	Other	0
28	OW	OOL	Oil Waste	Other Oil	0
29	PC		Petroleum Coke	Other Oil	0
30	PET		Petroleum	Diesel Oil	0
31		PRS	Process Sludge	Other	0
32	RT		Railroad Ties	Biomass	0
33	SL		Solar	Solar	0
34	SS		Spent Sulfite Liquor	Biomass	0
35	SU		Sulfur	Other	0
36	TI		Tires	Other Gas	0
37	UR		Uranium	Nuclear	0
38	WC		Waste Coal	Coal	0.12
39	WH		Waste Heat	Other	0
40		WL	Waste Liquid	Other	0
41	WT		Water	Hydro	0
42	WW	W	Waste Wood	Biomass	0

RBLCID	ORIS_CODE	FACILITY_NAME	FACILITY_ TYPE	OWNER_NAME	OWNER_ TYPE	OPERATOR_ NAME	COMPANY_ NAME	STREET_ ADDRESS	CITY
	50805	ABITIBI CONSOLIDATED SNOWFLAKE DIVISION	NON-UTILITY	Abitibi Consolidated		Abitibi Consolidated			
	141	Agua Fria Generating Station							
	160	Apache Station							
	118	APS Saguaro Power Plant							
	54594	BIOSPHERE 2 CENTER INC	NON-UTILITY	Decisions Investments Corp		Biosphere 2 Center Inc			
	55780	Bowie Power Station							
	112	CHILDS	UTILITY	Arizona Public Service Co		Arizona Public Service Co	Pinnacle West Capital Corporation		
	113	Cholla							
	6177	Coronado Generating Station							
	143	Crosscut							
	152	DAVIS	UTILITY	USBR-Lower Colorado Region		USBR-Lower Colorado Region	US Bureau Of Reclamation		
	124	De Moss Petrie Generating Station							
AZ-0044	55129	Desert Basin Generating Station							
	114	DOUGLAS	UTILITY	Arizona Public Service Co		Arizona Public Service Co	Pinnacle West Capital Corporation		
AZ-0035	55282	Duke Energy Arlington Valley							
	923	Gila Bend							
AZ-0038	55507	Gila Bend Power Generation Station							
AZ-0037	55306	Gila River Power Station							
	153	GLEN CANYON	UTILITY	USBR-Upper Colorado Region		USBR-Upper Colorado Region	US Bureau Of Reclamation		
	54838	GOULD ELECTRONICS FOIL DIVISION	NON-UTILITY	Japan Energy Corp Ltd		Japan Energy Corp Ltd			
	55124	Griffith Energy LLC							
AZ-0034	55372	Harquahala Generating Project							
	8902	HOOVER	UTILITY	USBR-Lower Colorado Region		USBR-Lower Colorado Region	US Bureau Of Reclamation		
	145	HORSE MESA	UTILITY	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist			
	55257	INA ROAD WATER POLLUTION CONTROL FACILITY	NON-UTILITY	PIMA County Wastewater Manage		PIMA County Wastewater Manage			
	10564	INTERMOUNTAIN REFINING COMPANY, INC	NON-UTILITY	INTERMOUNTAIN REFINING CO (NM)		INTERMOUNTAIN REFINING CO	N/A		
	115	IRVING	UTILITY	Arizona Public Service Co		Arizona Public Service Co	Pinnacle West Capital Corporation		
	126	Irvington Generating Station							
AZ-0041	147	Kyrene Generating Station							
	55711	La Paz Generating Facility							
AZ-0033	55481	Mesquite Generating Station							
	148	MORMON FLAT	UTILITY	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist			
	4941	Navajo Generating Station							
	54245	NELSON PLANT GENERATORS	NON-UTILITY	Chemical Lime Co		Chemical Lime Co			
	50738	NEW CORNELIA BRANCH POWER PLANT	NON-UTILITY	Phelps Dodge Corp		Phelps Dodge Corp			

RBLCID	ORIS_CODE	FACILITY_NAME	FACILITY_TYPE	OWNER_NAME	OWNER_TYPE	OPERATOR_NAME	COMPANY_NAME	STREET_ADDRESS	CITY
	54949	NORDIC POWER OF SOUTH POINT I	NON-UTILITY	NORDIC POWER OF SOUTH POINT I (MI)		NORDIC POWER OF SOUTH POINT I	N/A		
	6088	NORTH LOOP	UTILITY	Tucson Electric Power Co		Tucson Electric Power Co	UniSource Energy Corporation		
	116	Ocotillo Power Plant							
	6008	PALO VERDE	UTILITY	Arizona Public Service Co		Arizona Public Service Co	Pinnacle West Capital Corporation		
AZ-0045	55522	PPL Sundance Energy, LLC							
AZ-0036	55455	Redhawk Generating Facility							
	149	ROOSEVELT	UTILITY	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist			
AZ-0039	8068	Santan							
	55692	Signal Peak Generating Facility							
	100	SOUTH CONSOLIDATED	UTILITY	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist			
	55177	South Point Energy Center, LLC							
	8223	Springerville Generating Station							
	50238	STARWOOD HOTELS RESORTS	NON-UTILITY	Starwood Hotels Resorts		Starwood Hotels Resorts			
	150	STEWART MTN	UTILITY	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist			
	6515	VALENCIA	UTILITY	Citizens Utilities Co-AZ		Citizens Utilities Co-AZ	Citizens Utilities Co		
AZ-0040	117	West Phoenix Power Plant							
	120	Yuma Axis							
	54694	YUMA COGENERATION ASSOCIATES	NON-UTILITY	Yuma Cogeneration Associates		Yuma Cogeneration Associates			
	464	Alamosa							
	10755	AMERICAN ATLAS 1 COGENERATION PLANT	NON-UTILITY	American Atlas #1 Ltd		American Atlas #1 Ltd			
	54630	AMERICAN GYPSUM COGENERATION	NON-UTILITY	Centex Eagle Gypsum Co LLC		Centex Eagle Gypsum Co LLC			
	6207	AMES	UTILITY	Public Service Co of Colorado	PRIVATELY OWNED	Public Service Co of Colorado	Xcel Energy Inc		
	465	Arapahoe							
CO-0049	55200	Arapahoe Combustion Turbine							
	54680	BETASSO HYDROELECTRIC PLANT	NON-UTILITY	City of Boulder		City of Boulder			
	515	BIG THOMPSON	UTILITY	USBR-Great Plains Region		USBR-Great Plains Region	US Bureau Of Reclamation		
	512	BLUE MESA	UTILITY	USBR-Upper Colorado Region		USBR-Upper Colorado Region	US Bureau Of Reclamation		
	55645	Blue Spruce Energy Center							
	466	BOULDER	NON-UTILITY	City of Boulder		City of Boulder			
	10682	Brush 3							
	55209	Brush 4							
CO-0027 & CO-0045	10683	BRUSH COGEN PROJECT PHASE 2 BCP	NON-UTILITY	Brush Power, LLC		Colorado Cogeneration Operator			
	6619	BURLINGTON	UTILITY	Tri-State G & T Assn Inc		Tri-State G & T Assn Inc			
	467	CABIN CREEK	UTILITY	Public Service Co of Colorado		Public Service Co of Colorado	Xcel Energy Inc		
	468	Cameo							

RBLCID	ORIS_CODE	FACILITY_NAME	FACILITY_TYPE	OWNER_NAME	OWNER_TYPE	OPERATOR_NAME	COMPANY_NAME	STREET_ADDRESS	CITY
	469	Cherokee							
	54679	CITY OF BOULDER - LAKEWOOD HYDROELECTRIC PLT	NON-UTILITY	BOULDER CITY OF (CO)		BOULDER CITY OF	N/A		

ORIS_CODE	FACILITY_NAME	COUNTY_ NAME	COUNTY_ CODE_ FIPS	STATE	ZIP_PLUS_4	LATITUDE	LONGITUDE	LAT_ LONG_ DATUM	LAT_ LONG_ SOURCE	POWER_ CAPACITY_ MW
50805	ABITIBI CONSOLIDATED SNOWFLAKE DIVISION		17	AZ		35.2863	-110.2885		EGRID	70.55
141	Agua Fria Generating Station	Maricopa	13	AZ		33.5569	-112.22		EPA	
160	Apache Station	Cochise	3	AZ		32.0556	-109.89		EPA	
118	APS Saguaro Power Plant	Pinal	21	AZ		32.5522	-111.3		EPA	
54594	BIOSPHERE 2 CENTER INC		21	AZ		32.9836	-111.3255		EGRID	3.05
55780	Bowie Power Station			AZ					EPA	
112	CHILDS		25	AZ		34.7053	-112.4042		EGRID	5.4
113	Cholla	Navajo	17	AZ		34.9414	-110.3		EPA	
6177	Coronado Generating Station	Apache	1	AZ		34.5778	-109.27		EPA	
143	Crosscut	Maricopa	13	AZ					EPA	
152	DAVIS		15	AZ		35.6134	-113.6474		EGRID	240
124	De Moss Petrie Generating Station	Pima	19	AZ		32.25	-110.98		EPA	
55129	Desert Basin Generating Station	Pinal	21	AZ					EPA	
114	DOUGLAS		3	AZ		31.8799	-109.754		EGRID	21.4
55282	Duke Energy Arlington Valley	Maricopa	13	AZ					EPA	
923	Gila Bend	Maricopa	13	AZ		33.2765	-111.88		EPA	
55507	Gila Bend Power Generation Station	Maricopa	13	AZ					EPA	
55306	Gila River Power Station	Maricopa	13	AZ					EPA	
153	GLEN CANYON		5	AZ		35.6337	-112.0444		EGRID	1296
54838	GOULD ELECTRONICS FOIL DIVISION		13	AZ		33.35	-112.49		EGRID	1.05
55124	Griffith Energy LLC	Mohave	15	AZ					EPA	
55372	Harquahala Generating Project	Maricopa	13	AZ					EPA	
8902	HOOVER		15	AZ		35.6134	-113.6474		EGRID	1039.4
145	HORSE MESA		13	AZ		33.35	-112.49		EGRID	129.58
55257	INA ROAD WATER POLLUTION CONTROL FACILITY		19	AZ		31.9699	-111.8899		EGRID	4.54
10564	INTERMOUNTAIN REFINING COMPANY, INC		5	AZ		35.6337	-112.0444		EGRID	3
115	IRVING		25	AZ		34.7053	-112.4042		EGRID	1.6
126	Irvington Generating Station	Pima	19	AZ		32.16	-110.9		EPA	
147	Kyrene Generating Station	Maricopa	13	AZ		33.3547	-111.94		EPA	
55711	La Paz Generating Facility			AZ					EPA	
55481	Mesquite Generating Station	Maricopa	13	AZ					EPA	
148	MORMON FLAT		13	AZ		33.35	-112.49		EGRID	57.85
4941	Navajo Generating Station	Coconino	5	AZ		36.9125	-111.39		EPA	
54245	NELSON PLANT GENERATORS		15	AZ		35.6134	-113.6474		EGRID	2.27
50738	NEW CORNELIA BRANCH POWER PLANT		19	AZ		31.9699	-111.8899		EGRID	10.5

ORIS_CODE	FACILITY_NAME	COUNTY_ NAME	COUNTY_ CODE_ FIPS	STATE	ZIP_PLUS_4	LATITUDE	LONGITUDE	LAT_ LONG_ DATUM	LAT_ LONG_ SOURCE	POWER_ CAPACITY_ MW
54949	NORDIC POWER OF SOUTH POINT I		15	AZ		35.6134	-113.6474		EGRID	233.2
6088	NORTH LOOP		19	AZ		31.9699	-111.8899		EGRID	81
116	Ocotillo Power Plant	Maricopa	13	AZ		33.4467	-111.94		EPA	
6008	PALO VERDE		13	AZ		33.35	-112.49		EGRID	4209.57
55522	PPL Sundance Energy, LLC	Pinal	21	AZ					EPA	
55455	Redhawk Generating Facility	Maricopa	13	AZ					EPA	
149	ROOSEVELT		13	AZ		33.35	-112.49		EGRID	36.02
8068	Santan			AZ					EPA	
55692	Signal Peak Generating Facility			AZ					EPA	
100	SOUTH CONSOLIDATED		13	AZ		33.35	-112.49		EGRID	1.4
55177	South Point Energy Center, LLC	Mohave	15	AZ					EPA	
8223	Springerville Generating Station	Apache	1	AZ		34.3186	-109.16		EPA	
50238	STARWOOD HOTELS RESORTS		13	AZ		33.35	-112.49		EGRID	1.65
150	STEWART MTN		13	AZ		33.35	-112.49		EGRID	10.4
6515	VALENCIA		23	AZ		31.532	-110.909		EGRID	54.4
117	West Phoenix Power Plant	Maricopa	13	AZ		33.4428	-112.15		EPA	
120	Yuma Axis	Yuma	27	AZ		33.22	-113.94		EPA	
54694	YUMA COGENERATION ASSOCIATES		27	AZ		32.7504	-114.0678		EGRID	62.64
464	Alamosa	Alamosa	3	CO					EPA	
10755	AMERICAN ATLAS 1 COGENERATION PLANT		45	CO		39.7286	-107.5255		EGRID	85
54630	AMERICAN GYPSUM COGENERATION		37	CO		39.6415	-106.6443		EGRID	9.85
6207	AMES		113	CO		37.9645	-108.3899		EGRID	3.6
465	Arapahoe	Denver	31	CO		39.67	-105.003		EPA	
55200	Arapahoe Combustion Turbine	Denver	31	CO					EPA	
54680	BETASSO HYDROELECTRIC PLANT		13	CO		40.0884	-105.3453		EGRID	3
515	BIG THOMPSON		69	CO		40.6281	-105.5665		EGRID	4.5
512	BLUE MESA		51	CO		38.7019	-106.9407		EGRID	86.4
55645	Blue Spruce Energy Center	Adams	1	CO					EPA	
466	BOULDER		31	CO		39.7114	-104.9217		EGRID	20
10682	Brush 3	Morgan	87	CO		40.1506	103.3722		EPA	
55209	Brush 4	Morgan	87	CO		40.1506	103.3722		EPA	
10683	BRUSH COGEN PROJECT PHASE 2 BCP		87	CO		40.2627	-103.807		EGRID	74
6619	BURLINGTON		63	CO		39.3061	-102.6048		EGRID	129.4
467	CABIN CREEK		19	CO		39.7085	-105.6604		EGRID	300
468	Cameo	Mesa	77	CO		39.1333	-108.32		EPA	

ORIS_CODE	FACILITY_NAME	COUNTY_ NAME	COUNTY_ CODE_ FIPS	STATE	ZIP_PLUS_4	LATITUDE	LONGITUDE	LAT_ LONG_ DATUM	LAT_ LONG_ SOURCE	POWER_ CAPACITY_ MW
469	Cherokee	Denver	31	CO		39.8083	-105.97		EPA	
54679	CITY OF BOULDER - LAKEWOOD HYDROELECTRIC PLT		13	CO		40.0884	-105.3453		EGRID	1.5

RBLCID	FACILITY	COMPANY	COUNTY	CONTACT	ADDRESS	CITY	STATE	ZIP	PHONE	EMAIL	REGION	AGENCY CODE	AGENCYNAME	AGENCY CONTACT	AGENCY PHONE	AGENCY EMAIL	PERMITNUM	SIC	NAICS	AIRSID	EPAID	UTM ZONE	XCOORD	YCOORD	RCVD DATE	PERMIT DATE	STARTUP DATE	VERIFY DATE
UT-0059	ASH GROVE CEMENT COMPANY	ASH GROVE CEMENT COMPANY	JUAB	KEN WARE	PO BOX 51	NEPHI		84648	801-857-1202		8	UT001	UTAH BUREAU OF AIR QUALITY	TIM BLANCHARD	(801) 536-4057		DAQE-958-96	3241				12	390000	4377500		10/24/1996		
UT-0059	ASH GROVE CEMENT COMPANY	ASH GROVE CEMENT COMPANY	JUAB	KEN WARE	PO BOX 51	NEPHI		84648	801-857-1202		8	UT001	UTAH BUREAU OF AIR QUALITY	TIM BLANCHARD	(801) 536-4057		DAQE-958-96	3241				12	390000	4377500		10/24/1996		
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UT-0059	ASH GROVE CEMENT COMPANY	ASH GROVE CEMENT COMPANY	JUAB	KEN WARE	PO BOX 51	NEPHI		84648	801-857-1202		8	UT001	UTAH BUREAU OF AIR QUALITY	TIM BLANCHARD	(801) 536-4057		DAQE-958-96	3241				12	390000	4377500		10/24/1996		
UT-0059	ASH GROVE CEMENT COMPANY	ASH GROVE CEMENT COMPANY	JUAB	KEN WARE	PO BOX 51	NEPHI		84648	801-857-1202		8	UT001	UTAH BUREAU OF AIR QUALITY	TIM BLANCHARD	(801) 536-4057		DAQE-958-96	3241				12	390000	4377500		10/24/1996		
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	HOLNAM, DEVIL'S SLIDE PLANT	MORGAN	KEVIN OVARD	6055 EAST CROYDEN ROAD	MORGAN		84050	801-829-6821		8	UT001	UTAH BUREAU OF AIR QUALITY	JOHN JENKS	(801) 536-4000		DAQE-522-96	3241	32731			12	455.4	4545.8	3/29/1996	5/13/1996		
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	HOLNAM, DEVIL'S SLIDE PLANT	MORGAN	KEVIN OVARD	6055 EAST CROYDEN ROAD	MORGAN		84050	801-829-6821		8	UT001	UTAH BUREAU OF AIR QUALITY	JOHN JENKS	(801) 536-4000		DAQE-522-96	3241	32731			12	455.4	4545.8	3/29/1996	5/13/1996		
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	HOLNAM, DEVIL'S SLIDE PLANT	MORGAN	KEVIN OVARD	6055 EAST CROYDEN ROAD	MORGAN		84050	801-829-6821		8	UT001	UTAH BUREAU OF AIR QUALITY	JOHN JENKS	(801) 536-4000		DAQE-522-96	3241	32731			12	455.4	4545.8	3/29/1996	5/13/1996		
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	HOLNAM, DEVIL'S SLIDE PLANT	MORGAN	KEVIN OVARD	6055 EAST CROYDEN ROAD	MORGAN		84050	801-829-6821		8	UT001	UTAH BUREAU OF AIR QUALITY	JOHN JENKS	(801) 536-4000		DAQE-522-96	3241	32731			12	455.4	4545.8	3/29/1996	5/13/1996		
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	HOLNAM, DEVIL'S SLIDE PLANT	MORGAN	KEVIN OVARD	6055 EAST CROYDEN ROAD	MORGAN		84050	801-829-6821		8	UT001	UTAH BUREAU OF AIR QUALITY	JOHN JENKS	(801) 536-4000		DAQE-522-96	3241	32731			12	455.4	4545.8	3/29/1996	5/13/1996		
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UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	HOLNAM, DEVIL'S SLIDE PLANT	MORGAN	KEVIN OVARD	6055 EAST CROYDEN ROAD	MORGAN		84050	801-829-6821		8	UT001	UTAH BUREAU OF AIR QUALITY	JOHN JENKS	(801) 536-4000		DAQE-522-96	3241	32731			12	455.4	4545.8	3/29/1996	5/13/1996		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	CLARK		1714 W. BONANZA ROAD	LAS VEGAS		-89106			9	NV002	CLARK CO DEPT OF AIR QUALITY MANAGEMENT	DAVID C. LEE	(702) 383-1276		A139	3241							10/15/1993	10/24/1995		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	CLARK		1714 W. BONANZA ROAD	LAS VEGAS		-89106			9	NV002	CLARK CO DEPT OF AIR QUALITY MANAGEMENT	DAVID C. LEE	(702) 383-1276		A139	3241							10/15/1993	10/24/1995		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	CLARK		1714 W. BONANZA ROAD	LAS VEGAS		-89106			9	NV002	CLARK CO DEPT OF AIR QUALITY MANAGEMENT	DAVID C. LEE	(702) 383-1276		A139	3241							10/15/1993	10/24/1995		
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WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	ALBANY		5 SAND CREEK ROAD	LARAMIE		-82070			8	WY001	WYOMING AIR QUAL DIV, DEPT OF ENV QUAL	CHAD SCHLICHTMEI ER-DISTRICT 1	(307) 777-7391		CT-1137	3241		56-001-00002					5/16/1994	3/6/1995	1/31/1996	4/24/1996
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	ALBANY		5 SAND CREEK ROAD	LARAMIE		-82070			8	WY001	WYOMING AIR QUAL DIV, DEPT OF ENV QUAL	CHAD SCHLICHTMEI ER-DISTRICT 1	(307) 777-7391		CT-1137	3241		56-001-00002					5/16/1994	3/6/1995	1/31/1996	4/24/1996
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RBLCID	FACILITY	ENTRY DATE	LASTUP DATE	NEW_ MOD	PUBLIC HEAR	FUEL	EMISSSOURCES	ABATEMENT
UT-0059	ASH GROVE CEMENT COMPANY	10/16/2001	6/6/2002	M		COAL, TIRE DERIVED FUEL (TDF), DIESEL, NATURAL GAS, USED OIL FUEL	COMBUSTION FOR KILN, KILN, CLINKER COOLING PROCESS	BAGHOUSES, LOW NOX BURNER
UT-0059	ASH GROVE CEMENT COMPANY	10/16/2001	6/6/2002	M		COAL, TIRE DERIVED FUEL (TDF), DIESEL, NATURAL GAS, USED OIL FUEL	COMBUSTION FOR KILN, KILN, CLINKER COOLING PROCESS	BAGHOUSES, LOW NOX BURNER
UT-0059	ASH GROVE CEMENT COMPANY	10/16/2001	6/6/2002	M		COAL, TIRE DERIVED FUEL (TDF), DIESEL, NATURAL GAS, USED OIL FUEL	COMBUSTION FOR KILN, KILN, CLINKER COOLING PROCESS	BAGHOUSES, LOW NOX BURNER
UT-0059	ASH GROVE CEMENT COMPANY	10/16/2001	6/6/2002	M		COAL, TIRE DERIVED FUEL (TDF), DIESEL, NATURAL GAS, USED OIL FUEL	COMBUSTION FOR KILN, KILN, CLINKER COOLING PROCESS	BAGHOUSES, LOW NOX BURNER
UT-0059	ASH GROVE CEMENT COMPANY	10/16/2001	6/6/2002	M		COAL, TIRE DERIVED FUEL (TDF), DIESEL, NATURAL GAS, USED OIL FUEL	COMBUSTION FOR KILN, KILN, CLINKER COOLING PROCESS	BAGHOUSES, LOW NOX BURNER
UT-0059	ASH GROVE CEMENT COMPANY	10/16/2001	6/6/2002	M		COAL, TIRE DERIVED FUEL (TDF), DIESEL, NATURAL GAS, USED OIL FUEL	COMBUSTION FOR KILN, KILN, CLINKER COOLING PROCESS	BAGHOUSES, LOW NOX BURNER
UT-0059	ASH GROVE CEMENT COMPANY	10/16/2001	6/6/2002	M		COAL, TIRE DERIVED FUEL (TDF), DIESEL, NATURAL GAS, USED OIL FUEL	COMBUSTION FOR KILN, KILN, CLINKER COOLING PROCESS	BAGHOUSES, LOW NOX BURNER
UT-0059	ASH GROVE CEMENT COMPANY	10/16/2001	6/6/2002	M		COAL, TIRE DERIVED FUEL (TDF), DIESEL, NATURAL GAS, USED OIL FUEL	COMBUSTION FOR KILN, KILN, CLINKER COOLING PROCESS	BAGHOUSES, LOW NOX BURNER
UT-0059	ASH GROVE CEMENT COMPANY	10/16/2001	6/6/2002	M		COAL, TIRE DERIVED FUEL (TDF), DIESEL, NATURAL GAS, USED OIL FUEL	COMBUSTION FOR KILN, KILN, CLINKER COOLING PROCESS	BAGHOUSES, LOW NOX BURNER
UT-0059	ASH GROVE CEMENT COMPANY	10/16/2001	6/6/2002	M		COAL, TIRE DERIVED FUEL (TDF), DIESEL, NATURAL GAS, USED OIL FUEL	COMBUSTION FOR KILN, KILN, CLINKER COOLING PROCESS	BAGHOUSES, LOW NOX BURNER
UT-0059	ASH GROVE CEMENT COMPANY	10/16/2001	6/6/2002	M		COAL, TIRE DERIVED FUEL (TDF), DIESEL, NATURAL GAS, USED OIL FUEL	COMBUSTION FOR KILN, KILN, CLINKER COOLING PROCESS	BAGHOUSES, LOW NOX BURNER
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	10/18/2001	3/3/2004	M		COAL, NATURAL GAS, COKE, FUEL OIL, TIRE DERIVED FUEL (TDF), DIAPER DERIVED FUEL (DDF)	KILN EXHAUST, FUGITIVES	BAGHOUSES, LOW NOX BURNER (COMPUTER CONTROLLED)
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	10/18/2001	3/3/2004	M		COAL, NATURAL GAS, COKE, FUEL OIL, TIRE DERIVED FUEL (TDF), DIAPER DERIVED FUEL (DDF)	KILN EXHAUST, FUGITIVES	BAGHOUSES, LOW NOX BURNER (COMPUTER CONTROLLED)
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	10/18/2001	3/3/2004	M		COAL, NATURAL GAS, COKE, FUEL OIL, TIRE DERIVED FUEL (TDF), DIAPER DERIVED FUEL (DDF)	KILN EXHAUST, FUGITIVES	BAGHOUSES, LOW NOX BURNER (COMPUTER CONTROLLED)
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	10/18/2001	3/3/2004	M		COAL, NATURAL GAS, COKE, FUEL OIL, TIRE DERIVED FUEL (TDF), DIAPER DERIVED FUEL (DDF)	KILN EXHAUST, FUGITIVES	BAGHOUSES, LOW NOX BURNER (COMPUTER CONTROLLED)
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	10/18/2001	3/3/2004	M		COAL, NATURAL GAS, COKE, FUEL OIL, TIRE DERIVED FUEL (TDF), DIAPER DERIVED FUEL (DDF)	KILN EXHAUST, FUGITIVES	BAGHOUSES, LOW NOX BURNER (COMPUTER CONTROLLED)
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	10/18/2001	3/3/2004	M		COAL, NATURAL GAS, COKE, FUEL OIL, TIRE DERIVED FUEL (TDF), DIAPER DERIVED FUEL (DDF)	KILN EXHAUST, FUGITIVES	BAGHOUSES, LOW NOX BURNER (COMPUTER CONTROLLED)

RBLCID	FACILITY	ENTRY DATE	LASTUP DATE	NEW_ MOD	PUBLIC HEAR	FUEL	EMISSSOURCES	ABATEMENT
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	10/18/2001	3/3/2004	M		COAL, NATURAL GAS, COKE, FUEL OIL, TIRE DERIVED FUEL (TDF), DIAPER DERIVED FUEL (DDF)	KILN EXHAUST, FUGITIVES	BAGHOUSES, LOW NOX BURNER (COMPUTER CONTROLLED)
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	2/26/1996	12/18/2001					
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	2/26/1996	12/18/2001					
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NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	2/26/1996	12/18/2001					
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	2/26/1996	12/18/2001					
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	2/26/1996	12/18/2001					
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	2/26/1996	12/18/2001					
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	2/26/1996	12/18/2001					
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	4/13/1999	12/18/2001					
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	4/13/1999	12/18/2001					
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	4/13/1999	12/18/2001					
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	4/13/1999	12/18/2001					
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	4/13/1999	12/18/2001					
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	4/13/1999	12/18/2001					
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	4/13/1999	12/18/2001					
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	4/13/1999	12/18/2001					
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	4/13/1999	12/18/2001					
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	4/13/1999	12/18/2001					
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	4/13/1999	12/18/2001					

RBLCID	FACILITY	NARRATIVE	NOTES	PROCESS	PROCT YPE	SCC	FUEL	THRUPUT	THRUPUT UNIT	COMP VERIFY	STACK TEST	INSPECTION	CALCULATED	OTHER TEST	OTHER METHD
UT-0059	ASH GROVE CEMENT COMPANY	CEMENT PLANT	PHYSICAL PLANT - LEAMINGTON, UT. ALSO REFER TO TITLE V PERMIT 1/05/2000 DAQO-795067-99. LIMITS NOT TO BE EXCEEDED WITHOUT PRIOR APPROVAL WITH R307-1-3.1 UAC. A)QUARRY ORE AND WASTE PRODUCTION HANDLER BY CRUSHING/ CONVEXING SYSTEM 1.549 E 6 T/12 MO PERIOD. B) ANNUAL COAL CONSUMPTION-113,000 T/12 MO PERIOD. C) ANNUAL USED ORE CONSUMPTION-85,724 T/12 MO PERIOD. PLANTWIDE EMISSIONS - LEAD - 0.5	FUGITIVES - PLANTWIDE	90.028	30500699				N	N	N	N	N	
UT-0059	ASH GROVE CEMENT COMPANY	CEMENT PLANT	PHYSICAL PLANT - LEAMINGTON, UT. ALSO REFER TO TITLE V PERMIT 1/05/2000 DAQO-795067-99. LIMITS NOT TO BE EXCEEDED WITHOUT PRIOR APPROVAL WITH R307-1-3.1 UAC. A)QUARRY ORE AND WASTE PRODUCTION HANDLER BY CRUSHING/ CONVEXING SYSTEM 1.549 E 6 T/12 MO PERIOD. B) ANNUAL COAL CONSUMPTION-113,000 T/12 MO PERIOD. C) ANNUAL USED ORE CONSUMPTION-85,724 T/12 MO PERIOD. PLANTWIDE EMISSIONS - LEAD - 0.5	KILN	90.028	30500606	COAL	170	T/H	N	N	N	N	N	
UT-0059	ASH GROVE CEMENT COMPANY	CEMENT PLANT	PHYSICAL PLANT - LEAMINGTON, UT. ALSO REFER TO TITLE V PERMIT 1/05/2000 DAQO-795067-99. LIMITS NOT TO BE EXCEEDED WITHOUT PRIOR APPROVAL WITH R307-1-3.1 UAC. A)QUARRY ORE AND WASTE PRODUCTION HANDLER BY CRUSHING/ CONVEXING SYSTEM 1.549 E 6 T/12 MO PERIOD. B) ANNUAL COAL CONSUMPTION-113,000 T/12 MO PERIOD. C) ANNUAL USED ORE CONSUMPTION-85,724 T/12 MO PERIOD. PLANTWIDE EMISSIONS - LEAD - 0.5	KILN	90.028	30500606	COAL	170	T/H	N	N	N	N	N	
UT-0059	ASH GROVE CEMENT COMPANY	CEMENT PLANT	PHYSICAL PLANT - LEAMINGTON, UT. ALSO REFER TO TITLE V PERMIT 1/05/2000 DAQO-795067-99. LIMITS NOT TO BE EXCEEDED WITHOUT PRIOR APPROVAL WITH R307-1-3.1 UAC. A)QUARRY ORE AND WASTE PRODUCTION HANDLER BY CRUSHING/ CONVEXING SYSTEM 1.549 E 6 T/12 MO PERIOD. B) ANNUAL COAL CONSUMPTION-113,000 T/12 MO PERIOD. C) ANNUAL USED ORE CONSUMPTION-85,724 T/12 MO PERIOD. PLANTWIDE EMISSIONS - LEAD - 0.5	KILN	90.028	30500606	COAL	170	T/H	N	N	N	N	N	
UT-0059	ASH GROVE CEMENT COMPANY	CEMENT PLANT	PHYSICAL PLANT - LEAMINGTON, UT. ALSO REFER TO TITLE V PERMIT 1/05/2000 DAQO-795067-99. LIMITS NOT TO BE EXCEEDED WITHOUT PRIOR APPROVAL WITH R307-1-3.1 UAC. A)QUARRY ORE AND WASTE PRODUCTION HANDLER BY CRUSHING/ CONVEXING SYSTEM 1.549 E 6 T/12 MO PERIOD. B) ANNUAL COAL CONSUMPTION-113,000 T/12 MO PERIOD. C) ANNUAL USED ORE CONSUMPTION-85,724 T/12 MO PERIOD. PLANTWIDE EMISSIONS - LEAD - 0.5	KILN	90.028	30500606	COAL	170	T/H	N	N	N	N	N	
UT-0059	ASH GROVE CEMENT COMPANY	CEMENT PLANT	PHYSICAL PLANT - LEAMINGTON, UT. ALSO REFER TO TITLE V PERMIT 1/05/2000 DAQO-795067-99. LIMITS NOT TO BE EXCEEDED WITHOUT PRIOR APPROVAL WITH R307-1-3.1 UAC. A)QUARRY ORE AND WASTE PRODUCTION HANDLER BY CRUSHING/ CONVEXING SYSTEM 1.549 E 6 T/12 MO PERIOD. B) ANNUAL COAL CONSUMPTION-113,000 T/12 MO PERIOD. C) ANNUAL USED ORE CONSUMPTION-85,724 T/12 MO PERIOD. PLANTWIDE EMISSIONS - LEAD - 0.5	KILN	90.028	30500606	COAL	170	T/H	N	N	N	N	N	
UT-0059	ASH GROVE CEMENT COMPANY	CEMENT PLANT	PHYSICAL PLANT - LEAMINGTON, UT. ALSO REFER TO TITLE V PERMIT 1/05/2000 DAQO-795067-99. LIMITS NOT TO BE EXCEEDED WITHOUT PRIOR APPROVAL WITH R307-1-3.1 UAC. A)QUARRY ORE AND WASTE PRODUCTION HANDLER BY CRUSHING/ CONVEXING SYSTEM 1.549 E 6 T/12 MO PERIOD. B) ANNUAL COAL CONSUMPTION-113,000 T/12 MO PERIOD. C) ANNUAL USED ORE CONSUMPTION-85,724 T/12 MO PERIOD. PLANTWIDE EMISSIONS - LEAD - 0.5	CLINKER COOLER	90.028	30500614				N	N	N	N	N	
UT-0059	ASH GROVE CEMENT COMPANY	CEMENT PLANT	PHYSICAL PLANT - LEAMINGTON, UT. ALSO REFER TO TITLE V PERMIT 1/05/2000 DAQO-795067-99. LIMITS NOT TO BE EXCEEDED WITHOUT PRIOR APPROVAL WITH R307-1-3.1 UAC. A)QUARRY ORE AND WASTE PRODUCTION HANDLER BY CRUSHING/ CONVEXING SYSTEM 1.549 E 6 T/12 MO PERIOD. B) ANNUAL COAL CONSUMPTION-113,000 T/12 MO PERIOD. C) ANNUAL USED ORE CONSUMPTION-85,724 T/12 MO PERIOD. PLANTWIDE EMISSIONS - LEAD - 0.5	CLINKER COOLER	90.028	30500614				N	N	N	N	N	
UT-0059	ASH GROVE CEMENT COMPANY	CEMENT PLANT	PHYSICAL PLANT - LEAMINGTON, UT. ALSO REFER TO TITLE V PERMIT 1/05/2000 DAQO-795067-99. LIMITS NOT TO BE EXCEEDED WITHOUT PRIOR APPROVAL WITH R307-1-3.1 UAC. A)QUARRY ORE AND WASTE PRODUCTION HANDLER BY CRUSHING/ CONVEXING SYSTEM 1.549 E 6 T/12 MO PERIOD. B) ANNUAL COAL CONSUMPTION-113,000 T/12 MO PERIOD. C) ANNUAL USED ORE CONSUMPTION-85,724 T/12 MO PERIOD. PLANTWIDE EMISSIONS - LEAD - 0.5	CLINKER COOLER	90.028	30500614				N	N	N	N	N	
UT-0059	ASH GROVE CEMENT COMPANY	CEMENT PLANT	PHYSICAL PLANT - LEAMINGTON, UT. ALSO REFER TO TITLE V PERMIT 1/05/2000 DAQO-795067-99. LIMITS NOT TO BE EXCEEDED WITHOUT PRIOR APPROVAL WITH R307-1-3.1 UAC. A)QUARRY ORE AND WASTE PRODUCTION HANDLER BY CRUSHING/ CONVEXING SYSTEM 1.549 E 6 T/12 MO PERIOD. B) ANNUAL COAL CONSUMPTION-113,000 T/12 MO PERIOD. C) ANNUAL USED ORE CONSUMPTION-85,724 T/12 MO PERIOD. PLANTWIDE EMISSIONS - LEAD - 0.5	COAL DELIVERY SYSTEM	90.011	30501017				N	N	N	N	N	
UT-0059	ASH GROVE CEMENT COMPANY	CEMENT PLANT	PHYSICAL PLANT - LEAMINGTON, UT. ALSO REFER TO TITLE V PERMIT 1/05/2000 DAQO-795067-99. LIMITS NOT TO BE EXCEEDED WITHOUT PRIOR APPROVAL WITH R307-1-3.1 UAC. A)QUARRY ORE AND WASTE PRODUCTION HANDLER BY CRUSHING/ CONVEXING SYSTEM 1.549 E 6 T/12 MO PERIOD. B) ANNUAL COAL CONSUMPTION-113,000 T/12 MO PERIOD. C) ANNUAL USED ORE CONSUMPTION-85,724 T/12 MO PERIOD. PLANTWIDE EMISSIONS - LEAD - 0.5	COAL DELIVERY SYSTEM	90.011	30501017				N	N	N	N	N	
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	PORTLAND CEMENT TERMINAL	Facility now named Holcim. THIS A.O.REPLACES A.O. DATED 12/23/1993 (DAQE-1127-93), 8/31/1988(BAQE-741-88), 11/20/1987 (BAQE-043-87), 8/26/1985 START UP. FILE INCLUDED 10/20/1999 APPROVAL ORDER FOR ADDITION OF FINISH MILL AND CEMENT STORAGE SILOS, WHICH WAS A MINOR MODIFICATION WITH RESPECT TO PSD - WAS USED FOR CONTACT INFORMATION ETC. FILE ALSO INCLUDES A.O.'S FROM 6/15/1992 (DAQE-558-92), 11/20/1987 (BAQE-043-87). 8/8/96 APPROVAL ORDER MODIFICATION FOR SYNTHETIC MINOR STATUS LIMITING ANNUAL EMISSIONS TO 1) TSP - 6.0 T/YR 2) PM10 - 4.8 T/YR. ADDITIONAL PLANTWIDE EMISSIONS (T/YR): TSP = 804.29 TOTAL (659.18 CHANGE); PM10 = 377.26 TOTAL (-312.94 CHANGE); SO2 = 15 CHANGE; NOX =25.06 CHANGE; CO = 1655.46 CHANGE; VOC = 30 CHANGE. {SO2, NOX, CO, AND VOC TOTALS IN PLANTWIDE EMISSIONS FIELDS}	ROADS AND FUGITIVE DUST	99.19	2294015000				N	N	N	N	N	
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	PORTLAND CEMENT TERMINAL	Facility now named Holcim. THIS A.O.REPLACES A.O. DATED 12/23/1993 (DAQE-1127-93), 8/31/1988(BAQE-741-88), 11/20/1987 (BAQE-043-87), 8/26/1985 START UP. FILE INCLUDED 10/20/1999 APPROVAL ORDER FOR ADDITION OF FINISH MILL AND CEMENT STORAGE SILOS, WHICH WAS A MINOR MODIFICATION WITH RESPECT TO PSD - WAS USED FOR CONTACT INFORMATION ETC. FILE ALSO INCLUDES A.O.'S FROM 6/15/1992 (DAQE-558-92), 11/20/1987 (BAQE-043-87). 8/8/96 APPROVAL ORDER MODIFICATION FOR SYNTHETIC MINOR STATUS LIMITING ANNUAL EMISSIONS TO 1) TSP - 6.0 T/YR 2) PM10 - 4.8 T/YR. ADDITIONAL PLANTWIDE EMISSIONS (T/YR): TSP = 804.29 TOTAL (659.18 CHANGE); PM10 = 377.26 TOTAL (-312.94 CHANGE); SO2 = 15 CHANGE; NOX =25.06 CHANGE; CO = 1655.46 CHANGE; VOC = 30 CHANGE. {SO2, NOX, CO, AND VOC TOTALS IN PLANTWIDE EMISSIONS FIELDS}	KILN	90.028	30500606	COAL			N	N	N	N	N	
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	PORTLAND CEMENT TERMINAL	Facility now named Holcim. THIS A.O.REPLACES A.O. DATED 12/23/1993 (DAQE-1127-93), 8/31/1988(BAQE-741-88), 11/20/1987 (BAQE-043-87), 8/26/1985 START UP. FILE INCLUDED 10/20/1999 APPROVAL ORDER FOR ADDITION OF FINISH MILL AND CEMENT STORAGE SILOS, WHICH WAS A MINOR MODIFICATION WITH RESPECT TO PSD - WAS USED FOR CONTACT INFORMATION ETC. FILE ALSO INCLUDES A.O.'S FROM 6/15/1992 (DAQE-558-92), 11/20/1987 (BAQE-043-87). 8/8/96 APPROVAL ORDER MODIFICATION FOR SYNTHETIC MINOR STATUS LIMITING ANNUAL EMISSIONS TO 1) TSP - 6.0 T/YR 2) PM10 - 4.8 T/YR. ADDITIONAL PLANTWIDE EMISSIONS (T/YR): TSP = 804.29 TOTAL (659.18 CHANGE); PM10 = 377.26 TOTAL (-312.94 CHANGE); SO2 = 15 CHANGE; NOX =25.06 CHANGE; CO = 1655.46 CHANGE; VOC = 30 CHANGE. {SO2, NOX, CO, AND VOC TOTALS IN PLANTWIDE EMISSIONS FIELDS}	KILN	90.028	30500606	COAL			N	N	N	N	N	
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	PORTLAND CEMENT TERMINAL	Facility now named Holcim. THIS A.O.REPLACES A.O. DATED 12/23/1993 (DAQE-1127-93), 8/31/1988(BAQE-741-88), 11/20/1987 (BAQE-043-87), 8/26/1985 START UP. FILE INCLUDED 10/20/1999 APPROVAL ORDER FOR ADDITION OF FINISH MILL AND CEMENT STORAGE SILOS, WHICH WAS A MINOR MODIFICATION WITH RESPECT TO PSD - WAS USED FOR CONTACT INFORMATION ETC. FILE ALSO INCLUDES A.O.'S FROM 6/15/1992 (DAQE-558-92), 11/20/1987 (BAQE-043-87). 8/8/96 APPROVAL ORDER MODIFICATION FOR SYNTHETIC MINOR STATUS LIMITING ANNUAL EMISSIONS TO 1) TSP - 6.0 T/YR 2) PM10 - 4.8 T/YR. ADDITIONAL PLANTWIDE EMISSIONS (T/YR): TSP = 804.29 TOTAL (659.18 CHANGE); PM10 = 377.26 TOTAL (-312.94 CHANGE); SO2 = 15 CHANGE; NOX =25.06 CHANGE; CO = 1655.46 CHANGE; VOC = 30 CHANGE. {SO2, NOX, CO, AND VOC TOTALS IN PLANTWIDE EMISSIONS FIELDS}	KILN	90.028	30500606	COAL			N	N	N	N	N	
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	PORTLAND CEMENT TERMINAL	Facility now named Holcim. THIS A.O.REPLACES A.O. DATED 12/23/1993 (DAQE-1127-93), 8/31/1988(BAQE-741-88), 11/20/1987 (BAQE-043-87), 8/26/1985 START UP. FILE INCLUDED 10/20/1999 APPROVAL ORDER FOR ADDITION OF FINISH MILL AND CEMENT STORAGE SILOS, WHICH WAS A MINOR MODIFICATION WITH RESPECT TO PSD - WAS USED FOR CONTACT INFORMATION ETC. FILE ALSO INCLUDES A.O.'S FROM 6/15/1992 (DAQE-558-92), 11/20/1987 (BAQE-043-87). 8/8/96 APPROVAL ORDER MODIFICATION FOR SYNTHETIC MINOR STATUS LIMITING ANNUAL EMISSIONS TO 1) TSP - 6.0 T/YR 2) PM10 - 4.8 T/YR. ADDITIONAL PLANTWIDE EMISSIONS (T/YR): TSP = 804.29 TOTAL (659.18 CHANGE); PM10 = 377.26 TOTAL (-312.94 CHANGE); SO2 = 15 CHANGE; NOX =25.06 CHANGE; CO = 1655.46 CHANGE; VOC = 30 CHANGE. {SO2, NOX, CO, AND VOC TOTALS IN PLANTWIDE EMISSIONS FIELDS}	KILN	90.028	30500606	COAL			N	N	N	N	N	
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	PORTLAND CEMENT TERMINAL	Facility now named Holcim. THIS A.O.REPLACES A.O. DATED 12/23/1993 (DAQE-1127-93), 8/31/1988(BAQE-741-88), 11/20/1987 (BAQE-043-87), 8/26/1985 START UP. FILE INCLUDED 10/20/1999 APPROVAL ORDER FOR ADDITION OF FINISH MILL AND CEMENT STORAGE SILOS, WHICH WAS A MINOR MODIFICATION WITH RESPECT TO PSD - WAS USED FOR CONTACT INFORMATION ETC. FILE ALSO INCLUDES A.O.'S FROM 6/15/1992 (DAQE-558-92), 11/20/1987 (BAQE-043-87). 8/8/96 APPROVAL ORDER MODIFICATION FOR SYNTHETIC MINOR STATUS LIMITING ANNUAL EMISSIONS TO 1) TSP - 6.0 T/YR 2) PM10 - 4.8 T/YR. ADDITIONAL PLANTWIDE EMISSIONS (T/YR): TSP = 804.29 TOTAL (659.18 CHANGE); PM10 = 377.26 TOTAL (-312.94 CHANGE); SO2 = 15 CHANGE; NOX =25.06 CHANGE; CO = 1655.46 CHANGE; VOC = 30 CHANGE. {SO2, NOX, CO, AND VOC TOTALS IN PLANTWIDE EMISSIONS FIELDS}	KILN	90.028	30500606	COAL			N	N	N	N	N	

RBLCID	FACILITY	NARRATIVE	NOTES	PROCESS	PROCT YPE	SCC	FUEL	THRUPUT	THRUPUT UNIT	COMP VERIFY	STACK TEST	INSPECTION	CALCULATED	OTHER TEST	OTHER METHD
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	PORTLAND CEMENT TERMINAL	Facility now named Holcim. THIS A.O.REPLACES A.O. DATED 12/23/1993 (DAQE-1127-93), 8/31/1988(BAQE-741-88), 11/20/1987 (BAQE-043-87), 8/26/1985 START UP. FILE INCLUDED 10/20/1999 APPROVAL ORDER FOR ADDITION OF FINISH MILL AND CEMENT STORAGE SILOS, WHICH WAS A MINOR MODIFICATION WITH RESPECT TO PSD - WAS USED FOR CONTACT INFORMATION ETC. FILE ALSO INCLUDES A.O.'S FROM 6/15/1992 (DAQE-558-92), 11/20/1987 (BAQE-043-87). 8/8/96 APPROVAL ORDER MODIFICATION FOR SYNTHETIC MINOR STATUS LIMITING ANNUAL EMISSIONS TO 1) TSP - 6.0 T/YR 2) PM10 - 4.8 T/YR. ADDITIONAL PLANTWIDE EMISSIONS (T/YR): TSP = 804.29 TOTAL (659.18 CHANGE); PM10 = 377.26 TOTAL (-312.94 CHANGE); SO2 = 15 CHANGE; NOX =25.06 CHANGE; CO = 1655.46 CHANGE; VOC = 30 CHANGE. {SO2, NOX, CO, AND VOC TOTALS IN PLANTWIDE EMISSIONS FIELDS}	KILN	90.028	30500606	COAL			N	N	N	N	N	
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		ONE QUARRY WITH ANNUAL MINING CAPACITY OF FOUR MILLION TONS WILL PROVIDE RAW MATERIALS FOR PORTLAND CEMENT MANUFACTURING AND SAND AND GRAVEL PROCESSING WITHIN ONE CONTIGUOUS PROPERTY. THE ANNUAL PRODUCTION CAPACITY FOR CLINKER IS ONE MILLION TONS. THE CEMENT PLANT WILL USE LOW-SULFUR WESTERN COAL ONLY.	CEMENT STORAGE SILO W/VENT	90.024	3-05-006-18		0		F	F	F	F	F	
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		ONE QUARRY WITH ANNUAL MINING CAPACITY OF FOUR MILLION TONS WILL PROVIDE RAW MATERIALS FOR PORTLAND CEMENT MANUFACTURING AND SAND AND GRAVEL PROCESSING WITHIN ONE CONTIGUOUS PROPERTY. THE ANNUAL PRODUCTION CAPACITY FOR CLINKER IS ONE MILLION TONS. THE CEMENT PLANT WILL USE LOW-SULFUR WESTERN COAL ONLY.	MATL TRANSFER, SAND/GRAVEL LOADERS & CONVEYORS	90.024	3-05-025-04, -06		0		F	F	F	F	F	
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		ONE QUARRY WITH ANNUAL MINING CAPACITY OF FOUR MILLION TONS WILL PROVIDE RAW MATERIALS FOR PORTLAND CEMENT MANUFACTURING AND SAND AND GRAVEL PROCESSING WITHIN ONE CONTIGUOUS PROPERTY. THE ANNUAL PRODUCTION CAPACITY FOR CLINKER IS ONE MILLION TONS. THE CEMENT PLANT WILL USE LOW-SULFUR WESTERN COAL ONLY.	CEMENT KILN/CLINKER COOLER FACILITY	90.028	3-05-006		0		F	F	F	F	F	
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		ONE QUARRY WITH ANNUAL MINING CAPACITY OF FOUR MILLION TONS WILL PROVIDE RAW MATERIALS FOR PORTLAND CEMENT MANUFACTURING AND SAND AND GRAVEL PROCESSING WITHIN ONE CONTIGUOUS PROPERTY. THE ANNUAL PRODUCTION CAPACITY FOR CLINKER IS ONE MILLION TONS. THE CEMENT PLANT WILL USE LOW-SULFUR WESTERN COAL ONLY.	CEMENT KILN/CLINKER COOLER FACILITY	90.028	3-05-006		0		F	F	F	F	F	
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		ONE QUARRY WITH ANNUAL MINING CAPACITY OF FOUR MILLION TONS WILL PROVIDE RAW MATERIALS FOR PORTLAND CEMENT MANUFACTURING AND SAND AND GRAVEL PROCESSING WITHIN ONE CONTIGUOUS PROPERTY. THE ANNUAL PRODUCTION CAPACITY FOR CLINKER IS ONE MILLION TONS. THE CEMENT PLANT WILL USE LOW-SULFUR WESTERN COAL ONLY.	CEMENT KILN/CLINKER COOLER FACILITY	90.028	3-05-006		0		F	F	F	F	F	
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		ONE QUARRY WITH ANNUAL MINING CAPACITY OF FOUR MILLION TONS WILL PROVIDE RAW MATERIALS FOR PORTLAND CEMENT MANUFACTURING AND SAND AND GRAVEL PROCESSING WITHIN ONE CONTIGUOUS PROPERTY. THE ANNUAL PRODUCTION CAPACITY FOR CLINKER IS ONE MILLION TONS. THE CEMENT PLANT WILL USE LOW-SULFUR WESTERN COAL ONLY.	CEMENT KILN CALCINING	90.028	3-05-006-06		1.6	MILLION TONS	F	F	F	F	F	
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		ONE QUARRY WITH ANNUAL MINING CAPACITY OF FOUR MILLION TONS WILL PROVIDE RAW MATERIALS FOR PORTLAND CEMENT MANUFACTURING AND SAND AND GRAVEL PROCESSING WITHIN ONE CONTIGUOUS PROPERTY. THE ANNUAL PRODUCTION CAPACITY FOR CLINKER IS ONE MILLION TONS. THE CEMENT PLANT WILL USE LOW-SULFUR WESTERN COAL ONLY.	CLINKER COOLER	90.028	3-05-006-14		0		F	F	F	F	F	
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		ONE QUARRY WITH ANNUAL MINING CAPACITY OF FOUR MILLION TONS WILL PROVIDE RAW MATERIALS FOR PORTLAND CEMENT MANUFACTURING AND SAND AND GRAVEL PROCESSING WITHIN ONE CONTIGUOUS PROPERTY. THE ANNUAL PRODUCTION CAPACITY FOR CLINKER IS ONE MILLION TONS. THE CEMENT PLANT WILL USE LOW-SULFUR WESTERN COAL ONLY.	MATL HANDLING, SEPARATOR VENT	90.024	3-05-006-99		0		F	F	F	F	F	
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		ONE QUARRY WITH ANNUAL MINING CAPACITY OF FOUR MILLION TONS WILL PROVIDE RAW MATERIALS FOR PORTLAND CEMENT MANUFACTURING AND SAND AND GRAVEL PROCESSING WITHIN ONE CONTIGUOUS PROPERTY. THE ANNUAL PRODUCTION CAPACITY FOR CLINKER IS ONE MILLION TONS. THE CEMENT PLANT WILL USE LOW-SULFUR WESTERN COAL ONLY.	QUARRYING	90.024	3-05-020		0		F	F	F	F	F	
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		ONE QUARRY WITH ANNUAL MINING CAPACITY OF FOUR MILLION TONS WILL PROVIDE RAW MATERIALS FOR PORTLAND CEMENT MANUFACTURING AND SAND AND GRAVEL PROCESSING WITHIN ONE CONTIGUOUS PROPERTY. THE ANNUAL PRODUCTION CAPACITY FOR CLINKER IS ONE MILLION TONS. THE CEMENT PLANT WILL USE LOW-SULFUR WESTERN COAL ONLY.	LIMESTONE CRUSHING	90.024	3-05-020-01		0		F	F	F	F	F	
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		ONE QUARRY WITH ANNUAL MINING CAPACITY OF FOUR MILLION TONS WILL PROVIDE RAW MATERIALS FOR PORTLAND CEMENT MANUFACTURING AND SAND AND GRAVEL PROCESSING WITHIN ONE CONTIGUOUS PROPERTY. THE ANNUAL PRODUCTION CAPACITY FOR CLINKER IS ONE MILLION TONS. THE CEMENT PLANT WILL USE LOW-SULFUR WESTERN COAL ONLY.	SAND AND GRAVEL SCREENING	90.024	3-05-025-11		0		F	F	F	F	F	
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		ONE QUARRY WITH ANNUAL MINING CAPACITY OF FOUR MILLION TONS WILL PROVIDE RAW MATERIALS FOR PORTLAND CEMENT MANUFACTURING AND SAND AND GRAVEL PROCESSING WITHIN ONE CONTIGUOUS PROPERTY. THE ANNUAL PRODUCTION CAPACITY FOR CLINKER IS ONE MILLION TONS. THE CEMENT PLANT WILL USE LOW-SULFUR WESTERN COAL ONLY.	MATL HANDLING, RAW MATERIALS BLENDING	90.024	3-05-006-13		0		F	F	F	F	F	
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		ONE QUARRY WITH ANNUAL MINING CAPACITY OF FOUR MILLION TONS WILL PROVIDE RAW MATERIALS FOR PORTLAND CEMENT MANUFACTURING AND SAND AND GRAVEL PROCESSING WITHIN ONE CONTIGUOUS PROPERTY. THE ANNUAL PRODUCTION CAPACITY FOR CLINKER IS ONE MILLION TONS. THE CEMENT PLANT WILL USE LOW-SULFUR WESTERN COAL ONLY.	MATL HANDLING, COLLECTING AT FINISH MILL	90.024	3-05-006-19		0		F	F	F	F	F	
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		MODIFY AND REACTIVATE #1 KILN, CLINKER COOLER AND ASSOCIATED EQUIPMENT	KILN, COAL FIRED	90.028	30500606		45.3	T/H COAL	T	T	F	F	F	
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		MODIFY AND REACTIVATE #1 KILN, CLINKER COOLER AND ASSOCIATED EQUIPMENT	KILN, COAL FIRED	90.028	30500606		45.3	T/H COAL	T	T	F	F	F	
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		MODIFY AND REACTIVATE #1 KILN, CLINKER COOLER AND ASSOCIATED EQUIPMENT	KILN, COAL FIRED	90.028	30500606		45.3	T/H COAL	T	T	F	F	F	
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		MODIFY AND REACTIVATE #1 KILN, CLINKER COOLER AND ASSOCIATED EQUIPMENT	KILN, COAL FIRED	90.028	30500606		45.3	T/H COAL	T	T	F	F	F	
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		MODIFY AND REACTIVATE #1 KILN, CLINKER COOLER AND ASSOCIATED EQUIPMENT	KILN, COAL FIRED	90.028	30500606		45.3	T/H COAL	T	T	F	F	F	
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		MODIFY AND REACTIVATE #1 KILN, CLINKER COOLER AND ASSOCIATED EQUIPMENT	KILN, COAL FIRED	90.028	30500606		45.3	T/H COAL	T	T	F	F	F	
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		MODIFY AND REACTIVATE #1 KILN, CLINKER COOLER AND ASSOCIATED EQUIPMENT	CONVEYOR, CLINKER	90.028	30500616		0		F	F	F	F	F	
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		MODIFY AND REACTIVATE #1 KILN, CLINKER COOLER AND ASSOCIATED EQUIPMENT	CONVEYOR, CLINKER	90.028	30500616		0		F	F	F	F	F	
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		MODIFY AND REACTIVATE #1 KILN, CLINKER COOLER AND ASSOCIATED EQUIPMENT	DUST RETURN ELEVATOR SYSTEM	90.028	30500699		0		F	F	F	F	F	
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		MODIFY AND REACTIVATE #1 KILN, CLINKER COOLER AND ASSOCIATED EQUIPMENT	DUST RETURN ELEVATOR SYSTEM	90.028	30500699		0		F	F	F	F	F	
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		MODIFY AND REACTIVATE #1 KILN, CLINKER COOLER AND ASSOCIATED EQUIPMENT	MILL, FINISH	90.028	30500699		0		F	F	F	F	F	

RBLCID	FACILITY	PRNOTES	POLLUTANT	CAS	CONTROL COD	CTRLDESC	RANKOPTS	RANK SEL	EMIS LIMIT1	EMISLIMIT1 UNIT	EMISLIMIT1 CONDITION	BASIS	PCTEFFIC	EMISLIMIT2	EMISLIMIT2UNIT	EMISLIMIT2CONDITION	STDEMISS	STDUNIT	STOTHER CONDITIONS	EMISSTYPE	CAPCOST	ANNUAL COST	OMCOST
UT-0059	ASH GROVE CEMENT COMPANY	FUGITIVES PLANTWIDE: PAVED ROADS TO BE SWEPT/WATER SPRAYED AS DAY CONDITIONS WARRANT - VISIBLE EMISSIONS NOT TO EXCEED 20% OPACITY. WATER OR COMMERCIAL DUST SURPRESSANTS SPRAYS AT 1) ALL CRUSHERS EXCEPT THE NEW ONE FEEDING THE FINISH MILL 2) ALL SCREENS 3) ALL FUGITIVE EMISSIONS POINTS ASSOCIATED WITH WASTE HANDLING. WATER TO BE ADDED TO MINED MATERIAL - MINED MATERIAL PASSED THROUGH PORTABLE CRUSHER TO HAVE NO LESS THAN 4.0% BY WEIGHT MOISTURE CONTENT.	VE	VE	P	SEE PROCESS NOTES.			20	% OPACITY		BACT-PSD					20	% OPACITY		P			
UT-0059	ASH GROVE CEMENT COMPANY	THROUGHPUT IS KILN FEES RATE LIMIT. ALSO USES TIRE DERIVED FUEL, NOT TO EXCEED 15% OF COMBINED ENERGY INPUT (AS PER DAQE -958-96) OTHER FUELS INCLUDE USED OIL, DIESEL AND NATURAL GAS. USED OIL CONTENTS NOT TO EXCEED: ARSENIC 5 PPM BY WT, BARIUM 100 PPM BY WT, CADIUM 2 PPM BY WT, CHROMIUM 10 PPM BY WT, LEAD 100 PPM BY WT, SULFER .5% BY WT, TOTAL HALOGENS 1000 PPM BY WT, FLASH POINT 100F (MINIMUM). CO LIMIT TO BE ESTABLISHED AFTER COMPLIANCE TEST. EMISSIONS FROM SOURCE HAVE BEEN ESTIMATED AT 501 LB CO/H.	TSP	PM	A	BAGHOUSE. EMISSION LIMITS 23.45 LB/H @170 T/H KILN FEED RATE.			23.45	LB/H	@170 T/H	BACT-PSD					0.14	LB/T		P			
UT-0059	ASH GROVE CEMENT COMPANY	THROUGHPUT IS KILN FEES RATE LIMIT. ALSO USES TIRE DERIVED FUEL, NOT TO EXCEED 15% OF COMBINED ENERGY INPUT (AS PER DAQE -958-96) OTHER FUELS INCLUDE USED OIL, DIESEL AND NATURAL GAS. USED OIL CONTENTS NOT TO EXCEED: ARSENIC 5 PPM BY WT, BARIUM 100 PPM BY WT, CADIUM 2 PPM BY WT, CHROMIUM 10 PPM BY WT, LEAD 100 PPM BY WT, SULFER .5% BY WT, TOTAL HALOGENS 1000 PPM BY WT, FLASH POINT 100F (MINIMUM). CO LIMIT TO BE ESTABLISHED AFTER COMPLIANCE TEST. EMISSIONS FROM SOURCE HAVE BEEN ESTIMATED AT 501 LB CO/H.	PM10	PM	A	BAGHOUSE. EMISSION LIMIT: 21.11 LB/H @ 170 T/H KILN FEED.			21.11	LB/H	@ 170 T/H	BACT-PSD					0.12	LB/T		P			
UT-0059	ASH GROVE CEMENT COMPANY	THROUGHPUT IS KILN FEES RATE LIMIT. ALSO USES TIRE DERIVED FUEL, NOT TO EXCEED 15% OF COMBINED ENERGY INPUT (AS PER DAQE -958-96) OTHER FUELS INCLUDE USED OIL, DIESEL AND NATURAL GAS. USED OIL CONTENTS NOT TO EXCEED: ARSENIC 5 PPM BY WT, BARIUM 100 PPM BY WT, CADIUM 2 PPM BY WT, CHROMIUM 10 PPM BY WT, LEAD 100 PPM BY WT, SULFER .5% BY WT, TOTAL HALOGENS 1000 PPM BY WT, FLASH POINT 100F (MINIMUM). CO LIMIT TO BE ESTABLISHED AFTER COMPLIANCE TEST. EMISSIONS FROM SOURCE HAVE BEEN ESTIMATED AT 501 LB CO/H.	SO2	9/5/7446	P	LOW SULFER FUEL REQUIREMENT. SULFER CONTENT OF FUEL NO GREATER THAN 1.0 LB/MMBTU FOR COAL, 0.5% BY WEIGHT FOR USED OIL.			1	LB/MMBTU		BACT-PSD								P			
UT-0059	ASH GROVE CEMENT COMPANY	THROUGHPUT IS KILN FEES RATE LIMIT. ALSO USES TIRE DERIVED FUEL, NOT TO EXCEED 15% OF COMBINED ENERGY INPUT (AS PER DAQE -958-96) OTHER FUELS INCLUDE USED OIL, DIESEL AND NATURAL GAS. USED OIL CONTENTS NOT TO EXCEED: ARSENIC 5 PPM BY WT, BARIUM 100 PPM BY WT, CADIUM 2 PPM BY WT, CHROMIUM 10 PPM BY WT, LEAD 100 PPM BY WT, SULFER .5% BY WT, TOTAL HALOGENS 1000 PPM BY WT, FLASH POINT 100F (MINIMUM). CO LIMIT TO BE ESTABLISHED AFTER COMPLIANCE TEST. EMISSIONS FROM SOURCE HAVE BEEN ESTIMATED AT 501 LB CO/H.	NOX	10102	P	LOW NOX BURNER. PRIMARY EMISSION LIMIT: 400 LB/H AT 90% OF MAX PRODUCTION CAPACITY. NOTE: TITLE V PERMIT DOES NOT INCLUDE				400	LB/H		BACT-PSD								P		
UT-0059	ASH GROVE CEMENT COMPANY	THROUGHPUT IS KILN FEES RATE LIMIT. ALSO USES TIRE DERIVED FUEL, NOT TO EXCEED 15% OF COMBINED ENERGY INPUT (AS PER DAQE -958-96) OTHER FUELS INCLUDE USED OIL, DIESEL AND NATURAL GAS. USED OIL CONTENTS NOT TO EXCEED: ARSENIC 5 PPM BY WT, BARIUM 100 PPM BY WT, CADIUM 2 PPM BY WT, CHROMIUM 10 PPM BY WT, LEAD 100 PPM BY WT, SULFER .5% BY WT, TOTAL HALOGENS 1000 PPM BY WT, FLASH POINT 100F (MINIMUM). CO LIMIT TO BE ESTABLISHED AFTER COMPLIANCE TEST. EMISSIONS FROM SOURCE HAVE BEEN ESTIMATED AT 501 LB CO/H.	VE	VE	A	BAGHOUSE			20	% OPACITY		BACT-PSD					20	% OPACITY		P			
UT-0059	ASH GROVE CEMENT COMPANY	TITLE V PERMIT:		TSP	PM	A	BAGHOUSE. EMISSION LIMIT 2 AS PER TITLE V PERMIT. NO EMISSION LIMIT IN LB/T.			10.69	LB/H		BACT-PSD		0.01	GR/DSCF					P		
UT-0059	ASH GROVE CEMENT COMPANY	TITLE V PERMIT:		PM10	PM	A	BAGHOUSE. EMISSION LIMIT 2: .009 GR/DSCF AS PER TITLE V. NO EMISSION LIMIT AS LB/T.			9.63	LB/H		BACT-PSD		0.009	GR/SCF					P		
UT-0059	ASH GROVE CEMENT COMPANY	TITLE V PERMIT:		VE	VE	A	BAGHOUSE			10	% OPACITY		BACT-PSD					10	% OPACITY		P		
UT-0059	ASH GROVE CEMENT COMPANY	EMISSION LIMITS ARE FOR COAL SYSTEM BAGHOUSE. TITLE V PERMIT LISTS AS (R140) COAL GRINDING SYSTEM AND SAYS	,	,	,	,	,	,	,	,	,	,	,	,	,	,	,	,	,	,	,	,	,
UT-0059	ASH GROVE CEMENT COMPANY	EMISSION LIMITS ARE FOR COAL SYSTEM BAGHOUSE. TITLE V PERMIT LISTS AS (R140) COAL GRINDING SYSTEM AND SAYS	,	,	,	,	,	,	,	,	,	,	,	,	,	,	,	,	,	,	,	,	,
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	1)UNPAVED ROADS AND OPERATIONAL AREAS WATER SPRAYED OR CHEMICALLY TREATED TO CONTROL FUGITIVE DUST. OPACITY NOT TO EXCEED 20%. 2)HAUL ROAD SPEED LIMITS: 25 MPH FOR HAULERS, 15 MPH FOR LOADERS. 3)DUST SUPRESSION SYSTEMS AT CRUSHER DUMP AND CONVEYOR TRANSFER POINTS.	VE	VE	P	WATER SPRAYS AND CHEMICAL TREATMENTS, PAVED ROADS, HAUL ROAD LIMITS, DUST SUPPRESSION SYSTEMS AT CRUSHER DUMP AND CONVEYOR TRANSFER POINTS			20	% OPACITY		BACT-OTHER					20	% OPACITY		F			
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	BASIS OF LIMITS IS UNCLEAR. APPROVAL ORDER REFERENCES NSPS AND TITLE V.	HALOGENS		P	LOW HALOGEN CONTENT IN FUELS					See POLLUTANT note.	OTHER								P			
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	BASIS OF LIMITS IS UNCLEAR. APPROVAL ORDER REFERENCES NSPS AND TITLE V.	PM10	PM	A	BAGHOUSE. NOTE: OPACITY LIMIT FOR KILN EXHAUST GASES IS 20%.			14	LB/H		NSPS							Not Available	P			
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	BASIS OF LIMITS IS UNCLEAR. APPROVAL ORDER REFERENCES NSPS AND TITLE V.	SO2	9/5/7446	P	LOW SULFUR FUELS			110	LB/H		NSPS								P			
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	BASIS OF LIMITS IS UNCLEAR. APPROVAL ORDER REFERENCES NSPS AND TITLE V.	NOX	10102	P	LOW NOX BURNER			251	LB/H		NSPS								P			
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	BASIS OF LIMITS IS UNCLEAR. APPROVAL ORDER REFERENCES NSPS AND TITLE V.	CO	630-08-0	P	COMBUSTION CONTROLS			438	LB/H		BACT-PSD								P			

RBLCID	FACILITY	PRNOTES	POLLUTANT	CAS	CONTROL COD	CTRLDESC	RANKOPTS	RANK SEL	EMIS LIMIT1	EMISLIMIT1 UNIT	EMISLIMIT1 CONDITION	BASIS	PCTE FFIC	EMISL IMIT2	EMISLI MIT2U NIT	EMISLI MIT2C ONDITI ON	STDEMISS	STDUNIT	STOTHER CONDITIONS	EMISSTYPE	CAPCOST	ANNUAL COST	OMCOST
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT	BASIS OF LIMITS IS UNCLEAR. APPROVAL ORDER REFERENCES NSPS AND TITLE V.	VE	VE	A	FABRIC FILTER			20	% OPACITY		NSPS					20	% OPACITY		P			
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		PM10	PM	A	BAGHOUSE WITH A STACK	3	1	1.269	LB/HR & .010 GR/DSCF		BACT-PSD	99	4.72	TPY & 7% OPACITY		0			P	0	0	0
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		PM10	PM	P	WET SUPPRESSION	1	1	399.4	LB/HR		BACT-PSD	0	49.93	TPY		0			F	0	0	0
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		NOX	10102	B	SELECTIVE NON-CATALYTIC REDUCTION (SNCR) UREA INJECTION SYSTEM AT PREHEATER	3	1	3.1	LB/TON CLINKER PROD.		BACT-PSD	50	1548	TPY		0			P	0	0	0
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		CO	630-08-0	P	GOOD COMBUSTION PRACTICE. AIR/FUEL RATIO CONTROL SYSTEM	3	3	5.67	LB/TON CLINKER PROD.		BACT-PSD	0	2835	TPY		0			P	0	0	0
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		SO2	9/5/7446	P	FUEL SPEC: LIMIT FUEL TO COAL WITH 1% SULFUR (COAL SULFUR ANALYSIS)	3	2	0.416	LB/TON CLINKER PROD.		BACT-PSD	90	208	TPY		0			P	0	0	0
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	THROUGHPUT CAPACITY/SIZE: 1.6 MILLION TONS FOR THE CEMENT KILN	PM10	PM	A	BAGHOUSE WITH A STACK	3	1	23.7	LB/HR & .015 GR/DSCF		BACT-PSD	99	88	TPY & 10% OPACITY		0			P	0	0	0
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		PM10	PM	A	BAGHOUSE WITH A STACK	3	1	21	LB/HR & .015 GR/DSCF		BACT-PSD	99	78.2	TPY		0			P	0	0	0
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		PM10	PM	A	BAGHOUSE WITH A STACK	3	1	18.7	LB/HR & .010 GR/DSCF		BACT-PSD	99	69.5	TPY & 7% OPACITY		0			P	0	0	0
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		PM10	PM	P	WET SUPPRESSION	1	1	399.6	LB/HR		BACT-PSD	90	49.95	TPY		0			F	0	0	0
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		PM10	PM	A	BAGHOUSE WITH A STACK	3	1	0.05	LB/HR & .010 GR/DSCF		BACT-PSD	99	3.57	TPY & 7% OPACITY		0			P	0	0	0
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		PM10	PM	P	WET SUPPRESSION	1	1	274.9	LB/HR		BACT-PSD	82	34.37	TPY		0			F	0	0	0
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		PM10	PM	A	BAGHOUSE WITH A STACK	3	1	2.334	LB/HR & .010 GR/DSCF		BACT-PSD	99	8.682	TPY & 7% OPACITY		0			P	0	0	0
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		PM10	PM	A	BAGHOUSE WITH A STACK	3	1	3.32	LB/HR & .010 GR/DSCF		BACT-PSD	99	12.34	TPY & 7% OPACITY		0			P	0	0	0
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	KILN #1 FORMERLY WET PROCESS KILN MODIFIED TO A LONG DRY PROCESS KILN. 29 T/H CLINKER PRODUCTION. SPECIFIED COAL INPUT IS 7.3T/H.	VOC	VOC	P	PROPER COMBUSTION/BURNER DESIGN	0	0	7.3	LB/H		BACT-PSD	0	0			0			P	0	0	0
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	KILN #1 FORMERLY WET PROCESS KILN MODIFIED TO A LONG DRY PROCESS KILN. 29 T/H CLINKER PRODUCTION. SPECIFIED COAL INPUT IS 7.3T/H.	VE	VE	N		0	0	20	% OPACITY		NSPS	0	0			0			P	0	0	0
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	KILN #1 FORMERLY WET PROCESS KILN MODIFIED TO A LONG DRY PROCESS KILN. 29 T/H CLINKER PRODUCTION. SPECIFIED COAL INPUT IS 7.3T/H.	CO	630-08-0	P	PROPER COMBUSTION/BURNER DESIGN	0	0	3.2	LB/H		BACT-PSD	0	0			0			P	0	0	0
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	KILN #1 FORMERLY WET PROCESS KILN MODIFIED TO A LONG DRY PROCESS KILN. 29 T/H CLINKER PRODUCTION. SPECIFIED COAL INPUT IS 7.3T/H.	NOX	10102	P	COMBUSTION UNIT DESIGN (WELL DESIGNED PROCESS BURNER OPERATED IN DESIGN RANGE)	4	4	208.8	LB/H (30DAY ROLLING)		BACT-PSD	20	0			0			P	0	0	0
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	KILN #1 FORMERLY WET PROCESS KILN MODIFIED TO A LONG DRY PROCESS KILN. 29 T/H CLINKER PRODUCTION. SPECIFIED COAL INPUT IS 7.3T/H.	PM	PM	A	ELECTROSTATIC PRECIPITATOR (RECONSTRUCT EXISTING)	2	0	13.59	LB/H		BACT-PSD	99.9	0			0.3	LB/TON		P	0	0	0
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	KILN #1 FORMERLY WET PROCESS KILN MODIFIED TO A LONG DRY PROCESS KILN. 29 T/H CLINKER PRODUCTION. SPECIFIED COAL INPUT IS 7.3T/H.	SO2	9/5/7446	P	LOW SULFUR COAL AND ABSORPTION OF SO2 BY THE ALKA-LINE RAW MATERIAL	3	3	406	LB/H (3 H ROLLING)		BACT-PSD	50	0			0			P	0	0	0
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	CONVEYOR FROM KILN #1 8000 ACFM BAGHOUSE	PM	PM	A	BAGHOUSE	0	0	0.01	GR/ACF		BACT-PSD	99.9	0.69	LB/H		0			P	0	0	0
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	CONVEYOR FROM KILN #1 8000 ACFM BAGHOUSE	VE	VE	N		0	0	10	% OPACITY		NSPS	0	0			0			P	0	0	0
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	ASSOCIATED WITH KILN #1 2000 ACFM BAGHOUSE	VE	VE	N		0	0	10	% OPACITY		NSPS	0	0			0			P	0	0	0
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	ASSOCIATED WITH KILN #1 2000 ACFM BAGHOUSE	PM	PM	A	BAGHOUSE	0	0	0.01	GR/ACF		BACT-PSD	99.9	0.17	LB/H		0			P	0	0	0
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	FINISH MILL	EXISTING GRINDING MILL USED IN OLD WET PROCESS SYSTEM WHICH WILL BE CONVERTED TO PROCESS CLINKER. 2000 ACFM BAGHOUSE	PM	PM	A	BAGHOUSE	0	0		0.01 GR/ACF		BACT-PSD	99.9	1.89 LB/H			0			P	0	0

RBLCID	FACILITY	COST EFFECT	COST VERIFY	DOLLAR YEAR	POLNOTES
UT-0059	ASH GROVE CEMENT COMPANY		N		
UT-0059	ASH GROVE CEMENT COMPANY		N		
UT-0059	ASH GROVE CEMENT COMPANY		N		
UT-0059	ASH GROVE CEMENT COMPANY		N		
UT-0059	ASH GROVE CEMENT COMPANY			N	
UT-0059	ASH GROVE CEMENT COMPANY		N		
UT-0059	ASH GROVE CEMENT COMPANY			N	
UT-0059	ASH GROVE CEMENT COMPANY			N	
UT-0059	ASH GROVE CEMENT COMPANY			N	
UT-0059	ASH GROVE CEMENT COMPANY	,	,	,	,
UT-0059	ASH GROVE CEMENT COMPANY	,	,	,	,
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT		N		
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT		N		NO EMISSION LIMITS FOR POLLUTANTS:METALS AND HALOGENS. LIMITS INSTEAD FOR USED FUEL OIL NOT TO EXCEED: 1)ARSENIC-5 PPM BY WT. 2)CADIUM-2 PPM BY WEIGHT 3)CHROMIUM-10 PPM BY WT. 4)LEAD-100 PPM BY WT. 5)TOTAL HALOGENS 1000 PPM BY WT. FLASH POINT NOT LESS THAN 100 F.
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT		N		permitted limit is lb/h. Clinker production rate can vary so long as lb/h emission rate is achieved.
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT		N		FUELS NOT TO EXCEED 1.0 POUND SULFuR PER MMBTU HEAT INPUT FOR COAL. 2) USED OIL NOT TO EXCEED .5 PERCENT BY WEIGHT.
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT		N		
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT		N		

RBLCID	FACILITY	COST EFFECT	COST VERIFY	DOLLAR YEAR	POLNOTES
UT-0062	HOLNAM, DEVIL'S SLIDE PLANT		N		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		N		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		N		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		N		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		N		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		N		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		N		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		N		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		N		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		N		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		N		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		N		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		N		
NV-0032	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.		N		
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		N		
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		N		
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		N		
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		N		
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		N		
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		N		
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		N		
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		N		
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		N		
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY		N		
WY-0044	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	0		N	

RBLCID	FACILITY	COMPANY	COUNTY	CONTACT	ADDRESS	CITY	STATE	ZIP	PHONE	EMAIL	REGION	AGENCY CODE	AGENCYNAME	AGENCYCONTACT	AGENCY PHONE	AGENCY EMAIL	PERMITNUM	SIC	NAICS	AIRSID	EPAID	UTMZONE	XCOORD	YCOORD	RCVD DATE	PERMIT DATE	STARTUP DATE	EMISLIMIT2 UNIT	STOTHER CONDITIONS	CAP COST	OM COST	COST EFFECT	COST VERIFY	DOLLAR YEAR
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000		T/YR					N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000		T/YR					N	
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RBLCID	FACILITY	COMPANY	COUNTY	CONTACT	ADDRESS	CITY	STATE	ZIP	PHONE	EMAIL	REGION	AGENCY CODE	AGENCYNAME	AGENCYCONTACT	AGENCY PHONE	AGENCY EMAIL	PERMITNUM	SIC	NAICS	AIRSID	EPAID	UTMZONE	XCOORD	YCOORD	RCVD DATE	PERMIT DATE	STARTUP DATE	EMISLIMIT2 UNIT	STOTHER CONDITIONS	CAP COST	OM COST	COST EFFECT	COST VERIFY	DOLLAR YEAR
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000							N	
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*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000		T/YR					N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000		T/YR					N	
*TX-0280	AGRIFIOS- OLIN FACILITY	AGRIFIOS FERTILIZER, L.P.	HARRIS	JOHN L. MURRAY, JR.	PO BOX 3447	PASADENA		77501	713-920-5362		6	TX001	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	JOHNNY VERMILLION	512-239-1292		PSD-TX-949	2874	325312						7/8/1999	4/27/2000		T/YR					N	
WY-0050	SF PHOSPHATES LIMITED CO - FERTILIZER COMPLEX	SF PHOSPHATES LIMITED CO - FERTILIZER COMPLEX	SWEETWATER		P.O. BOX 1789	ROCK SPRINGS		-82902			8	WY001	WYOMING AIR QUAL DIV, DEPT OF ENV QUAL	LEE GRIBOVICZ-DISTRICT 5 ENGIN	(307) 332-6755		MD-384	2874		3700022					4/28/1998	12/22/1998	1/31/2000			0	0		N	
WY-0050	SF PHOSPHATES LIMITED CO - FERTILIZER COMPLEX	SF PHOSPHATES LIMITED CO - FERTILIZER COMPLEX	SWEETWATER		P.O. BOX 1789	ROCK SPRINGS		-82902			8	WY001	WYOMING AIR QUAL DIV, DEPT OF ENV QUAL	LEE GRIBOVICZ-DISTRICT 5 ENGIN	(307) 332-6755		MD-384	2874		3700022					4/28/1998	12/22/1998	1/31/2000	LB/H (ANNUAL AVG)		0	0		N	

RBLCID	FACILITY	POLNOTES
*TX-0280	AGRIFIOS- OLIN FACILITY	
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*TX-0280	AGRIFIOS- OLIN FACILITY	
*TX-0280	AGRIFIOS- OLIN FACILITY	
*TX-0280	AGRIFIOS- OLIN FACILITY	THE EMISSIONS FROM THIS SOURCE ARE INCLUDED IN EPN F-9BFD007 (FERTILIZER STORAGE AND LOADING).
*TX-0280	AGRIFIOS- OLIN FACILITY	
*TX-0280	AGRIFIOS- OLIN FACILITY	
*TX-0280	AGRIFIOS- OLIN FACILITY	
*TX-0280	AGRIFIOS- OLIN FACILITY	
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WY-0050	SF PHOSPHATES LIMITED CO - FERTILIZER COMPLEX	
WY-0050	SF PHOSPHATES LIMITED CO - FERTILIZER COMPLEX	

RBLCID	FACILITY	COMPANY	COUNTY	CONTACT	ADDRESS	CITY	STATE	ZIP	PHONE	EMAIL	REGION	AGENCYCODE	AGENCYNAME	AGENCY CONTACT	AGENCYPHONE	AGENCYEMAIL	PERMITNUM	SIC	NAICS	AIRSID	EPAID	UTMZONE	XCOORD	YCOORD
AZ-0022	INTEL CORPORATION	INTEL CORPORATION			OLD PRICE RD ALIGNMENT	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		93-0046	3674	334413					
AZ-0022	INTEL CORPORATION	INTEL CORPORATION			OLD PRICE RD ALIGNMENT	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		93-0046	3674	334413					
AZ-0022	INTEL CORPORATION	INTEL CORPORATION			OLD PRICE RD ALIGNMENT	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		93-0046	3674	334413					
AZ-0022	INTEL CORPORATION	INTEL CORPORATION			OLD PRICE RD ALIGNMENT	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		93-0046	3674	334413					
AZ-0022	INTEL CORPORATION	INTEL CORPORATION			OLD PRICE RD ALIGNMENT	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		93-0046	3674	334413					
AZ-0028	SITIX OF PHOENIX, INC.	SITIX OF PHOENIX, INC.	MARICOPA		1901 N. TATUM BLVD	PHOENIX	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	HARRY H. CHIU	(602) 506-6736		950460	3674	334413					
AZ-0028	SITIX OF PHOENIX, INC.	SITIX OF PHOENIX, INC.	MARICOPA		1901 N. TATUM BLVD	PHOENIX	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	HARRY H. CHIU	(602) 506-6736		950460	3674	334413					
AZ-0028	SITIX OF PHOENIX, INC.	SITIX OF PHOENIX, INC.	MARICOPA		1901 N. TATUM BLVD	PHOENIX	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	HARRY H. CHIU	(602) 506-6736		950460	3674	334413					
AZ-0032	INTEL CORPORATION	INTEL CORPORATION			4500 S. DOBSON RD	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE LIEB	(602) 506-6738		96-0743	3674	334413					
AZ-0032	INTEL CORPORATION	INTEL CORPORATION			4500 S. DOBSON RD	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE LIEB	(602) 506-6738		96-0743	3674	334413					
AZ-0032	INTEL CORPORATION	INTEL CORPORATION			4500 S. DOBSON RD	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE LIEB	(602) 506-6738		96-0743	3674	334413					
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	RIO GRANDE PORTLAND CEMENT CORP.	PUEBLO	BRIAN MCGILL	APPROX 6 MI SSE OF PUEBLO	PUEBLO	CO		505-281-3311	BMCGILL@GCC.COM	8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	RAM N. SEETHARAM	303-692-3198		98PB0893	3241		1010252		13	534.5	4220.1
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	RIO GRANDE PORTLAND CEMENT CORP.	PUEBLO	BRIAN MCGILL	APPROX 6 MI SSE OF PUEBLO	PUEBLO	CO		505-281-3311	BMCGILL@GCC.COM	8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	RAM N. SEETHARAM	303-692-3198		98PB0893	3241		1010252		13	534.5	4220.1
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	RIO GRANDE PORTLAND CEMENT CORP.	PUEBLO	BRIAN MCGILL	APPROX 6 MI SSE OF PUEBLO	PUEBLO	CO		505-281-3311	BMCGILL@GCC.COM	8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	RAM N. SEETHARAM	303-692-3198		98PB0893	3241		1010252		13	534.5	4220.1
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	RIO GRANDE PORTLAND CEMENT CORP.	PUEBLO	BRIAN MCGILL	APPROX 6 MI SSE OF PUEBLO	PUEBLO	CO		505-281-3311	BMCGILL@GCC.COM	8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	RAM N. SEETHARAM	303-692-3198		98PB0893	3241		1010252		13	534.5	4220.1
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	RIO GRANDE PORTLAND CEMENT CORP.	PUEBLO	BRIAN MCGILL	APPROX 6 MI SSE OF PUEBLO	PUEBLO	CO		505-281-3311	BMCGILL@GCC.COM	8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	RAM N. SEETHARAM	303-692-3198		98PB0893	3241		1010252		13	534.5	4220.1
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	RIO GRANDE PORTLAND CEMENT CORP.	PUEBLO	BRIAN MCGILL	APPROX 6 MI SSE OF PUEBLO	PUEBLO	CO		505-281-3311	BMCGILL@GCC.COM	8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	RAM N. SEETHARAM	303-692-3198		98PB0893	3241		1010252		13	534.5	4220.1
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	RIO GRANDE PORTLAND CEMENT CORP.	PUEBLO	BRIAN MCGILL	APPROX 6 MI SSE OF PUEBLO	PUEBLO	CO		505-281-3311	BMCGILL@GCC.COM	8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	RAM N. SEETHARAM	303-692-3198		98PB0893	3241		1010252		13	534.5	4220.1
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	RIO GRANDE PORTLAND CEMENT CORP.	PUEBLO	BRIAN MCGILL	APPROX 6 MI SSE OF PUEBLO	PUEBLO	CO		505-281-3311	BMCGILL@GCC.COM	8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	RAM N. SEETHARAM	303-692-3198		98PB0893	3241		1010252		13	534.5	4220.1
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	RIO GRANDE PORTLAND CEMENT CORP.	PUEBLO	BRIAN MCGILL	APPROX 6 MI SSE OF PUEBLO	PUEBLO	CO		505-281-3311	BMCGILL@GCC.COM	8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	RAM N. SEETHARAM	303-692-3198		98PB0893	3241		1010252		13	534.5	4220.1
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6

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CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6

RBLCID	FACILITY	COMPANY	COUNTY	CONTACT	ADDRESS	CITY	STATE	ZIP	PHONE	EMAIL	REGION	AGENCYCODE	AGENCYNAME	AGENCY CONTACT	AGENCYPHONE	AGENCYEMAIL	PERMITNUM	SIC	NAICS	AIRSID	EPAID	UTMZONE	XCOORD	YCOORD
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6
CO-0047	HOLNAM, FLORENCE	HOLNAM, FLORENCE	FREMONT	BOB MCGILVRAY	3500 STATE HWY 120	FLORENCE	CO	81266	719-784-6325		8	CO001	COLORADO DEPT OF HEALTH - AIR POLL CTRL	DENNIS M. MYERS	(303) 692-3176		98-FR-0895	3241					498.5	4248.6

RBLCID	FACILITY	RCVDDATE	PERMITDATE	STARTUPDATE	VERIFYDATE	ENTRYDATE	LASTUPDATE	NEW_MOD	PUBLICHEAR	FUEL	EMISSSOURCES	ABATEMENT	NARRATIVE
AZ-0022	INTEL CORPORATION		4/10/1994	4/1/1995		5/16/1994	12/18/2001						
AZ-0022	INTEL CORPORATION		4/10/1994	4/1/1995		5/16/1994	12/18/2001						
AZ-0022	INTEL CORPORATION		4/10/1994	4/1/1995		5/16/1994	12/18/2001						
AZ-0022	INTEL CORPORATION		4/10/1994	4/1/1995		5/16/1994	12/18/2001						
AZ-0022	INTEL CORPORATION		4/10/1994	4/1/1995		5/16/1994	12/18/2001						
AZ-0028	SITIX OF PHOENIX, INC.		2/1/1996	1/1/1996		2/26/1996	12/18/2001						
AZ-0028	SITIX OF PHOENIX, INC.		2/1/1996	1/1/1996		2/26/1996	12/18/2001						
AZ-0028	SITIX OF PHOENIX, INC.		2/1/1996	1/1/1996		2/26/1996	12/18/2001						
AZ-0032	INTEL CORPORATION		9/1/1996			10/21/1996	12/18/2001						
AZ-0032	INTEL CORPORATION		9/1/1996			10/21/1996	12/18/2001						
AZ-0032	INTEL CORPORATION		9/1/1996			10/21/1996	12/18/2001						
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	12/30/1998	9/25/2000	3/1/2003	9/1/2003	11/9/2000	3/2/2004	N		PRIMARILY COAL, NATURAL GAS USED OCCASIONALLY.	5-STAGE PREHEATER/PRECALCINER/KILN, CLINKER COOLER, CEMENT MILL, RAW MATERIALS QUARRIES, MATERIAL HANDLING	HIGH TEMPERATURE FABRIC FILTER FOR KILN & CLINKER COOLER GASES, LOW TEMPERATURE MEMBRANE FILTERS FOR ALL OTHER PARTICULATE EMISSION, MULTI- STAGE COMBUSTION AND GOOD COMBUSTION MANAGEMENT PRACTICES, COUNTER-CURRENT DRY SCRUBBING (ABSORPTION) FOR SO2, VARIOUS FUGITIVE DUST CONTROLS	MANUFACTURE OF PORTLAND CEMENT (DRY PROCESS)
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	12/30/1998	9/25/2000	3/1/2003	9/1/2003	11/9/2000	3/2/2004	N		PRIMARILY COAL, NATURAL GAS USED OCCASIONALLY.	5-STAGE PREHEATER/PRECALCINER/KILN, CLINKER COOLER, CEMENT MILL, RAW MATERIALS QUARRIES, MATERIAL HANDLING	HIGH TEMPERATURE FABRIC FILTER FOR KILN & CLINKER COOLER GASES, LOW TEMPERATURE MEMBRANE FILTERS FOR ALL OTHER PARTICULATE EMISSION, MULTI- STAGE COMBUSTION AND GOOD COMBUSTION MANAGEMENT PRACTICES, COUNTER-CURRENT DRY SCRUBBING (ABSORPTION) FOR SO2, VARIOUS FUGITIVE DUST CONTROLS	MANUFACTURE OF PORTLAND CEMENT (DRY PROCESS)
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	12/30/1998	9/25/2000	3/1/2003	9/1/2003	11/9/2000	3/2/2004	N		PRIMARILY COAL, NATURAL GAS USED OCCASIONALLY.	5-STAGE PREHEATER/PRECALCINER/KILN, CLINKER COOLER, CEMENT MILL, RAW MATERIALS QUARRIES, MATERIAL HANDLING	HIGH TEMPERATURE FABRIC FILTER FOR KILN & CLINKER COOLER GASES, LOW TEMPERATURE MEMBRANE FILTERS FOR ALL OTHER PARTICULATE EMISSION, MULTI- STAGE COMBUSTION AND GOOD COMBUSTION MANAGEMENT PRACTICES, COUNTER-CURRENT DRY SCRUBBING (ABSORPTION) FOR SO2, VARIOUS FUGITIVE DUST CONTROLS	MANUFACTURE OF PORTLAND CEMENT (DRY PROCESS)
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	12/30/1998	9/25/2000	3/1/2003	9/1/2003	11/9/2000	3/2/2004	N		PRIMARILY COAL, NATURAL GAS USED OCCASIONALLY.	5-STAGE PREHEATER/PRECALCINER/KILN, CLINKER COOLER, CEMENT MILL, RAW MATERIALS QUARRIES, MATERIAL HANDLING	HIGH TEMPERATURE FABRIC FILTER FOR KILN & CLINKER COOLER GASES, LOW TEMPERATURE MEMBRANE FILTERS FOR ALL OTHER PARTICULATE EMISSION, MULTI- STAGE COMBUSTION AND GOOD COMBUSTION MANAGEMENT PRACTICES, COUNTER-CURRENT DRY SCRUBBING (ABSORPTION) FOR SO2, VARIOUS FUGITIVE DUST CONTROLS	MANUFACTURE OF PORTLAND CEMENT (DRY PROCESS)
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	12/30/1998	9/25/2000	3/1/2003	9/1/2003	11/9/2000	3/2/2004	N		PRIMARILY COAL, NATURAL GAS USED OCCASIONALLY.	5-STAGE PREHEATER/PRECALCINER/KILN, CLINKER COOLER, CEMENT MILL, RAW MATERIALS QUARRIES, MATERIAL HANDLING	HIGH TEMPERATURE FABRIC FILTER FOR KILN & CLINKER COOLER GASES, LOW TEMPERATURE MEMBRANE FILTERS FOR ALL OTHER PARTICULATE EMISSION, MULTI- STAGE COMBUSTION AND GOOD COMBUSTION MANAGEMENT PRACTICES, COUNTER-CURRENT DRY SCRUBBING (ABSORPTION) FOR SO2, VARIOUS FUGITIVE DUST CONTROLS	MANUFACTURE OF PORTLAND CEMENT (DRY PROCESS)
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	12/30/1998	9/25/2000	3/1/2003	9/1/2003	11/9/2000	3/2/2004	N		PRIMARILY COAL, NATURAL GAS USED OCCASIONALLY.	5-STAGE PREHEATER/PRECALCINER/KILN, CLINKER COOLER, CEMENT MILL, RAW MATERIALS QUARRIES, MATERIAL HANDLING	HIGH TEMPERATURE FABRIC FILTER FOR KILN & CLINKER COOLER GASES, LOW TEMPERATURE MEMBRANE FILTERS FOR ALL OTHER PARTICULATE EMISSION, MULTI- STAGE COMBUSTION AND GOOD COMBUSTION MANAGEMENT PRACTICES, COUNTER-CURRENT DRY SCRUBBING (ABSORPTION) FOR SO2, VARIOUS FUGITIVE DUST CONTROLS	MANUFACTURE OF PORTLAND CEMENT (DRY PROCESS)
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	12/30/1998	9/25/2000	3/1/2003	9/1/2003	11/9/2000	3/2/2004	N		PRIMARILY COAL, NATURAL GAS USED OCCASIONALLY.	5-STAGE PREHEATER/PRECALCINER/KILN, CLINKER COOLER, CEMENT MILL, RAW MATERIALS QUARRIES, MATERIAL HANDLING	HIGH TEMPERATURE FABRIC FILTER FOR KILN & CLINKER COOLER GASES, LOW TEMPERATURE MEMBRANE FILTERS FOR ALL OTHER PARTICULATE EMISSION, MULTI- STAGE COMBUSTION AND GOOD COMBUSTION MANAGEMENT PRACTICES, COUNTER-CURRENT DRY SCRUBBING (ABSORPTION) FOR SO2, VARIOUS FUGITIVE DUST CONTROLS	MANUFACTURE OF PORTLAND CEMENT (DRY PROCESS)
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	12/30/1998	9/25/2000	3/1/2003	9/1/2003	11/9/2000	3/2/2004	N		PRIMARILY COAL, NATURAL GAS USED OCCASIONALLY.	5-STAGE PREHEATER/PRECALCINER/KILN, CLINKER COOLER, CEMENT MILL, RAW MATERIALS QUARRIES, MATERIAL HANDLING	HIGH TEMPERATURE FABRIC FILTER FOR KILN & CLINKER COOLER GASES, LOW TEMPERATURE MEMBRANE FILTERS FOR ALL OTHER PARTICULATE EMISSION, MULTI- STAGE COMBUSTION AND GOOD COMBUSTION MANAGEMENT PRACTICES, COUNTER-CURRENT DRY SCRUBBING (ABSORPTION) FOR SO2, VARIOUS FUGITIVE DUST CONTROLS	MANUFACTURE OF PORTLAND CEMENT (DRY PROCESS)
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	12/30/1998	9/25/2000	3/1/2003	9/1/2003	11/9/2000	3/2/2004	N		PRIMARILY COAL, NATURAL GAS USED OCCASIONALLY.	5-STAGE PREHEATER/PRECALCINER/KILN, CLINKER COOLER, CEMENT MILL, RAW MATERIALS QUARRIES, MATERIAL HANDLING	HIGH TEMPERATURE FABRIC FILTER FOR KILN & CLINKER COOLER GASES, LOW TEMPERATURE MEMBRANE FILTERS FOR ALL OTHER PARTICULATE EMISSION, MULTI- STAGE COMBUSTION AND GOOD COMBUSTION MANAGEMENT PRACTICES, COUNTER-CURRENT DRY SCRUBBING (ABSORPTION) FOR SO2, VARIOUS FUGITIVE DUST CONTROLS	MANUFACTURE OF PORTLAND CEMENT (DRY PROCESS)
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.

RBLCID	FACILITY	RCVDDATE	PERMITDATE	STARTUPDATE	VERIFYDATE	ENTRYDATE	LASTUPDATE	NEW_MOD	PUBLICHEAR	FUEL	EMISSSOURCES	ABATEMENT	NARRATIVE
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.

RBLCID	FACILITY	RCVDDATE	PERMITDATE	STARTUPDATE	VERIFYDATE	ENTRYDATE	LASTUPDATE	NEW_MOD	PUBLICHEAR	FUEL	EMISSSOURCES	ABATEMENT	NARRATIVE
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.
CO-0047	HOLNAM, FLORENCE		7/29/1999	5/30/2002		10/19/2001	3/2/2004	M		COAL, TIRE DERIVED FUEL	KILN WITH 5-STAGE PREHEATER/CALCINER, QUARRIES, RAW MATERIAL PROCESSING		PORTLAND CEMENT PLANT - MOD CHANGES WET PROCESS TO DRY PROCESS.

RBLCID	FACILITY	NOTES	PROCESS	PROCTYPE	SCC	FUEL	THRUPUT	THRUPUTUNIT	COMPVERIFY	STACKTEST	INSPECTION	CALCULATED	OTHERTEST	OTHERMETHD	PRNOTES
AZ-0022	INTEL CORPORATION		BOILERS, 5	13.31	10200602	NATURAL GAS	50	MMBTU/HR	F	F	F	F	F		
AZ-0022	INTEL CORPORATION		BOILERS, 5	13.31	10200602	NATURAL GAS	50	MMBTU/HR	F	F	F	F	F		
AZ-0022	INTEL CORPORATION		PHOTORESIST OPERATIONS	99.011	40100399		0		F	F	F	F	F		
AZ-0022	INTEL CORPORATION		GENERATORS, BACKUP, 5	17.13	20200202	NATURAL GAS	2220	BHP	F	F	F	F	F		
AZ-0022	INTEL CORPORATION		GENERATORS, BACKUP, 5	17.13	20200202	NATURAL GAS	2220	BHP	F	F	F	F	F		
AZ-0028	SITIX OF PHOENIX, INC.		WAFER CLEANING	99.011	3-13-999-9		131	TPY	F	F	F	F	F		
AZ-0028	SITIX OF PHOENIX, INC.		WAFER POLISHING	99.011	3-13-999-9		240000	WAFERS/MO	F	F	F	F	F		
AZ-0028	SITIX OF PHOENIX, INC.		BOILER, GAS-FIRED	13.31	1-02-006-02	NATURAL GAS	42	MMBTU/HR	F	F	F	F	F		
AZ-0032	INTEL CORPORATION	PROJECT XL PERMIT	SEMICONDUCTOR MANUFACTURING	99.011	3-13-999-99		0		F	F	F	F	F		
AZ-0032	INTEL CORPORATION	PROJECT XL PERMIT	BOILERS, GENERATORS	16.11	1-02-005-02		0		F	F	F	F	F		
AZ-0032	INTEL CORPORATION	PROJECT XL PERMIT	BOILERS (10)	13.31	1-02-005-02		54	MMBTU	F	F	F	F	F		
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	CLINKER PRODUCTION: 950,000 T/YR; FINISHED CEMENT: 1,000,000 T/YR; COAL CONSUMED: 122,500 T/YR. RAW MATERIALS QUARRIES ADJACENT TO PLANT, CONTINUOUS EMISSION MONITOR FOR SO2, CO, NOX, CONTINUOUS OPACITY MONITORS, CEMENT KILN SUBJECT TO MACT. PLANTWIDE EMISSIONS (IN T/YR) INCLUDE: FILTERABLE PM = 155.4, PM10 FILT = 148, PM(ALL PM10) = 49.7, PM FUGITIVE = 42.7, PM10 FUGITIVE = 17.8, AND PB = 0.038. DIVISION DID NOT DETERMINE BACT EMISSION LIMIT BASED ON STANDARD UNITS. LIMITS IN STANDARD UNITS HAVE BEEN CALCULATED USING THROUGHPUT AND LB/H LIMITS.	RAW MATERIAL TRANSFER, ROAD DUST	99.19	2294015002		950000	T/YR	N	N	N	N	N		THROUGHPUT IS CEMENT CLINKER.
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	CLINKER PRODUCTION: 950,000 T/YR; FINISHED CEMENT: 1,000,000 T/YR; COAL CONSUMED: 122,500 T/YR. RAW MATERIALS QUARRIES ADJACENT TO PLANT, CONTINUOUS EMISSION MONITOR FOR SO2, CO, NOX, CONTINUOUS OPACITY MONITORS, CEMENT KILN SUBJECT TO MACT. PLANTWIDE EMISSIONS (IN T/YR) INCLUDE: FILTERABLE PM = 155.4, PM10 FILT = 148, PM(ALL PM10) = 49.7, PM FUGITIVE = 42.7, PM10 FUGITIVE = 17.8, AND PB = 0.038. DIVISION DID NOT DETERMINE BACT EMISSION LIMIT BASED ON STANDARD UNITS. LIMITS IN STANDARD UNITS HAVE BEEN CALCULATED USING THROUGHPUT AND LB/H LIMITS.	KILN, CLINKER COOLER	90.028	30500614		950000	T/YR	N	N	N	N	N		THROUGHPUT IS CEMENT CLINKER. ADDITIONAL SCC: 30500606, KILN.
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	CLINKER PRODUCTION: 950,000 T/YR; FINISHED CEMENT: 1,000,000 T/YR; COAL CONSUMED: 122,500 T/YR. RAW MATERIALS QUARRIES ADJACENT TO PLANT, CONTINUOUS EMISSION MONITOR FOR SO2, CO, NOX, CONTINUOUS OPACITY MONITORS, CEMENT KILN SUBJECT TO MACT. PLANTWIDE EMISSIONS (IN T/YR) INCLUDE: FILTERABLE PM = 155.4, PM10 FILT = 148, PM(ALL PM10) = 49.7, PM FUGITIVE = 42.7, PM10 FUGITIVE = 17.8, AND PB = 0.038. DIVISION DID NOT DETERMINE BACT EMISSION LIMIT BASED ON STANDARD UNITS. LIMITS IN STANDARD UNITS HAVE BEEN CALCULATED USING THROUGHPUT AND LB/H LIMITS.	MATERIAL MILLING	90.028	30500627		1000000	T/YR	N	N	N	N	N		FINISH MILLING OF CLINKER AND ADDITIVES TO PRODUCE PORTLAND CEMENT. PARTICULATE ROUTED THROUGH LOW TEMPERATURE BAGHOUSE. ADDITIONAL SCC NUMBERS: 30500628 AND 30500629.
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	CLINKER PRODUCTION: 950,000 T/YR; FINISHED CEMENT: 1,000,000 T/YR; COAL CONSUMED: 122,500 T/YR. RAW MATERIALS QUARRIES ADJACENT TO PLANT, CONTINUOUS EMISSION MONITOR FOR SO2, CO, NOX, CONTINUOUS OPACITY MONITORS, CEMENT KILN SUBJECT TO MACT. PLANTWIDE EMISSIONS (IN T/YR) INCLUDE: FILTERABLE PM = 155.4, PM10 FILT = 148, PM(ALL PM10) = 49.7, PM FUGITIVE = 42.7, PM10 FUGITIVE = 17.8, AND PB = 0.038. DIVISION DID NOT DETERMINE BACT EMISSION LIMIT BASED ON STANDARD UNITS. LIMITS IN STANDARD UNITS HAVE BEEN CALCULATED USING THROUGHPUT AND LB/H LIMITS.	MATERIAL HANDLING	90.028	30500616		950000	T/YR	N	N	N	N	N		MATERIAL HANDLING PARTICULATE, ROUTED THROUGH LOW TEMPERATURE BAGHOUSE
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	CLINKER PRODUCTION: 950,000 T/YR; FINISHED CEMENT: 1,000,000 T/YR; COAL CONSUMED: 122,500 T/YR. RAW MATERIALS QUARRIES ADJACENT TO PLANT, CONTINUOUS EMISSION MONITOR FOR SO2, CO, NOX, CONTINUOUS OPACITY MONITORS, CEMENT KILN SUBJECT TO MACT. PLANTWIDE EMISSIONS (IN T/YR) INCLUDE: FILTERABLE PM = 155.4, PM10 FILT = 148, PM(ALL PM10) = 49.7, PM FUGITIVE = 42.7, PM10 FUGITIVE = 17.8, AND PB = 0.038. DIVISION DID NOT DETERMINE BACT EMISSION LIMIT BASED ON STANDARD UNITS. LIMITS IN STANDARD UNITS HAVE BEEN CALCULATED USING THROUGHPUT AND LB/H LIMITS.	PREHEATER/PRECALCINER, KILN	90.028	30500606		950000	T/YR	N	N	N	N	N		THROUGHPUT IS CEMENT CLINKER. PYROPROCESSING OF CRUDE IN A 5-STAGE PREHEATER/PRECALCINER AND CLINKERING ROTORY KILN TO PRODUCE CEMENT CLINKER. PM10 EMISSIONS ROUTED THROUGH THE KILN & CLINKER BAGHOUSE - THIS IS ENTERED AS A SEPARATE PROCESS IN THIS DETERMINATION. BACT DETERMINATIONS FOR CO, NOX, PM, PM10 AND SOX.
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	CLINKER PRODUCTION: 950,000 T/YR; FINISHED CEMENT: 1,000,000 T/YR; COAL CONSUMED: 122,500 T/YR. RAW MATERIALS QUARRIES ADJACENT TO PLANT, CONTINUOUS EMISSION MONITOR FOR SO2, CO, NOX, CONTINUOUS OPACITY MONITORS, CEMENT KILN SUBJECT TO MACT. PLANTWIDE EMISSIONS (IN T/YR) INCLUDE: FILTERABLE PM = 155.4, PM10 FILT = 148, PM(ALL PM10) = 49.7, PM FUGITIVE = 42.7, PM10 FUGITIVE = 17.8, AND PB = 0.038. DIVISION DID NOT DETERMINE BACT EMISSION LIMIT BASED ON STANDARD UNITS. LIMITS IN STANDARD UNITS HAVE BEEN CALCULATED USING THROUGHPUT AND LB/H LIMITS.	PREHEATER/PRECALCINER, KILN	90.028	30500606		950000	T/YR	N	N	N	N	N		THROUGHPUT IS CEMENT CLINKER. PYROPROCESSING OF CRUDE IN A 5-STAGE PREHEATER/PRECALCINER AND CLINKERING ROTORY KILN TO PRODUCE CEMENT CLINKER. PM10 EMISSIONS ROUTED THROUGH THE KILN & CLINKER BAGHOUSE - THIS IS ENTERED AS A SEPARATE PROCESS IN THIS DETERMINATION. BACT DETERMINATIONS FOR CO, NOX, PM, PM10 AND SOX.
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	CLINKER PRODUCTION: 950,000 T/YR; FINISHED CEMENT: 1,000,000 T/YR; COAL CONSUMED: 122,500 T/YR. RAW MATERIALS QUARRIES ADJACENT TO PLANT, CONTINUOUS EMISSION MONITOR FOR SO2, CO, NOX, CONTINUOUS OPACITY MONITORS, CEMENT KILN SUBJECT TO MACT. PLANTWIDE EMISSIONS (IN T/YR) INCLUDE: FILTERABLE PM = 155.4, PM10 FILT = 148, PM(ALL PM10) = 49.7, PM FUGITIVE = 42.7, PM10 FUGITIVE = 17.8, AND PB = 0.038. DIVISION DID NOT DETERMINE BACT EMISSION LIMIT BASED ON STANDARD UNITS. LIMITS IN STANDARD UNITS HAVE BEEN CALCULATED USING THROUGHPUT AND LB/H LIMITS.	PREHEATER/PRECALCINER, KILN	90.028	30500606		950000	T/YR	N	N	N	N	N		THROUGHPUT IS CEMENT CLINKER. PYROPROCESSING OF CRUDE IN A 5-STAGE PREHEATER/PRECALCINER AND CLINKERING ROTORY KILN TO PRODUCE CEMENT CLINKER. PM10 EMISSIONS ROUTED THROUGH THE KILN & CLINKER BAGHOUSE - THIS IS ENTERED AS A SEPARATE PROCESS IN THIS DETERMINATION. BACT DETERMINATIONS FOR CO, NOX, PM, PM10 AND SOX.
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	CLINKER PRODUCTION: 950,000 T/YR; FINISHED CEMENT: 1,000,000 T/YR; COAL CONSUMED: 122,500 T/YR. RAW MATERIALS QUARRIES ADJACENT TO PLANT, CONTINUOUS EMISSION MONITOR FOR SO2, CO, NOX, CONTINUOUS OPACITY MONITORS, CEMENT KILN SUBJECT TO MACT. PLANTWIDE EMISSIONS (IN T/YR) INCLUDE: FILTERABLE PM = 155.4, PM10 FILT = 148, PM(ALL PM10) = 49.7, PM FUGITIVE = 42.7, PM10 FUGITIVE = 17.8, AND PB = 0.038. DIVISION DID NOT DETERMINE BACT EMISSION LIMIT BASED ON STANDARD UNITS. LIMITS IN STANDARD UNITS HAVE BEEN CALCULATED USING THROUGHPUT AND LB/H LIMITS.	PREHEATER/PRECALCINER, KILN	90.028	30500606		950000	T/YR	N	N	N	N	N		THROUGHPUT IS CEMENT CLINKER. PYROPROCESSING OF CRUDE IN A 5-STAGE PREHEATER/PRECALCINER AND CLINKERING ROTORY KILN TO PRODUCE CEMENT CLINKER. PM10 EMISSIONS ROUTED THROUGH THE KILN & CLINKER BAGHOUSE - THIS IS ENTERED AS A SEPARATE PROCESS IN THIS DETERMINATION. BACT DETERMINATIONS FOR CO, NOX, PM, PM10 AND SOX.
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	CLINKER PRODUCTION: 950,000 T/YR; FINISHED CEMENT: 1,000,000 T/YR; COAL CONSUMED: 122,500 T/YR. RAW MATERIALS QUARRIES ADJACENT TO PLANT, CONTINUOUS EMISSION MONITOR FOR SO2, CO, NOX, CONTINUOUS OPACITY MONITORS, CEMENT KILN SUBJECT TO MACT. PLANTWIDE EMISSIONS (IN T/YR) INCLUDE: FILTERABLE PM = 155.4, PM10 FILT = 148, PM(ALL PM10) = 49.7, PM FUGITIVE = 42.7, PM10 FUGITIVE = 17.8, AND PB = 0.038. DIVISION DID NOT DETERMINE BACT EMISSION LIMIT BASED ON STANDARD UNITS. LIMITS IN STANDARD UNITS HAVE BEEN CALCULATED USING THROUGHPUT AND LB/H LIMITS.	PREHEATER/PRECALCINER, KILN	90.028	30500606		950000	T/YR	N	N	N	N	N		THROUGHPUT IS CEMENT CLINKER. PYROPROCESSING OF CRUDE IN A 5-STAGE PREHEATER/PRECALCINER AND CLINKERING ROTORY KILN TO PRODUCE CEMENT CLINKER. PM10 EMISSIONS ROUTED THROUGH THE KILN & CLINKER BAGHOUSE - THIS IS ENTERED AS A SEPARATE PROCESS IN THIS DETERMINATION. BACT DETERMINATIONS FOR CO, NOX, PM, PM10 AND SOX.
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	FINISH MILL SYSTEM	90.028	30500628				N	N	N	N	N		MILL #1 - AIRS ID 115 A. MILL #2 - AIRS ID 115 B. MILL #3 - AIRS ID 115 C: TO BE CONSTRUCTED
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	FINISH MILL SYSTEM	90.028	30500628				N	N	N	N	N		MILL #1 - AIRS ID 115 A. MILL #2 - AIRS ID 115 B. MILL #3 - AIRS ID 115 C: TO BE CONSTRUCTED
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	TRANSFER, CEMENT TO CEMENT SILOS	90.028	30500618				N	N	N	N	N		AIRS ID 116
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	TRANSFER, CEMENT TO CEMENT SILOS	90.028	30500618				N	N	N	N	N		AIRS ID 116
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	MATERIAL HANDLING, CEMENT PACKHOUSE	90.028	30500619				N	N	N	N	N		AIRS ID 117
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	MATERIAL HANDLING, CEMENT PACKHOUSE	90.028	30500619				N	N	N	N	N		AIRS ID 117

RBLCID	FACILITY	NOTES	PROCESS	PROCTYPE	SCC	FUEL	THRUPUT	THRUPUTUNIT	COMPVERIFY	STACKTEST	INSPECTION	CALCULATED	OTHERTEST	OTHERMETHD	PRNOTES
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	MATERIAL HANDLING, CEMENT BULK LOADOUTS	90.028	30500619				N	N	N	N	N		AIRS ID 118
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	MATERIAL HANDLING, CEMENT BULK LOADOUTS	90.028	30500619				N	N	N	N	N		AIRS ID 118
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	PAVED ROADS, CEMENT PRODUCT HAULOUT	99.14	2294015000				N	N	N	N	N		AIRS ID 119
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	PAVED ROADS, CEMENT PRODUCT HAULOUT	99.14	2294015000				N	N	N	N	N		AIRS ID 119
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	DRILLING AND BLASTING	90.023					N	N	N	N	N		AIRS ID 101B
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	DRILLING AND BLASTING	90.023					N	N	N	N	N		AIRS ID 101B
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	DRILLING AND BLASTING	90.023					N	N	N	N	N		AIRS ID 101B
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	DRILLING AND BLASTING	90.023					N	N	N	N	N		AIRS ID 101B
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	UNLOADING, TRANSFER, CONVEYING RAW MAT. & ADD.	90.028	30500607				N	N	N	N	N		UNLOADING, TRANSFER, CONVEYING RAW MATERIALS & ADDITIVES TO TRANSFER TOWER. AIRS ID 104
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	UNLOADING, TRANSFER, CONVEYING RAW MAT. & ADD.	90.028	30500607				N	N	N	N	N		UNLOADING, TRANSFER, CONVEYING RAW MATERIALS & ADDITIVES TO TRANSFER TOWER. AIRS ID 104
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	PRE-BLENDING	90.028	30500612				N	N	N	N	N		STACKER BELT, RECLAIMER, CONVEYORS, ALL ENCLOSED TO BE CONSTRUCTED AIRS ID 102 K
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	PRE-BLENDING	90.028	30500612				N	N	N	N	N		STACKER BELT, RECLAIMER, CONVEYORS, ALL ENCLOSED TO BE CONSTRUCTED AIRS ID 102 K
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	RAW MATERIALS CONVEYING, RAW MILL FEED BINS	90.028	30500612				N	N	N	N	N		RAW MATERIALS CONVEYING - RAW MILL FEED BINS TO TRANSFER TOWER. TRANSFER ACROSS THE RIVER. AIRS ID 102 L.
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	RAW MATERIALS CONVEYING, RAW MILL FEED BINS	90.028	30500612				N	N	N	N	N		RAW MATERIALS CONVEYING - RAW MILL FEED BINS TO TRANSFER TOWER. TRANSFER ACROSS THE RIVER. AIRS ID 102 L.
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	UNLOADING & CONVEYING, COAL TO STOCKPILE	90.011	30510103				N	N	N	N	N		AIRS ID 103 A. PM EMISSIONS NOT SUBJECT TO BACT ANALYSIS, STANDARD EMISSON UNITS NOT AVAILABLE.
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	UNLOADING & CONVEYING, COAL TO STOCKPILE	90.011	30510103				N	N	N	N	N		AIRS ID 103 A. PM EMISSIONS NOT SUBJECT TO BACT ANALYSIS, STANDARD EMISSON UNITS NOT AVAILABLE.
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	COAL STOCKPILE	90.011	30510303				N	N	N	N	N		
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	COAL STOCKPILE	90.011	30510303				N	N	N	N	N		
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	RECLAIMING, CONVEYING, & TRANS COAL TO COAL SCREEN	90.011	30510103				N	N	N	N	N		AIRS ID 103 C. PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	RECLAIMING, CONVEYING, & TRANS COAL TO COAL SCREEN	90.011	30510103				N	N	N	N	N		AIRS ID 103 C. PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.

RBLCID	FACILITY	NOTES	PROCESS	PROCTYPE	SCC	FUEL	THRUPUT	THRUPUTUNIT	COMPVERIFY	STACKTEST	INSPECTION	CALCULATED	OTHERTEST	OTHERMETHD	PRNOTES
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	SCREENING AND CRUSHING OVERSIZE COAL	90.011	30501017				N	N	N	N	N		PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	SCREENING AND CRUSHING OVERSIZE COAL	90.011	30501017				N	N	N	N	N		PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	TRANS & CONVEYING - CRUSHED COAL TO TRANSFER TOWER	90.011	30510103				N	N	N	N	N		AIRS ID 103 E. PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	TRANS & CONVEYING - CRUSHED COAL TO TRANSFER TOWER	90.011	30510103				N	N	N	N	N		AIRS ID 103 E. PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	TRANSFER, COAL, TRANSFER TOWER TO SILO	90.011	30510103				N	N	N	N	N		AIRS ID 105. PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	TRANSFER, COAL, TRANSFER TOWER TO SILO	90.011	30510103				N	N	N	N	N		AIRS ID 105. PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	RAW MATERIALS EXTRACTION	90.023	305040				N	N	N	N	N		AIRS ID 101 (A)
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	RAW MATERIALS EXTRACTION	90.023	305040				N	N	N	N	N		AIRS ID 101 (A)
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	OVERBURDEN AND WASTE ROCK REMOVAL	90.023	30504024				N	N	N	N	N		AIRS ID 101C
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	OVERBURDEN AND WASTE ROCK REMOVAL	90.023	30504024				N	N	N	N	N		AIRS ID 101C
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	RAW MATERIAL, REMOVAL AND HAULAGE	90.023	305040				N	N	N	N	N		AIRS ID 101D
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	RAW MATERIAL, REMOVAL AND HAULAGE	90.023	305040				N	N	N	N	N		AIRS ID 101D
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	CEMENT KILN DUST HAULING	90.028	30500699				N	N	N	N	N		AIRS ID 101E
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	CEMENT KILN DUST HAULING	90.028	30500699				N	N	N	N	N		AIRS ID 101E
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	DISTURBED AREAS IN QUARRY AND PLANT	90.999	30500699				N	N	N	N	N		MINIMIZATION OF AREAS EXPOSED TO EROSION. AIRS ID 101 F
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	DISTURBED AREAS IN QUARRY AND PLANT	90.999	30500699				N	N	N	N	N		MINIMIZATION OF AREAS EXPOSED TO EROSION. AIRS ID 101 F
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	MATERIAL TRANSFER, HAUL TRUCKS TO PRI CRUSH FEED	90.028	30500607				N	N	N	N	N		TRANSFER FROM HAUL TRUCK TO PRIMARY CRUSHER FEED HOPPER. (2)TO BE CONSTRUCTED. AIRS ID 102
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	MATERIAL TRANSFER, HAUL TRUCKS TO PRI CRUSH FEED	90.028	30500607				N	N	N	N	N		TRANSFER FROM HAUL TRUCK TO PRIMARY CRUSHER FEED HOPPER. (2)TO BE CONSTRUCTED. AIRS ID 102
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	ROCK CRUSHER	90.028	30500609				N	N	N	N	N		AIRS ID 102 C
CO-0047	HOLNAM, FLORENCE	CLASS 1 AREA AFFECTED: GREAT SAND DUNES - 45 MILES. ONLY DRAFT CONSTRUCTION PERMIT AND PSD PERMIT APPLICATION WAS AVAILABLE FOR ENTRY IN RBLC. MODIFICATION PROPOSES TO REPLACE ALL WET PROCESS KILNS WITH ONE DRY PROCESS CEMENT KILN WITH A 5-STAGE PREHEATER/PRECALCINER. MODIFICATION RESULTED IN REDUCTION OF SO2, NOX AND PM. BACT FOR CO ONLY. COLORADO AIR QUALITY COMMISSION REG. #6 REQUIRES BEST PRACTICAL CONTROL TECHNOLOGY FOR SO2 CONTROL. ESTIMATED START UP DATE HAS BEEN FURTHER DELAYED. NO COMPLIANCE DATE SET.	ROCK CRUSHER	90.028	30500609				N	N	N	N	N		AIRS ID 102 C

RBLCID	FACILITY	POLLUTANT	CAS	CONTROLCOD	CTRLDESC	RANKOPTS	,	RANKSEL	EMISLIMIT1	EMISLIMIT1UNIT	EMISLIMIT1CONDITION	BASIS	PCTEFFIC	EMISLIMIT2	EMISLIMIT2UNIT	EMISLIMIT2CONDITION	STDEMISS	STDUNIT	STOTHERCONDITIONS	EMISSTYPE	CAPCOST	ANNUALCOST
AZ-0022	INTEL CORPORATION	NOX	10102	P	LOW NOX BURNERS	0	,	0	0			BACT	0	0			0			P	0	0
AZ-0022	INTEL CORPORATION	SOX/PM10	7446	P	FUEL SPEC: NATURAL GAS PRIMARY, .055 WT % S FUEL OIL BACKUP ONLY	0	,	0	0			BACT	0	0			0			P	0	0
AZ-0022	INTEL CORPORATION	VOC	VOC	A	AFTERBURNERS	0	,	0	0			BACT	90	0			0			P	0	0
AZ-0022	INTEL CORPORATION	NOX/PM10	10102	A	CYANURIC ACID INJECTION TAILPIPE CONTROL	0	,	0	0			BACT	80	0			0			P	0	0
AZ-0022	INTEL CORPORATION	SOX	7446	P	FUEL SPEC: .055 WT % S FUEL OIL	0	,	0	0			BACT	0	0			0			P	0	0
AZ-0028	SITIX OF PHOENIX, INC.	VOC	VOC	A	THERMAL OXIDIZER	0	,	0	49	TPY		BACT-PSD	90	0			0			P	0	0
AZ-0028	SITIX OF PHOENIX, INC.	PM10	PM	A	FILTERS	0	,	0	35	TPY		BACT-PSD	95	0			0			P	0	0
AZ-0028	SITIX OF PHOENIX, INC.	NOX	10102	A	FLUE GAS RECIRCULATION (FGR) NOX NOT TO EXCEED 30 PPM	0	,	0	49	TPY		BACT-PSD	0	0			0			P	0	0
AZ-0032	INTEL CORPORATION	VOC	VOC	A	CARBON ADSORPTION KREHA CONTINUOUSLY DESORBED WITH CHILLER	0	,	0	40	TPY		BACT-OTHER	90	0			0			P	0	0
AZ-0032	INTEL CORPORATION	SOX	7446	P	FUEL SPEC: 0.055 WT% S OIL	0	,	0	5	TPY		BACT-OTHER	0	0			0			P	0	0
AZ-0032	INTEL CORPORATION	NOX	10102	P	LOW NOX BURNERS < 50 PPM NOX	0	,	0	49	TPY		BACT-OTHER	0	0			0			P	0	0
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	PM10	PM	P	CE = 85-90%. TREATMENT OF UNPAVED HAUL SURFACES WITH CHEMICAL STABILIZERS AND REGULAR WATERING. REGULAR INSPECTION AND CLEANING OF PAVED HAUL SURFACES. USE OF SURFACTANTS IN SPRAY WATERS. NO LIMIT SET FOR FUGITIVE EMISSION		,		85	% REDUCTION		BACT-PSD	85							F		
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	PM10	PM	A	HIGH TEMPERATURE FABRIC FILTER BAGHOUSES FOR CLINKER COOLER.	4	,	2	0.01	GR/DSCF		BACT-PSD	99.9	46.08	T/YR		0.097	LB/T		P	2000000	212000
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	PM10	PM	A	LOW TEMPERATURE MEMBRANE TYPE FILTER BAGHOUSE	4	,	2	0.005	GR/DSCF		BACT-PSD	99.9				0.036	LB/T		P		
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	PM10	PM	A	LOW TEMPERATURE MEMBRANE TYPE FILTER BAGHOUSE; CE > 99.9%	4	,	2	0.005	GR/DSCF		BACT-PSD	99.9	10	T/YR		0.021	LB/T		P	2280000	122905
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	SO2	9/5/7446	P	RAW MATERIALS QUARRY WILL BE MANAGED FOR OPTIMUM SULFUR CONTENTS. SO2 WILL BE ABSORBED IN 5-STAGE PRECALCINER/PREHEATER/KILN AND RAW MILL. EMISSION LIMIT IN LB/T OF CLINKER, 12-MO ROLLING AVG.		,		1.99	LB/T		BACT-PSD	85				1.99	LB/T		P	7373600	437760
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	PM	PM	A	HIGH TEMPERATURE BAGHOUSE. EMISSION LIMITS SET IN GR/DSCF AND LB/T CLINKER.		,		0.01	GR/DSCF		BACT-PSD		94.7	T/YR		0.105	LB/T		P		
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	PM10	PM	A	HIGH TEMPERATURE FILTER BAGHOUSE		,		45.9	T/YR		BACT-PSD					0.097	LB/T		P		
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	CO	630-08-0	P	MULTI-STAGE COMBUSTION AND GOOD COMBUSTION MANAGEMENT PRACTICES. EMISSION LIMIT IN LB/T OF CLINKER. LB/T LIMIT IS 12-MO ROLLING AVG.	3	,	2	2.11	LB/T		BACT-PSD	90	1000	T/YR		2.11	LB/T		P	1734900	360650
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	NOX	10102	P	MULTI-STAGE COMBUSTION AND RECIRCULATION. EMISSION LIMIT IN LB/T OF CLINKER. LB/T LIMIT IS 12-MO ROLLING AVG.	3	,	2	2.32	LB/T		BACT-PSD	85	1100	T/YR		2.32	LB/T		P	3032100	294830
CO-0047	HOLNAM, FLORENCE	PM10	PM	A	BAGHOUSE		,		70.78	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM	PM	A	BAGHOUSE		,		70.78	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM	PM	A	BAGHOUSE		,		2.55	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM10	PM	A	BAGHOUSE		,		2.54	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM	PM	A	BAGHOUSE		,		0.13	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM10	PM	A	BAGHOUSE		,		0.13	T/YR		NSPS								P		

RBLCID	FACILITY	POLLUTANT	CAS	CONTROLCOD	CTRLDESC	RANKOPTS	,	RANKSEL	EMISLIMIT1	EMISLIMIT1UNIT	EMISLIMIT1CONDITION	BASIS	PCTEFFIC	EMISLIMIT2	EMISLIMIT2UNIT	EMISLIMIT2CONDITION	STDEMISS	STDUNIT	STOTHERCONDITIONS	EMISSTYPE	CAPCOST	ANNUALCOST
CO-0047	HOLNAM, FLORENCE	PM	PM	A	BAGHOUSE		,		2.58	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM10	PM	A	BAGHOUSE		,		2.46	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM	PM	P	CONTROL PLAN		,		1.6	T/YR		OTHER								F		
CO-0047	HOLNAM, FLORENCE	PM10	PM	A	CONTROL PLAN		,		1.2	T/YR		OTHER								F		
CO-0047	HOLNAM, FLORENCE	CO	630-08-0	N			,		70.6	T/YR		BACT-PSD								P		
CO-0047	HOLNAM, FLORENCE	NOX	10102	N			,		17.9	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM	PM	N			,		1.35	T/YR		NSPS								F		
CO-0047	HOLNAM, FLORENCE	PM10	PM	A			,		0.7	T/YR		NSPS								F		
CO-0047	HOLNAM, FLORENCE	PM10	PM	A	BAGHOUSE		,		0.16	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM	PM	A	BAGHOUSE		,		0.17	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM	PM	A	BAGHOUSE		,		0.25	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM10	PM	A	BAGHOUSE		,		0.25	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM	PM	A	BAGHOUSE		,		0.22	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM10	PM	A	BAGHOUSE		,		0.21	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM10	PM	A	NEG PRESSURE AND BAGHOUSE. STANDARD EMISSION UNITS NOT AVAILABLE.		,		1.85	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM	PM	A	NEG PRESSURE AND BAGHOUSE. STANDARD EMISSION UNITS NOT AVAILABLE.		,		1.94	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM	PM	P	SURFACE MOISTURE		,		0.45	T/YR		NSPS								F		
CO-0047	HOLNAM, FLORENCE	PM10	PM	P	SURFACE MOISTURE		,		0.33	T/YR		NSPS								F		
CO-0047	HOLNAM, FLORENCE	PM	PM	A	BAGHOUSE. PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.		,		0.19	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM10	PM	A	BAGHOUSE. PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.		,		0.19	T/YR		NSPS								P		

RBLCID	FACILITY	POLLUTANT	CAS	CONTROLCOD	CTRLDESC	RANKOPTS	,	RANKSEL	EMISLIMIT1	EMISLIMIT1UNIT	EMISLIMIT1CONDITION	BASIS	PCTEFFIC	EMISLIMIT2	EMISLIMIT2UNIT	EMISLIMIT2CONDITION	STDEMISS	STDUNIT	STOTHERCONDITIONS	EMISSTYPE	CAPCOST	ANNUALCOST
CO-0047	HOLNAM, FLORENCE	PM	PM	A	BAGHOUSE. PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.		,		0.19	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM10	PM	A	BAGHOUSE. PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.		,		0.19	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM	PM	A	BAGHOUSE. PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.		,		0.02	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM10	PM	A	BAGHOUSE. PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.		,		0.02	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM	PM	A	BAGHOUSE. PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.		,		0.02	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM10	PM	A	BAGHOUSE. PERMIT MODIFICATION TRIGGERED BACT REVIEW OF CO ONLY. PM LIMITS IN STANDARD EMISSION UNITS NOT AVAILABLE.		,		0.02	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM	PM	P	MINIMIZE DISTANCE AREA, REVEGETATION, CHEMICAL STABILIZERS		,		2.63	T/YR		NSPS								F		
CO-0047	HOLNAM, FLORENCE	PM10	PM	P	MINIMIZE DISTANCE AREA, REVEGETATION, CHEMICAL STABILIZERS		,		1.32	T/YR		NSPS								F		
CO-0047	HOLNAM, FLORENCE	PM	PM	P	CONTROL PLAN		,		32.37	T/YR		OTHER								F		
CO-0047	HOLNAM, FLORENCE	PM10	PM	P	CONTROL PLAN		,		16.73	T/YR		OTHER								F		
CO-0047	HOLNAM, FLORENCE	PM	PM	P	CONTROL PLAN		,		62.47	T/YR		NSPS								F		
CO-0047	HOLNAM, FLORENCE	PM10	PM	P	CONTROL PLAN		,		37.27	T/YR		NSPS								F		
CO-0047	HOLNAM, FLORENCE	PM10	PM	P	WETTING MATERIAL PRIOR TO PLACEMENT.		,		1.34	T/YR		NSPS								F		
CO-0047	HOLNAM, FLORENCE	PM	PM	P	WETTING MATERIAL PRIOR TO PLACEMENT.		,		2.23	T/YR		NSPS								F		
CO-0047	HOLNAM, FLORENCE	PM	PM	P			,		167.21	T/YR		NSPS								F		
CO-0047	HOLNAM, FLORENCE	PM10	PM	P			,		83.61	T/YR		NSPS								F		
CO-0047	HOLNAM, FLORENCE	PM	PM	B	ENCLOSURE UNDER NEG PRESSURE, DUST CURTAINS, WATER SPRAY, BAGHOUSE		,		0.01	T/YR	transfer 1	OTHER		0.02	T/YR	transfer 2				P		
CO-0047	HOLNAM, FLORENCE	PM10	PM	B	ENCLOSURE UNDER NEG PRESSURE, DUST CURTAINS, WATER SPRAY, BAGHOUSE		,		0.01	T/YR	transfer 1	OTHER		0.02	T/YR	transfer 2				P		
CO-0047	HOLNAM, FLORENCE	PM	PM	A	BAGHOUSE		,		0.05	T/YR		NSPS								P		
CO-0047	HOLNAM, FLORENCE	PM10	PM	A	BAGHOUSE		,		0.05	T/YR		NSPS								P		

RBLCID	FACILITY	OMCOST	COSTEFFECT	COSTVERIFY	DOLLARYEAR	POLNOTES
AZ-0022	INTEL CORPORATION	0		N		
AZ-0022	INTEL CORPORATION	0		N		
AZ-0022	INTEL CORPORATION	0		N		
AZ-0022	INTEL CORPORATION	0		N		
AZ-0022	INTEL CORPORATION	0		N		
AZ-0028	SITIX OF PHOENIX, INC.	0		N		
AZ-0028	SITIX OF PHOENIX, INC.	0		N		
AZ-0028	SITIX OF PHOENIX, INC.	0		N		
AZ-0032	INTEL CORPORATION	0		N		
AZ-0032	INTEL CORPORATION	0		N		
AZ-0032	INTEL CORPORATION	0		N		
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.			N		
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	112000	5.18	N	1998	
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.			N		
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	8905	21.25	N	1998	
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	66080	27.05	N	1998	
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.			N		
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.			N		
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	206000		N	1998	
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	75320		N	1998	
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		

RBLCID	FACILITY	OMCOST	COSTEFFECT	COSTVERIFY	DOLLARYEAR	POLNOTES
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		

RBLCID	FACILITY	OMCOST	COSTEFFECT	COSTVERIFY	DOLLARYEAR	POLNOTES
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		no regulatory basis provided.
CO-0047	HOLNAM, FLORENCE			N		no regulatory basis provided.
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		regulatory basis not provided.
CO-0047	HOLNAM, FLORENCE			N		regulatory basis not provided.
CO-0047	HOLNAM, FLORENCE			N		
CO-0047	HOLNAM, FLORENCE			N		

HCMREG	BASCODE	BASIN	FORMATION	NRES	NCOMP	ULT_COMP	AVDEPTH	CO2AV	CO2MIN
G	221	Texas Gulf Coast	Wilcox	1358	15026	2.49245	10210	3.3	0.1
D	260	East Texas Basin	Cotton Valley	208	6137	1.83996	10813	2.2	0.8
FR	535	Green River Basin	Madison	8	26	300.15773	15994	65.6	65.2
G	221	Texas Gulf Coast	Austin Chalk	45	1463	1.75877	13303	4.7	4.7
JS	430	Permian Basin	Ellenburger	150	1014	17.86021	16920	18.1	0.1
FR	535	Green River Basin	Mesaverde	127	1470	2.60129	9099	2.4	0.1
TB	507	Overthrust	Madison	5	54	40.48403	14655	7.2	7.2
G	221	Texas Gulf Coast	Edwards Lime	85	874	4.10249	11736	6.8	3.8
JN	345	Arkoma Basin	Atoka	151	6618	1.78807	7167	1.6	0.0
FR	515	Powder River Basin	Fort Union Coal	2	2629	0.4	494	0.5	0.5
FR	575	Uinta Basin	Mesaverde Group Coal	6	455	1.69404	2487	4.3	3.1
D	260	East Texas Basin	Smackover	96	324	10.08857	12096	5.7	2.8
JN	360	Anadarko Basin	Hunton	128	1017	4.36172	17071	3.3	0.0
FR	530	Wind River Basin	Fort Union	25	270	3.84961	7263	2.0	0.3
JN	345	Arkoma Basin	Other	652	4670	0.99011	5694	0.9	0.0
JN	360	Anadarko Basin	Morrow	877	10817	2.23185	10706	1.0	0.0
FR	540	Denver Basin	Other	56	1754	0.5652	7622	2.0	2.0
FR	595	Piceance Basin	Mesaverde	43	958	1.1197	6520	2.9	0.8
FR	540	Denver Basin	J Sand	180	2447	0.55486	7885	2.5	0.3
D	260	East Texas Basin	Bossier	45	255	1.45852	12474	2.4	2.0
D	260	East Texas Basin	Haynesville	12	182	4.74496	11711	2.5	1.2
FR	530	Wind River Basin	Madison	1	3	102.75904	23877	19.0	19.0
JS	430	Permian Basin	Other	836	4458	1.49725	5760	0.3	0.0
FR	535	Green River Basin	Weber	9	29	21.41971	15007	19.7	10.6
JS	430	Permian Basin	Strawn	334	2254	1.12572	10066	1.9	0.1
JN	360	Anadarko Basin	Other	2221	12567	1.62904	8221	0.7	0.0
JS	430	Permian Basin	Fusselman	81	397	7.02808	16292	5.0	0.1
FR	535	Green River Basin	Frontier	113	2630	1.93548	9501	0.7	0.1
FR	535	Green River Basin	Other	162	397	1.24587	7465	0.4	0.1
FR	585	Paradox Basin	Mississippian	5	12	16.73878	8483	22.9	22.9
JN	360	Anadarko Basin	Douglas	72	830	1.5925	7233	3.6	0.1
FR	515	Powder River Basin	Muddy	37	134	1.45668	10802	1.9	0.4
G	221	Texas Gulf Coast	Vicksburg	507	5721	2.50623	11311	0.3	0.0
G	221	Texas Gulf Coast	Yegua	940	5410	2.0855	8835	1.0	0.1
FR	535	Green River Basin	Nugget	15	43	9.29993	15344	2.4	1.4
JN	345	Arkoma Basin	Arbuckle	4	20	19.55891	13891	2.0	1.7

HCMREG	BASCODE	BASIN	FORMATION	NRES	NCOMP	ULT_COMP	AVDEPTH	CO2AV	CO2MIN
D	260	East Texas Basin	Woodbine	83	622	2.03957	4651	1.9	0.5
FR	595	Piceance Basin	Dakota	47	321	0.81646	6571	4.1	0.1
FR	530	Wind River Basin	Cody	11	39	8.41204	16798	2.9	1.5
FR	530	Wind River Basin	Other	58	96	2.77003	10734	3.3	0.1
FR	530	Wind River Basin	Mesaverde	10	33	4.23784	14868	4.0	1.3
FR	540	Denver Basin	Niobrara	47	1484	0.37251	2265	0.9	0.2
FR	595	Piceance Basin	Wasatch	13	190	2.12091	3133	1.5	0.0
JN	360	Anadarko Basin	Viola	44	100	1.36674	11944	2.3	0.2
FR	535	Green River Basin	Lewis	65	461	2.10241	8707	0.7	0.0
JS	430	Permian Basin	Wolfcamp	287	1167	2.05626	9140	0.7	0.0
FR	595	Piceance Basin	Other	74	224	0.97037	5658	0.5	0.3
JN	360	Anadarko Basin	Skinner	63	644	1.55135	10955	1.1	0.1
FR	585	Paradox Basin	Other	86	183	0.99482	5783	1.3	0.0
FR	595	Piceance Basin	Mesaverde Group Coal	13	146	0.41521	6820	14.8	14.8
TB	507	Overthrust	Weber	3	10	6.93112	12817	5.3	5.3
JS	430	Permian Basin	Atoka	246	801	1.61476	13724	0.5	0.0
FR	575	Uinta Basin	Other	53	177	1.47338	6947	0.9	0.0
FR	540	Denver Basin	Dakota	5	74	0.37364	8177	2.3	2.3
JS	430	Permian Basin	San Andres	68	606	0.81152	4213	1.7	0.1
FR	535	Green River Basin	Phosphoria	2	8	2.32811	10009	28.2	28.2
FR	515	Powder River Basin	Other	78	176	0.28963	6155	0.9	0.1
D	260	East Texas Basin	Rodessa	192	1133	2.41318	8254	1.4	0.0
JN	360	Anadarko Basin	Red Fork	135	2480	2.0527	12305	1.2	0.1
D	260	East Texas Basin	Pettit	188	2109	4.27018	7046	1.0	0.5
JN	360	Anadarko Basin	Marmaton	114	254	0.57939	7821	0.8	0.1
FR	535	Green River Basin	Dakota	68	536	2.64748	11934	0.8	0.0
FR	585	Paradox Basin	Entrada	4	12	1.35918	5516	15.8	1.5
JS	430	Permian Basin	Tubb	26	299	1.66603	5675	0.8	0.1
TB	507	Overthrust	Other	12	14	1.33158	7667	0.0	0.0
JN	360	Anadarko Basin	Chester	243	2518	1.01939	7066	0.5	0.1
FR	535	Green River Basin	Mesaverde Group Coal	6	20	0.13585	6100	0.0	0.0
FR	535	Green River Basin	Fort Union	24	120	2.90528	5779	0.7	0.1
FR	540	Denver Basin	D Sand	129	259	0.64767	5927	1.3	0.9
JN	360	Anadarko Basin	Chase	95	15639	4.18928	2755	0.1	0.0
JS	430	Permian Basin	Queen	64	487	0.36983	3187	0.0	0.0
D	260	East Texas Basin	Glen Rose	32	260	1.45441	6347	0.6	0.2

HCMREG	BASCODE	BASIN	FORMATION	NRES	NCOMP	ULT_COMP	AVDEPTH	CO2AV	CO2MIN
D	260	East Texas Basin	Hill	37	306	1.78225	6132	0.7	0.4
D	260	East Texas Basin	James Lime	35	133	2.4993	8823	3.1	2.3
D	260	East Texas Basin	Jeter	2	37	8.1009	4944	1.3	1.3
D	260	East Texas Basin	Other	188	1154	1.08279	10334	0.7	0.1
D	260	East Texas Basin	Paluxy	27	192	1.99473	4797	0.3	0.2
D	260	East Texas Basin	Travis Peak	296	4393	1.49973	8113	0.9	0.4
D	415	Strawn Basin	Big Saline	8	138	0.40827	3808	0.6	0.3
D	415	Strawn Basin	Conglomerate	11	29	0.13508	3463	0.1	0.1
D	415	Strawn Basin	Marble Falls	26	419	0.46882	4165	0.4	0.1
D	415	Strawn Basin	Other	46	223	0.11282	4160	0.0	0.0
D	415	Strawn Basin	Strawn	32	345	0.11067	2892	0.1	0.1
D	420	Fort Worth Syncline	Atoka	133	984	0.29277	5565	0.4	0.2
D	420	Fort Worth Syncline	Barnett Shale	1	556	1.21501	7656	1.5	1.5
D	420	Fort Worth Syncline	Bend	65	3908	0.94008	5736	0.4	0.4
D	420	Fort Worth Syncline	Big Saline	14	124	0.31396	4770	1.5	1.5
D	420	Fort Worth Syncline	Caddo	115	683	0.31811	4666	0.3	0.2
D	420	Fort Worth Syncline	Conglomerate	176	1161	0.34608	5616	0.6	0.1
D	420	Fort Worth Syncline	Marble Falls	70	300	0.26676	5471	0.1	0.1
D	420	Fort Worth Syncline	Other	105	646	0.19196	4760	0.2	0.2
D	420	Fort Worth Syncline	Strawn	154	1168	0.18993	3293	0.3	0.1
D	425	Bend Arch	Bend	136	726	0.35291	4015	0.3	0.3
D	425	Bend Arch	Big Saline	28	243	0.4117	3765	0.3	0.2
D	425	Bend Arch	Caddo	244	787	0.25019	3532	0.3	0.0
D	425	Bend Arch	Conglomerate	275	1072	0.24836	3928	0.3	0.1
D	425	Bend Arch	Duffer	128	712	0.22313	3840	0.3	0.2
D	425	Bend Arch	Fry	60	1103	0.09271	2877	0.2	0.2
D	425	Bend Arch	Gardner	62	128	0.19579	3186	0.2	0.2
D	425	Bend Arch	Gray	51	111	0.20026	3116	0.1	0.1
D	425	Bend Arch	Jennings	36	129	0.30605	2986	0.1	0.1
D	425	Bend Arch	Marble Falls	250	2485	0.22606	3316	0.3	0.1
D	425	Bend Arch	Morris	59	142	0.22171	2862	0.1	0.1
D	425	Bend Arch	Other	673	4041	0.12572	3427	0.2	0.2
D	425	Bend Arch	Strawn	207	878	0.13245	2699	0.1	0.1
FR	450	Las Animas Arch	Morrow	49	145	1.25692	5178	0.8	0.2
FR	450	Las Animas Arch	Niobrara	6	125	0.16844	1291	1.5	0.0
FR	450	Las Animas Arch	Other	13	52	1.05401	4882	0.3	0.3

HCMREG	BASCODE	BASIN	FORMATION	NRES	NCOMP	ULT_COMP	AVDEPTH	CO2AV	CO2MIN
FR	455	Raton/Las Vegas Basins	Other	5	12	0.1695	5490	0.0	0.0
FR	455	Raton/Las Vegas Basins	Vermejo Coal	10	280	1.53359	1277	1.0	1.0
FR	515	Powder River Basin	Frontier	11	86	2.32626	12066	0.0	0.0
FR	515	Powder River Basin	Turner	5	58	0.89013	9535	0.9	0.9
FR	520	Big Horn Basin	Chugwater	4	31	4.24559	2933	0.1	0.1
FR	520	Big Horn Basin	Dakota	9	20	1.0014	2179	0.1	0.1
FR	520	Big Horn Basin	Frontier	36	162	1.67598	7664	0.6	0.1
FR	520	Big Horn Basin	Muddy	19	72	1.57204	8363	0.3	0.1
FR	520	Big Horn Basin	Other	43	98	0.68278	3389	0.0	0.0
FR	520	Big Horn Basin	Phosphoria	10	21	0.57955	4761	0.0	0.0
FR	530	Wind River Basin	Frontier	30	141	4.73159	7853	0.3	0.1
FR	530	Wind River Basin	Lance	19	111	6.2425	10055	0.1	0.1
FR	530	Wind River Basin	Muddy	21	55	4.30152	17088	0.3	0.0
FR	530	Wind River Basin	Phosphoria	6	35	2.87246	10556	0.7	0.7
FR	530	Wind River Basin	Tensleep	1	4	0.08597	1758	0.5	0.5
FR	530	Wind River Basin	Wind River	3	30	3.8462	3314	0.0	0.0
FR	535	Green River Basin	Almy	15	205	0.58244	2368	0.1	0.1
FR	535	Green River Basin	Bear River	28	314	1.13259	8532	0.3	0.1
FR	535	Green River Basin	Lance	24	218	5.32791	10905	0.7	0.6
FR	535	Green River Basin	Morgan	5	10	0.72865	18489	23.3	22.4
FR	535	Green River Basin	Wasatch	11	71	3.58078	3159	0.9	0.9
FR	540	Denver Basin	Codell	3	217	0.28554	7244	1.0	1.0
FR	540	Denver Basin	Sussex	6	169	0.47335	4493	0.2	0.2
FR	575	Uinta Basin	Dakota	13	43	0.73191	8567	1.0	0.9
FR	575	Uinta Basin	Frontier	1	17	11.57782	5547	0.1	0.1
FR	575	Uinta Basin	Green River	19	174	1.25994	5187	0.4	0.1
FR	575	Uinta Basin	Wasatch	31	1314	1.49993	6395	0.2	0.1
FR	585	Paradox Basin	Cedar Mountain	11	34	0.86599	6255	0.8	0.7
FR	585	Paradox Basin	Dakota	21	271	1.03999	4784	0.8	0.1
FR	585	Paradox Basin	Desert Creek	9	14	0.6991	6078	0.2	0.2
FR	585	Paradox Basin	Morrison	8	78	0.42631	4869	0.8	0.5
FR	590	Black Mesa	Other	0	0	0	3132	12.9	0.0
FR	595	Piceance Basin	Mancos	30	522	1.18108	2936	0.4	0.2
FR	595	Piceance Basin	Morrison	12	25	0.263	4985	2.7	1.4
G	221	Texas Gulf Coast	Catahoula	155	1373	0.62256	3136	0.2	0.2
G	221	Texas Gulf Coast	Cockfield	93	884	1.81167	5066	0.3	0.3

HCMREG	BASCODE	BASIN	FORMATION	NRES	NCOMP	ULT_COMP	AVDEPTH	CO2AV	CO2MIN
G	221	Texas Gulf Coast	Cook Mountain	112	397	1.49055	8594	0.3	0.1
G	221	Texas Gulf Coast	Frio	2586	38788	1.57339	8366	0.4	0.0
G	221	Texas Gulf Coast	Jackson	434	2170	0.59917	5939	0.2	0.1
G	221	Texas Gulf Coast	Marginulina	111	674	2.13413	7110	0.2	0.2
G	221	Texas Gulf Coast	Miocene	677	9791	0.83648	3631	0.1	0.1
G	221	Texas Gulf Coast	Oakville	44	275	0.33138	2674	0.1	0.0
G	221	Texas Gulf Coast	Olmos	188	2439	0.50746	8510	0.1	0.1
G	221	Texas Gulf Coast	Other	1369	5647	1.39514	10636	3.3	0.1
G	221	Texas Gulf Coast	Queen City	191	906	1.03463	7433	1.0	0.2
G	221	Texas Gulf Coast	San Miguel	106	484	0.52022	4290	0.0	0.0
JN	345	Arkoma Basin	Hartshorne Coal	16	201	0.29172	1828	0.9	0.9
JN	345	Arkoma Basin	Hunton	23	99	2.3968	6129	1.1	0.3
JN	345	Arkoma Basin	Morrow	2	2	0.32933	5346	2.1	0.3
JN	350	South Ok. Folded Belt	Cisco	21	96	1.61012	5430	0.2	0.1
JN	350	South Ok. Folded Belt	Deese	22	201	0.67602	8838	0.3	0.3
JN	350	South Ok. Folded Belt	Goddard	11	39	1.31367	12546	0.2	0.2
JN	350	South Ok. Folded Belt	Granite Wash	23	187	0.11177	7906	0.0	0.0
JN	350	South Ok. Folded Belt	Hart	5	364	1.00191	7802	0.0	0.0
JN	350	South Ok. Folded Belt	Hoxbar	35	172	0.91544	7918	0.2	0.0
JN	350	South Ok. Folded Belt	Hunton	11	78	1.52848	7631	0.6	0.2
JN	350	South Ok. Folded Belt	Other	269	1773	0.69937	9965	0.3	0.0
JN	350	South Ok. Folded Belt	Pontotoc	20	76	0.16303	2539	0.0	0.0
JN	350	South Ok. Folded Belt	Simpson	61	382	2.538	9691	0.2	0.1
JN	350	South Ok. Folded Belt	Springer	34	304	1.89864	9208	0.1	0.0
JN	350	South Ok. Folded Belt	Sycamore	13	165	2.25029	7630	0.5	0.2
JN	350	South Ok. Folded Belt	Viola	30	85	1.38258	11208	0.0	0.0
JN	350	South Ok. Folded Belt	Woodford	6	38	0.87132	4937	0.2	0.2
JN	355	Chautauqua Platform	Bartlesville	174	889	0.3711	2988	0.2	0.1
JN	355	Chautauqua Platform	Booch	95	807	0.32756	1926	0.2	0.1
JN	355	Chautauqua Platform	Burgess	42	190	0.06893	1491	0.1	0.1
JN	355	Chautauqua Platform	Cherokee Group Coal	20	176	0.14174	934	0.5	0.5
JN	355	Chautauqua Platform	Cleveland	77	375	0.34942	3959	0.1	0.1
JN	355	Chautauqua Platform	Cromwell	133	545	0.41113	3413	0.2	0.1
JN	355	Chautauqua Platform	Dutcher	111	1285	0.09471	2062	0.1	0.0
JN	355	Chautauqua Platform	Gilcrease	121	834	0.28456	2631	0.2	0.0
JN	355	Chautauqua Platform	Hart	35	224	0.43667	3445	0.1	0.0

HCMREG	BASCODE	BASIN	FORMATION	NRES	NCOMP	ULT_COMP	AVDEPTH	CO2AV	CO2MIN
JN	355	Chautauqua Platform	Hoover	25	68	0.31601	3027	0.1	0.1
JN	355	Chautauqua Platform	Hunton	96	295	0.59086	5731	0.1	0.0
JN	355	Chautauqua Platform	Layton	67	220	0.35468	4147	0.4	0.0
JN	355	Chautauqua Platform	Neva	9	381	0.01466	828	0.5	0.5
JN	355	Chautauqua Platform	Osborne	4	55	3.35092	9088	0.4	0.4
JN	355	Chautauqua Platform	Oswego	59	188	0.85408	4864	0.4	0.4
JN	355	Chautauqua Platform	Other	1168	6990	0.32423	4342	0.1	0.1
JN	355	Chautauqua Platform	Prue	90	378	0.55516	5062	0.2	0.0
JN	355	Chautauqua Platform	Red Fork	155	606	0.31484	3836	0.2	0.0
JN	355	Chautauqua Platform	Senora	39	126	0.16657	1624	0.3	0.3
JN	355	Chautauqua Platform	Skinner	163	450	0.38647	5891	0.1	0.0
JN	355	Chautauqua Platform	Tonkawa	32	56	0.21498	2912	0.1	0.0
JN	355	Chautauqua Platform	Viola	42	95	0.55676	9177	0.3	0.2
JN	355	Chautauqua Platform	Wilcox	51	97	0.26421	4900	0.3	0.3
JN	360	Anadarko Basin	Arbuckle	23	66	2.53792	17062	1.2	0.1
JN	360	Anadarko Basin	Cherokee	144	545	1.02124	10691	0.9	0.0
JN	360	Anadarko Basin	Cleveland	75	1375	0.89596	7502	0.5	0.1
JN	360	Anadarko Basin	Council Grove	73	2997	1.33942	2911	0.1	0.0
JN	360	Anadarko Basin	Granite Wash	94	1155	1.41488	10763	0.5	0.0
JN	360	Anadarko Basin	Hoxbar	14	80	1.16849	8330	0.2	0.2
JN	360	Anadarko Basin	Kansas City	37	76	0.38208	4807	0.1	0.1
JN	360	Anadarko Basin	Lansing	46	114	0.67458	4422	0.0	0.0
JN	360	Anadarko Basin	Manning	41	501	1.24747	6827	0.3	0.2
JN	360	Anadarko Basin	Oswego	86	734	1.18307	7660	0.4	0.1
JN	360	Anadarko Basin	Springer	115	1827	3.25034	13921	1.1	0.2
JN	360	Anadarko Basin	Tonkawa	104	1396	1.71522	6962	0.3	0.0
JN	360	Anadarko Basin	Topeka	47	578	2.36438	3252	0.1	0.0
JN	360	Anadarko Basin	Toronto	12	21	1.62976	4389	0.0	0.0
JN	360	Anadarko Basin	Wabaunsee	27	63	0.57183	3377	0.2	0.1
JN	365	Cherokee/Forest City	Cherokee Group Coal	11	39	0.08318	1047	1.4	1.2
JN	365	Cherokee/Forest City	Other	224	1283	0.083	1188	0.1	0.1
JN	370	Nemaha Anticline	Bartlesville	7	13	0.10939	3365	0.0	0.0
JN	370	Nemaha Anticline	Cleveland	12	32	0.22831	2473	0.0	0.0
JN	370	Nemaha Anticline	Oswego	1	1	0.35298	3082	0.2	0.2
JN	370	Nemaha Anticline	Other	156	566	0.10487	1518	0.1	0.1
JN	370	Nemaha Anticline	Wabaunsee	3	5	0.2499	591	0.0	0.0

HCMREG	BASCODE	BASIN	FORMATION	NRES	NCOMP	ULT_COMP	AVDEPTH	CO2AV	CO2MIN
JN	375	Sedgwick Basin	Douglas	36	132	0.84749	3390	0.2	0.1
JN	375	Sedgwick Basin	Kansas City	17	22	0.1713	3742	0.1	0.1
JN	375	Sedgwick Basin	Lansing	12	31	0.73438	3718	0.1	0.1
JN	375	Sedgwick Basin	Other	722	4327	0.62307	4216	0.2	0.0
JN	375	Sedgwick Basin	Topeka	6	18	0.30248	3593	0.1	0.1
JN	385	Central Kansas Uplift	Arbuckle	53	231	0.40623	3800	0.2	0.2
JN	385	Central Kansas Uplift	Chase	42	157	0.19628	1934	0.1	0.1
JN	385	Central Kansas Uplift	Cherokee	16	49	0.4864	4436	0.1	0.1
JN	385	Central Kansas Uplift	Kansas City	25	46	0.30289	3312	0.1	0.1
JN	385	Central Kansas Uplift	Lansing	35	53	0.22459	3671	0.3	0.1
JN	385	Central Kansas Uplift	Other	504	1395	0.22836	3652	0.2	0.0
JN	385	Central Kansas Uplift	Simpson	33	53	0.34785	3838	0.2	0.1
JN	385	Central Kansas Uplift	Topeka	9	47	0.37046	3044	0.2	0.2
JN	385	Central Kansas Uplift	Viola	39	87	0.28069	4066	0.2	0.2
JN	385	Central Kansas Uplift	Wabaunsee	45	87	0.28698	2895	0.1	0.1
JN	400	Ouachita Tectonic Belt	Anacacho	6	35	0.06635	973	0.0	0.0
JN	400	Ouachita Tectonic Belt	Bromide	2	10	1.70887	7467	0.2	0.2
JN	400	Ouachita Tectonic Belt	Mclish	1	6	3.50406	7736	0.5	0.5
JN	400	Ouachita Tectonic Belt	Olmos Navarro	8	75	0.03907	1111	0.0	0.0
JN	400	Ouachita Tectonic Belt	Other	40	125	0.88168	7296	0.3	0.3
JN	435	Palo Duro Basin	Atoka	2	8	0.58795	4291	0.1	0.1
JN	435	Palo Duro Basin	Cisco	4	41	0.48352	1763	0.1	0.1
JN	435	Palo Duro Basin	Keyes	4	195	2.66319	4654	0.6	0.2
JN	435	Palo Duro Basin	Morrow	7	92	1.39335	4596	0.2	0.1
JN	435	Palo Duro Basin	Other	46	716	1.81375	3053	0.4	0.0
JN	435	Palo Duro Basin	Topeka	5	41	0.6447	3533	0.4	0.4
JN	435	Palo Duro Basin	Wichita Falls	3	39	0.53127	978	0.1	0.1
JS	410	Llano Uplift	Other	19	54	0.03844	1024	0.4	0.2
JS	410	Llano Uplift	Strawn	13	105	0.08949	1184	0.1	0.1
JS	430	Permian Basin	Abo	29	1240	0.44464	4497	0.2	0.2
JS	430	Permian Basin	Canyon	242	8247	0.60827	6425	0.5	0.0
JS	430	Permian Basin	Cisco	42	318	0.59474	7054	0.5	0.1
JS	430	Permian Basin	Clear Fork	59	462	0.4774	4243	0.4	0.0
JS	430	Permian Basin	Delaware	89	396	0.92605	5109	0.1	0.0
JS	430	Permian Basin	Devonian	175	1649	6.63736	12409	1.0	0.7
JS	430	Permian Basin	Grayburg	44	280	1.14532	3151	0.1	0.0

HCMREG	BASCODE	BASIN	FORMATION	NRES	NCOMP	ULT_COMP	AVDEPTH	CO2AV	CO2MIN
JS	430	Permian Basin	Judkins	1	330	3.17719	2953	1.7	1.7
JS	430	Permian Basin	Mckee	24	172	1.57574	9703	0.1	0.1
JS	430	Permian Basin	Mcknight	1	117	1.34253	3260	1.7	1.7
JS	430	Permian Basin	Montoya	23	82	4.28962	14012	1.8	1.8
JS	430	Permian Basin	Morrow	245	2007	2.25048	11479	0.5	0.2
JS	430	Permian Basin	Pennsylvanian	189	2229	2.18633	8550	1.1	0.3
JS	430	Permian Basin	Silurian	14	75	14.32901	16842	0.0	0.0
JS	430	Permian Basin	Wichita Albany	33	162	1.11576	4786	0.4	0.1
JS	430	Permian Basin	Yates	92	1141	0.74697	2623	0.1	0.0
L	475	Southern Basin And Range	All	0	0	0	0	0.0	0.0
TB	507	Overthrust	Big Horn	4	21	6.6725	15516	0.9	0.7
TB	507	Overthrust	Nugget	9	76	43.03867	13866	0.3	0.0
TB	507	Overthrust	Phosphoria	3	9	8.7473	12176	1.3	1.3
TB	507	Overthrust	Sun River	1	4	1.751	1079	5.9	5.9
TB	507	Overthrust	Thaynes	3	4	2.23356	15780	0.1	0.1
TB	507	Overthrust	Twin Creek	5	22	3.3606	7467	0.1	0.1

BASIN	FORMATION	CO2MAX	CO2STD	RAW_RUR	R_SAMP	GASAN	CONVGROW	CONVNEWF
Texas Gulf Coast	Wilcox	17.9	2.03	6523	0.16	991	12064	14017
East Texas Basin	Cotton Valley	3.1	0.54	4642	0.37	464	10302	796
Green River Basin	Madison	65.7	0.23	5204	1.00	221	199	4688
Texas Gulf Coast	Austin Chalk	5.2	0.13	482	0.99	220	597	352
Permian Basin	Ellenburger	47.7	14.03	1660	0.96	220	858	3846
Green River Basin	Mesaverde	5.7	0.71	1900	0.86	132	6631	12368
Overthrust	Madison	7.2	0	741	1.00	85	746	2472
Texas Gulf Coast	Edwards Lime	9.9	0.87	455	0.95	68	1169	2082
Arkoma Basin	Atoka	4.5	1.13	2579	0.90	268	4590	1089
Powder River Basin	Fort Union Coal	0.5	0	1785	0.00	58	0	0
Uinta Basin	Mesaverde Group Coal	5.5	1.75	657	0.00	52	0	0
East Texas Basin	Smackover	9.0	1.12	373	0.95	40	364	351
Anadarko Basin	Hunton	8.4	2.38	490	0.81	50	1030	332
Wind River Basin	Fort Union	4.9	0.99	647	0.95	49	511	393
Arkoma Basin	Other	4.8	0.81	1155	0.44	121	1622	418
Anadarko Basin	Morrow	5.1	0.7	3682	0.79	375	17107	20271
Denver Basin	Other	2.0	0	652	0.00	51	48	317
Piceance Basin	Mesaverde	18.3	2.13	790	0.91	51	2275	1583
Denver Basin	J Sand	2.7	0.26	387	0.94	27	283	435
East Texas Basin	Bossier	2.4	0.09	259	0.77	26	37	118
East Texas Basin	Haynesville	2.9	0.66	239	1.00	26	169	542
Wind River Basin	Madison	19.0	0	2143	1.00	19	0	1510
Permian Basin	Other	7.2	0.24	511	0.52	81	720	2297
Green River Basin	Weber	22.4	4.99	248	0.99	18	59	1563
Permian Basin	Strawn	4.9	1.41	865	0.74	90	1022	376
Anadarko Basin	Other	2.9	0.44	2891	0.26	298	9474	11235
Permian Basin	Fusselman	21.3	4.39	89	0.89	13	107	656
Green River Basin	Frontier	4.2	0.85	2496	0.89	168	496	2786
Green River Basin	Other	0.7	0.17	266	0.08	19	7	122
Paradox Basin	Mississippian	22.9	0	192	0.90	8	3	306
Anadarko Basin	Douglas	10.9	4.93	260	0.67	24	832	989
Powder River Basin	Muddy	2.2	0.64	119	0.12	9	29	511
Texas Gulf Coast	Vicksburg	3.3	0.43	2814	0.40	413	3600	4069
Texas Gulf Coast	Yegua	3.0	0.72	605	0.12	118	1025	2249
Green River Basin	Nugget	3.0	0.62	122	0.79	9	21	377
Arkoma Basin	Arbuckle	2.0	0.01	48	1.00	5	724	555

BASIN	FORMATION	CO2MAX	CO2STD	RAW_RUR	R_SAMP	GASAN	CONVGROW	CONVNEWF
East Texas Basin	Woodbine	2.4	0.83	66	0.02	7	249	254
Piceance Basin	Dakota	27.9	3.48	107	0.62	7	139	69
Wind River Basin	Cody	3.0	0.34	61	0.99	5	138	599
Wind River Basin	Other	4.0	1.39	125	0.11	9	14	59
Wind River Basin	Mesaverde	5.1	1.61	72	0.98	5	261	735
Denver Basin	Niobrara	2.9	0.91	299	0.80	21	113	171
Piceance Basin	Wasatch	3.2	1.54	91	0.96	6	118	61
Anadarko Basin	Viola	2.7	0.86	32	0.55	3	96	115
Green River Basin	Lewis	2.0	0.52	412	0.65	29	133	459
Permian Basin	Wolfcamp	6.8	1.12	524	0.25	67	1090	2255
Piceance Basin	Other	37.5	1.49	66	0.02	5	75	60
Anadarko Basin	Skinner	3.5	0.7	268	0.77	30	395	471
Paradox Basin	Other	4.4	1.8	69	0.26	4	6	252
Piceance Basin	Mesaverde Group Coal	14.8	0	24	0.37	2	0	0
Overthrust	Weber	5.3	0	44	0.30	2	24	931
Permian Basin	Atoka	3.3	0.7	233	0.21	36	825	1560
Uinta Basin	Other	1.7	0.24	79	0.66	3	56	197
Denver Basin	Dakota	2.3	0	24	0.99	1	8	7
Permian Basin	San Andres	10.6	2.04	23	0.48	4	143	46
Green River Basin	Phosphoria	28.2	0	15	0.56	1	1	14
Powder River Basin	Other	14.3	1.73	13	0.43	1	17	748
East Texas Basin	Rodessa	2.4	0.39	128	0.40	14	208	191
Anadarko Basin	Red Fork	2.3	0.55	1345	0.86	144	5022	5199
East Texas Basin	Pettit	2.0	0.22	326	0.78	36	415	254
Anadarko Basin	Marmaton	4.1	1.3	40	0.08	4	120	136
Green River Basin	Dakota	3.2	0.33	487	0.73	34	366	2175
Paradox Basin	Entrada	22.5	9.74	5	1.00	0	0	13
Permian Basin	Tubb	2.4	0.65	22	0.55	3	23	72
Overthrust	Other	0.0	0	3	0.13	0	0	872
Anadarko Basin	Chester	14.6	0.62	516	0.76	55	2376	2826
Green River Basin	Mesaverde Group Coal	0.0	0	1	0.00	0	0	0
Green River Basin	Fort Union	2.6	0.52	69	0.83	5	391	165
Denver Basin	D Sand	2.2	0.28	10	0.08	1	8	54
Anadarko Basin	Chase	4.5	0.05	6550	0.80	555	6411	638
Permian Basin	Queen	3.2	0.23	36	0.18	5	35	233
East Texas Basin	Glen Rose	1.9	0.6	58	0.70	7	42	128

BASIN	FORMATION	CO2MAX	CO2STD	RAW_RUR	R_SAMP	GASAN	CONVGROW	CONVNEWF
East Texas Basin	Hill	1.4	0.22	17	0.20	2	7	49
East Texas Basin	James Lime	3.9	1.13	118	0.00	13	594	63
East Texas Basin	Jeter	1.3	0	6	0.99	1	1	14
East Texas Basin	Other	1.3	0.43	218	0.77	22	91	711
East Texas Basin	Paluxy	0.7	0.23	17	0.25	2	20	32
East Texas Basin	Travis Peak	1.6	0.31	1488	0.59	157	1216	574
Strawn Basin	Big Saline	0.6	0.06	8	0.88	1	158	112
Strawn Basin	Conglomerate	0.1	0	1	0.00	0	19	14
Strawn Basin	Marble Falls	0.4	0.07	10	0.46	2	39	27
Strawn Basin	Other	0.0	0	5	0.00	1	16	11
Strawn Basin	Strawn	0.1	0	4	0.00	1	59	38
Fort Worth Syncline	Atoka	0.5	0.12	49	0.26	5	126	91
Fort Worth Syncline	Barnett Shale	1.5	0	477	1.00	41	0	0
Fort Worth Syncline	Bend	0.4	0	476	0.94	42	1697	1223
Fort Worth Syncline	Big Saline	1.5	0	2	0.00	0	35	26
Fort Worth Syncline	Caddo	0.3	0.03	25	0.18	3	61	45
Fort Worth Syncline	Conglomerate	0.7	0.17	53	0.07	5	330	237
Fort Worth Syncline	Marble Falls	0.1	0	17	0.00	2	35	26
Fort Worth Syncline	Other	0.2	0	19	0.00	2	352	254
Fort Worth Syncline	Strawn	0.3	0.06	32	0.11	3	120	85
Bend Arch	Bend	0.4	0.03	24	0.09	4	73	52
Bend Arch	Big Saline	0.3	0.04	8	0.42	1	51	36
Bend Arch	Caddo	0.5	0.08	18	0.07	3	81	58
Bend Arch	Conglomerate	0.6	0.18	32	0.04	5	315	228
Bend Arch	Duffer	0.6	0.13	22	0.18	4	150	107
Bend Arch	Fry	0.2	0	12	0.00	2	7	6
Bend Arch	Gardner	0.3	0.05	1	0.18	0	42	30
Bend Arch	Gray	0.1	0	1	0.00	0	35	26
Bend Arch	Jennings	0.1	0	1	0.00	0	12	7
Bend Arch	Marble Falls	1.7	0.26	44	0.33	7	257	185
Bend Arch	Morris	0.1	0	1	0.00	0	19	14
Bend Arch	Other	0.3	0.04	48	0.05	7	646	465
Bend Arch	Strawn	0.1	0	15	0.00	2	59	41
Las Animas Arch	Morrow	1.6	0.35	117	0.58	8	10	60
Las Animas Arch	Niobrara	1.9	0.76	8	0.57	1	2	13
Las Animas Arch	Other	0.3	0	8	0.82	1	4	22

BASIN	FORMATION	CO2MAX	CO2STD	RAW_RUR	R_SAMP	GASAN	CONVGROW	CONVNEWF
Raton/Las Vegas Basins	Other	0.0	0	0	0.00	0	0	926
Raton/Las Vegas Basins	Vermejo Coal	1.0	0	816	0.00	28	0	0
Powder River Basin	Frontier	0.0	0	71	0.00	5	52	911
Powder River Basin	Turner	0.9	0	15	0.70	1	29	349
Big Horn Basin	Chugwater	0.1	0	58	0.15	4	2	10
Big Horn Basin	Dakota	0.1	0	5	0.15	0	1	4
Big Horn Basin	Frontier	0.7	0.21	73	0.71	5	42	218
Big Horn Basin	Muddy	0.6	0.15	43	0.41	3	15	78
Big Horn Basin	Other	0.0	0	30	0.28	2	15	934
Big Horn Basin	Phosphoria	0.0	0	7	0.91	1	0	1
Wind River Basin	Frontier	0.7	0.09	158	0.74	8	157	1096
Wind River Basin	Lance	0.3	0.01	579	0.56	42	436	67
Wind River Basin	Muddy	0.6	0.26	157	0.06	12	61	265
Wind River Basin	Phosphoria	0.7	0	8	1.00	1	22	94
Wind River Basin	Tensleep	0.5	0	0	0.00	0	0	302
Wind River Basin	Wind River	0.0	0	40	1.00	3	16	70
Green River Basin	Almy	0.1	0.01	44	0.06	3	6	110
Green River Basin	Bear River	1.4	0.19	129	0.62	10	29	418
Green River Basin	Lance	0.7	0.02	1051	0.02	78	4	71
Green River Basin	Morgan	24.2	1.3	0	0.00	0	1	0
Green River Basin	Wasatch	0.9	0	31	0.20	2	6	102
Denver Basin	Codell	1.0	0	28	0.97	2	28	189
Denver Basin	Sussex	0.2	0.01	18	0.47	1	16	17
Uinta Basin	Dakota	1.1	0.07	16	0.71	1	9	31
Uinta Basin	Frontier	0.1	0	32	1.00	1	6	100
Uinta Basin	Green River	0.6	0.2	72	0.91	3	24	79
Uinta Basin	Wasatch	0.2	0.02	1579	0.93	64	823	956
Paradox Basin	Cedar Mountain	0.8	0.05	11	0.27	0	1	40
Paradox Basin	Dakota	1.0	0.26	103	0.79	4	5	30
Paradox Basin	Desert Creek	0.2	0	2	0.40	0	0	61
Paradox Basin	Morrison	1.0	0.21	11	0.97	0	1	34
Black Mesa	Other	99.8	25.7	0	0.00	0	0	185
Piceance Basin	Mancos	1.1	0.31	173	0.95	12	210	125
Piceance Basin	Morrison	3.7	1.18	1	0.00	0	4	1
Texas Gulf Coast	Catahoula	0.2	0	14	0.04	2	46	100
Texas Gulf Coast	Cockfield	0.5	0.06	129	0.01	26	37	80

BASIN	FORMATION	CO2MAX	CO2STD	RAW_RUR	R_SAMP	GASAN	CONVGROW	CONVNEWF
Texas Gulf Coast	Cook Mountain	0.4	0.14	87	0.00	18	49	106
Texas Gulf Coast	Frio	1.9	0.47	2392	0.36	414	3515	6748
Texas Gulf Coast	Jackson	0.2	0.05	64	0.03	11	65	140
Texas Gulf Coast	Marginulina	0.2	0	28	0.01	6	35	75
Texas Gulf Coast	Miocene	0.4	0.06	151	0.06	28	316	691
Texas Gulf Coast	Oakville	0.2	0.14	5	0.00	1	12	24
Texas Gulf Coast	Olmos	0.6	0.03	331	0.09	38	1148	988
Texas Gulf Coast	Other	7.4	1.94	696	0.34	122	12936	27406
Texas Gulf Coast	Queen City	1.9	0.42	73	0.08	12	201	442
Texas Gulf Coast	San Miguel	0.0	0	31	0.11	3	83	180
Arkoma Basin	Hartshorne Coal	0.9	0	29	0.67	3	0	0
Arkoma Basin	Hunton	1.5	0.37	24	0.78	2	724	555
Arkoma Basin	Morrow	4.3	0.87	0	0.00	0	1176	306
South Ok. Folded Belt	Cisco	0.3	0.09	17	0.64	2	15	17
South Ok. Folded Belt	Deese	0.3	0.02	8	0.28	1	18	20
South Ok. Folded Belt	Goddard	0.2	0	10	0.04	1	6	6
South Ok. Folded Belt	Granite Wash	0.0	0	4	0.11	0	6	4
South Ok. Folded Belt	Hart	0.0	0	11	0.00	1	15	16
South Ok. Folded Belt	Hoxbar	0.3	0.06	33	0.58	4	56	59
South Ok. Folded Belt	Hunton	1.2	0.38	23	0.89	3	33	37
South Ok. Folded Belt	Other	0.8	0.18	257	0.03	28	187	205
South Ok. Folded Belt	Pontotoc	0.1	0.05	2	0.09	0	0	0
South Ok. Folded Belt	Simpson	0.4	0.04	37	0.76	4	63	72
South Ok. Folded Belt	Springer	0.2	0.04	191	0.17	21	175	190
South Ok. Folded Belt	Sycamore	0.8	0.3	100	0.64	11	135	144
South Ok. Folded Belt	Viola	0.0	0	22	0.01	2	27	31
South Ok. Folded Belt	Woodford	0.2	0	4	0.00	0	6	7
Chautauqua Platform	Bartlesville	0.5	0.11	23	0.23	3	81	86
Chautauqua Platform	Booch	0.3	0.05	15	0.20	2	9	10
Chautauqua Platform	Burgess	0.1	0	3	0.00	0	6	6
Chautauqua Platform	Cherokee Group Coal	0.5	0	20	0.06	2	0	0
Chautauqua Platform	Cleveland	0.1	0	10	0.05	1	43	42
Chautauqua Platform	Cromwell	0.9	0.28	13	0.06	1	90	96
Chautauqua Platform	Dutcher	0.8	0.22	10	0.35	1	84	90
Chautauqua Platform	Gilcrease	0.3	0.07	31	0.19	3	72	76
Chautauqua Platform	Hart	0.2	0.07	14	0.14	2	48	51

BASIN	FORMATION	CO2MAX	CO2STD	RAW_RUR	R_SAMP	GASAN	CONVGROW	CONVNEWF
Chautauqua Platform	Hoover	0.1	0	1	0.00	0	15	16
Chautauqua Platform	Hunton	0.3	0.1	21	0.06	2	157	167
Chautauqua Platform	Layton	0.4	0.1	5	0.17	1	12	14
Chautauqua Platform	Neva	0.5	0	0	0.00	0	3	3
Chautauqua Platform	Osborne	0.4	0	15	1.00	2	42	45
Chautauqua Platform	Oswego	0.4	0	9	0.19	1	27	26
Chautauqua Platform	Other	0.3	0.05	128	0.03	14	380	405
Chautauqua Platform	Prue	0.4	0.17	17	0.40	2	45	48
Chautauqua Platform	Red Fork	0.3	0.07	11	0.25	1	90	96
Chautauqua Platform	Senora	0.3	0	2	0.00	0	9	10
Chautauqua Platform	Skinner	0.4	0.16	22	0.18	2	51	56
Chautauqua Platform	Tonkawa	0.3	0.14	1	0.63	0	6	4
Chautauqua Platform	Viola	0.3	0.02	8	0.04	1	21	23
Chautauqua Platform	Wilcox	0.3	0	3	0.15	0	12	14
Anadarko Basin	Arbuckle	1.3	0.27	34	0.44	4	112	110
Anadarko Basin	Cherokee	1.6	0.46	166	0.44	18	1478	989
Anadarko Basin	Cleveland	1.3	0.17	340	0.92	30	2538	927
Anadarko Basin	Council Grove	0.1	0.01	1188	0.94	98	1113	222
Anadarko Basin	Granite Wash	0.8	0.16	445	0.76	43	3473	2244
Anadarko Basin	Hoxbar	0.5	0.06	17	0.32	2	383	455
Anadarko Basin	Kansas City	0.1	0	6	0.04	1	109	129
Anadarko Basin	Lansing	0.4	0.04	8	0.40	1	45	56
Anadarko Basin	Manning	0.5	0.11	62	0.27	7	235	279
Anadarko Basin	Oswego	0.6	0.22	92	0.76	10	645	766
Anadarko Basin	Springer	1.7	0.34	1135	0.75	127	4813	5717
Anadarko Basin	Tonkawa	0.9	0.11	252	0.83	27	1137	1350
Anadarko Basin	Topeka	1.0	0.11	153	0.81	12	401	474
Anadarko Basin	Toronto	0.0	0	29	0.00	3	27	33
Anadarko Basin	Wabaunsee	0.3	0.09	10	0.09	1	21	26
Cherokee/Forest City	Cherokee Group Coal	1.4	0.1	1	0.35	0	0	0
Cherokee/Forest City	Other	0.1	0	35	0.00	3	0	899
Nemaha Anticline	Bartlesville	0.0	0	0	0.00	0	0	0
Nemaha Anticline	Cleveland	0.0	0	0	0.00	0	6	1
Nemaha Anticline	Oswego	0.2	0	0	0.00	0	0	0
Nemaha Anticline	Other	0.1	0	3	0.00	0	39	20
Nemaha Anticline	Wabaunsee	0.0	0	0	0.00	0	0	0

BASIN	FORMATION	CO2MAX	CO2STD	RAW_RUR	R_SAMP	GASAN	CONVGROW	CONVNEWF
Sedgwick Basin	Douglas	0.2	0.05	4	0.50	0	15	1
Sedgwick Basin	Kansas City	0.1	0	0	0.00	0	6	0
Sedgwick Basin	Lansing	0.1	0	2	0.50	0	18	1
Sedgwick Basin	Other	0.4	0.13	298	0.01	24	633	51
Sedgwick Basin	Topeka	0.1	0	0	1.00	0	3	0
Central Kansas Uplift	Arbuckle	0.4	0.07	2	0.36	0	6	0
Central Kansas Uplift	Chase	0.1	0	8	0.00	1	18	1
Central Kansas Uplift	Cherokee	0.1	0	1	0.00	0	6	0
Central Kansas Uplift	Kansas City	0.1	0	1	1.00	0	6	0
Central Kansas Uplift	Lansing	0.4	0.13	1	0.19	0	6	0
Central Kansas Uplift	Other	0.3	0.06	43	0.09	3	127	10
Central Kansas Uplift	Simpson	0.3	0.1	5	0.00	0	3	0
Central Kansas Uplift	Topeka	0.2	0	1	1.00	0	3	0
Central Kansas Uplift	Viola	0.3	0.05	5	0.53	0	6	0
Central Kansas Uplift	Wabaunsee	0.1	0	4	0.03	0	6	0
Ouachita Tectonic Belt	Anacacho	0.0	0	0	0.00	0	0	0
Ouachita Tectonic Belt	Bromide	0.2	0	1	1.00	0	0	0
Ouachita Tectonic Belt	Mclish	0.5	0	1	1.00	0	0	0
Ouachita Tectonic Belt	Olmos Navarro	0.0	0	0	0.00	0	0	0
Ouachita Tectonic Belt	Other	0.3	0	24	0.05	3	0	899
Palo Duro Basin	Atoka	0.1	0	0	1.00	0	6	1
Palo Duro Basin	Cisco	0.1	0	1	0.00	0	0	0
Palo Duro Basin	Keyes	0.6	0.08	11	1.00	1	45	19
Palo Duro Basin	Morrow	0.3	0.1	8	1.00	1	45	19
Palo Duro Basin	Other	0.9	0.28	79	0.06	8	112	44
Palo Duro Basin	Topeka	0.4	0	3	0.24	0	9	3
Palo Duro Basin	Wichita Falls	0.1	0	14	1.00	1	3	0
Llano Uplift	Other	0.7	0.25	0	0.00	0	0	0
Llano Uplift	Strawn	0.1	0	0	0.36	0	0	0
Permian Basin	Abo	0.2	0	77	0.91	13	1542	938
Permian Basin	Canyon	0.9	0.1	1361	0.91	131	7460	6565
Permian Basin	Cisco	1.6	0.07	33	0.60	4	96	187
Permian Basin	Clear Fork	0.5	0.2	30	0.55	4	34	111
Permian Basin	Delaware	0.4	0.08	22	0.35	3	30	96
Permian Basin	Devonian	1.8	0.5	999	0.45	130	509	2063
Permian Basin	Grayburg	1.1	0.35	19	0.86	3	30	96

BASIN	FORMATION	CO2MAX	CO2STD	RAW_RUR	R_SAMP	GASAN	CONVGROW	CONVNEWF
Permian Basin	Judkins	1.7	0	43	1.00	6	185	592
Permian Basin	Mckee	0.1	0	29	0.93	4	24	77
Permian Basin	Mcknight	1.7	0	13	1.00	2	45	145
Permian Basin	Montoya	1.8	0	61	0.91	9	50	159
Permian Basin	Morrow	1.3	0.24	821	0.48	136	2381	3931
Permian Basin	Pennsylvanian	1.2	0.16	1044	0.22	140	1444	3150
Permian Basin	Silurian	0.0	0	67	0.85	9	447	1425
Permian Basin	Wichita Albany	1.4	0.56	32	0.82	5	95	303
Permian Basin	Yates	0.2	0.06	53	0.62	9	35	233
Southern Basin And Range	All	0.0	0	0	0.00	0	0	1171
Overthrust	Big Horn	1.2	0.22	27	0.74	3	37	1628
Overthrust	Nugget	0.5	0.06	509	0.88	118	60	582
Overthrust	Phosphoria	1.3	0	36	0.14	4	0	0
Overthrust	Sun River	5.9	0	0	0.00	0	2	1163
Overthrust	Thaynes	0.1	0.04	0	0.00	0	1	29
Overthrust	Twin Creek	0.1	0.02	4	1.00	0	5	58

BASIN	FORMATION	UNCONV	TYPUNCNV	PRD	RUR	UND
Texas Gulf Coast	Wilcox	15671	Tight	447	2939	18811
East Texas Basin	Cotton Valley	37561	Tight	407	4103	43005
Green River Basin	Madison	14689	Low Btu	221	5204	19576
Texas Gulf Coast	Austin Chalk	1015	Tight	220	482	1964
Permian Basin	Ellenburger	0		204	1547	4383
Green River Basin	Mesaverde	117288	Tight	86	1229	88212
Overthrust	Madison	0		85	741	3218
Texas Gulf Coast	Edwards Lime	1006	Tight	68	455	4257
Arkoma Basin	Atoka	2758	Tight	67	618	2022
Powder River Basin	Fort Union Coal	10036	Coal	58	1785	10036
Uinta Basin	Mesaverde Group Coal	3810	Coal	52	657	3810
East Texas Basin	Smackover	0		40	373	715
Anadarko Basin	Hunton	212	Tight	32	311	998
Wind River Basin	Fort Union	8280	Tight	32	414	5883
Arkoma Basin	Other	0		31	287	507
Anadarko Basin	Morrow	178	Tight	31	336	3429
Denver Basin	Other	0		29	384	215
Piceance Basin	Mesaverde	43843	Tight	28	427	25752
Denver Basin	J Sand	2426	Tight	27	377	3061
East Texas Basin	Bossier	73	Tight	24	245	216
East Texas Basin	Haynesville	332	Tight	20	187	815
Wind River Basin	Madison	0		19	2143	1510
Permian Basin	Other	0		18	113	670
Green River Basin	Weber	0		18	248	1622
Permian Basin	Strawn	1099	Tight	16	152	439
Anadarko Basin	Other	0		14	133	952
Permian Basin	Fusselman	0		11	80	682
Green River Basin	Frontier	7342	Tight	9	145	616
Green River Basin	Other	0		9	152	74
Paradox Basin	Mississippian	0		8	192	309
Anadarko Basin	Douglas	0		8	81	568
Powder River Basin	Muddy	0		7	100	451
Texas Gulf Coast	Vicksburg	4758	Tight	7	36	159
Texas Gulf Coast	Yegua	9417	CoProd	7	41	853
Green River Basin	Nugget	0		7	92	300
Arkoma Basin	Arbuckle	0		5	48	1278

BASIN	FORMATION	UNCONV	TYPUNCNV	PRD	RUR	UND
East Texas Basin	Woodbine	0		5	49	372
Piceance Basin	Dakota	1062	Tight	4	73	859
Wind River Basin	Cody	0		4	58	697
Wind River Basin	Other	540	Coal	4	86	423
Wind River Basin	Mesaverde	4541	Tight	4	54	4163
Denver Basin	Niobrara	982	Tight	3	49	208
Piceance Basin	Wasatch	821	Tight	3	41	445
Anadarko Basin	Viola	0		3	27	177
Green River Basin	Lewis	205	Tight	3	39	75
Permian Basin	Wolfcamp	1254	Tight	2	15	128
Piceance Basin	Other	0		2	31	64
Anadarko Basin	Skinner	0		2	20	64
Paradox Basin	Other	0		2	42	156
Piceance Basin	Mesaverde Group Coal	11550	Coal	2	24	11550
Overthrust	Weber	0		2	44	955
Permian Basin	Atoka	1099	Tight	2	11	169
Uinta Basin	Other	0		1	22	71
Denver Basin	Dakota	106	Tight	1	24	121
Permian Basin	San Andres	0		1	5	40
Green River Basin	Phosphoria	0		1	15	15
Powder River Basin	Other	0		1	12	725
East Texas Basin	Rodessa	0		1	8	24
Anadarko Basin	Red Fork	4726	Tight	1	6	70
East Texas Basin	Pettit	0		1	7	13
Anadarko Basin	Marmaton	36	Tight	0	5	38
Green River Basin	Dakota	1143	Tight	0	4	33
Paradox Basin	Entrada	0		0	3	9
Permian Basin	Tubb	0		0	1	4
Overthrust	Other	0		0	1	503
Anadarko Basin	Chester	0		0	1	9
Green River Basin	Mesaverde Group Coal	4660	Coal	0	1	4660
Green River Basin	Fort Union	7526	Tight	0	1	109
Denver Basin	D Sand	0		0	1	4
Anadarko Basin	Chase	0		0	0	0
Permian Basin	Queen	0		0	0	0
East Texas Basin	Glen Rose	0		0	0	0

BASIN	FORMATION	UNCONV	TYPUNCNV	PRD	RUR	UND
East Texas Basin	Hill	0		0	0	0
East Texas Basin	James Lime	1575	Tight	0	0	0
East Texas Basin	Jeter	0		0	0	0
East Texas Basin	Other	0		0	0	0
East Texas Basin	Paluxy	0		0	0	0
East Texas Basin	Travis Peak	2363	Tight	0	0	0
Strawn Basin	Big Saline	0		0	0	0
Strawn Basin	Conglomerate	0		0	0	0
Strawn Basin	Marble Falls	0	Tight	0	0	0
Strawn Basin	Other	0		0	0	0
Strawn Basin	Strawn	16	Tight	0	0	0
Fort Worth Syncline	Atoka	0		0	0	0
Fort Worth Syncline	Barnett Shale	7110	Shale	0	0	0
Fort Worth Syncline	Bend	0		0	0	0
Fort Worth Syncline	Big Saline	0		0	0	0
Fort Worth Syncline	Caddo	0		0	0	0
Fort Worth Syncline	Conglomerate	0		0	0	0
Fort Worth Syncline	Marble Falls	0		0	0	0
Fort Worth Syncline	Other	0		0	0	0
Fort Worth Syncline	Strawn	3	Tight	0	0	0
Bend Arch	Bend	0		0	0	0
Bend Arch	Big Saline	0		0	0	0
Bend Arch	Caddo	0		0	0	0
Bend Arch	Conglomerate	0		0	0	0
Bend Arch	Duffer	0		0	0	0
Bend Arch	Fry	0		0	0	0
Bend Arch	Gardner	0		0	0	0
Bend Arch	Gray	0		0	0	0
Bend Arch	Jennings	0		0	0	0
Bend Arch	Marble Falls	0		0	0	0
Bend Arch	Morris	0		0	0	0
Bend Arch	Other	0		0	0	0
Bend Arch	Strawn	3	Tight	0	0	0
Las Animas Arch	Morrow	0		0	0	0
Las Animas Arch	Niobrara	0		0	0	0
Las Animas Arch	Other	0		0	0	0

BASIN	FORMATION	UNCONV	TYPUNCNV	PRD	RUR	UND
Raton/Las Vegas Basins	Other	0		0	0	0
Raton/Las Vegas Basins	Vermejo Coal	1880	Coal	0	0	0
Powder River Basin	Frontier	0		0	0	0
Powder River Basin	Turner	176	Tight	0	0	0
Big Horn Basin	Chugwater	0		0	0	0
Big Horn Basin	Dakota	0		0	0	0
Big Horn Basin	Frontier	0		0	0	0
Big Horn Basin	Muddy	0		0	0	0
Big Horn Basin	Other	0		0	0	0
Big Horn Basin	Phosphoria	0		0	0	0
Wind River Basin	Frontier	861	Tight	0	0	0
Wind River Basin	Lance	8280	Tight	0	0	0
Wind River Basin	Muddy	0		0	0	0
Wind River Basin	Phosphoria	0		0	0	0
Wind River Basin	Tensleep	0		0	0	0
Wind River Basin	Wind River	0		0	0	0
Green River Basin	Almy	0		0	0	0
Green River Basin	Bear River	112	Tight	0	0	0
Green River Basin	Lance	0		0	0	0
Green River Basin	Morgan	0		0	0	0
Green River Basin	Wasatch	0		0	0	0
Denver Basin	Codell	218	Tight	0	0	0
Denver Basin	Sussex	202	Tight	0	0	0
Uinta Basin	Dakota	0		0	0	0
Uinta Basin	Frontier	0		0	0	0
Uinta Basin	Green River	0		0	0	0
Uinta Basin	Wasatch	10556	Tight	0	0	0
Paradox Basin	Cedar Mountain	0		0	0	0
Paradox Basin	Dakota	0	Tight	0	0	0
Paradox Basin	Desert Creek	0		0	0	0
Paradox Basin	Morrison	6	Tight	0	0	0
Black Mesa	Other	0		0	0	0
Piceance Basin	Mancos	1062	Tight	0	0	0
Piceance Basin	Morrison	48	Tight	0	0	0
Texas Gulf Coast	Catahoula	424	CoProd	0	0	0
Texas Gulf Coast	Cockfield	336	CoProd	0	0	0

BASIN	FORMATION	UNCONV	TYPUNCNV	PRD	RUR	UND
Texas Gulf Coast	Cook Mountain	439	CoProd	0	0	0
Texas Gulf Coast	Frio	2689	Tight	0	0	0
Texas Gulf Coast	Jackson	585	CoProd	0	0	0
Texas Gulf Coast	Marginulina	307	CoProd	0	0	0
Texas Gulf Coast	Miocene	2895	CoProd	0	0	0
Texas Gulf Coast	Oakville	102	CoProd	0	0	0
Texas Gulf Coast	Olmos	1736	Tight	0	0	0
Texas Gulf Coast	Other	8096	Tight	0	0	0
Texas Gulf Coast	Queen City	1857	CoProd	0	0	0
Texas Gulf Coast	San Miguel	760	CoProd	0	0	0
Arkoma Basin	Hartshorne Coal	3813	Coal	0	0	0
Arkoma Basin	Hunton	0		0	0	0
Arkoma Basin	Morrow	0		0	0	0
South Ok. Folded Belt	Cisco	0		0	0	0
South Ok. Folded Belt	Deese	0		0	0	0
South Ok. Folded Belt	Goddard	0		0	0	0
South Ok. Folded Belt	Granite Wash	0		0	0	0
South Ok. Folded Belt	Hart	0		0	0	0
South Ok. Folded Belt	Hoxbar	33	Tight	0	0	0
South Ok. Folded Belt	Hunton	0		0	0	0
South Ok. Folded Belt	Other	0		0	0	0
South Ok. Folded Belt	Pontotoc	0		0	0	0
South Ok. Folded Belt	Simpson	0		0	0	0
South Ok. Folded Belt	Springer	0		0	0	0
South Ok. Folded Belt	Sycamore	37	Tight	0	0	0
South Ok. Folded Belt	Viola	0		0	0	0
South Ok. Folded Belt	Woodford	0		0	0	0
Chautauqua Platform	Bartlesville	0		0	0	0
Chautauqua Platform	Booch	0		0	0	0
Chautauqua Platform	Burgess	0		0	0	0
Chautauqua Platform	Cherokee Group Coal	700	Coal	0	0	0
Chautauqua Platform	Cleveland	25	Tight	0	0	0
Chautauqua Platform	Cromwell	0		0	0	0
Chautauqua Platform	Dutcher	0		0	0	0
Chautauqua Platform	Gilcrease	0		0	0	0
Chautauqua Platform	Hart	0		0	0	0

BASIN	FORMATION	UNCONV	TYPUNCNV	PRD	RUR	UND
Chautauqua Platform	Hoover	0		0	0	0
Chautauqua Platform	Hunton	0		0	0	0
Chautauqua Platform	Layton	0		0	0	0
Chautauqua Platform	Neva	0		0	0	0
Chautauqua Platform	Osborne	0		0	0	0
Chautauqua Platform	Oswego	0		0	0	0
Chautauqua Platform	Other	0		0	0	0
Chautauqua Platform	Prue	0		0	0	0
Chautauqua Platform	Red Fork	0		0	0	0
Chautauqua Platform	Senora	0		0	0	0
Chautauqua Platform	Skinner	0		0	0	0
Chautauqua Platform	Tonkawa	0		0	0	0
Chautauqua Platform	Viola	0		0	0	0
Chautauqua Platform	Wilcox	0		0	0	0
Anadarko Basin	Arbuckle	0		0	0	0
Anadarko Basin	Cherokee	4726	Tight	0	0	0
Anadarko Basin	Cleveland	12808	Tight	0	0	0
Anadarko Basin	Council Grove	0		0	0	0
Anadarko Basin	Granite Wash	11595	Tight	0	0	0
Anadarko Basin	Hoxbar	0		0	0	0
Anadarko Basin	Kansas City	0		0	0	0
Anadarko Basin	Lansing	0		0	0	0
Anadarko Basin	Manning	0		0	0	0
Anadarko Basin	Oswego	0		0	0	0
Anadarko Basin	Springer	0		0	0	0
Anadarko Basin	Tonkawa	0		0	0	0
Anadarko Basin	Topeka	0		0	0	0
Anadarko Basin	Toronto	0		0	0	0
Anadarko Basin	Wabaunsee	0		0	0	0
Cherokee/Forest City	Cherokee Group Coal	2930	Coal	0	0	0
Cherokee/Forest City	Other	0		0	0	0
Nemaha Anticline	Bartlesville	0		0	0	0
Nemaha Anticline	Cleveland	0		0	0	0
Nemaha Anticline	Oswego	0		0	0	0
Nemaha Anticline	Other	0		0	0	0
Nemaha Anticline	Wabaunsee	0		0	0	0

BASIN	FORMATION	UNCONV	TYPUNCNV	PRD	RUR	UND
Sedgwick Basin	Douglas	0		0	0	0
Sedgwick Basin	Kansas City	0		0	0	0
Sedgwick Basin	Lansing	0		0	0	0
Sedgwick Basin	Other	0		0	0	0
Sedgwick Basin	Topeka	0		0	0	0
Central Kansas Uplift	Arbuckle	0		0	0	0
Central Kansas Uplift	Chase	0		0	0	0
Central Kansas Uplift	Cherokee	0		0	0	0
Central Kansas Uplift	Kansas City	0		0	0	0
Central Kansas Uplift	Lansing	0		0	0	0
Central Kansas Uplift	Other	0		0	0	0
Central Kansas Uplift	Simpson	0		0	0	0
Central Kansas Uplift	Topeka	0		0	0	0
Central Kansas Uplift	Viola	0		0	0	0
Central Kansas Uplift	Wabaunsee	0		0	0	0
Ouachita Tectonic Belt	Anacacho	0		0	0	0
Ouachita Tectonic Belt	Bromide	0		0	0	0
Ouachita Tectonic Belt	Mclish	0		0	0	0
Ouachita Tectonic Belt	Olmos Navarro	0		0	0	0
Ouachita Tectonic Belt	Other	0		0	0	0
Palo Duro Basin	Atoka	0		0	0	0
Palo Duro Basin	Cisco	0		0	0	0
Palo Duro Basin	Keyes	0		0	0	0
Palo Duro Basin	Morrow	0		0	0	0
Palo Duro Basin	Other	0		0	0	0
Palo Duro Basin	Topeka	0		0	0	0
Palo Duro Basin	Wichita Falls	0		0	0	0
Llano Uplift	Other	0		0	0	0
Llano Uplift	Strawn	0		0	0	0
Permian Basin	Abo	4068	Tight	0	0	0
Permian Basin	Canyon	17627	Tight	0	0	0
Permian Basin	Cisco	120	Tight	0	0	0
Permian Basin	Clear Fork	1	Tight	0	0	0
Permian Basin	Delaware	0		0	0	0
Permian Basin	Devonian	261	Tight	0	0	0
Permian Basin	Grayburg	0		0	0	0

BASIN	FORMATION	UNCONV	TYPUNCNV	PRD	RUR	UND
Permian Basin	Judkins	0		0	0	0
Permian Basin	Mckee	0		0	0	0
Permian Basin	Mcknight	0		0	0	0
Permian Basin	Montoya	0		0	0	0
Permian Basin	Morrow	3753	Tight	0	0	0
Permian Basin	Pennsylvanian	1490	Tight	0	0	0
Permian Basin	Silurian	0		0	0	0
Permian Basin	Wichita Albany	0		0	0	0
Permian Basin	Yates	0		0	0	0
Southern Basin And Range	All	0		0	0	0
Overthrust	Big Horn	0		0	0	0
Overthrust	Nugget	0		0	0	0
Overthrust	Phosphoria	0		0	0	0
Overthrust	Sun River	0		0	0	0
Overthrust	Thaynes	0		0	0	0
Overthrust	Twin Creek	0		0	0	0

HCMREG	Hydrocarbon Supply Model Region (see map)
BASCODE	AAPG Basin Code
BASIN	Basin name
FORMATION	Formation name
NRES	Number of reservoirs
NCOMP	Number of gas well completions
ULT_COMP	Average recovery per completion
AVDEPTH	Average depth
CO2AV	Carbon dioxide average
CO2MIN	Carbon dioxide minimum
CO2MAX	Carbon dioxide maximum
CO2STD	Carbon dioxide standard deviation
HEATAV	Average heating value
HEATMIN	Minimum heating value
HEATMAX	Maximum heating value
HEATSTD	Heating value standard deviation
RAW_RUR	Proven raw gas reserves as of 12/32/99
R_SAMP	Fraction of raw gas reserves sampled
GASAN	1999 raw gas production
CONVGROW	Reserve growth in existing conventional fields
CONVNEWF	Conventional new field potential
UNCONV	Undiscovered unconventional reserves
TYPUNCNV	Type of unconventional gas: TIGHT, COAL, SHALE, LOW_Btu, CoProduction
PRD	1999 production CO2>2%
RUR	1999 reserves of CO2>2%
UND	Undiscovered resources of CO2>2%

CO2 Emissions*, MMTCE

	AZ	CO	NM	OK	UT	KS	NV	TX	WY
Energy - Residential		1.6	0.5	1.1	0.7	1		3.5	
Energy - commercial		1.1	0.5	0.7	0.4	0.8		3.3	
Energy - Industrial		2.4	2.2	6.2	2.2	3.8		52.3	
Energy - Transport		5.2	4	6.5	2.8	5.2		42.1	
Energy- Utility		9.6	7.3	9.4	8.1	7.1		48.3	
Energy - Exported Electricity									
Energy - Other									
Total Energy	0	19.9	14.5	23.9	14.2	17.9	0	149.5	0
Waste				-0.2					
Agriculture				0					
Industry		0.2	0	0.3	0.4	0		0.9	
Land Use		-19.5	-1	-10.2	-0.003	0.1		4.8	
Total	0	0.6	13.5	13.8	14.597	18	0	155.2	0

* 1990 Data

Company	Plant Name	address	City	State	Zip	Phone	PhoneFree	Fax	NoKilms	K ton/y
Arizona Portland Cement Co (California Portland)	Rillito Cement Plant	11115 Casa Grande Hwy PO Box 338	Rillito	AZ	85654	520-682-2221			4	1045
Phoenix Cement Company	Clarkdale Plant	3000 W. Cement Plant Road PO Box 428	Clarkdale	AZ	86324	928-634-2261		928-634-3543	3	1618
CEMEX	Lyons Operation	5134 Ute Hwy	Lyons	CO	80503		800-492-9004		1	391
Holcim	Portland Plant	3500 Highway 120	Florence	CO	81226	719-784-6325		719-784-3470	3	761
Ash Grove	Chanute, KS Plant	1801 N. Santa Fe	Chanute	KS	66720	620-431-4500			2	440
Heartland Cement Company	Independence Plant	PO Box 428	Independence	KS	67301	316-331-0200		316-331-3890	4	272
LaFarge	Fredonia Cement Plant	1400 South Cement Road	Fredonia	KS		620-378-4458		620-378-2573	2	349
Monarch Cement Company	Humboldt Plant	449 1200 Street, PO Box 1000	Humboldt	KS	66748-1000	620-473-2222			3	611
GCC	Rio Grande Cement Plant	11783 State Highway 14 S	Tijeras	NM	87059	505-281-3311		505-281-9126	2	432
Holcim	Ada Plant	1100 West 18th St.	Ada	OK	74820	580-332-1512	800-890-9332	580-436-3273	2	554
LaFarge	Tulsa Cement Plant	2609 N. 145th East Avenue	Tulsa	OK		918-437-3902		918-234-7599	2	590
Lonestart	Pryor	PO Box 68	Pryor	OK	74362	918-825-1937			3	622
Lonestart	Maryneal	FM 608	Maryneal	TX	79556	915-228-4221			3	441
Ash Grove	Midlothian Plant	900 Gifco Road	Midlothian	TX	76065	972-723-2301			3	774
Holcim	Midlothian Plant	1800 Dove Lane	Midlothian	TX	76065	972-923-5800		972-923-5923	1	1015
TXI	Midlothian Plant	245 Ward Road	Midlothian	TX	76065	972-647-4985			4	1144
CEMEX	Balcones Plant	2580 Wald Road	New Braunfels	TX	78132		800-492-9004		1	891
TXI	Hunter Cement	7781 FM 1102	New Braunfels	TX	78132		800-292-7852		1	770
CEMEX	Odessa Operation	13 miles west of Odessa Exit 104 off Interstate 20	Odessa	TX	79776		800-492-9004		2	478
Alamo Cement	San Antonio	6055 West Green Mountain Road	San Antonio	TX	78265	210-208-1881		210-208-1990	1	769
Capitol Aggregates	San Antonio		San Antonio	TX	78265				2	763
Texas Lehigh Cement	Buda Plant	FM 2770 South	Buda	TX	78132	512-295-6111	800-252-5408	512-295-2440	1	1003
Lehigh Portland Cement	Waco Plant	PO Box 2576	Waco	TX	76720	254-776-7162			1	77
Ash Grove	Learnington, UT Plant	PO Box 51	Nephi	UT	84648	435-857-1212			1	717
Holcim	Devil's Slide Plant	6055 E. Croydon Rd.	Morgan	UT	84050	801-829-6821		801-829-2100	2	228
Mountain Cement Company	Laramie Plant	5 Sand Creek Road	Laramie	WY	82072	307-745-4879 ext 145		307-742-4534	2	585

FROM INTERCEM (cement distribution consultants)

Company	Website	US?
Aalborg Portland	Aalborg Portland	Denmark
Adelaide Brighton	Adelaide Brighton	Australian
Alsen	Alsen	Holcim Germany
Alsons Cement Corporation	Alsons Cement Corporation	Philippines
Anneliese	Anneliese	Germany
Apasco	Apasco	Holcim Mexico
Aso Cement	Aso Cement	
Australian Cement Holdings	Australian Cement Holdings	
Bacnotan Cement Corp	Bacnotan Cement Corp	
Blue Circle	Blue Circle	
Blue Circle N. America	Blue Circle N. America	
Blue Circle S. Africa	Blue Circle S. Africa	
California Portland	California Portland	AZ
Caribbean Cement	Caribbean Cement	Kingston
Castle Cement	Castle Cement	Lehigh Cement, USA
Cemento Melón	Cemento Melón	Italy
Cementos Caribe	Cementos Caribe	Holcim (Venezuela)
Cementos Catatumbo	Cementos Catatumbo	Columbia
Cementos Molins	Cementos Molins	South America
Cementos Valderrivas	Cementos Valderrivas	South America
Cemex Mexico	Cemex Mexico	Mexico
Cemroc	Cemroc	Holcim
Centex Dallas	Centex Dallas	?
Cimento Itambé	Cimento Itambé	
Ciments Calcia	Ciments Calcia	
Ciments Francais	Ciments Francais	
Ciments Nationale S.A.L.	Ciments Nationale S.A.L.	
Cimpor	Cimpor	Portugal
Cimsa Cimento Sanayi ve Ticaret A.S.	Cimsa Cimento Sanayi ve	
Civil and Marine Slag Cement Ltd	Civil and Marine Slag Cement	
CMS Cement	CMS Cement	
Cockburn Cement	Cockburn Cement	
Dyckerhoff	Dyckerhoff	
Ehdasse Sanat	Ehdasse Sanat	
ENCI	ENCI	
Galadari Cement	Galadari Cement	
Golden Bay Cement Co.	Golden Bay Cement Co.	
Gyproc	Gyproc	
Halla Group	Halla Group	
HCB	HCB	
HCB, Switzerland	HCB, Switzerland	
Heidelberger	Heidelberger	
Holcim South Africa (Pty) Limited	Holcim South Africa (Pty) Limited	
Holderbank	Holderbank	Holcim
Holdercim Brazil	Holdercim Brazil	
Holnam	Holnam	yes

Company	Website	US?
Hirocem	Hirocem	
Indocement	Indocement	
Italcementi Group	Italcementi Group	Italian
Kaiser Cement	Kaiser Cement	California
Kuwait Cement	Kuwait Cement	
Khuzestan Cement	Khuzestan Cement	
Lafarge	Lafarge	YES
Larsen & Toubro	Larsen & Toubro	India
Loma Negra	Loma Negra	
Lone Star	Lone Star	yes
Milburn Cement	Milburn Cement	
Norcem	Norcem	Noway
Origny Cement	Origny Cement	
Oskol Cement	Oskol Cement	
Oyak Group	Oyak Group	
Phinma Group	Phinma Group	
PPC	PPC	
PT Semen Andalas	PT Semen Andalas	
PT Semen Baturaja	PT Semen Baturaja	
PT Semen Cibinong	PT Semen Cibinong	
PT Indocement	PT Indocement	
PT Semen Kupang	PT Semen Kupang	
PT Semen Nusantara	PT Semen Nusantara	
PT Semen Padang	PT Semen Padang	
PT Semen Tonasa	PT Semen Tonasa	
Queensland Cement	Queensland Cement	
Quinn Group	Quinn Group	Ireland
RH Cement	RH Cement	
Riverside Cement	Riverside Cement	TXI
Rugby Group	Rugby Group	
Roanoke Cement	Roanoke Cement	
Sabanci Holding	Sabanci Holding	
Scancem	Scancem	North Europe
Siam Cement	Siam Cement	
Skanska	Skanska	
St.Lawrence	St.Lawrence	Holcim Canada
Southdown	Southdown	
Ssangyong Cement	Ssangyong Cement	
Suedwestzement	Suedwestzement	
Sumitomo	Sumitomo	
TBS Transportbeton	TBS Transportbeton	
Taiheiyo Cement Co.	Taiheiyo Cement Co.	
Taiwan Cement Corporation	Taiwan Cement Corporation	
Titan Cement	Titan Cement	Greek
Tong Yang Cement Corporation	Tong Yang Cement	Korean
TPI Cement	TPI Cement	
Turkish Factories	Turkish Factories	
TXI	TXI	Riverside

Company	Website	US?
FROM PORTLAND CEMENT ASSOCIATION		
Alamo Cement Company	Alamo Cement Company	
Arizona Portland Cement Company	Arizona Portland Cement	y
Ash Grove Cement Company	Ash Grove Cement Company	y
Ash Grove Texas, L.P.	Ash Grove Texas, L.P.	y
Buzzi Unicem USA Inc.	Buzzi Unicem USA Inc.	
California Portland Cement Company	California Portland Cement	y
Capitol Aggregates, Ltd.	Capitol Aggregates, Ltd.	
CEMEX	CEMEX	
Ciment Quebec, Inc	Ciment Quebec, Inc	
Coastal Cement Corporation	Coastal Cement Corporation	
CPC Terminals	CPC Terminals	
Dragon Products Company	Dragon Products Company	
Essroc Canada, Inc.	Essroc Canada, Inc.	
Essroc Cement Corporation	Essroc Cement Corporation	
Federal White Cement Ltd.	Federal White Cement Ltd.	
GCC America	GCC America	
Giant Cement Holding, Inc.	Giant Cement Holding, Inc.	
Glacier Northwest, Inc.	Glacier Northwest, Inc.	
Glens Falls Lehigh Cement Company	Glens Falls Lehigh Cement	
Hanson Permanente Cement, Inc.	Hanson Permanente Cement,	
Heartland Cement Company	Heartland Cement Company	
Hercules Cement Company	Hercules Cement Company	
Holcim (US) Inc.	Holcim (US) Inc.	
Illinois Cement Company	Illinois Cement Company	
Keystone Cement Company	Keystone Cement Company	
Lafarge Canada	Lafarge Canada	
Lafarge North America Inc.	Lafarge North America Inc.	
Lehigh Cement Company	Lehigh Cement Company	
Lehigh Inland Cement Limited	Lehigh Inland Cement Limited	
Lehigh Northwest Cement Company	Lehigh Northwest Cement	
Lehigh Northwest Cement Limited	Lehigh Northwest Cement	
Lehigh Southwest Cement Company	Lehigh Southwest Cement	
Mitsubishi Cement Corporation	Mitsubishi Cement Corporation	
Phoenix Cement Company	Phoenix Cement Company	
Rinker Materials Corporation	Rinker Materials Corporation	
River Cement Company	River Cement Company	
RMC Pacific Materials, Inc.	RMC Pacific Materials, Inc.	
Signal Mountain Cement Company	Signal Mountain Cement	
St. Lawrence Cement Company	St. Lawrence Cement Company	
St. Lawrence Cement, Inc.	St. Lawrence Cement, Inc.	
St. Marys Cement Inc.	St. Marys Cement Inc.	
Suwannee American Cement	Suwannee American Cement	
Texas Industries, Inc.	Texas Industries, Inc.	
Texas-Lehigh Cement Company	Texas-Lehigh Cement Company	
The Monarch Cement Company	The Monarch Cement Company	

Licensor/Construction	City	State	Tonnes/yea	Feedstock
Agrium Inc	Borger	TX	439	NG
Air Products	Pensacola	FL	46	NG
Allied Signal	Hopewell	WV	409	NG
Ampro	Donaldsonville	LA	386	NG
Arcadian	Geismar	LA	501	NG/RG
Arcadian	Clinton	IA	237	NG
Arcadian	Augusta	GA	576	NG
Arcadian	La Platte	NE	182	NG
Arcadian	Lima	OH	523	NG
Arcadian	Memphis	TN	340	NG
Arcadian	Woodstock	TN	356	NG
Avondale Ammonia	Fortier	LA	399	NG
Borden Chemical	Geismar	LA	363	NG
CF Industries	Donaldsonville	LA	1740	NG
Coastal St. Helens Chemical	St. Helens	OR	85	NG
Coastal Chem	Cheyenne	WY	172	NG
Cytec Industries	Avondale	LA	385	NG
Dakota Gasification Co.	Beulah ND	ND	91	N/A
Du Pont Beaumont	Beaumont	TX	364	NG
Farmland Industries	Beatrice	NE	255	NG
Farmland Industries	Dodge City	KS	255	NG
Farmland Industries	Enid	OK	919	NG
Farmland Industries	Fort Dodge	IO	241	NG
Farmland Industries	Lawrence	KS	409	NG
Farmland Industries	Pollock	LA	459	NG
Greenvalley Chemical	Creston	IA	33	NG
IMC Agrico	Donaldsonville LA 482,000 NG	LA	482	NG
IMC Nitrogen Co.	East Dubuque	IL	269	NG
J.R. Simplot Co.	Pocatello	ID	93	NG
Koch Industries	Sterlington	LA	1,110	NG
LaRoche Ind	Cherokee	AL	159	NG
Missippi Chemical Co.	Yazoo City	MS	364	NG
Missippi Chemical Co.	Donaldsonville	LA	409	NG
Missippi Chemical Co.	Donaldsonville	LA	500	NG
Monsanto	Luling	LA	446	NG
Nitromite Fertilizer	Dumas	TX	128	NG
Shoreline Chem	Gordon	GA	31	H2
Terra International	Blythville	AR	364	NG/FO
Terra International	Sergeant Bluff	IA	319	NG/FO
Terra International	Verdigris OK	OK	955	NG/FO
Terra International	Woodward City	OK	446	NG/FO
Union Chemical Co. (Unocal)	Finley	WA	150	NG/FO
Union Chemical Co. (Unocal)	Kenia	AK	1180	NG
Wil-Grow Fertilizer	Pryor	OK	86	NG
			17656	

Notes: Feedstock: Natural Gas (NG), Refinery Gas (RG), Fuel Oil (FO), Hydrogen (H2)

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www.energystar.gov/ia/business/industry/LBNL-44314.pdf

Company	City	State	k METRIC TONS/YEAR
Farmland Industires	Dodge City	KS	255
Farmland Industires	Lawrence	KS	409
Farmland Industires	Enid	OK	919
Wil-Grow Fertilizer Co.	Pryor	OK	86
Terra International	Verdigris	OK	955
Terra International	Woodward	OK	446
E. I. du Pont de Nemours & Co. Inc.	Beaumont	TX	433
Agrium Inc.	Borger	TX	439
Nitromite Fertilizer Dumas	Dumas	TX	128
Coastal Chem, Inc.	Cheyenne	WY	172

Company	City	State	Capacity (Kt/year)[a]	Age of Process in 1994*[b]	Process[c]
Ashta Chemicals	Ashtabula	OH	36	31	KCl electrolysis; mercury cell; KOH by-product
BF Goodrich	Calvert City	KY	109	28	Salt; mercury cell; diaphragm
Dow	Freeport	TX	2,041	54	MgCl containing brines; diaphragm and by-product of magnesium metal production
Dow	Plaquemine	LA	1,075	36	Brine; diaphragm
DuPont	Niagara Falls	NY	77	96	Downs; By-product of metallic sodium production
Elf Atochem	Portland	OR	169	47	Salt; diaphragm
Formosa Plastics	Baton Rouge	LA	180	13	Brine; diaphragm (upgraded in 1981)
Formosa Plastics	Point Comfort	TX	505	0	Membrane
Fort Howard	Green Bay	WI	8	26	Rocksalt; diaphragm
Fort Howard	Muskogee	OK	5	9	Rocksalt; membrane (upgraded 1985)
Fort Howard	Rincon	GA	6	4	
GE	Burkville	AL	24	7	Membrane
GE	Mount Vernon	IN	50	18	Captive brine; diaphragm
Georgia Gulf Corp.	Plaquemine	LA	410	19	Captive brine; diaphragm
Georgia Gulf Corp.	Bellingham	WA	82	29	Salt; mercury cell
HoltraChem	Acme	NC	48	31	Salt; mercury cell
HoltraChem	Orrington	ME	73	27	Salt; mercury cell
La Roche Holdings Inc.	Gramercy	LA	181	36	Brine; diaphragm
Miles Inc.	Baytown	TX	82	22	By-Product HCl; HCl electrolysis
Niachlor Inc.	Niagara Falls	NY	218	7	Brine; membrane (upgraded 1987)
Occidental	Convent	LA	279	13	Captive salt dome; diaphragm
Occidental	Corpus Christi	TX	417	20	Brine; diaphragm
Occidental	Deer Park	TX	347	56	Captive salt dome; mercury cell; diaphragm
Occidental	Delaware City	DE	126	29	Salt mercury cell
Occidental	La Porte	TX	480	20	Captive salt dome; diaphragm
Occidental	Mobile	AL	41	3	Mercury cell; KOH is produced; membrane (upgraded 1991)
Occidental	Muscle Shoals	AL	132	42	Mercury cell; KOH is produced
Occidental	Niagara Falls	NY	293	20	Captive salt dome; diaphragm (upgraded 1974)
Occidental	Tacoma	WA	195	6	Rock salt; diaphragm; membrane (upgraded 1988)
Occidental	Taft	LA	581	19/8	Captive salt dome; diaphragm (upgraded 1975); membrane (upgraded in 1986)
Olin Corporation	Augusta	GA	102	29	Salt; mercury cell
Olin Corporation	Charleston	TN	230	32	Rock salt; mercury cell
Olin Corporation	McIntosh	AL	365	17	Brine diaphragm (upgraded 1977)
Olin Corporation	Niagara Falls	NY	82	34	Rock salt; mercury cell (upgraded 1960)
Oregon Metallugical Corp.	Albany	OR	2	23	Magnesium chloride; by-product of metallic magnesium
PioneerChlor Alkali Co.	Henderson	NV	104	18	Salt; diaphragm (upgraded 1976)
PioneerChlor Alkali Co.	St. Gabriel	LA	160	24	Salt; mercury cell
PPG Industries	Lake Charles	LA	1,126	25/17	Brine; mercury cell (upgraded 1969); diaphragm (upgraded 1977)
PPG Industries	Natrium	WV	356	36/10	Brine; mercury cell (upgraded 1958); diaphragm (upgraded 1984)
Renco Group (Magnesium Corp. of America)	Rowley	UT	14	17	Brine; by-product of magnesium metal production
Vicksburg Chemical Co.	Vicksburg	MS	33	32	By-product of production of potassium nitrate from KCl
Vulcan Materials Co.	Geismar	LA	243	18	Brine; diaphragm
Vulcan Materials Co.	Port Edwards	WI	65	27	Salt; mercury cell; KOH is also produced
Vulcan Materials Co.	Wichita	KS	239	19/11	Brine; diaphragm (upgraded 1975); membrane (upgraded 1983)
Weyerhaeuser	Longview	WA	136	19	Brine; diaphragm (upgraded 1975)
TOTAL			11,525	29[d]	
Total Production			10,973[e]		

a. Capacity numbers taken from Directory of Chemical Producers (DCP), SRI International FOR 1994
b. Cell type data and year of plant upgrade taken from Chlorine Institute Pamphlet 10 (1994)
c. Process data taken from DCP
d. Capacity weighted average age
e. Chemical Manufacturers Association
*Time since last major upgrade

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Company	Location	State	Year of start up	Ethylene Capacity (ktonne/a)	Feedstock Mix (%)						Licensor, Remarks
					Ethane	Propane	Butane	Naphtha	Gas oil	Other	
Amoco	Chocolate Bayou	TX		1,451	36%	40%	0%	24%	0%		Braun ?
Chevron	Cedar Bayou	TX		681	25%	40%	5%	30%	0%		Stone & Webster
Chevron	Port Arthur	TX		784	80%	20%	0%	0%	0%		
Concea Vista	Lake Charles	LA	1968	430	100%	0%	0%	0%	0%		Lummus; Including expansion of 150kt in 1990; Formerly Vista Chemicals
Dow	Freeport	TX		1,224	50%	50%	0%	0%	0%		
Dow	Freeport	TX			50%	50%	0%	0%	0%		
Dow	Plaquemine	LA		1,102	50%	50%	0%	0%	0%		
Dow	Plaquemine	LA			25%	25%	25%	25%	0%		
DuPont	Orange	TX		590	50%	50%	0%	0%	0%		Lummus
Eastman	Long-view	TX		675	30%	50%	5%	15%	0%		Lummus/Kelloggg ?
Equistar	Channelview	TX		873	5%	5%	5%	40%	45%		Before 1997: Lyondell
Equistar	Channelview	TX		873	5%	5%	5%	40%	45%		Before 1997: Lyondell
Equistar	Clinton	IA	1968	435	95%	5%	0%	0%	0%		Kelloggg; Before 1997 Quantum; Expansion planned of 37kt in 1997
Equistar	LaPorte	TX	1991	789	80%	20%	0%	0%	0%		Before 1997: Quantum; Expansion planned of 182kt in 1996
Equistar	Morris	IL	1971	512	90%	10%	0%	0%	0%		Lummus; Before 1997: Quantum; Including expansion of 32kt in 1996
Exxon	Baton Rouge	LA	1973	882	0%	0%	0%	0%	0%		Kelloggg; Including expansion in 1993
Exxon	Baytown	TX		1,890	0%	0%	0%	0%	0%		Kelloggg; Including expansion of 700kt in 1997 by Lummus/Exxon
Formosa Plastics	Point Comfort	TX	1994	714	45%	25%	0%	15%	15%		Kelloggg Millisecond; Expansion planned of 204kt in 1997
Huntsman	Port Arthur	TX	1978	551	0%	0%	0%	60%	0%	40% LPG	Stone & Webster; Before 1994: Texaco
Huntsman	Port Neches	TX		136	50%	50%	0%	0%	0%	RG	Scientific Design
Javelina Co.	Corpus Christi	TX		108	0%	0%	0%	0%	0%	100% RG	
Mobil	Beaumont	TX	1975	566	70%	24%	6%	0%	0%		Stone & Webster; Expansion planned of 250kt in 1995
Mobil	Houston	TX		342	70%	30%	0%	0%	0%		Kelloggg
Occidental	Chocolate Bayou	TX	1980	500	0%	0%	0%	75%	25%		Brown & Root, Lummus
Occidental	Corpus Christi	TX	1980	773	15%	30%	0%	35%	20%		Stone & Webster
Occidental	Lake Charles	LA	1986	364	50%	50%	0%	0%	0%		Lummus Crest
Philips	Sweeny	TX		2,040	70%	30%	0%	0%	0%		
Philips	Sweeny	TX	1978		92%	8%	0%	0%	0%		
Philips	Sweeny	TX			75%	25%	0%	0%	0%		Selas, debottlenecking 1990
Philips	Sweeny	TX	1990		30%	60%	10%	0%	0%		1,000kt Braun, 1990; Including expansion of 227kt in 1996
Rexene Prod.	Odessa	TX		230	50%	50%	0%	0%	0%		Expansion planned of 188kt in 1998
Shell	Deer Park	TX		952	10%	0%	0%	60%	30%		Kellogg
Shell	Norco	LA	1976	793	0%	0%	0%	30%	70%		Kellogg
Shell	Norco	LA	1976	535	50%	0%	0%	50%	0%		Kellogg: Including expansion of 182kt in 1996
Sun	Brandenburg	KY		45	100%	0%	0%	0%	0%		Lummus
Sun Marcus	Hook	PA		102	0%	0%	0%	0%	0%		
Union Carbide	Seadrift	TX	1962	415	80%	20%	0%	0%	0%		
Union Carbide	Taft	LA	1978	680	30%	30%	0%	40%	0%		Wulff/Lummus, restarted in 1989; expansion planned of 318kt in 1997
Union Carbide	Texas City	TX		680	0%	60%	10%	30%	0%		
Union Texas	Geismar	LA	1968	545	82%	18%	0%	0%	0%		Lummus
Westlake Pol	Calvert City	KY	1964	170	0%	100%	0%	0%	0%		Braun; Before 1994: BF Goodrich
Westlake Pol	Lake Charles	LA	1992	1,043	80%	20%	0%	0%	0%		Kellogg Millisecond; Including 590kt expansion in 1997
Total				**25,475**							

Type	Operator	Field	State	County	Pay zone	Formation	Project Maturity
CO2 Immiscible	Chaparral Energy	Sho-Vel-Tum	OK	Stephens	Aldridge	Sandstone	
CO2 Misible	Amerada Hess	Adair San Andres Unit	TX	Gaines	San Andres	Dolomite	js
CO2 Misible	Amerada Hess	Seminole Unit-Main Pay Zone	TX	Gaines	San Andres	Dolomite	hf
CO2 Misible	Amerada Hess	Seminole Unit-ROZ Phase 1	TX	Gaines	San Andres	Dolomite	hf
CO2 Misible	Anadarko	Bradley Unit	OK	Garvin/Gardy	Springer	Sandstone	js
CO2 Misible	Anadarko	Northeast Prudy	OK	Garvin	Springer	Sandstone	hf
CO2 Misible	Anadarko	Patrick Draw Monell	WY	Sweetwater	Mesaverde Almond	Sandstone	js
CO2 Misible	Anadarko	Slaughter (HT Boyd lease)	TX	Cochran	San Andres	Dolomite	js
CO2 Misible	Chaparral Energy	Camrick	OK	Beaver	Morrow	Sandstone	js
CO2 Misible	Chaparral Energy	Sho-Vel-Tum	OK	Stephens	Sims	Sandstone	hf
CO2 Misible	ChevronTexaco	Goldsmith	TX	Ector	San Andres	Dolomite	js
CO2 Misible	ChevronTexaco	Greater Aneth	UT	San Juan	Desert Creek	Limestone	js
CO2 Misible	ChevronTexaco	Mabee	TX	Andrews-Martin	San Andres	Dolomite	nc
CO2 Misible	ChevronTexaco	Rangely Weber Sand	CO	Rio Blanco	Weber SS	Sandstone	js
CO2 Misible	ChevronTexaco	Slaughter Sundown	TX	Hockley Co	San Andres	Dolomite	hf
CO2 Misible	ChevronTexaco	Vacuum	NM	Lea Co.	San Andres	Dolomite	js
CO2 Misible	ExxonMobil	Cordona Lake	TX	Crane	Devonian	Tripolite	hf
CO2 Misible	ExxonMobil	GMK South	TX	Gaines	San Andres	Dolomite	js
CO2 Misible	ExxonMobil	Greater Aneth Area	UT	San Juan	Ismay Desert Creek	Limestone	js
CO2 Misible	ExxonMobil	Means (San Andres)	TX	Andrews-Martin	San Andres	Dolomite	
CO2 Misible	ExxonMobil	Postle	OK	Texas	Morrow	SS	
CO2 Misible	ExxonMobil	Salt Creek	TX	Kent	Canyon	Limestone	
CO2 Misible	ExxonMobil	Sharon Ridge	TX	Scurry	Canyon Reef	Limestone	
CO2 Misible	ExxonMobil	Slaughter	TX	Hockley & Terry	San Andres	Dolomite	
CO2 Misible	ExxonMobil	Slaughter	TX	Hockley & Cochran	San Andres	Dolomite	
CO2 Misible	ExxonMobil	Wasson	TX	Yoakum	San Andres	Dolomite	
CO2 Misible	ExxonMobil	Wasson (Cornell Unit)	TX	Yoakum	San Andres	Dolomite	
CO2 Misible	Fasken	Hanford	TX	Gaines	San Andres	Dolomite	
CO2 Misible	Fasken	Hanford East	TX	Gaines	San Andres	Dolomite	
CO2 Misible	First Permian	East Penwell (SA) Unit	TX	Ector	San Andres	Dolomite	
CO2 Misible	Great Western Drilling	Twofreds	TX	Loving, Ward, Reeves	Delawar, Ramsey	Sandstone	
CO2 Misible	Kinder Morgan	SACROC	TX	Scurry	Canyon Reef	Limestone	
CO2 Misible	Merit Energy	Lost Soldier	WY	Sweetwater	Tensleep	Sandstone	
CO2 Misible	Merit Energy	Lost Soldier	WY	Sweetwater	Darwin-Madiison	Sandstone	
CO2 Misible	Merit Energy	Lost Soldier	WY	Sweetwater	Cambrian	Sandstone	
CO2 Misible	Merit Energy	Wertz	WY	Carbon, Sweetwater	Tensleep	Sandstone	
CO2 Misible	Merit Energy	Wertz	WY	Carbon, Sweetwater	Darwin-Madiison	s/Limestone-Dolomite	
CO2 Misible	Murfin Drilling	Hall-Gurney	KS	Russell	LKC XC	Limestone	
CO2 Misible	Occidental Permian	Alex Slughter Estate	TX	Hockley	San Andres	Dolomite/Limestone	
CO2 Misible	Occidental Permian	Anton Irish	TX	Hale	Clearfork	Dolomite	

Type	Operator	Field	State	County	Pay zone	Formation	Project Maturity
CO2 Misible	Occidental Permian	Bennett Ranch Unit	TX	Yoakum	San Andres	Dolomite	
CO2 Misible	Occidental Permian	Cedar Lake	TX	Gaines	San Andres	Dolomite	
CO2 Misible	Occidental Permian	Cogdell	TX	Scurry/Kent	Canyon Reef	Limestone	
CO2 Misible	Occidental Permian	Mid Cross - Devonian Unit	TX	Crane, Upton & Crockett	Devonian	Tripolite	
CO2 Misible	Occidental Permian	N. Cross	TX	Crane & Upton	Devonian	Tripolite	
CO2 Misible	Occidental Permian	North Cowden	TX	Ector	Grayburg	Dolomite	
CO2 Misible	Occidental Permian	North Hobbs	NM	Lea Co.	San Andres	Dolomite	
CO2 Misible	Occidental Permian	S. Cross - Devonian Unit	TX	Crockett	Devonian	Tripolite	
CO2 Misible	Occidental Permian	Slaughter (Central Mallet)	TX	Hockley	San Andres	Dolomite/Limestone	
CO2 Misible	Occidental Permian	Slaughter Estate	TX	Hockley	San Andres	Dolomite/Limestone	
CO2 Misible	Occidental Permian	Slaughter Frazier	TX	Hockley	San Andres	Dolomite/Limestone	
CO2 Misible	Occidental Permian	T-Star (Slaughter Consolidated)	TX	Hockley	Abo	Dolomite	
CO2 Misible	Occidental Permian	Wasson (Denver)	TX	Yoakum & Gaines	San Andres	Dolomite	
CO2 Misible	Occidental Permian	Wasson ODC	TX	Yoakum	San Andres	Dolomite/Limestone	
CO2 Misible	Occidental Permian	Wasson-Willard	TX	Yoakum	San Andres	Dolomite	
CO2 Misible	Orla Petco	East Ford	TX	Reeves	Delaware, Ramsey	Sandstone	
CO2 Misible	Oxy USA	El-Mar	TX	Loving	Delaware	Sandstone	
CO2 Misible	Oxy USA	North dollarhide	TX	Andrews	Devonian	Tripolite	
CO2 Misible	Oxy USA	South Welch	TX	Dawson	San Andres	Dolomite	
CO2 Misible	Oxy USA	West Welch	TX	Gaines	San Andres	Dolomite	
CO2 Misible	Phillips	South Cowden	TX	Lea Co.	San Andres	Dolomite	
CO2 Misible	Phillips	Vacuum	NM	Lea Co.	San Andres	Dolomite	
CO2 Misible	Pioneer Natural Resources	Sprayberry	TX	Midland	Sprayberry	Sandstone	
CO2 Misible	Pure Resources	Dollarhide (Clearfork "A" Unit)	TX	Andrews	Clearfork	Dolomite	
CO2 Misible	Pure Resources	Dollarhide (Devonian) Unit	TX	Andrews	Devonian	Dolomite/Tripolite	
CO2 Misible	Pure Resources	Reinecke	TX	Borden	Cisco Canyon Reef	Dolomite/Limestone	
CO2 Misible	Stanberry Oil	Hansford Marmaton	TX	Hansford	Marmaton	Sandstone	
Hot Water	Carrizo	Camp Hill	TX	Anderson	Carrizo	Sandstone	hf
N2 Immiscible	ExxonMobil	Hawkins	TX	Woodbine-East FB	Woodbine	Sandstone	
N2 Immiscible	ExxonMobil	Hawkins	TX	Woodbine-West FB	Woodbine	Sandstone	
N2 Immiscible	Marthon Oil	Yates	TX	Pecos & Crockett	Grayburg/San Andres	Dolomite	
Polymer/Chemical	Ballard & Associates	Mitten Prong	WY	Crook	Minnelusa	Sandstone	
Polymer/Chemical	Continental Resources	Cottenwood Creek	WY	Washakie	Phosphoria	L	
Steam	Marathon	Yates	TX	Pecos & Crockett	Grayburg/San Andres	Dolomite	js

Operator	Field	Proj. Eval	Profit	Project Scope
Chaparral Energy	Sho-Vel-Tum			
Amerada Hess	Adair San Andres Unit	prom		p
Amerada Hess	Seminole Unit-Main Pay Zone	succ	y	fw
Amerada Hess	Seminole Unit-ROZ Phase 1	prom		p
Anadarko	Bradley Unit	prom		el
Anadarko	Northeast Prudy	succ		fw
Anadarko	Patrick Draw Monell	tett		lw
Anadarko	Slaughter (HT Boyd lease)	prom		lw
Chaparral Energy	Camrick	succ	y	Phase 1 (1/3 FW)
Chaparral Energy	Sho-Vel-Tum	succ	y	fw
ChevronTexaco	Goldsmith	tett		p
ChevronTexaco	Greater Aneth	prom	y	p
ChevronTexaco	Mabee	succ	n	fw
ChevronTexaco	Rangely Weber Sand	succ		fw
ChevronTexaco	Slaughter Sundown	succ	y	lw
ChevronTexaco	Vacuum	succ	y	lw
ExxonMobil	Cordona Lake	prom	y	lw
ExxonMobil	GMK South	succ	y	lw
ExxonMobil	Greater Aneth Area	succ	y	lw
ExxonMobil	Means (San Andres)			
ExxonMobil	Postle			
ExxonMobil	Salt Creek			
ExxonMobil	Sharon Ridge			
ExxonMobil	Slaughter			
ExxonMobil	Slaughter			
ExxonMobil	Wasson			
ExxonMobil	Wasson (Cornell Unit)			
Fasken	Hanford			
Fasken	Hanford East			
First Permian	East Penwell (SA) Unit			
Great Western Drilling	Twofreds			
Kinder Morgan	SACROC			
Merit Energy	Lost Soldier			
Merit Energy	Lost Soldier			
Merit Energy	Lost Soldier			
Merit Energy	Wertz			
Merit Energy	Wertz			
Murfin Drilling	Hall-Gurney			
Occidental Permian	Alex Slughter Estate			
Occidental Permian	Anton Irish			

Operator	Field	Proj. Eval	Profit	Project Scope
Occidental Permian	Bennett Ranch Unit			
Occidental Permian	Cedar Lake			
Occidental Permian	Cogdell			
Occidental Permian	Mid Cross - Devonian Unit			
Occidental Permian	N. Cross			
Occidental Permian	North Cowden			
Occidental Permian	North Hobbs			
Occidental Permian	S. Cross - Devonian Unit			
Occidental Permian	Slaughter (Central Mallet)			
Occidental Permian	Slaughter Estate			
Occidental Permian	Slaughter Frazier			
Occidental Permian	T-Star (Slaughter Consolidated)			
Occidental Permian	Wasson (Denver)			
Occidental Permian	Wasson ODC			
Occidental Permian	Wasson-Willard			
Orla Petco	East Ford			
Oxy USA	El-Mar			
Oxy USA	North dollarhide			
Oxy USA	South Welch			
Oxy USA	West Welch			
Phillips	South Cowden			
Phillips	Vacuum			
Pioneer Natural Resources	Sprayberry			
Pure Resources	Dollarhide (Clearfork "A" Unit)			
Pure Resources	Dollarhide (Devonian) Unit			
Pure Resources	Reinecke			
Stanberry Oil	Hansford Marmaton			
Carrizo	Camp Hill	succ		lw
ExxonMobil	Hawkins			
ExxonMobil	Hawkins			
Marthon Oil	Yates			
Ballard & Associates	Mitten Prong			
Continental Resources	Cottenwood Creek			
Marathon	Yates	prom		p

STATE	ORIS_ CODE	FACILITY_NAME	UNIT_ID	YEAR	SumOf CO2_TONS	SumOf SO2_TONS	SumOf NOX_TONS	SumOf HEAT_INPUT	SumOf TOTAL_ OPERATING_HOURS	DESCRIPTION_ SPECIFIC	DESCRIPTION_ GENERIC	CO2_ CONCENTRATION
AZ	141	Agua Fria Generating Station	1	2002	133741.8	2	307.8	2252797	2339	Natural Gas	Natural Gas	0.045
AZ	141	Agua Fria Generating Station	2	2002	47458.7	1.5	116.5	800198	1908	Natural Gas	Natural Gas	0.045
AZ	141	Agua Fria Generating Station	3	2002	241576	5.4	1154	4069773	3927	Natural Gas	Natural Gas	0.045
AZ	160	Apache Station	1	2002	165726.2	0.8	194.3	2788345	5262	Natural Gas	Natural Gas	0.045
AZ	160	Apache Station	2	2002	1514137.5	2720.9	3398.5	14869246	8554	Coal	Coal	0.12
AZ	160	Apache Station	3	2002	1383705	2445.2	2934.5	13532211	7843	Coal	Coal	0.12
AZ	160	Apache Station	4	2002	5278.9		0.7	88828	278	Natural Gas	Natural Gas	0.045
AZ	118	APS Saguaro Power Plant	1	2002	64080.3	0.4	79.5	1078270	1994	Natural Gas	Natural Gas	0.045
AZ	118	APS Saguaro Power Plant	2	2002	71897.6	0.4	80.4	1209839	2082	Natural Gas	Natural Gas	0.045
AZ	118	APS Saguaro Power Plant	CT3	2002	19261.2		4.8	324128	562	Natural Gas	Natural Gas	0.045
AZ	113	Cholla	1	2002	1039269.7	961.4	1857.3	10135096	8466	Coal	Coal	0.12
AZ	113	Cholla	2	2002	2174596.6	1420.3	3375.1	21208981	7430	Coal	Coal	0.12
AZ	113	Cholla	3	2002	2202917.5	8830.9	3393.3	21469660	8556	Coal	Coal	0.12
AZ	113	Cholla	4	2002	2933904.6	9557.3	4255.3	28625404	8019	Coal	Coal	0.12
AZ	6177	Coronado Generating Station	U1B	2002	2638379.3	7808.8	5236.9	25715201	7750	Coal	Coal	0.12
AZ	6177	Coronado Generating Station	U2B	2002	3066213	9918.5	6696	29885143	8336	Coal	Coal	0.12
AZ	124	De Moss Petrie Generating Station	GT1	2002	45909.6		8.8	772533	1426	Natural Gas	Natural Gas	0.045
AZ	55129	Desert Basin Generating Station	DBG1	2002	794992.2	4.2	68.2	13377300	7807	Natural Gas	Natural Gas	0.045
AZ	55129	Desert Basin Generating Station	DBG2	2002	769892.8	4.1	71.4	12954947	7527	Natural Gas	Natural Gas	0.045
AZ	55282	Duke Energy Arlington Valley	CTG1	2002	145238.7	0.6	15.3	2443933	1834	Natural Gas	Natural Gas	0.045
AZ	55282	Duke Energy Arlington Valley	CTG2	2002	159424.2	0.8	17.8	2682628	2028	Natural Gas	Natural Gas	0.045
AZ	55124	Griffith Energy LLC	P1	2002	313868.6	1.7	49.8	5281387	3912	Natural Gas	Natural Gas	0.045
AZ	55124	Griffith Energy LLC	P2	2002	381844.2	2	59.6	6425231	4757	Natural Gas	Natural Gas	0.045
AZ	126	Irvington Generating Station	1	2002	109272.8	0.5	190.3	1838717	5081	Natural Gas	Natural Gas	0.045
AZ	126	Irvington Generating Station	2	2002	102942.7	0.5	212	1732244	4396	Natural Gas	Natural Gas	0.045
AZ	126	Irvington Generating Station	3	2002	209219.1	1.1	394.9	3520437	7321	Natural Gas	Natural Gas	0.045
AZ	126	Irvington Generating Station	4	2002	805643.8	3116.5	1742.8	7895976	8607	Coal	Coal	0.12
AZ	147	Kyrene Generating Station	K-1	2002	7686.9	0.3	18.1	129682	443	Natural Gas	Natural Gas	0.045
AZ	147	Kyrene Generating Station	K-2	2002	40839.1	1.8	241	688822	1017	Diesel Fuel Oil	Diesel Oil	0
AZ	147	Kyrene Generating Station	K-7	2002	301357	1.5	31	5070942	3652	Natural Gas	Natural Gas	0.045
AZ	4941	Navajo Generating Station	1	2002	6684086.9	1272.9	11630.8	65147476	8524	Coal	Coal	0.12
AZ	4941	Navajo Generating Station	2	2002	6828039.5	1151.7	11677.8	66550066	8200	Coal	Coal	0.12
AZ	4941	Navajo Generating Station	3	2002	6946138.6	1582.7	12260.1	67701145	8551	Coal	Coal	0.12
AZ	116	Ocotillo Power Plant	1	2002	116851.4	0.6	107.5	1966274	4579	Natural Gas	Natural Gas	0.045
AZ	116	Ocotillo Power Plant	2	2002	71308.1	0.4	54.8	1199791	2832	Natural Gas	Natural Gas	0.045
AZ	55522	PPL Sundance Energy, LLC	CT01	2002	1684.1		0.5	28340	88	Natural Gas	Natural Gas	0.045
AZ	55522	PPL Sundance Energy, LLC	CT02	2002	1331.7		0.4	22407	67	Natural Gas	Natural Gas	0.045
AZ	55522	PPL Sundance Energy, LLC	CT03	2002	1884		0.8	31711	92	Natural Gas	Natural Gas	0.045
AZ	55522	PPL Sundance Energy, LLC	CT04	2002	2115.9		0.5	35604	108	Natural Gas	Natural Gas	0.045
AZ	55522	PPL Sundance Energy, LLC	CT05	2002	2490.4		1	41913	141	Natural Gas	Natural Gas	0.045
AZ	55522	PPL Sundance Energy, LLC	CT06	2002	1832.7		0.6	30839	99	Natural Gas	Natural Gas	0.045
AZ	55522	PPL Sundance Energy, LLC	CT07	2002	1646.9		0.9	27712	100	Natural Gas	Natural Gas	0.045
AZ	55522	PPL Sundance Energy, LLC	CT08	2002	1699.8		0.5	28598	94	Natural Gas	Natural Gas	0.045
AZ	55522	PPL Sundance Energy, LLC	CT09	2002	1090.2		0.4	18345	61	Natural Gas	Natural Gas	0.045
AZ	55522	PPL Sundance Energy, LLC	CT10	2002	1743.7		0.6	29340	100	Natural Gas	Natural Gas	0.045
AZ	55455	Redhawk Generating Facility	CC1A	2002	243260.7	1.3	20	4092393	2938	Natural Gas	Natural Gas	0.045
AZ	55455	Redhawk Generating Facility	CC1B	2002	237534.1	1.2	21.2	4018817	2900	Natural Gas	Natural Gas	0.045
AZ	55455	Redhawk Generating Facility	CC2A	2002	181829.7	1	16.8	3060963	2233	Natural Gas	Natural Gas	0.045
AZ	55455	Redhawk Generating Facility	CC2B	2002	158908.4	0.8	14.5	2675648	1944	Natural Gas	Natural Gas	0.045
AZ	55177	South Point Energy Center, LLC	A	2002	552496.5	2.8	42.8	9296828	6905	Natural Gas	Natural Gas	0.045
AZ	55177	South Point Energy Center, LLC	B	2002	679503.7	3.4	54	11433969	7767	Natural Gas	Natural Gas	0.045
AZ	8223	Springerville Generating Station	1	2002	3171808.8	9807.1	6342.5	30914350	7876	Coal	Coal	0.12
AZ	8223	Springerville Generating Station	2	2002	3279265	10055.1	6229.2	31961643	8692	Coal	Coal	0.12
AZ	117	West Phoenix Power Plant	CC4	2002	226569.2	1	58.8	3812454	5454	Natural Gas	Natural Gas	0.045
AZ	120	Yuma Axis	1	2002	204545.6	1.6	194.4	3441418	7980	Natural Gas	Natural Gas	0.045
CO	465	Arapahoe	1	2002	414718.5	1060.4	1412.4	4044321	7836	Coal	Coal	0.12
CO	465	Arapahoe	2	2002	312828.5	758.3	1095.8	3049897	6044	Coal	Coal	0.12
CO	465	Arapahoe	3	2002	501346.8	1344.8	1772	4890120	8274	Coal	Coal	0.12
CO	465	Arapahoe	4	2002	957691	1944	1062.8	9336380	8256	Coal	Coal	0.12
CO	55200	Arapahoe Combustion Turbine	CT5	2002	29847.8		15.2	502285	1834	Natural Gas	Natural Gas	0.045

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CO	55200	Arapahoe Combustion Turbine	CT6	2002	32566.8	0.1	16.3	548024	1921	Natural Gas	Natural Gas	0.045
CO	10682	Brush 3	GT2	2002	48454.8	0.1	35.5	815339	1559	Natural Gas	Natural Gas	0.045
CO	55209	Brush 4	GT4	2002	29278.8		20.5	492680	1231	Natural Gas	Natural Gas	0.045
CO	55209	Brush 4	GT5	2002	30093.7		20.8	506386	1180	Natural Gas	Natural Gas	0.045
CO	468	Cameo	2	2002	434629.2	2095.4	819.2	4239546	8641	Coal	Coal	0.12
CO	469	Cherokee	1	2002	918504.6	3082.4	1459.4	8970803	8148	Coal	Coal	0.12
CO	469	Cherokee	2	2002	629958	2526.5	2472.4	6203590	5837	Coal	Coal	0.12
CO	469	Cherokee	3	2002	995926.4	3082.8	1557.9	9797921	7240	Coal	Coal	0.12
CO	469	Cherokee	4	2002	2216333.6	7265.2	3985.6	21731931	7498	Coal	Coal	0.12
CO	470	Comanche (470)	1	2002	2893746.9	8023.9	4773.2	28241573	7662	Coal	Coal	0.12
CO	470	Comanche (470)	2	2002	2799628.5	8749.5	4036.5	27300712	8550	Coal	Coal	0.12
CO	6021	Craig	C1	2002	3640704.6	4261.1	6607.4	35484468	8484	Coal	Coal	0.12
CO	6021	Craig	C2	2002	3906720.9	4736.7	7428.1	38077168	8687	Coal	Coal	0.12
CO	6021	Craig	C3	2002	3117803.8	1393.1	5345.6	30387919	8248	Coal	Coal	0.12
CO	6112	Fort St. Vrain	2	2002	778987	4.1	236.5	13107969	8524	Natural Gas	Natural Gas	0.045
CO	6112	Fort St. Vrain	3	2002	751052.4	3.7	166.1	12637865	8147	Natural Gas	Natural Gas	0.045
CO	6112	Fort St. Vrain	4	2002	778000.8	4	90.8	13091422	8456	Natural Gas	Natural Gas	0.045
CO	55453	Fountain Valley Combustion Turbine	1	2002	63771.4		48	1073099	3564	Natural Gas	Natural Gas	0.045
CO	55453	Fountain Valley Combustion Turbine	2	2002	54535.8		41.3	917668	3168	Natural Gas	Natural Gas	0.045
CO	55453	Fountain Valley Combustion Turbine	3	2002	44622.2		34.7	750816	2656	Natural Gas	Natural Gas	0.045
CO	55453	Fountain Valley Combustion Turbine	4	2002	40160.7		29.4	675764	2413	Natural Gas	Natural Gas	0.045
CO	55453	Fountain Valley Combustion Turbine	5	2002	38041.9		30.9	640100	2343	Natural Gas	Natural Gas	0.045
CO	55453	Fountain Valley Combustion Turbine	6	2002	32341.9		24.1	544193	2039	Natural Gas	Natural Gas	0.045
CO	55505	Frank Knutson Station	BR1	2002	42783.3	0.2	9.4	719922	990	Natural Gas	Natural Gas	0.045
CO	55505	Frank Knutson Station	BR2	2002	33868.3	0.1	6.7	569905	791	Natural Gas	Natural Gas	0.045
CO	525	Hayden	H1	2002	1932554.4	1242.1	4139.2	18836044	8345	Coal	Coal	0.12
CO	525	Hayden	H2	2002	2500623	1625.7	4464	24378570	8498	Coal	Coal	0.12
CO	55504	Limon Generating Station	L1	2002	21022.5	0.1	6.1	352372	599	Natural Gas	Natural Gas	0.045
CO	55504	Limon Generating Station	L2	2002	16947.3	0.1	4.6	283861	499	Natural Gas	Natural Gas	0.045
CO	55127	Manchief Station	CT1	2002	260661.7	1.3	114.5	4381502	4168	Natural Gas	Natural Gas	0.045
CO	55127	Manchief Station	CT2	2002	266772.9	1.3	120.2	4481751	4215	Natural Gas	Natural Gas	0.045
CO	492	Martin Drake	5	2002	399761.1	1577.6	793.6	3915442	8671	Coal	Coal	0.12
CO	492	Martin Drake	6	2002	778866.7	3019.1	1414.7	7651219	8439	Coal	Coal	0.12
CO	492	Martin Drake	7	2002	1014376	3932.4	1996.7	9967348	7260	Coal	Coal	0.12
CO	527	Nucla	1	2002	922996.4	1486.8	1332.6	9001128	8265	Coal	Coal	0.12
CO	6248	Pawnee	1	2002	3968365.8	14832.4	4591.8	38786014	7563	Coal	Coal	0.12
CO	6761	Rawhide Energy Station	101	2002	2491624.2	898.3	4006.8	24284891	7916	Coal	Coal	0.12
CO	6761	Rawhide Energy Station	A	2002	13747.2		3.7	231328	396	Natural Gas	Natural Gas	0.045
CO	6761	Rawhide Energy Station	B	2002	2188.5		0.8	36832	66	Natural Gas	Natural Gas	0.045
CO	6761	Rawhide Energy Station	C	2002	4110.3		2.7	69155	122	Natural Gas	Natural Gas	0.045
CO	8219	Ray D Nixon	1	2002	1881113.9	4968.2	2830.9	18339258	8285	Coal	Coal	0.12
CO	8219	Ray D Nixon	2	2002	8293.8		2.3	139574	553	Natural Gas	Natural Gas	0.045
CO	8219	Ray D Nixon	3	2002	2087.5		0.8	35139	150	Natural Gas	Natural Gas	0.045
CO	477	Valmont	5	2002	1362313.4	3786.3	2056.9	13293777	7393	Coal	Coal	0.12
CO	55207	Valmont Combustion Turbine Facility	CT7	2002	17770.4		13.7	299018	1185	Natural Gas	Natural Gas	0.045
CO	55207	Valmont Combustion Turbine Facility	CT8	2002	17885.7		13.1	300987	1181	Natural Gas	Natural Gas	0.045
CO	478	Zuni	1	2002	35069.1		66	590132	4177	Natural Gas	Natural Gas	0.045
CO	478	Zuni	2	2002	3989.4		2.8	67135	1661	Natural Gas	Natural Gas	0.045
CO	478	Zuni	3	2002	12028.1		29.4	202401	539	Natural Gas	Natural Gas	0.045
KS	1235	Arthur Mullergren	3	2002	67408.1	0.4	129	1133717	2654	Natural Gas	Natural Gas	0.045
KS	3355	Chanute 2	14	2002	2704.1		1.9	45505	105	Natural Gas	Natural Gas	0.045
KS	1230	Cimarron River	1	2002	85124.5	0.5	159.3	1432397	4452	Natural Gas	Natural Gas	0.045
KS	1271	Coffeyville	4	2002	30683.5		31.5	516299	2154	Natural Gas	Natural Gas	0.045
KS	7013	East 12th Street	4	2002	2968.6		6.1	53026	695	Natural Gas	Natural Gas	0.045
KS	1336	Garden City	S-2	2002	93535.7	0.4	209.8	1573896	2870	Natural Gas	Natural Gas	0.045
KS	1240	Gordon Evans Energy Center	1	2002	113886.4	617.6	258.7	1544185	1893	Natural Gas	Natural Gas	0.045
KS	1240	Gordon Evans Energy Center	2	2002	244868.3	3210.4	2023.1	6844242	3603	Natural Gas	Natural Gas	0.045
KS	1240	Gordon Evans Energy Center	E1CT	2002	13487.7		4.6	224801	363	Natural Gas	Natural Gas	0.045
KS	1240	Gordon Evans Energy Center	E2CT	2002	16216		6.6	276910	433	Natural Gas	Natural Gas	0.045
KS	1240	Gordon Evans Energy Center	E3CT	2002	66153.3	0.3	15.3	1113547	945	Natural Gas	Natural Gas	0.045

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KS	108	Holcomb	SGU1	2002	2728827.3	1669.4	3849	26626279	8299	Coal	Coal	0.12
KS	1248	Hutchinson Energy Center	1	2002						Natural Gas	Natural Gas	0.045
KS	1248	Hutchinson Energy Center	2	2002						Natural Gas	Natural Gas	0.045
KS	1248	Hutchinson Energy Center	3	2002						Natural Gas	Natural Gas	0.045
KS	1248	Hutchinson Energy Center	4	2002	135996.3	734.4	267.1	1902244	2490	Natural Gas	Natural Gas	0.045
KS	6068	Jeffrey Energy Center	1	2002	5552739.3	20458.9	9601.6	54120215	8208	Coal	Coal	0.12
KS	6068	Jeffrey Energy Center	2	2002	6449234.2	23715.3	10891.5	62858016	8157	Coal	Coal	0.12
KS	6068	Jeffrey Energy Center	3	2002	6721075.7	23206.1	10807.4	65507710	8096	Coal	Coal	0.12
KS	1233	Judson Large	4	2002	216254	1.1	407.8	3638851	6806	Natural Gas	Natural Gas	0.045
KS	1294	Kaw	1	2002						Natural Gas	Natural Gas	0.045
KS	1294	Kaw	2	2002						Coal	Coal	0.12
KS	1294	Kaw	3	2002	7350.7		14.6	124012	463	Natural Gas	Natural Gas	0.045
KS	1241	La Cygne	1	2002	5602433.8	6648.1	30057.6	54604668	7590	Coal	Coal	0.12
KS	1241	La Cygne	2	2002	5743929.5	19355.1	8362	55983770	8134	Coal	Coal	0.12
KS	1250	Lawrence Energy Center	3	2002	561000.2	1965.3	728.5	5467804	7790	Coal	Coal	0.12
KS	1250	Lawrence Energy Center	4	2002	1142450.3	1429.8	1986.7	11138048	8498	Coal	Coal	0.12
KS	1250	Lawrence Energy Center	5	2002	3508525.9	4353.8	3546.2	34196134	8324	Coal	Coal	0.12
KS	1305	McPherson 2	1	2002	606.5		0.8	10203	58	Natural Gas	Natural Gas	0.045
KS	7515	McPherson 3	1	2002	6724.4		10.6	112740	231	Natural Gas	Natural Gas	0.045
KS	1242	Murray Gill Energy Center	1	2002						Natural Gas	Natural Gas	0.045
KS	1242	Murray Gill Energy Center	2	2002	1693.4		4.5	29035	100	Natural Gas	Natural Gas	0.045
KS	1242	Murray Gill Energy Center	3	2002	79988.3	452.3	181.6	1082865	1879	Natural Gas	Natural Gas	0.045
KS	1242	Murray Gill Energy Center	4	2002	20144.9	333.3	103.9	620470	1276	Natural Gas	Natural Gas	0.045
KS	6064	Nearman Creek	N1	2002	1923067.1	7625	3860.2	18782216	7477	Coal	Coal	0.12
KS	1243	Neosho Energy Center	7	2002	13.4			220	8	Natural Gas	Natural Gas	0.045
KS	1295	Quindaro	1	2002	448540	1283.3	1772.7	4442357	5978	Coal	Coal	0.12
KS	1295	Quindaro	2	2002	731297.2	2061.9	913.1	7234579	7890	Coal	Coal	0.12
KS	1239	Riverton	39	2002	266788.3	2392.7	584.8	2622178	8446	Coal	Coal	0.12
KS	1239	Riverton	40	2002	407769	1039.5	874.6	3992110	8170	Coal	Coal	0.12
KS	1252	Tecumseh Energy Center	10	2002	1257561.6	4515	1876.9	12256919	8329	Coal	Coal	0.12
KS	1252	Tecumseh Energy Center	9	2002	788385.2	2692.8	1530.7	7684021	8630	Coal	Coal	0.12
NM	55210	Afton Generating Station	1	2002	13834.3	0.2	8.1	179423	183	Natural Gas	Natural Gas	0.045
NM	2454	Cunningham	121B	2002	148770	0.8	237.3	2509619	5726	Natural Gas	Natural Gas	0.045
NM	2454	Cunningham	122B	2002	542656.2	2.7	1021.8	9154050	8375	Natural Gas	Natural Gas	0.045
NM	2454	Cunningham	123T	2002	40253	0.1	27	679029	724	Natural Gas	Natural Gas	0.045
NM	2454	Cunningham	124T	2002	45807.7	0.1	31.5	772730	824	Natural Gas	Natural Gas	0.045
NM	2442	Four Corners Steam Elec Station	1	2002	1408312.4	3113.8	5445.4	13740127	7453	Coal	Coal	0.12
NM	2442	Four Corners Steam Elec Station	2	2002	1706921.9	3345.3	5203.9	16632803	8147	Coal	Coal	0.12
NM	2442	Four Corners Steam Elec Station	3	2002	2037207.6	4324.3	5754	19873581	8406	Coal	Coal	0.12
NM	2442	Four Corners Steam Elec Station	4	2002	5926809.2	13274.6	16502.9	57787847	8145	Coal	Coal	0.12
NM	2442	Four Corners Steam Elec Station	5	2002	3850893.8	8789.6	8670.7	37592637	5887	Coal	Coal	0.12
NM	7967	Lordsburg Generating Station	1	2002	7892.3		13.5	132785	510	Natural Gas	Natural Gas	0.045
NM	7967	Lordsburg Generating Station	2	2002	8103.1		6.8	136337	461	Natural Gas	Natural Gas	0.045
NM	2446	Maddox	051B	2002	278825.3	1.4	422.4	4703558	6523	Natural Gas	Natural Gas	0.045
NM	54814	Milagro	1	2002	253582.2	1.2	50.6	4267029	8406	Natural Gas	Natural Gas	0.045
NM	54814	Milagro	2	2002	229221.7	1.1	46.9	3857071	7711	Natural Gas	Natural Gas	0.045
NM	55039	Person Generating Project	GT-1	2002	25863	0.1	11.7	434865	480	Natural Gas	Natural Gas	0.045
NM	87	Prewitt Escalante Generating Statio	1	2002	1759793.3	1191.9	3469.8	17152014	8108	Coal	Coal	0.12
NM	2450	Reeves Generating Station	1	2002	25993.6		47.5	437369	1555	Natural Gas	Natural Gas	0.045
NM	2450	Reeves Generating Station	2	2002	20379.1		38	342937	1282	Natural Gas	Natural Gas	0.045
NM	2450	Reeves Generating Station	3	2002	48131.8	0.1	87.7	809875	2191	Natural Gas	Natural Gas	0.045
NM	2444	Rio Grande	6	2002	119341.9	0.8	215	2008236	5769	Natural Gas	Natural Gas	0.045
NM	2444	Rio Grande	7	2002	131582.2	0.9	159.6	2214072	6617	Natural Gas	Natural Gas	0.045
NM	2444	Rio Grande	8	2002	250875	1.3	537.3	4221386	5363	Natural Gas	Natural Gas	0.045
NM	2451	San Juan	1	2002	2519850	2553.9	5209.6	24550141	7406	Coal	Coal	0.12
NM	2451	San Juan	2	2002	2807211.4	2705.8	5976.1	27460582	8463	Coal	Coal	0.12
NM	2451	San Juan	3	2002	4487946.2	5589.4	9404.2	43742324	8278	Coal	Coal	0.12
NM	2451	San Juan	4	2002	4674481.5	5918.6	9762.8	45582346	8405	Coal	Coal	0.12
OK	3006	Anadarko	3	2002	3736.2		8.7	62860	466	Natural Gas	Natural Gas	0.045
OK	3006	Anadarko	7	2002	9292.3		6.2	156365	438	Natural Gas	Natural Gas	0.045

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OK	3006	Anadarko	8	2002	8765.2		6.7	147480	443	Natural Gas	Natural Gas	0.045
OK	7757	Chouteau Power Plant	1	2002	228556.8	1.3	60.6	3845890	2848	Natural Gas	Natural Gas	0.045
OK	7757	Chouteau Power Plant	2	2002	256877.9	1.2	62.7	4322463	3247	Natural Gas	Natural Gas	0.045
OK	8059	Comanche (8059)	7251	2002	361711.1	2	1529.9	6086401	7605	Natural Gas	Natural Gas	0.045
OK	8059	Comanche (8059)	7252	2002	378655.3	2.2	1443.9	6371486	7886	Natural Gas	Natural Gas	0.045
OK	7185	Conoco	**1	2002	177871.2	4.8	253.4	2993122	7897	Blast Furnace Gas	Other Gas	0
OK	7185	Conoco	**2	2002	191127.7	4.9	252.3	3216120	8377	Blast Furnace Gas	Other Gas	0
OK	165	Grand River Dam Authority	1	2002	3669801.5	13428.1	8292.9	35878645	7956	Coal	Coal	0.12
OK	165	Grand River Dam Authority	2	2002	4245903.2	3797.3	7094.1	41497880	7779	Coal	Coal	0.12
OK	55146	Green Country Energy, LLC	CTGEN1	2002	265970.8	1.3	65.6	4475473	3289	Natural Gas	Natural Gas	0.045
OK	55146	Green Country Energy, LLC	CTGEN2	2002	280994.2	1.4	67.9	4728243	3335	Natural Gas	Natural Gas	0.045
OK	55146	Green Country Energy, LLC	CTGEN3	2002	261679.5	1.2	67.9	4403264	3324	Natural Gas	Natural Gas	0.045
OK	2951	Horseshoe Lake	10	2002	10724.7		6.5	180467	491	Natural Gas	Natural Gas	0.045
OK	2951	Horseshoe Lake	6	2002	305417.3	1.5	608.6	5139231	5357	Natural Gas	Natural Gas	0.045
OK	2951	Horseshoe Lake	7	2002	294323.4	50.2	357.3	4942621	4223	Natural Gas	Natural Gas	0.045
OK	2951	Horseshoe Lake	8	2002	265980.6	1.4	627.1	4475648	2675	Natural Gas	Natural Gas	0.045
OK	2951	Horseshoe Lake	9	2002	11094.4		7.1	186697	499	Natural Gas	Natural Gas	0.045
OK	6772	Hugo	1	2002	3332938.3	8556.3	3831.9	32490593	7864	Coal	Coal	0.12
OK	55457	McClain Energy Facility	CT1	2002	299647.2	1.4	92.7	5042137	3893	Natural Gas	Natural Gas	0.045
OK	55457	McClain Energy Facility	CT2	2002	274900.3	1.3	79.1	4625697	3481	Natural Gas	Natural Gas	0.045
OK	3008	Mooreland	1	2002	17365.2		56.4	292228	1069	Natural Gas	Natural Gas	0.045
OK	3008	Mooreland	2	2002	107935.5	0.5	140.8	1816241	3656	Natural Gas	Natural Gas	0.045
OK	3008	Mooreland	3	2002	9433.6		9.6	158744	315	Natural Gas	Natural Gas	0.045
OK	2952	Muskogee	3	2002	195632.8	1	416.9	3291908	3376	Natural Gas	Natural Gas	0.045
OK	2952	Muskogee	4	2002	3604378.1	8586.2	5924.8	35169194	7128	Coal	Coal	0.12
OK	2952	Muskogee	5	2002	3643972.2	9068.5	5573.3	35556691	7366	Coal	Coal	0.12
OK	2952	Muskogee	6	2002	4056011.6	9865.9	5828.6	39591431	7868	Coal	Coal	0.12
OK	2953	Mustang	1	2002	5664.8		10.6	95327	253	Natural Gas	Natural Gas	0.045
OK	2953	Mustang	2	2002	3908.2		6.9	65753	186	Natural Gas	Natural Gas	0.045
OK	2953	Mustang	3	2002	159760.1	0.7	566.2	2688239	4340	Natural Gas	Natural Gas	0.045
OK	2953	Mustang	4	2002	481433.8	2.1	1844.1	8101065	6529	Natural Gas	Natural Gas	0.045
OK	2963	Northeastern	3301A	2002	392639.5	1.9	94.1	6606855	4630	Natural Gas	Natural Gas	0.045
OK	2963	Northeastern	3301B	2002	423596.9	2.1	87.5	7127866	4650	Natural Gas	Natural Gas	0.045
OK	2963	Northeastern	3302	2002	551186.2	2.8	1994.9	9274771	4532	Natural Gas	Natural Gas	0.045
OK	2963	Northeastern	3313	2002	4239209.6	18048.1	8279.8	41317831	8609	Coal	Coal	0.12
OK	2963	Northeastern	3314	2002	3861042.8	16457.4	7630	37631949	8060	Coal	Coal	0.12
OK	55225	Oneta Energy Center (Panda Oneta)	CTG-1	2002	90943.1	0.5	23	1530311	1018	Natural Gas	Natural Gas	0.045
OK	55225	Oneta Energy Center (Panda Oneta)	CTG-2	2002	72590	0.4	18.7	1221469	834	Natural Gas	Natural Gas	0.045
OK	762	Ponca	2	2002	112.9		0.2	1902	8	Natural Gas	Natural Gas	0.045
OK	762	Ponca	3	2002	33589.7		23.6	565185	1475	Natural Gas	Natural Gas	0.045
OK	4940	Riverside (4940)	1501	2002	621869.2	3.1	1215.8	10464083	4501	Natural Gas	Natural Gas	0.045
OK	4940	Riverside (4940)	1502	2002	877193	4.3	1792.2	14760411	7476	Natural Gas	Natural Gas	0.045
OK	2956	Seminole (2956)	1	2002	815283.2	4.2	1191.2	13718634	7666	Natural Gas	Natural Gas	0.045
OK	2956	Seminole (2956)	2	2002	680817.5	3.5	1496.9	11456038	6115	Natural Gas	Natural Gas	0.045
OK	2956	Seminole (2956)	3	2002	650131.7	9.1	1312.8	10938561	6896	Natural Gas	Natural Gas	0.045
OK	6095	Sooner	1	2002	4325174.3	10644.3	7391.7	42181821	8625	Coal	Coal	0.12
OK	6095	Sooner	2	2002	3061159.3	7748.5	4937.9	29849643	6619	Coal	Coal	0.12
OK	2964	Southwestern	8002	2002	33676.9		83.7	566701	8496	Natural Gas	Natural Gas	0.045
OK	2964	Southwestern	8003	2002	553357.9	2.7	2734.2	9311182	7950	Natural Gas	Natural Gas	0.045
OK	2964	Southwestern	801N	2002	12000.2		34.1	201933	7833	Natural Gas	Natural Gas	0.045
OK	2964	Southwestern	801S	2002	12162.1		37	204618	7821	Natural Gas	Natural Gas	0.045
OK	2965	Tulsa	1402	2002	80916.1	0.4	240.1	1361586	2901	Natural Gas	Natural Gas	0.045
OK	2965	Tulsa	1403	2002						Natural Gas	Natural Gas	0.045
OK	2965	Tulsa	1404	2002	70265.8	0.2	198.6	1182302	2361	Natural Gas	Natural Gas	0.045
TX	10670	AES Deepwater, Inc.	1001	2002	899152.1	2788.8	2372	8609303	5042	Municipal Waste	Other	0
TX	3602	Alex Ty Cooke Generating Station	1	2002	49272.6	0.1	80.7	829146	2991	Natural Gas	Natural Gas	0.045
TX	3602	Alex Ty Cooke Generating Station	2	2002	28644		41.4	481990	1759	Natural Gas	Natural Gas	0.045
TX	4939	Barney M. Davis	1	2002	483318.9	88.4	875.7	7976325	5403	Natural Gas	Natural Gas	0.045
TX	4939	Barney M. Davis	2	2002	556510.3	2.8	527	9364343	6136	Natural Gas	Natural Gas	0.045
TX	55168	Bastrop Clean Energy Center	CTG-1A	2002	346687.8	1.8	161.3	5833673	4003	Natural Gas	Natural Gas	0.045

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TX	55168	Bastrop Clean Energy Center	CTG-1B	2002	316234.2	1.7	210.6	5321288	3895	Natural Gas	Natural Gas	0.045
TX	55195	Baytown Energy Center	CTG-1	2002	438682.2	4.7	32.1	7381639	4888	Natural Gas	Natural Gas	0.045
TX	55195	Baytown Energy Center	CTG-2	2002	488023.3	5.3	37.5	8211944	5427	Natural Gas	Natural Gas	0.045
TX	55195	Baytown Energy Center	CTG-3	2002	448687.5	4.9	30.8	7549998	4884	Natural Gas	Natural Gas	0.045
TX	3497	Big Brown	1	2002	5354233.9	43412.7	3810.1	50485258	8278	Coal	Coal	0.12
TX	3497	Big Brown	2	2002	4245873.9	34447.7	3394.6	40202337	6529	Coal	Coal	0.12
TX	55064	Blackhawk Station	1	2002	678695	3.9	376.3	11420347	8339	Natural Gas	Natural Gas	0.045
TX	55064	Blackhawk Station	2	2002	653267.1	3.9	411.9	10992535	8190	Natural Gas	Natural Gas	0.045
TX	55172	Bosque County Power Plant	GT-1	2002	18566.6		8	312412	272	Natural Gas	Natural Gas	0.045
TX	55172	Bosque County Power Plant	GT-2	2002	29392		8.3	494585	408	Natural Gas	Natural Gas	0.045
TX	55172	Bosque County Power Plant	GT-3	2002	720749.4	3.6	192	12127958	8100	Natural Gas	Natural Gas	0.045
TX	3561	Bryan	6	2002	12275.7		22.9	207641	3602	Natural Gas	Natural Gas	0.045
TX	3574	C E Newman	BW5	2002	4408.6		3.6	74173	1189	Natural Gas	Natural Gas	0.045
TX	3460	Cedar Bayou	CBY1	2002	788750	4	679.7	13272229	6291	Natural Gas	Natural Gas	0.045
TX	3460	Cedar Bayou	CBY2	2002	547534.2	2.8	621.4	9212594	3646	Natural Gas	Natural Gas	0.045
TX	3460	Cedar Bayou	CBY3	2002	1144988	5.7	579.1	19266635	5520	Natural Gas	Natural Gas	0.045
TX	55299	Channel Energy Center	CTG1	2002	805835.5	3.4	77.6	13558870	7945	Other Gas	Other Gas	0
TX	55299	Channel Energy Center	CTG2	2002	485518.5	2.4	45.5	8168765	5251	Other Gas	Other Gas	0
TX	54817	Cleburne Cogeneration Facility	EAST	2002	685700.6	3.5	177.8	11538102	7203	Natural Gas	Natural Gas	0.045
TX	50815	Cogen Lyondell, Inc.	ENG101	2002	197801.1	1.2	202	3328286	4468	Natural Gas	Natural Gas	0.045
TX	50815	Cogen Lyondell, Inc.	ENG201	2002	204354	1.2	205.8	3438714	4454	Natural Gas	Natural Gas	0.045
TX	50815	Cogen Lyondell, Inc.	ENG301	2002	141537	0.6	141.8	2381525	3370	Natural Gas	Natural Gas	0.045
TX	50815	Cogen Lyondell, Inc.	ENG401	2002	118001.9	0.6	123.5	1985644	2799	Natural Gas	Natural Gas	0.045
TX	50815	Cogen Lyondell, Inc.	ENG501	2002	126480.9	0.6	127.4	2128240	2953	Natural Gas	Natural Gas	0.045
TX	50815	Cogen Lyondell, Inc.	ENG601	2002	243120.1	1.2	83.2	4090779	4484	Natural Gas	Natural Gas	0.045
TX	6178	Coleto Creek	1	2002	4378288	14288.5	3554.2	42673354	8436	Coal	Coal	0.12
TX	3500	Collin	1	2002	57085.2	0.8	26.6	959950	1358	Natural Gas	Natural Gas	0.045
TX	55206	Corpus Christi Energy Center	CU1	2002	126917.4	0.6	34.3	2221266	1452	Natural Gas	Natural Gas	0.045
TX	55206	Corpus Christi Energy Center	CU2	2002	148820.4	0.8	38.3	2601559	1949	Natural Gas	Natural Gas	0.045
TX	6243	Dansby	1	2002	179994.9	1.2	192.6	3027751	8163	Natural Gas	Natural Gas	0.045
TX	3548	Decker Creek	1	2002	323490.2	1.5	286	5443290	3509	Natural Gas	Natural Gas	0.045
TX	3548	Decker Creek	2	2002	662586.5	5.6	564.1	11146989	7829	Natural Gas	Natural Gas	0.045
TX	8063	Decordova	1	2002	1788280	10.7	5630.7	30079343	7479	Natural Gas	Natural Gas	0.045
TX	3461	Deepwater	DWP9	2002	29340.9	0.1	32.3	493711	665	Natural Gas	Natural Gas	0.045
TX	3436	E S Joslin	1	2002	76790	0.4	179.2	1292129	1270	Natural Gas	Natural Gas	0.045
TX	3489	Eagle Mountain	1	2002	88448.9	0.3	192	1488340	2406	Natural Gas	Natural Gas	0.045
TX	3489	Eagle Mountain	2	2002	145081.1	3.7	249.1	2443032	2903	Natural Gas	Natural Gas	0.045
TX	3489	Eagle Mountain	3	2002	420807.8	2.1	494.2	7080983	4150	Natural Gas	Natural Gas	0.045
TX	55176	Eastman Cogeneration Facility	1	2002	813350.1	4.2	196.4	13686142	8039	Natural Gas	Natural Gas	0.045
TX	55176	Eastman Cogeneration Facility	2	2002	748483.4	3.7	174	12594587	7461	Natural Gas	Natural Gas	0.045
TX	55223	Ennis-Tractebel Power Company	GT-1	2002	423456.1	2.2	127.4	7125474	3734	Natural Gas	Natural Gas	0.045
TX	55365	Exelon Laporte Generating Station	GT-1	2002	2970.2	1.6	3.7	50315	224	Natural Gas	Natural Gas	0.045
TX	55365	Exelon Laporte Generating Station	GT-2	2002	1215.3	0.5	1.5	20590	92	Natural Gas	Natural Gas	0.045
TX	55365	Exelon Laporte Generating Station	GT-3	2002	3696.7	1.9	4.7	62656	215	Natural Gas	Natural Gas	0.045
TX	55365	Exelon Laporte Generating Station	GT-4	2002	2203.1	1.2	2.8	37334	141	Natural Gas	Natural Gas	0.045
TX	4938	Fort Phantom Power Station	1	2002	158724.9	0.8	321.8	2670829	3332	Natural Gas	Natural Gas	0.045
TX	4938	Fort Phantom Power Station	2	2002	402748.5	2.1	438.1	6776981	6780	Natural Gas	Natural Gas	0.045
TX	55226	Freestone Power Generation	GT1	2002	416812.7	2	87.1	7013702	4299	Natural Gas	Natural Gas	0.045
TX	55226	Freestone Power Generation	GT2	2002	430459.8	2.2	96.3	7243286	4399	Natural Gas	Natural Gas	0.045
TX	55226	Freestone Power Generation	GT3	2002	323669.8	1.7	76.8	5446340	3284	Natural Gas	Natural Gas	0.045
TX	55226	Freestone Power Generation	GT4	2002	288918.3	1.6	69.1	4861652	2930	Natural Gas	Natural Gas	0.045
TX	55098	Frontera Power Facility	1	2002	322408	1.5	87.9	5425145	4275	Natural Gas	Natural Gas	0.045
TX	55098	Frontera Power Facility	2	2002	285062.5	1.6	76	4796752	3600	Natural Gas	Natural Gas	0.045
TX	6136	Gibbons Creek Steam Electric Station	1	2002	3215146.4	10815.9	2381.9	31336586	7722	Coal	Coal	0.12
TX	3490	Graham	1	2002	353333.3	38.3	989.5	5965847	4636	Natural Gas	Natural Gas	0.045
TX	3490	Graham	2	2002	410942.5	23.2	1070.5	6974732	4033	Natural Gas	Natural Gas	0.045
TX	3464	Greens Bayou	GBY5	2002	193999.1	1	107.8	3264180	2671	Natural Gas	Natural Gas	0.045
TX	55086	Gregory Power Facility	101	2002	929418.7	4.6	284.5	15639300	8218	Natural Gas	Natural Gas	0.045
TX	55086	Gregory Power Facility	102	2002	946756.5	4.7	258.6	15931063	8104	Natural Gas	Natural Gas	0.045
TX	55153	Guadalupe Generating Station	CTG-1	2002	522406	2.5	195.7	8790454	6187	Natural Gas	Natural Gas	0.045

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TX	55153	Guadalupe Generating Station	CTG-2	2002	379021.3	1.8	152.2	6377715	4521	Natural Gas	Natural Gas	0.045
TX	55153	Guadalupe Generating Station	CTG-3	2002	342966.8	1.7	128.6	5771086	4198	Natural Gas	Natural Gas	0.045
TX	55153	Guadalupe Generating Station	CTG-4	2002	412104.2	1.9	119.8	6934502	4927	Natural Gas	Natural Gas	0.045
TX	7902	H W Pirkey Power Plant	1	2002	5265723.5	19475.4	4748.6	48367081	7700	Coal	Coal	0.12
TX	3491	Handley Steam Electric Station	1A	2002	6405.7		8.4	107798	617	Natural Gas	Natural Gas	0.045
TX	3491	Handley Steam Electric Station	1B	2002	4754.8		3.6	80024	595	Natural Gas	Natural Gas	0.045
TX	3491	Handley Steam Electric Station	2	2002	35611.5	0.1	90.7	599210	1065	Natural Gas	Natural Gas	0.045
TX	3491	Handley Steam Electric Station	3	2002	661141.2	3.4	811.4	11125011	4440	Natural Gas	Natural Gas	0.045
TX	3491	Handley Steam Electric Station	4	2002	530118.3	2.6	639.1	8920323	4282	Natural Gas	Natural Gas	0.045
TX	3491	Handley Steam Electric Station	5	2002	380821.2	1.9	468.9	6408043	2708	Natural Gas	Natural Gas	0.045
TX	6193	Harrington Station	061B	2002	3378963.3	9197	4647.1	32933342	8531	Coal	Coal	0.12
TX	6193	Harrington Station	062B	2002	3150196.3	8926.6	4330.3	30703664	7821	Coal	Coal	0.12
TX	6193	Harrington Station	063B	2002	3158293.3	8843.8	4162.1	30782560	8634	Coal	Coal	0.12
TX	55144	Hays Energy Project	STK1	2002	216288.2	1.1	40.6	3639416	2850	Natural Gas	Natural Gas	0.045
TX	55144	Hays Energy Project	STK2	2002	251783.6	1.1	42.3	4236793	3170	Natural Gas	Natural Gas	0.045
TX	55144	Hays Energy Project	STK3	2002	206462.2	1	41.4	3474128	2587	Natural Gas	Natural Gas	0.045
TX	55144	Hays Energy Project	STK4	2002	146973.6	0.8	22.5	2473083	1828	Natural Gas	Natural Gas	0.045
TX	7762	Hidalgo Energy Facility	HRSG1	2002	398410.3	2.1	101	6704089	5064	Natural Gas	Natural Gas	0.045
TX	7762	Hidalgo Energy Facility	HRSG2	2002	465809	2.3	119.7	7838241	5721	Natural Gas	Natural Gas	0.045
TX	3549	Holly Street	1	2002	19781.6		23.7	332854	597	Natural Gas	Natural Gas	0.045
TX	3549	Holly Street	2	2002	4070.4		4.6	68486	375	Natural Gas	Natural Gas	0.045
TX	3549	Holly Street	3	2002	87974	0.6	77.6	1480327	1616	Natural Gas	Natural Gas	0.045
TX	3549	Holly Street	4	2002	175442.2	0.9	187.5	2951265	2832	Natural Gas	Natural Gas	0.045
TX	7097	J K Spruce	**1	2002	4440721.1	4781.4	4145.8	43281895	7798	Coal	Coal	0.12
TX	3438	J L Bates	1	2002	125605.8	0.6	1346.9	2113499	4540	Natural Gas	Natural Gas	0.045
TX	3438	J L Bates	2	2002	109224.4	0.5	250.8	1837855	3503	Natural Gas	Natural Gas	0.045
TX	3604	J Robert Massengale Generating Station	GT1	2002	128835.7	0.9	50.9	2167905	7390	Natural Gas	Natural Gas	0.045
TX	6181	J T Deely	1	2002	3079186.3	9964.4	2849.2	30011592	8213	Coal	Coal	0.12
TX	6181	J T Deely	2	2002	3516017.7	11604.7	3285.3	34269229	8558	Coal	Coal	0.12
TX	3482	Jones Station	151B	2002	611853.4	3.1	1213.6	10321409	7692	Natural Gas	Natural Gas	0.045
TX	3482	Jones Station	152B	2002	683477.9	3.6	692.7	11529613	8448	Natural Gas	Natural Gas	0.045
TX	3476	Knox Lee Power Plant	2	2002	2574.1		3.1	43326	258	Natural Gas	Natural Gas	0.045
TX	3476	Knox Lee Power Plant	3	2002	2950.2		4	49645	248	Natural Gas	Natural Gas	0.045
TX	3476	Knox Lee Power Plant	4	2002	51330		63.9	863628	1441	Natural Gas	Natural Gas	0.045
TX	3476	Knox Lee Power Plant	5	2002	403853.9	2.2	483	6795289	5964	Natural Gas	Natural Gas	0.045
TX	3442	La Palma	7	2002	289769.6	1.2	628.1	4875851	5100	Natural Gas	Natural Gas	0.045
TX	3502	Lake Creek	1	2002	34816.2	0.1	82	585851	740	Natural Gas	Natural Gas	0.045
TX	3502	Lake Creek	2	2002	192486.2	1.2	478.2	3238521	3158	Natural Gas	Natural Gas	0.045
TX	3452	Lake Hubbard	1	2002	335450.1	12.3	371.8	5605395	3602	Natural Gas	Natural Gas	0.045
TX	3452	Lake Hubbard	2	2002	835411.8	29.6	244	13993792	5559	Natural Gas	Natural Gas	0.045
TX	55097	Lamar Power (Paris)	1	2002	562768.9	2.8	162.8	9469660	6758	Natural Gas	Natural Gas	0.045
TX	55097	Lamar Power (Paris)	2	2002	588721.4	2.9	143.2	9906382	7019	Natural Gas	Natural Gas	0.045
TX	55097	Lamar Power (Paris)	3	2002	562769.7	2.7	138.9	9469768	6802	Natural Gas	Natural Gas	0.045
TX	55097	Lamar Power (Paris)	4	2002	551195.2	2.7	149.1	9274961	6748	Natural Gas	Natural Gas	0.045
TX	3439	Laredo	1	2002	55806.9	0.1	128.3	939039	3838	Natural Gas	Natural Gas	0.045
TX	3439	Laredo	2	2002	42469.3		111	714627	3034	Natural Gas	Natural Gas	0.045
TX	3439	Laredo	3	2002	248647.5	1.7	239.9	4181362	6696	Natural Gas	Natural Gas	0.045
TX	3609	Leon Creek	3	2002						Natural Gas	Natural Gas	0.045
TX	3609	Leon Creek	4	2002						Natural Gas	Natural Gas	0.045
TX	3457	Lewis Creek	1	2002	771379.8	3.8	1100	12979986	7358	Natural Gas	Natural Gas	0.045
TX	3457	Lewis Creek	2	2002	684457.7	3.2	1108.9	11517206	6629	Natural Gas	Natural Gas	0.045
TX	298	Limestone	LIM1	2002	6929259.7	17008.9	8053.4	63647147	8531	Coal	Coal	0.12
TX	298	Limestone	LIM2	2002	6073036.9	13830.3	5704.3	55782456	8220	Coal	Coal	0.12
TX	3440	Lon C Hill	1	2002	3327.9		10.5	56001	217	Natural Gas	Natural Gas	0.045
TX	3440	Lon C Hill	2	2002	140.6		0.2	2368	56	Natural Gas	Natural Gas	0.045
TX	3440	Lon C Hill	3	2002	15566.9		24.8	261941	496	Natural Gas	Natural Gas	0.045
TX	3440	Lon C Hill	4	2002	122011.7	0.6	163	2053080	2456	Natural Gas	Natural Gas	0.045
TX	3477	Lone Star Power Plant	1	2002	5280.1		10.6	88839	229	Natural Gas	Natural Gas	0.045
TX	55154	Lost Pines 1	1	2002	685560.4	3.4	100.3	11535830	7395	Natural Gas	Natural Gas	0.045
TX	55154	Lost Pines 1	2	2002	701503.4	3.4	103.7	11804145	7520	Natural Gas	Natural Gas	0.045

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TX	55123	Magic Valley Generating Station	CTG-1	2002	433324.7	2.1	122.3	7291554	3974	Natural Gas	Natural Gas	0.045
TX	55123	Magic Valley Generating Station	CTG-2	2002	563001.2	2.9	147.5	9473507	5129	Natural Gas	Natural Gas	0.045
TX	6146	Martin Lake	1	2002	5969420.7	24836.6	9480.4	58228170	7833	Coal	Coal	0.12
TX	6146	Martin Lake	2	2002	5791472.6	22523.6	4495.3	56549708	7696	Coal	Coal	0.12
TX	6146	Martin Lake	3	2002	5962876.7	19023.6	4502.7	54401534	6916	Coal	Coal	0.12
TX	55091	Midlothian Energy	STK1	2002	456425.6	2.4	75.4	7680224	5595	Natural Gas	Natural Gas	0.045
TX	55091	Midlothian Energy	STK2	2002	443636.2	2.2	71.5	7465028	5412	Natural Gas	Natural Gas	0.045
TX	55091	Midlothian Energy	STK3	2002	475362.8	2.5	59.4	7998887	5922	Natural Gas	Natural Gas	0.045
TX	55091	Midlothian Energy	STK4	2002	429764.8	2.2	63.3	7231611	5328	Natural Gas	Natural Gas	0.045
TX	55091	Midlothian Energy	STK5	2002	354003.6	1.9	58.7	5956805	4088	Natural Gas	Natural Gas	0.045
TX	55091	Midlothian Energy	STK6	2002	374849.8	1.9	55.9	6307532	4396	Natural Gas	Natural Gas	0.045
TX	3610	Mission Road	3	2002	13.3			224	8	Natural Gas	Natural Gas	0.045
TX	6147	Monticello	1	2002	4375891.2	28643.3	4102.6	41513236	7573	Coal	Coal	0.12
TX	6147	Monticello	2	2002	4915613.1	34700	6224.6	47267771	8212	Coal	Coal	0.12
TX	6147	Monticello	3	2002	6327764.8	22975.8	5593	60149597	7797	Coal	Coal	0.12
TX	3483	Moore County Station	3	2002	14245.6		18.7	240299	819	Natural Gas	Natural Gas	0.045
TX	3492	Morgan Creek	3	2002						Natural Gas	Natural Gas	0.045
TX	3492	Morgan Creek	4	2002	7227.2		22.1	121616	287	Natural Gas	Natural Gas	0.045
TX	3492	Morgan Creek	5	2002	152922.7	0.7	434.3	2573232	3231	Natural Gas	Natural Gas	0.045
TX	3492	Morgan Creek	6	2002	513591.5	2.6	2455	8642139	3096	Natural Gas	Natural Gas	0.045
TX	3453	Mountain Creek Steam Electric Sta	2	2002	11915.1		31.6	200504	1028	Natural Gas	Natural Gas	0.045
TX	3453	Mountain Creek Steam Electric Sta	3A	2002	19800.7	0.1	39.7	333171	1054	Natural Gas	Natural Gas	0.045
TX	3453	Mountain Creek Steam Electric Sta	3B	2002	5037.1		12.9	84756	444	Natural Gas	Natural Gas	0.045
TX	3453	Mountain Creek Steam Electric Sta	6	2002	82993.2	46.4	128.9	1523986	2512	Natural Gas	Natural Gas	0.045
TX	3453	Mountain Creek Steam Electric Sta	7	2002	84851	55.8	183.9	1558277	3016	Natural Gas	Natural Gas	0.045
TX	3453	Mountain Creek Steam Electric Sta	8	2002	470691.5	17.5	340.6	7961179	3166	Natural Gas	Natural Gas	0.045
TX	55065	Mustang Station	1	2002	650351.4	3.4	165.6	10943392	7322	Natural Gas	Natural Gas	0.045
TX	55065	Mustang Station	2	2002	625499.8	3.1	195.4	10525210	7405	Natural Gas	Natural Gas	0.045
TX	50137	Newgulf	1	2002	1298.7		2.5	21856	34	Natural Gas	Natural Gas	0.045
TX	3456	Newman	**4	2002	221272.2	1	340.7	3723084	6007	Natural Gas	Natural Gas	0.045
TX	3456	Newman	**5	2002	263268.6	1.1	377.8	4430021	6833	Natural Gas	Natural Gas	0.045
TX	3456	Newman	1	2002	145005.7	0.7	180.3	2440015	6007	Natural Gas	Natural Gas	0.045
TX	3456	Newman	2	2002	205716.3	1.2	263.2	3461619	8176	Natural Gas	Natural Gas	0.045
TX	3456	Newman	3	2002	229753.8	1	517	3866041	6559	Natural Gas	Natural Gas	0.045
TX	3484	Nichols Station	141B	2002	119788.2	0.6	154	2020713	3039	Natural Gas	Natural Gas	0.045
TX	3484	Nichols Station	142B	2002	98057	0.6	152.5	1654111	2650	Natural Gas	Natural Gas	0.045
TX	3484	Nichols Station	143B	2002	308716.1	1.6	602.1	5207795	5674	Natural Gas	Natural Gas	0.045
TX	3454	North Lake	1	2002	237176.8	2.7	289.8	3983189	4932	Natural Gas	Natural Gas	0.045
TX	3454	North Lake	2	2002	213182.7	10.3	229.3	3565359	4403	Natural Gas	Natural Gas	0.045
TX	3454	North Lake	3	2002	425881.7	8.1	570.8	7135999	5006	Natural Gas	Natural Gas	0.045
TX	3493	North Main	4	2002	44739.5	0.3	76	752847	1536	Natural Gas	Natural Gas	0.045
TX	3627	North Texas	3	2002	654.5		1.8	11011	74	Natural Gas	Natural Gas	0.045
TX	3441	Nueces Bay	5	2002	0.2			2	2	Natural Gas	Natural Gas	0.045
TX	3441	Nueces Bay	6	2002	36703.9	0.1	48	617611	822	Natural Gas	Natural Gas	0.045
TX	3441	Nueces Bay	7	2002	578172.8	2.8	924.7	9728752	5828	Natural Gas	Natural Gas	0.045
TX	3611	O W Sommers	1	2002	295533.7	1.6	340.9	4972071	2603	Natural Gas	Natural Gas	0.045
TX	3611	O W Sommers	2	2002	311898	1.6	333.1	5245644	3229	Natural Gas	Natural Gas	0.045
TX	3523	Oak Creek Power Station	1	2002	59774.3	0.3	102.3	1005724	2063	Natural Gas	Natural Gas	0.045
TX	55215	Odessa-Ector Generating Station	GT1	2002	489618.3	2.4	116	8238735	5948	Natural Gas	Natural Gas	0.045
TX	55215	Odessa-Ector Generating Station	GT2	2002	537870.8	2.7	122.8	9050675	6462	Natural Gas	Natural Gas	0.045
TX	55215	Odessa-Ector Generating Station	GT3	2002	494603.9	2.6	127	8322672	6210	Natural Gas	Natural Gas	0.045
TX	55215	Odessa-Ector Generating Station	GT4	2002	450113.3	2.4	114.4	7574036	5635	Natural Gas	Natural Gas	0.045
TX	127	Oklaunion Power Station	1	2002	4711710.9	3738.2	8265.7	45923130	8105	Coal	Coal	0.12
TX	3466	P H Robinson	PHR1	2002	460096.8	2.4	686.6	7742033	3644	Natural Gas	Natural Gas	0.045
TX	3466	P H Robinson	PHR2	2002	490713.5	2.4	832.6	8257157	3494	Natural Gas	Natural Gas	0.045
TX	3466	P H Robinson	PHR3	2002	449212.7	2.1	847.6	7558836	2982	Natural Gas	Natural Gas	0.045
TX	3466	P H Robinson	PHR4	2002	466903.8	2.4	631.3	7856544	2217	Natural Gas	Natural Gas	0.045
TX	3524	Paint Creek Power Station	1	2002	128.3			2148	40	Natural Gas	Natural Gas	0.045
TX	3524	Paint Creek Power Station	2	2002						Natural Gas	Natural Gas	0.045
TX	3524	Paint Creek Power Station	3	2002	382.7		0.4	6438	78	Natural Gas	Natural Gas	0.045

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TX	3524	Paint Creek Power Station	4	2002	34488.5	0.1	62.2	580278	1311	Natural Gas	Natural Gas	0.045
TX	3455	Parkdale	1	2002	49569.9	0.2	120.6	834130	1691	Natural Gas	Natural Gas	0.045
TX	3455	Parkdale	2	2002	76178.3	0.4	149.3	1281822	2061	Natural Gas	Natural Gas	0.045
TX	3455	Parkdale	3	2002	92209.4	0.4	220.5	1551575	2454	Natural Gas	Natural Gas	0.045
TX	55047	Pasadena Power Plant	CG-1	2002	707368.7	3.5	178.4	11902916	8471	Natural Gas	Natural Gas	0.045
TX	55047	Pasadena Power Plant	CG-2	2002	727033.8	3.5	291.8	12233747	8182	Natural Gas	Natural Gas	0.045
TX	55047	Pasadena Power Plant	CG-3	2002	663738.8	3.4	159	11168635	8013	Natural Gas	Natural Gas	0.045
TX	3494	Permian Basin	5	2002	69807.1	0.3	143	1174630	2142	Natural Gas	Natural Gas	0.045
TX	3494	Permian Basin	6	2002	1303154.7	6.5	2781.4	21928102	7711	Natural Gas	Natural Gas	0.045
TX	3485	Plant X	111B	2002	18679.2	0.1	54.3	315092	934	Natural Gas	Natural Gas	0.045
TX	3485	Plant X	112B	2002	72236.5	0.4	62.3	1218527	3023	Natural Gas	Natural Gas	0.045
TX	3485	Plant X	113B	2002	116004.8	0.6	198.8	1956916	3910	Natural Gas	Natural Gas	0.045
TX	3485	Plant X	114B	2002	360661.2	1.9	645.6	6084071	7503	Natural Gas	Natural Gas	0.045
TX	4195	Powerlane Plant	2	2002	529.4		1.1	8845	435	Natural Gas	Natural Gas	0.045
TX	4195	Powerlane Plant	3	2002	6385.5		5.8	107135	1805	Natural Gas	Natural Gas	0.045
TX	3628	R W Miller	**4	2002	32980.5	0.1	17.2	554911	759	Natural Gas	Natural Gas	0.045
TX	3628	R W Miller	**5	2002	23556.8	0.1	11.6	396398	584	Natural Gas	Natural Gas	0.045
TX	3628	R W Miller	1	2002	997.3		0.9	16783	140	Natural Gas	Natural Gas	0.045
TX	3628	R W Miller	2	2002	113733.2	0.6	145.8	1913764	2958	Natural Gas	Natural Gas	0.045
TX	3628	R W Miller	3	2002	309507.9	1.7	252.5	5207995	5973	Natural Gas	Natural Gas	0.045
TX	3576	Ray Olinger	BW2	2002	193700.7	1	247.1	3208873	8639	Natural Gas	Natural Gas	0.045
TX	3576	Ray Olinger	BW3	2002	242241.7	1.2	263	4067479	7268	Natural Gas	Natural Gas	0.045
TX	3576	Ray Olinger	CE1	2002	104405.8	0.8	107.8	1756587	7785	Natural Gas	Natural Gas	0.045
TX	3576	Ray Olinger	GE4	2002	59526.4	0.2	13.8	1001665	1421	Natural Gas	Natural Gas	0.045
TX	55187	Reliant Energy Channelview Cogen	CHV1	2002	594912.4	2.8	50.3	10010514	5290	Natural Gas	Natural Gas	0.045
TX	55187	Reliant Energy Channelview Cogen	CHV2	2002	455407.6	2.3	39.2	7663087	4216	Natural Gas	Natural Gas	0.045
TX	55187	Reliant Energy Channelview Cogen	CHV3	2002	472723.6	2.4	45.2	7954489	4145	Natural Gas	Natural Gas	0.045
TX	55187	Reliant Energy Channelview Cogen	CHV4	2002	847958.1	4.1	74.4	14268562	7478	Natural Gas	Natural Gas	0.045
TX	55137	Rio Nogales Power Project, LP	CTG-1	2002	216520.4	1	52.9	3643399	2653	Natural Gas	Natural Gas	0.045
TX	55137	Rio Nogales Power Project, LP	CTG-2	2002	166500.4	0.9	40.3	2801682	2193	Natural Gas	Natural Gas	0.045
TX	55137	Rio Nogales Power Project, LP	CTG-3	2002	136447.7	0.6	34.6	2296012	1680	Natural Gas	Natural Gas	0.045
TX	3526	Rio Pecos Power Station	5	2002	1853.3		1.7	31199	190	Natural Gas	Natural Gas	0.045
TX	3526	Rio Pecos Power Station	6	2002	124756.5	0.3	184.1	2099235	6878	Natural Gas	Natural Gas	0.045
TX	3503	River Crest	1	2002	542.7		0.7	9133	36	Natural Gas	Natural Gas	0.045
TX	3459	Sabine	1	2002	664783.2	3.2	786.3	11188191	8476	Natural Gas	Natural Gas	0.045
TX	3459	Sabine	2	2002	704178.4	3.3	724	11850092	8492	Natural Gas	Natural Gas	0.045
TX	3459	Sabine	3	2002	738375.9	3.7	834.9	12429596	5667	Natural Gas	Natural Gas	0.045
TX	3459	Sabine	4	2002	1188052.3	6.1	2122.8	19997594	6760	Natural Gas	Natural Gas	0.045
TX	3459	Sabine	5	2002	1126740.4	5.5	902.1	18959596	8569	Natural Gas	Natural Gas	0.045
TX	55104	Sabine Cogeneration Facility	SAB-1	2002	263124.8	1.2	38.6	4427531	8687	Natural Gas	Natural Gas	0.045
TX	55104	Sabine Cogeneration Facility	SAB-2	2002	257443.8	1.2	36.1	4331955	8722	Natural Gas	Natural Gas	0.045
TX	3468	Sam Bertron	SRB1	2002	76988.8	0.3	105.2	1295445	2207	Natural Gas	Natural Gas	0.045
TX	3468	Sam Bertron	SRB2	2002	98948.9	0.5	105	1665036	2445	Natural Gas	Natural Gas	0.045
TX	3468	Sam Bertron	SRB3	2002	195404	1	158	3288126	4659	Natural Gas	Natural Gas	0.045
TX	3468	Sam Bertron	SRB4	2002	178183.8	0.9	130.8	2998246	4374	Natural Gas	Natural Gas	0.045
TX	6179	Sam Seymour	1	2002	3914296.9	13617.3	6129.6	38201367	7199	Coal	Coal	0.12
TX	6179	Sam Seymour	2	2002	4737413.5	16401.2	6911.4	46197882	8615	Coal	Coal	0.12
TX	6179	Sam Seymour	3	2002	3824088.5	1779.1	6077.2	37294554	8459	Coal	Coal	0.12
TX	3527	San Angelo Power Station	2	2002	371304.5	2	422.8	6247924	7442	Natural Gas	Natural Gas	0.045
TX	7325	San Jacinto Steam Electric Station	SJS1	2002	499882.3	2.3	106.2	8411463	8434	Natural Gas	Natural Gas	0.045
TX	7325	San Jacinto Steam Electric Station	SJS2	2002	480873.4	2.3	131.8	8091602	8438	Natural Gas	Natural Gas	0.045
TX	6183	San Miguel	SM-1	2002	3891516.9	13172.5	7120	35744881	7830	Coal	Coal	0.12
TX	1700	Sand Hill Energy Center	SH1	2002	30807.9		7	518479	1874	Natural Gas	Natural Gas	0.045
TX	1700	Sand Hill Energy Center	SH2	2002	31739.8		8.6	534065	1944	Natural Gas	Natural Gas	0.045
TX	1700	Sand Hill Energy Center	SH3	2002	31948.4		5.5	537618	1889	Natural Gas	Natural Gas	0.045
TX	1700	Sand Hill Energy Center	SH4	2002	31027.6		6.9	522109	1864	Natural Gas	Natural Gas	0.045
TX	6648	Sandow	4	2002	4602757.5	23330.4	7670	44670713	7382	Coal	Coal	0.12
TX	3559	Silas Ray	9	2002	19556.4		10.8	329093	714	Natural Gas	Natural Gas	0.045
TX	3601	Sim Gideon	1	2002	83913.4	0.1	130.9	1411867	3126	Natural Gas	Natural Gas	0.045
TX	3601	Sim Gideon	2	2002	91369.8	0.3	135.3	1537476	2865	Natural Gas	Natural Gas	0.045

STATE	ORIS_ CODE	FACILITY_NAME	UNIT_ID	YEAR	SumOf CO2_TONS	SumOf SO2_TONS	SumOf NOX_TONS	SumOf HEAT_INPUT	SumOf TOTAL_ OPERATING_HOURS	DESCRIPTION_ SPECIFIC	DESCRIPTION_ GENERIC	CO2_ CONCENTRATION
TX	3601	Sim Gideon	3	2002	643673.1	3.4	632.8	10830711	7848	Natural Gas	Natural Gas	0.045
TX	4266	Spencer	4	2002	12219.8	0.4	5.8	204529	1395	Natural Gas	Natural Gas	0.045
TX	4266	Spencer	5	2002	25257.6	1.9	19.7	420301	2871	Natural Gas	Natural Gas	0.045
TX	55120	SRW Cogen Limited Partnership	CTG-1	2002	786115.2	3.7	162.8	11372834	6692	Natural Gas	Natural Gas	0.045
TX	55120	SRW Cogen Limited Partnership	CTG-2	2002	911804.4	4	135.3	13062604	7649	Natural Gas	Natural Gas	0.045
TX	3504	Stryker Creek	1	2002	44619.8	0.2	164.9	750820	912	Natural Gas	Natural Gas	0.045
TX	3504	Stryker Creek	2	2002	619066.8	43	461.7	10549791	4462	Natural Gas	Natural Gas	0.045
TX	55015	Sweeny Cogeneration Facility	1	2002	436910.1	2.3	330.1	7351770	5591	Natural Gas	Natural Gas	0.045
TX	55015	Sweeny Cogeneration Facility	2	2002	688742.8	2.9	402.7	11589281	8253	Natural Gas	Natural Gas	0.045
TX	55015	Sweeny Cogeneration Facility	3	2002	657582.2	3.2	448.4	11065016	8225	Natural Gas	Natural Gas	0.045
TX	55015	Sweeny Cogeneration Facility	4	2002	754800.1	3.7	438.1	12700981	8480	Natural Gas	Natural Gas	0.045
TX	50615	Sweetwater Generating Plant	GT01	2002	67217	0.3	79.8	1130313	2552	Natural Gas	Natural Gas	0.045
TX	50615	Sweetwater Generating Plant	GT02	2002	26615	0.1	34.5	447613	382	Natural Gas	Natural Gas	0.045
TX	50615	Sweetwater Generating Plant	GT03	2002	228457.1	1.2	253.2	3844306	3850	Natural Gas	Natural Gas	0.045
TX	4937	T C Ferguson	1	2002	424581	2.4	645.3	7713672	5273	Natural Gas	Natural Gas	0.045
TX	3469	T H Wharton	THW2	2002	99684.5	0.4	119.6	1677386	1645	Natural Gas	Natural Gas	0.045
TX	55062	Tenaska Frontier Generation Station	1	2002	666611.8	3.4	189	11217012	6826	Natural Gas	Natural Gas	0.045
TX	55062	Tenaska Frontier Generation Station	2	2002	672611.9	3.5	174.2	11317998	6886	Natural Gas	Natural Gas	0.045
TX	55062	Tenaska Frontier Generation Station	3	2002	555921.8	3	172.4	9352658	5695	Natural Gas	Natural Gas	0.045
TX	55132	Tenaska Gateway Generating Station	OGTDB1	2002	548403.4	2.7	141.3	9227855	6863	Natural Gas	Natural Gas	0.045
TX	55132	Tenaska Gateway Generating Station	OGTDB2	2002	525457	2.6	130.6	8841853	6589	Natural Gas	Natural Gas	0.045
TX	55132	Tenaska Gateway Generating Station	OGTDB3	2002	505003.3	2.6	129.5	8494617	6392	Natural Gas	Natural Gas	0.045
TX	6194	Tolk Station	171B	2002	4228720.3	12702.7	5985.5	41215600	8326	Coal	Coal	0.12
TX	6194	Tolk Station	172B	2002	4259195	12171.2	6129.1	41512586	7704	Coal	Coal	0.12
TX	3506	Tradinghouse	1	2002	910186.5	4.6	1707.7	15315634	6046	Natural Gas	Natural Gas	0.045
TX	3506	Tradinghouse	2	2002	929266.2	4.7	3639.8	15636655	3948	Natural Gas	Natural Gas	0.045
TX	3507	Trinidad	9	2002	149724.5	0.8	253.1	2519371	2425	Natural Gas	Natural Gas	0.045
TX	7030	Twin Oaks Power, LP	U1	2002	1370470.1	2533.2	1273.7	12588068	8339	Coal	Coal	0.12
TX	7030	Twin Oaks Power, LP	U2	2002	1415987.5	2599.3	1136.2	13006198	8053	Coal	Coal	0.12
TX	3612	V H Braunig	1	2002	135762.2	0.7	191.7	2284134	2006	Natural Gas	Natural Gas	0.045
TX	3612	V H Braunig	2	2002	72115.2	0.2	86.8	1213157	1495	Natural Gas	Natural Gas	0.045
TX	3612	V H Braunig	3	2002	295068.3	1.4	328	4965089	3111	Natural Gas	Natural Gas	0.045
TX	3612	V H Braunig	CT01	2002	306034.2	1.6	91.3	5149679	3754	Natural Gas	Natural Gas	0.045
TX	3612	V H Braunig	CT02	2002	299709.3	1.5	85	5043169	3687	Natural Gas	Natural Gas	0.045
TX	3508	Valley (TXU)	1	2002	128610	7	256.1	2147810	2482	Natural Gas	Natural Gas	0.045
TX	3508	Valley (TXU)	2	2002	758693.3	21.3	1693.9	12696233	5039	Natural Gas	Natural Gas	0.045
TX	3508	Valley (TXU)	3	2002	153700.8	0.9	227.2	2586303	1945	Natural Gas	Natural Gas	0.045
TX	3443	Victoria	6	2002	15.3			260	15	Natural Gas	Natural Gas	0.045
TX	3443	Victoria	7	2002	1663.6		3	27996	75	Natural Gas	Natural Gas	0.045
TX	3443	Victoria	8	2002	99678.4	0.5	154.3	1677307	1751	Natural Gas	Natural Gas	0.045
TX	3470	W A Parish	WAP1	2002	92688	0.2	130.6	1559680	2463	Natural Gas	Natural Gas	0.045
TX	3470	W A Parish	WAP2	2002	90134.9	0.3	79.3	1516926	2455	Natural Gas	Natural Gas	0.045
TX	3470	W A Parish	WAP3	2002	87529.2	0.4	109.5	1472837	1270	Natural Gas	Natural Gas	0.045
TX	3470	W A Parish	WAP4	2002	734500.7	3.7	629.2	12359377	4906	Natural Gas	Natural Gas	0.045
TX	3470	W A Parish	WAP5	2002	5422153.1	21310	4482.7	52859502	8709	Coal	Coal	0.12
TX	3470	W A Parish	WAP6	2002	4571700.5	18005.7	3850.6	44689054	7567	Coal	Coal	0.12
TX	3470	W A Parish	WAP7	2002	4694715.9	18459.4	3208.9	45768474	8544	Coal	Coal	0.12
TX	3470	W A Parish	WAP8	2002	5014135.2	4046.9	3977.5	48879458	8480	Coal	Coal	0.12
TX	3613	W B Tuttle	1	2002	313.5		0.4	5275	22	Natural Gas	Natural Gas	0.045
TX	3613	W B Tuttle	2	2002	6141.7		13.3	103333	248	Natural Gas	Natural Gas	0.045
TX	3613	W B Tuttle	3	2002	5503.7		10.4	92709	156	Natural Gas	Natural Gas	0.045
TX	3613	W B Tuttle	4	2002	25755		41	433374	659	Natural Gas	Natural Gas	0.045
TX	3471	Webster	WEB3	2002	90454.2	0.5	93.6	1522019	1491	Natural Gas	Natural Gas	0.045
TX	6139	Welsh Power Plant	1	2002	4566474.7	12258.9	3806.8	44460713	8210	Coal	Coal	0.12
TX	6139	Welsh Power Plant	2	2002	4396259.2	11937.5	7479.9	42775451	8219	Coal	Coal	0.12
TX	6139	Welsh Power Plant	3	2002	4282556.4	11584	3644.1	41740250	7889	Coal	Coal	0.12
TX	3478	Wilkes Power Plant	1	2002	117883.6	1	141.6	1979983	3063	Natural Gas	Natural Gas	0.045
TX	3478	Wilkes Power Plant	2	2002	385785.7	2.1	429.4	6491503	4371	Natural Gas	Natural Gas	0.045
TX	3478	Wilkes Power Plant	3	2002	536712.2	2.7	498.9	9031094	5997	Natural Gas	Natural Gas	0.045
UT	7790	Bonanza	37987	2002	4560071.2	980.9	6712.1	44445147	8650	Coal	Coal	0.12

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UT	3644	Carbon	1	2002	628314.3	2720.7	1377	6123951	8471	Coal	Coal	0.12
UT	3644	Carbon	2	2002	904331.7	4043.4	2001.1	8815679	8393	Coal	Coal	0.12
UT	55848	Desert Power Plant	UNT1	2002	39315.2	0.3	91.7	666184	1670	Natural Gas	Natural Gas	0.045
UT	55848	Desert Power Plant	UNT2	2002	40213.6	0.3	65.7	681409	1706	Natural Gas	Natural Gas	0.045
UT	3648	Gadsby	1	2002	67625.9	0.2	68.6	1137893	2971	Natural Gas	Natural Gas	0.045
UT	3648	Gadsby	2	2002	98795.9	0.6	99.1	1662409	3874	Natural Gas	Natural Gas	0.045
UT	3648	Gadsby	3	2002	215126.3	1	130.4	3619934	6389	Natural Gas	Natural Gas	0.045
UT	3648	Gadsby	4	2002	7338.2		1.4	123550	1106	Natural Gas	Natural Gas	0.045
UT	3648	Gadsby	5	2002	5529		0.8	93015	694	Natural Gas	Natural Gas	0.045
UT	3648	Gadsby	6	2002	4886.7		0.7	82268	757	Natural Gas	Natural Gas	0.045
UT	6165	Hunter (Emery)	1	2002	3661997.9	3113.6	7447.3	35692776	8164	Coal	Coal	0.12
UT	6165	Hunter (Emery)	2	2002	3023690.8	2543	5750.1	29470715	6930	Coal	Coal	0.12
UT	6165	Hunter (Emery)	3	2002	3396076.6	1369.5	6661	33100397	8209	Coal	Coal	0.12
UT	8069	Huntington	1	2002	3298680.4	2630.9	6236.7	32151774	8164	Coal	Coal	0.12
UT	8069	Huntington	2	2002	2564916.5	11078.7	4946.1	24999211	6682	Coal	Coal	0.12
UT	6481	Intermountain	1SGA	2002	7632494.6	1859.7	15767.6	74390802	8494	Coal	Coal	0.12
UT	6481	Intermountain	2SGA	2002	7351167.5	1788.5	14488.6	71648775	8073	Coal	Coal	0.12
UT	55622	West Valley Generation Project	U1	2002	50834.9	0.2	8.4	855443	2274	Natural Gas	Natural Gas	0.045
UT	55622	West Valley Generation Project	U2	2002	42875.1	0.1	6.9	721448	2025	Natural Gas	Natural Gas	0.045
UT	55622	West Valley Generation Project	U3	2002	59193.2	0.1	9.6	996008	2778	Natural Gas	Natural Gas	0.045
UT	55622	West Valley Generation Project	U4	2002	59529.2	0.3	9.7	1001722	2678	Natural Gas	Natural Gas	0.045
UT	55622	West Valley Generation Project	U5	2002	33463.4		5.7	563105	1545	Natural Gas	Natural Gas	0.045
WY	4158	Dave Johnston	BW41	2002	1011561.7	3851.3	2341.4	9859293	8504	Coal	Coal	0.12
WY	4158	Dave Johnston	BW42	2002	1031358	4159.8	2298.1	10052222	8662	Coal	Coal	0.12
WY	4158	Dave Johnston	BW43	2002	2033498.2	6113.5	5026.9	19819757	8211	Coal	Coal	0.12
WY	4158	Dave Johnston	BW44	2002	2983732.7	5853	5352.5	29081696	8054	Coal	Coal	0.12
WY	8066	Jim Bridger	BW71	2002	3906249.9	4812.8	7412.7	38072586	7463	Coal	Coal	0.12
WY	8066	Jim Bridger	BW72	2002	4132909.6	5246.3	7358.4	40285426	7995	Coal	Coal	0.12
WY	8066	Jim Bridger	BW73	2002	4640809.4	6738.1	8313.1	45232242	8451	Coal	Coal	0.12
WY	8066	Jim Bridger	BW74	2002	4040756.1	3373.6	7757.4	39383588	7840	Coal	Coal	0.12
WY	6204	Laramie River	1	2002	4931152.5	3797.7	6728.3	48061877	8241	Coal	Coal	0.12
WY	6204	Laramie River	2	2002	4987144.7	3872.9	6687	48607657	8434	Coal	Coal	0.12
WY	6204	Laramie River	3	2002	4151861.6	3463.1	5544.8	40466511	6973	Coal	Coal	0.12
WY	4162	Naughton	1	2002	1289768.9	6320.6	3365.2	12583676	7755	Coal	Coal	0.12
WY	4162	Naughton	2	2002	1621885.5	7937.6	4306.4	15835525	7515	Coal	Coal	0.12
WY	4162	Naughton	3	2002	2798255	5051.9	5240.7	28425578	8233	Coal	Coal	0.12
WY	7504	Neil Simpson II	1	2002	933115.2	704.8	785.8	9094730	8689	Coal	Coal	0.12
WY	7504	Neil Simpson II	CT1	2002	120974.1	1.8	34.8	1338417	5256	Natural Gas	Natural Gas	0.045
WY	55477	Neil Simpson II (CT2)	CT2	2002	88298.2	1.9	41.3	1485749	5097	Natural Gas	Natural Gas	0.045
WY	6101	Wyodak	BW91	2002	3661350.6	8291.2	4696.5	35685721	8625	Coal	Coal	0.12

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1311 Or "1321" Or "1411" Or "1422" Or "1423" Or "1474" Or "1475" Or "1479" Or "1481" Or "1499" Or "2813" Or "2873" Or "2874" Or "3271" Or "3272" Or "3274" Or "3275" Or "3312" Or "3331" Or "3334" Or "3341" Or "3365" Or "4911" Or "1061"

STATEFIPS	COUNTYFIPS	STATEABBREV	COUNTYNAME	FACILITYID	FACILITYNAME	STREET	CITY	STATE	ZIP
4	13	AZ	MARICOPA CO	518	MOSAIC PRINTED CIRCUITS LLC	5815 S 25TH ST	PHOENIX	AZ	85040-
4	13	AZ	MARICOPA CO	582	STONE CREEK INC	4221 E RAYMOND ST	PHOENIX	AZ	85040-
4	13	AZ	MARICOPA CO	562	PHOENIX NEWSPAPERS INC	22600 N 19TH AVE	PHOENIX	AZ	85027-
4	13	AZ	MARICOPA CO	552	THORNWOOD FURNITURE MFG	5125 E MADISON ST	PHOENIX	AZ	85034-
4	13	AZ	MARICOPA CO	545	ROCKFORD CORPORATION	546 S ROCKFORD DR	TEMPE	AZ	85281-
4	13	AZ	MARICOPA CO	544	FLEETWOOD HOMES OF ARIZONA INC #21	6112 N 56TH AVE	GLENDALE	AZ	85311-
4	13	AZ	MARICOPA CO	532	TRADE PRINTERS INC	2122 W SHANGRI-LA RD	PHOENIX	AZ	85029-
4	13	AZ	MARICOPA CO	89	UNITED MODULAR	5301 W MADISON ST	PHOENIX	AZ	85043-
4	13	AZ	MARICOPA CO	52382	OCOTILLO POWER PLANT	1500 E UNIVERSITY DR	TEMPE	AZ	85281-
4	13	AZ	MARICOPA CO	69	PHOENIX HEAT TREATING INC	2405 W MOHAVE RD	PHOENIX	AZ	85009-6413
4	13	AZ	MARICOPA CO	508	SAMUEL LAWRENCE FURNITURE COMPANY	601 S 65TH AVE	PHOENIX	AZ	85043-
4	13	AZ	MARICOPA CO	458	BRYANT INDUSTRIES INC	788 W ILLINI ST	PHOENIX	AZ	85041-
4	13	AZ	MARICOPA CO	4384	WESTERN SHUTTER LLC	4038 E MADISON ST	PHOENIX	AZ	85034-
4	13	AZ	MARICOPA CO	4360	LITHO TECH INC	2020 N 22ND AVE	PHOENIX	AZ	85009-
4	13	AZ	MARICOPA CO	43135	ARIZONA PACIFIC SPAS	210 N 24TH ST	PHOENIX	AZ	85034-
4	13	AZ	MARICOPA CO	4278	SCOTTSDALE SHUTTERS INC	16087 N 80TH ST	SCOTTSDALE	AZ	85260-
4	13	AZ	MARICOPA CO	529	HIGHLAND PRODUCTS INC	43 N 48TH AVE	PHOENIX	AZ	85043-
4	13	AZ	MARICOPA CO	779	G & G PRINTERS INC	10201 N 21ST AVE	PHOENIX	AZ	85021-
4	13	AZ	MARICOPA CO	3536	HOLSUM BAKERY INC	2322 W LINCOLN ST	PHOENIX	AZ	85009-5827
4	13	AZ	MARICOPA CO	83	METAL-WELD SPECIALTIES INC	8137 N 83RD AVE	PEORIA	AZ	85345-
4	13	AZ	MARICOPA CO	827	VALLEY INDUSTRIAL PAINTING	1131 W WATKINS ST	PHOENIX	AZ	85007-
4	13	AZ	MARICOPA CO	826	LAMINATE TECHNOLOGY CORP	1104 W GENEVA DR	TEMPE	AZ	85282-
4	13	AZ	MARICOPA CO	813	KELLY MOORE PAINT CO INC	905 W ALAMEDA DR	TEMPE	AZ	85282-
4	13	AZ	MARICOPA CO	790	INTESYS TECHNOLOGIES INC	500 S 52ND ST	TEMPE	AZ	85281-7243
4	13	AZ	MARICOPA CO	62	MASTERCRAFT CABINETS INC	305 S BROOKS	MESA	AZ	85202-
4	13	AZ	MARICOPA CO	782	TREFFERS PRECISION INC	1021 N 22ND AVE	PHOENIX	AZ	85009-
4	13	AZ	MARICOPA CO	654	IRONWOOD LITHOGRAPHERS INC	455 S 52ND ST	TEMPE	AZ	85281-
4	13	AZ	MARICOPA CO	777	INSULFOAM	3401 W COCOPAH ST	PHOENIX	AZ	85009-
4	13	AZ	MARICOPA CO	744	M E GLOBAL INC	5857 S KYRENE RD	TEMPE	AZ	85283-1731
4	13	AZ	MARICOPA CO	733	PAN-GLO WEST	2401 W SHERMAN ST	PHOENIX	AZ	85009-
4	13	AZ	MARICOPA CO	72	WOODSTUFF MANUFACTURING INC	1635 S 43RD AVE	PHOENIX	AZ	85009-6026
4	13	AZ	MARICOPA CO	70	PARKER HANNIFIN CSS DIV/TEMPE PLANT	708 W 22ND ST	TEMPE	AZ	85282-
4	13	AZ	MARICOPA CO	693	MUNTERS CORP	802 S 59TH AVE	PHOENIX	AZ	85043-
4	13	AZ	MARICOPA CO	41751	GCR TRUCK TIRE CENTER	2815 N 32ND AVE	PHOENIX	AZ	85009-
4	13	AZ	MARICOPA CO	788	KIRKWOOD SHUTTERS LTD	22201 N 24TH AVE	PHOENIX	AZ	85027-
4	13	AZ	MARICOPA CO	3691	SUPREME OIL CO	2110 GRAND AVE	PHOENIX	AZ	85009-
4	13	AZ	MARICOPA CO	419	PARKER HANNIFIN GTFSD	7777 N GLEN HARBOR BLVD	GLENDALE	AZ	85307-
4	13	AZ	MARICOPA CO	388	STOROPACK INC	77 N 45TH AVE	PHOENIX	AZ	85043-
4	13	AZ	MARICOPA CO	38731	CLAYTON HOMES-EL MIRAGE	12345 W BUTLER DR	EL MIRAGE	AZ	85335-
4	13	AZ	MARICOPA CO	3802	HOLSUM BAKERY/TEMPE	710 W GENEVA DR	TEMPE	AZ	85252-
4	13	AZ	MARICOPA CO	3773	REDSTONE INDUSTRIES INC	5820 W SAN MIGUEL AVE	GLENDALE	AZ	85301-
4	13	AZ	MARICOPA CO	376	WESTERN PACKAGING	6051 N 56TH AVE	GLENDALE	AZ	85301-
4	13	AZ	MARICOPA CO	3966	INTEL CORP-OCOTILLO CAMPUS (FAB 12)	4500 S DOBSON RD	CHANDLER	AZ	85248-
4	13	AZ	MARICOPA CO	36939	NATURALLY VITAMIN	14810 N 73RD ST	SCOTTSDALE	AZ	85260-
4	13	AZ	MARICOPA CO	3976	CHOLLA CUSTOM CABINETS INC	1727 E DEER VALLEY DR	PHOENIX	AZ	85024-5604
4	13	AZ	MARICOPA CO	365	GAYLORD CONTAINER CORP	4932 W COLTER ST	GLENDALE	AZ	85301-
4	13	AZ	MARICOPA CO	36485	BILLBOARD POSTER COMPANY INC	3940 W MONTECITO AVE	PHOENIX	AZ	85019-
4	13	AZ	MARICOPA CO	363	THUNDERBIRD FURNITURE	7501 E REDFIELD RD	SCOTTSDALE	AZ	85260-3403
4	13	AZ	MARICOPA CO	36224	EARNHARDT DODGE AUTO BODY	1301 N COLORADO ST	GILBERT	AZ	85234-
4	13	AZ	MARICOPA CO	35541	ALLIED TUBE & CONDUIT CORP-PHX OPERATION	2525 N 27TH AVE	PHOENIX	AZ	85009-
4	13	AZ	MARICOPA CO	355	HONEYWELL INTERNATIONAL INC	111 S 34TH ST	PHOENIX	AZ	85034-
4	13	AZ	MARICOPA CO	354	IMSAMET OF ARIZONA	3829 S ESTRELLA PKWY	GOODYEAR	AZ	85338-
4	13	AZ	MARICOPA CO	3744	DESERT SUN FIBERGLASS SYSTEMS LTD	21412 N 14TH AVE	PHOENIX	AZ	85027-
4	13	AZ	MARICOPA CO	4028	B & D LITHO INC	3820 N 38TH AVE	PHOENIX	AZ	85019-
4	13	AZ	MARICOPA CO	937	THE HEIL COMPANY	1500 S 7TH ST	PHOENIX	AZ	85034-
4	13	AZ	MARICOPA CO	4175	SFPP LP	49 N 53RD AVE	PHOENIX	AZ	85043-
4	13	AZ	MARICOPA CO	4131	ST MICROELECTRONICS	1000 E BELL RD	PHOENIX	AZ	85022-
4	13	AZ	MARICOPA CO	4111	MAGIC WOODS INC	4210 N 39TH AVE	PHOENIX	AZ	85019-
4	13	AZ	MARICOPA CO	40927	CASE PRODUCTS	1401 E JACKSON	PHOENIX	AZ	85034-2308
4	13	AZ	MARICOPA CO	4083	CHRIS FISCHER PRODUCTIONS INC	4741 W POLK ST	PHOENIX	AZ	85043-
4	13	AZ	MARICOPA CO	3953	OAKCRAFT INC	7733 W OLIVE AVE	PEORIA	AZ	85345-
4	13	AZ	MARICOPA CO	403	VAW OF AMERICA INC	249 S 51ST AVE	PHOENIX	AZ	85043-
4	13	AZ	MARICOPA CO	4182	LEGENDS FURNITURE INC	5555 N 51ST AVE	GLENDALE	AZ	85301-
4	13	AZ	MARICOPA CO	40236	TEAM FORMS	2002 N 23RD AVE	PHOENIX	AZ	85009-
4	13	AZ	MARICOPA CO	40233	CITY OF SCOTTSDALE/WATER SERVICES DIV	16800 N HAYDEN RD	SCOTTSDALE	AZ	85261-
4	13	AZ	MARICOPA CO	4023	CREATIVE SHUTTERS INC	2009 W IRONWOOD DR	PHOENIX	AZ	85021-
4	13	AZ	MARICOPA CO	40222	HEXCEL SATELLITE PRODUCTS	1331 W HOUSTON AVE	GILBERT	AZ	85233-
4	13	AZ	MARICOPA CO	4007	PRECISION TRUCK PAINTING & REPAIR INC	2212 N 27TH AVE	PHOENIX	AZ	85009-
4	13	AZ	MARICOPA CO	3982	O'NEIL PRINTING INC	366 N 2ND AVE	PHOENIX	AZ	85003-
4	13	AZ	MARICOPA CO	3978	TEAM TWO DESIGN ASSOC INC	310 S 43RD AVE	PHOENIX	AZ	85009-

STATEFIPS	COUNTYFIPS	STATEABBREV	COUNTYNAME	FACILITYID	FACILITYNAME	STREET	CITY	STATE	ZIP
4	13	AZ	MARICOPA CO	4050	PILLSBURY BAKERIES & FOOD SERVICE	1120 W FAIRMONT DR	TEMPE	AZ	85282-
4	19	AZ	PIMA CO	0081	EL PASO NATURAL GAS	Unknown	UNKNOWN	AZ	00000
4	21	AZ	PINAL CO	0349	UNITED METRO MATERIALS, INC._PLANT # 47	Unknown	UNKNOWN	AZ	00000
4	21	AZ	PINAL CO	0164	SUNBELT REFINING CO. (HUNTWAY REFINING)	Unknown	UNKNOWN	AZ	00000
4	21	AZ	PINAL CO	0072	BIOSPHERE II, ENERGY CENTRE	Unknown	UNKNOWN	AZ	00000
4	19	AZ	PIMA CO	0425	TUCSON ELECTRIC POWER COMPANY (TEP)	Unknown	UNKNOWN	AZ	00000
4	19	AZ	PIMA CO	0401900699	SIERRITA MINE	6200 W. DUVAL MINE ROAD	GREEN VALLEY	AZ	856220527
4	19	AZ	PIMA CO	0401900310	ARIZONA PORTLAND CEMENT COMPANY	11115 N.CASA GRANDE HIGHWAY	RILLITO	AZ	85654
4	13	AZ	MARICOPA CO	881	MOTOROLA INC	1300 N ALMA SCHOOL RD	CHANDLER	AZ	85224-
4	19	AZ	PIMA CO	0082	IRVINGTON	Not Available	UNKNOWN	AZ	UNKNOWN
4	21	AZ	PINAL CO	U118	SAGUARO	Not Available	UNKNOWN	AZ	UNKNOWN
4	17	AZ	NAVAJO CO	0401701020	CHOLLA FLYASH	FOUR CORNERS CHOLLA PLANT	JOSEPH CITY	AZ	86032
4	17	AZ	NAVAJO CO	0401700776	PEN ROB LANDFILL	4 MILES NORTH I-40 ON PORTER D	JOSEPH CITY	AZ	86032
4	17	AZ	NAVAJO CO	0401700424	ABITIBI CONSOLIDATED SNOWFLAKE DIVISION	15 M.W.OF SNWFLK ON SPUR 277	SNOWFLAKE	AZ	85937
4	17	AZ	NAVAJO CO	0076	HATCH CONST. - STANSTEEL PLT MODLE #732	Unknown	UNKNOWN	AZ	00000
4	17	AZ	NAVAJO CO	0027	HATCH CONST.- STANSTEEL PLT MODLE #628	Unknown	UNKNOWN	AZ	00000
4	17	AZ	NAVAJO CO	0001	CHOLLA	Not Available	UNKNOWN	AZ	UNKNOWN
4	19	AZ	PIMA CO	0086	GRANITE CONSTRUCTION	Unknown	UNKNOWN	AZ	00000
4	25	AZ	YAVAPAI CO	0402501199	SELIGMAN COMPRESSOR STATION	9 MI EAST OF SELIGMAN	SELIGMAN	AZ	85337
4	1	AZ	APACHE CO	0034	TRANSWESTERN PIPELINE COMPANY	Unknown	UNKNOWN	AZ	00000
4	27	AZ	YUMA CO	U120	YUCCA	Not Available	UNKNOWN	AZ	UNKNOWN
4	27	AZ	YUMA CO	0404	CONDOR SEED PRODUCTION INC.	Unknown	UNKNOWN	AZ	00000
4	27	AZ	YUMA CO	0402702388	COPPER MOUNTAIN LANDFILL	AVENUE 35E & COUNTY 12TH ST.	WELLTON	AZ	85356
4	27	AZ	YUMA CO	0402700141	YUMA COGENERATION ASSOCIATES	280 N. 27TH DRIVE	YUMA	AZ	85364
4	27	AZ	YUMA CO	0331	ARIZONA PUBLIC SERVICE COMPANY (APS)	Unknown	UNKNOWN	AZ	00000
4	21	AZ	PINAL CO	0350	UNITED METRO MATERIALS, INC.(49)	Unknown	UNKNOWN	AZ	00000
4	25	AZ	YAVAPAI CO	0698	CHEMICAL LIME CO., AKA: CHEMSTAR LIME, I	Unknown	UNKNOWN	AZ	00000
4	21	AZ	PINAL CO	0402101392	BHP COPPER- SAN MANUEL OPERATIONS	200 SOUTH REDDINGTON ROAD	SAN MANUEL	AZ	85631
4	25	AZ	YAVAPAI CO	0402500864	GRAY WOLF REGIONAL LANDFILL	23355 EAST HIGHWAY 169, MP 11	DEWEY	AZ	86327
4	25	AZ	YAVAPAI CO	0402500701	PRINTPACK INC	6800 E 2ND ST	PRESCOTT VALLEY	AZ	86314
4	25	AZ	YAVAPAI CO	0402500421	PHOENIX CEMENT	CEMENT PLANT RD	CLARKDALE	AZ	86324
4	25	AZ	YAVAPAI CO	0402500405	PHELPS DODGE BAGDAD, INC.	TERMINUS OF HIGHWAY 96	BAGDAD	AZ	86321
4	25	AZ	YAVAPAI CO	0326	US VETERAN'S ADMINISTRATION (USVA)	Unknown	UNKNOWN	AZ	00000
4	25	AZ	YAVAPAI CO	0037	ASPHALT PAVING & SUPPLY	Unknown	UNKNOWN	AZ	00000
4	15	AZ	Mohave County	0401501232	NORTH STAR STEEL ARIZONA	3000 HWY 66 SOUTH	KINGMAN	AZ	86413
4	27	AZ	YUMA CO	0154	WESTERN ROCK PRODUCTS AZTEC QUARRY	Unknown	UNKNOWN	AZ	00000
4	13	AZ	MARICOPA CO	996	CHAPMAN CHEVROLET ISUZU INC	1717 E BASELINE RD	TEMPE	AZ	85283-
4	15	AZ	Mohave County	1115	ADVANTAGE BOATS, INC.	Unknown	UNKNOWN	AZ	00000
4	13	AZ	MARICOPA CO	R-07	United Metro Materials - McKellips Concrete Plant	Dobson & McKellips	Scottsdale	AZ	85256
4	13	AZ	MARICOPA CO	R-06	CalMat Arizona - Higley Asphalt Plant	Higley & Dobson	Mesa	AZ	85215
4	13	AZ	MARICOPA CO	R-05	CalMat Arizona - Mesa Asphalt Plant	1900 Longmore	Mesa	AZ	85201
4	13	AZ	MARICOPA CO	R-04	United Metro Materials - Beeline Asphalt Plant	Beeline Highway & McDowell Rd	Scottsdale	AZ	85256
4	13	AZ	MARICOPA CO	R-03	North Center Street Landfill	13602 E. Beeline Highway	Scottsdale	AZ	85256
4	13	AZ	MARICOPA CO	R-09	United Metro Materials - Beeline Concrete Plant	Beeline Highway & McDowell Rd.	Scottsdale	AZ	85256
4	13	AZ	MARICOPA CO	R-01	Salt River Landfill	13602 E. Beeline Highway	Scottsdale	AZ	85256
4	13	AZ	MARICOPA CO	R-10	CalMat Arizona - Mesa Concrete Plant	1900 Longmore	Mesa	AZ	85201
4	13	AZ	MARICOPA CO	991	RANDALLS VIP TRAILERS INC	17066 S 54TH ST	CHANDLER	AZ	85226-
4	13	AZ	MARICOPA CO	983	ISOLA LAMINATE SYSTEMS CORP	165 S PRICE RD	CHANDLER	AZ	85224-
4	13	AZ	MARICOPA CO	98	PALO VERDE NUCLEAR GENERATING STATION	5801 S WINTERSBURG RD	TONOPAH	AZ	85354-7529
4	13	AZ	MARICOPA CO	975	BUSE PRINTING & ADVERTISING	1616 E HARVARD ST	PHOENIX	AZ	85006-
4	13	AZ	MARICOPA CO	971	MECHTRONICS OF ARIZONA CORP	1601 E BROADWAY RD	PHOENIX	AZ	85040-2499
4	13	AZ	MARICOPA CO	961	BIG SURF	1500 N MCCLINTOCK DR	TEMPE	AZ	85281-
4	13	AZ	MARICOPA CO	948	NESCO MFG INC	1510 W DRAKE DR	TEMPE	AZ	85283-
4	13	AZ	MARICOPA CO	R-02	Tri-Cities Landfill	13602 E. Beeline Highway	Scottsdale	AZ	85256
4	15	AZ	Mohave County	0177	ARCO PRODUCTS-ROBERT L. & SHIRLEY WALKER	Unknown	UNKNOWN	AZ	00000
4	27	AZ	YUMA CO	1054	YUMA REGIONAL MEDICAL CENTER	Unknown	UNKNOWN	AZ	00000
4	15	AZ	Mohave County	0401501041	DUTCH FLAT COMPRESSOR STATION	NEAR LAKE HAVASU	LAKE HAVASU	AZ	86401
4	15	AZ	Mohave County	0401500815	MOJAVE TOPOCK COMPRESSOR STATION	5499 WEST NEEDLE MOUNTAIN ROAD	TOPOCK	AZ	86436
4	15	AZ	Mohave County	0401500522	HACKBERRY COMPRESSOR STATION	18 MILES EAST OF KINGMAN	KINGMAN	AZ	86471
4	15	AZ	Mohave County	0401500229	ARIZONA PROVING GROUND	#1 PROVING GROUND ROAD	YUCCA	AZ	86438
4	15	AZ	Mohave County	0238	MCCULLOCH CORP.	Unknown	UNKNOWN	AZ	00000
4	13	AZ	MARICOPA CO	R-08	United Metro Materials - Higley Concrete Plant	Higley & Thomas	Mesa	AZ	85215
4	15	AZ	Mohave County	0178	ARCO PRODUCTS-PRESTIGE STATIONS INC.	Unknown	UNKNOWN	AZ	00000
4	15	AZ	Mohave County	0402	POTTERS INDUSTRIES, INC.	Unknown	UNKNOWN	AZ	00000
4	15	AZ	Mohave County	0131	TRANSWESTERN PIPELINE COMPANY	Unknown	UNKNOWN	AZ	00000
4	13	AZ	MARICOPA CO	R-16	Salt River Sand & Rock - Beeline Facility	P.O. Box 728	Scottsdale	AZ	85256
4	13	AZ	MARICOPA CO	R-15	Salt River Sand & Rock - Dobson Facility	P.O. Box 728	Scottsdale	AZ	85256
4	13	AZ	MARICOPA CO	R-14	Salt River Sand & Rock - Higley Facility	P.O. Box 728	Scottsdale	AZ	85256
4	13	AZ	MARICOPA CO	R-13	United Metro Materials - Beeline Crushing Plant	Beeline Highway & McDowell Rd.	Scottsdale	AZ	85256
4	13	AZ	MARICOPA CO	R-12	Sunward Materials	1901 N. Alma School Rd.	Mesa	AZ	85201
4	13	AZ	MARICOPA CO	R-11	CalMat Arizona - Higley Concrete Plant	Higley & Dobson	Mesa	AZ	85215
4	15	AZ	Mohave County	0236	KINGMAN REGIONAL MEDICAL CENTER	Unknown	UNKNOWN	AZ	00000
4	13	AZ	MARICOPA CO	1075	91ST AVE WASTEWATER TREATMENT PLANT	5615 S 91ST AVE	TOLLESON	AZ	85353-

'1479" Or "1481" Or "1499" Or "2813" Or "2873" Or "2874" Or "3271" Or "3272" Or "327

FACILITYID	FACILITYNAME	FACILITYADDRESS	EPAREGION	INVNETORYYEAR	SIC	LATITUDE	LONGITUDE	CO	NH3	NOX	PMCON	PMFIL
518	MOSAIC PRINTED CIRCUITS LLC	5815 S 25TH ST PHOENIX AZ 85040-	9	1999	3672	34.6091	-86.9706		0.01			
582	STONE CREEK INC	4221 E RAYMOND ST PHOENIX AZ 85040-	9	1999	2511	34.6343	-87.0218				0.002	
562	PHOENIX NEWSPAPERS INC	22600 N 19TH AVE PHOENIX AZ 85027-	9	1999	2711	34.6433	-87.0415	0.148		0.232	0.009	
552	THORNWOOD FURNITURE MFG	5125 E MADISON ST PHOENIX AZ 85034-	9	1999	2511	34.3421	-86.9011				2.012	
545	ROCKFORD CORPORATION	546 S ROCKFORD DR TEMPE AZ 85281-	9	1999	3672	34.6199	-87.0807					
544	FLEETWOOD HOMES OF ARIZONA INC #21	6112 N 56TH AVE GLENDALE AZ 85311-	9	1999	2451	34.5973	-86.9607					
532	TRADE PRINTERS INC	2122 W SHANGRI-LA RD PHOENIX AZ 85029-	9	1999	2761	34.6163	-87.0175					
89	UNITED MODULAR	5301 W MADISON ST PHOENIX AZ 85043-	9	1999	2452	34.6316	-87.0415				0.003	
52382	OCOTILLO POWER PLANT	1500 E UNIVERSITY DR TEMPE AZ 85281-	9	1999	4911	34.6422	-87.0643	82.787	8.561	555.776	16.585	
69	PHOENIX HEAT TREATING INC	2405 W MOHAVE RD PHOENIX AZ 85009-6413	9	1999	3398	34.6091	-86.9716	1.182	3.243	1.407	0.08	
508	SAMUEL LAWRENCE FURNITURE COMPANY	601 S 65TH AVE PHOENIX AZ 85043-	9	1999	2511	32.3948	-86.3164	0.022		0.026	2.858	
458	BRYANT INDUSTRIES INC	788 W ILLINI ST PHOENIX AZ 85041-	9	1999	2431	32.4163	-86.2982				0.007	
4384	WESTERN SHUTTER LLC	4038 E MADISON ST PHOENIX AZ 85034-	9	1999	2431	32.3833	-86.3675				0.016	
4360	LITHO TECH INC	2020 N 22ND AVE PHOENIX AZ 85009-	9	1999	2752	32.3947	-86.3058					
43135	ARIZONA PACIFIC SPAS	210 N 24TH ST PHOENIX AZ 85034-	9	1999	3088	32.4019	-86.3089					
4278	SCOTTSDALE SHUTTERS INC	16087 N 80TH ST SCOTTSDALE AZ 85260-	9	1999	2431	32.2327	-86.2142					
529	HIGHLAND PRODUCTS INC	43 N 48TH AVE PHOENIX AZ 85043-	9	1999	3086	34.6009	-86.9575	0.761		0.906	0.052	
779	G & G PRINTERS INC	10201 N 21ST AVE PHOENIX AZ 85021-	9	1999	2752	34.6379	-87.096					
3536	HOLSUM BAKERY INC	2322 W LINCOLN ST PHOENIX AZ 85009-5827	9	1999	2051	30.7144	-88.0919	7.249		8.63	0.492	
83	METAL-WELD SPECIALTIES INC	8137 N 83RD AVE PEORIA AZ 85345-	9	1999	3446	34.6307	-87.0022					
827	VALLEY INDUSTRIAL PAINTING	1131 W WATKINS ST PHOENIX AZ 85007-	9	1999	3479	34.6307	-87.0175					
826	LAMINATE TECHNOLOGY CORP	1104 W GENEVA DR TEMPE AZ 85282-	9	1999	3672	34.6199	-86.9869	1.924		2.289	0.129	
813	KELLY MOORE PAINT CO INC	905 W ALAMEDA DR TEMPE AZ 85282-	9	1999	2851	34.6397	-87.0731					
790	INTESYS TECHNOLOGIES INC	500 S 52ND ST TEMPE AZ 85281-7243	9	1999	3479	34.6406	-87.0415	0.308		0.366	0.021	
62	MASTERCRAFT CABINETS INC	305 S BROOKS MESA AZ 85202-	9	1999	2434	34.5946	-86.9531	0.116		0.138	0.089	
782	TREFFERS PRECISION INC	1021 N 22ND AVE PHOENIX AZ 85009-	9	1999	3471	34.6352	-87.0349		0.85			
654	IRONWOOD LITHOGRAPHERS INC	455 S 52ND ST TEMPE AZ 85281-	9	1999	2752	34.5486	-86.9826					
777	INSULFOAM	3401 W COCOPAH ST PHOENIX AZ 85009-	9	1999	3086	34.6154	-87.0622	0.882		1.05	0.06	
744	M E GLOBAL INC	5857 S KYRENE RD TEMPE AZ 85283-1731	9	1999	3325	34.6073	-86.9651	47.672		8.99	17.634	
733	PAN-GLO WEST	2401 W SHERMAN ST PHOENIX AZ 85009-	9	1999	7699	34.637	-87.0371	0.527		0.628	0.036	
72	WOODSTUFF MANUFACTURING INC	1635 S 43RD AVE PHOENIX AZ 85009-6026	9	1999	2511	34.4242	-86.9238	0.13		0.155	3.826	
70	PARKER HANNIFIN CSS DIV/TEMPE PLANT	708 W 22ND ST TEMPE AZ 85282-	9	1999	3053	34.6055	-86.9651					
693	MUNTERS CORP	802 S 59TH AVE PHOENIX AZ 85043-	9	1999	3585	34.5901	-86.9498	0.15		0.179	0.01	
41751	GCR TRUCK TIRE CENTER	2815 N 32ND AVE PHOENIX AZ 85009-	9	1999	7534	32.4291	-86.3364				1.198	
788	KIRKWOOD SHUTTERS LTD	22201 N 24TH AVE PHOENIX AZ 85027-	9	1999	2431	34.6181	-87.0393		0.001		0.107	
3691	SUPREME OIL CO	2110 GRAND AVE PHOENIX AZ 85009-	9	1999	5171	31.7171	-87.2153					
419	PARKER HANNIFIN GTFSD	7777 N GLEN HARBOR BLVD GLENDALE AZ 85307-	9	1999	3724	32.3007	-86.4414					
388	STOROPACK INC	77 N 45TH AVE PHOENIX AZ 85043-	9	1999	3086	32.3932	-86.0708	0.131		0.156	0.009	
38731	CLAYTON HOMES-EL MIRAGE	12345 W BUTLER DR EL MIRAGE AZ 85335-	9	1999	2451	32.3526	-86.3571				0.043	
3802	HOLSUM BAKERY/TEMPE	710 W GENEVA DR TEMPE AZ 85252-	9	1999	2051	32.4015	-86.4025	0.92		1.095	0.062	
3773	REDSTONE INDUSTRIES INC	5820 W SAN MIGUEL AVE GLENDALE AZ 85301-	9	1999	3089	32.3527	-86.3837					
376	WESTERN PACKAGING	6051 N 56TH AVE GLENDALE AZ 85301-	9	1999	2671	32.3929	-86.3079					
3966	INTEL CORP-OCOTILLO CAMPUS (FAB 12)	4500 S DOBSON RD CHANDLER AZ 85248-	9	1999	3674	32.4118	-86.1472	6.049	2.005	9.461	0.549	
36939	NATURALLY VITAMIN	14810 N 73RD ST SCOTTSDALE AZ 85260-	9	1999	2834	32.3759	-86.3399	0.038		0.045	0.002	
3976	CHOLLA CUSTOM CABINETS INC	1727 E DEER VALLEY DR PHOENIX AZ 85024-5604	9	1999	2434	32.2327	-86.2142				0.025	
365	GAYLORD CONTAINER CORP	4932 W COLTER ST GLENDALE AZ 85301-	9	1999	2653	31.569	-87.2813	1.99	0.656	2.369	0.951	
36485	BILLBOARD POSTER COMPANY INC	3940 W MONTECITO AVE PHOENIX AZ 85019-	9	1999	7312	31.7316	-87.21					
363	THUNDERBIRD FURNITURE	7501 E REDFIELD RD SCOTTSDALE AZ 85260-3403	9	1999	2511	31.5176	-87.2959				0.045	
36224	EARNHARDT DODGE AUTO BODY	1301 N COLORADO ST GILBERT AZ 85234-	9	1999	7532	31.4577	-87.4094	0.083		0.098	0.006	
35541	ALLIED TUBE & CONDUIT CORP-PHX OPERATION	2525 N 27TH AVE PHOENIX AZ 85009-	9	1999	3317	31.5056	-87.3938	0.345		0.411	0.024	
355	HONEYWELL INTERNATIONAL INC	111 S 34TH ST PHOENIX AZ 85034-	9	1999	3724	31.5819	-87.49	31.362	0.496	76.548	0.686	
354	IMSAMET OF ARIZONA	3829 S ESTRELLA PKWY GOODYEAR AZ 85338-	9	1999	3341	31.5266	-87.2728	94.17		18.396	12.688	
3744	DESERT SUN FIBERGLASS SYSTEMS LTD	21412 N 14TH AVE PHOENIX AZ 85027-	9	1999	3089	32.3527	-86.3805					
4028	B & D LITHO INC	3820 N 38TH AVE PHOENIX AZ 85019-	9	1999	2752	32.3059	-86.3989					
937	THE HEIL COMPANY	1500 S 7TH ST PHOENIX AZ 85034-	9	1999	3799	34.564	-86.976					
4175	SFPP LP	49 N 53RD AVE PHOENIX AZ 85043-	9	1999	4226	32.276	-86.3704	5.506		3.905		
4131	ST MICROELECTRONICS	1000 E BELL RD PHOENIX AZ 85022-	9	1999	3674	32.3618	-86.0956	2.749	0.002	3.272	0.187	
4111	MAGIC WOODS INC	4210 N 39TH AVE PHOENIX AZ 85019-	9	1999	2512	32.4096	-86.2366					
40927	CASE PRODUCTS	1401 E JACKSON PHOENIX AZ 85034-2308	9	1999	2521	32.3165	-86.351				0.016	
4083	CHRIS FISCHER PRODUCTIONS INC	4741 W POLK ST PHOENIX AZ 85043-	9	1999	2431	32.4096	-86.2334				0.032	
3953	OAKCRAFT INC	7733 W OLIVE AVE PEORIA AZ 85345-	9	1999	2434	32.2921	-86.3416	0.072		0.086	0.061	
403	VAW OF AMERICA INC	249 S 51ST AVE PHOENIX AZ 85043-	9	1999	3354	32.4142	-86.412	11.887		17.023	9.879	
4182	LEGENDS FURNITURE INC	5555 N 51ST AVE GLENDALE AZ 85301-	9	1999	2511	32.3685	-86.3017				0.176	
40236	TEAM FORMS	2002 N 23RD AVE PHOENIX AZ 85009-	9	1999	2752	32.3929	-86.3058					
40233	CITY OF SCOTTSDALE/WATER SERVICES DIV	16800 N HAYDEN RD SCOTTSDALE AZ 85261-	9	1999	9511	32.3716	-86.3761	11.492		8.202	0.065	
4023	CREATIVE SHUTTERS INC	2009 W IRONWOOD DR PHOENIX AZ 85021-	9	1999	2431	32.2651	-86.3588				0.001	
40222	HEXCEL SATELLITE PRODUCTS	1331 W HOUSTON AVE GILBERT AZ 85233-	9	1999	3663	32.3962	-86.108					
4007	PRECISION TRUCK PAINTING & REPAIR INC	2212 N 27TH AVE PHOENIX AZ 85009-	9	1999	3479	32.3791	-86.4335					
3982	O'NEIL PRINTING INC	366 N 2ND AVE PHOENIX AZ 85003-	9	1999	2752	32.3553	-86.3571					
3978	TEAM TWO DESIGN ASSOC INC	310 S 43RD AVE PHOENIX AZ 85009-	9	1999	2511	32.3157	-86.2193				0.003	

FACILITYID	FACILITYNAME	FACILITYADDRESS	EPAREGION	INVNETORYYEAR	SIC	LATITUDE	LONGITUDE	CO	NH3	NOX	PMCON	PMFIL
4050	PILLSBURY BAKERIES & FOOD SERVICE	1120 W FAIRMONT DR TEMPE AZ 85282-	9	1999	2051	32.4114	-86.2323	0.431		0.513	0.038	
0081	EL PASO NATURAL GAS	Unknown UNKNOWN AZ 00000	9	1999	4924	32.4133	-84.9971	37.57		335.92		
0349	UNITED METRO MATERIALS, INC._PLANT # 47	Unknown UNKNOWN AZ 00000	9	1999	3273	33.7468	-86.5002				0.215	
0164	SUNBELT REFINING CO. (HUNTWAY REFINING)	Unknown UNKNOWN AZ 00000	9	1999	2911	33.5877	-86.25	4.5		18.4	0.181	
0072	BIOSPHERE II, ENERGY CENTRE	Unknown UNKNOWN AZ 00000	9	1999	8733	33.9346	-86.1994	58.64			0.49	
0425	TUCSON ELECTRIC POWER COMPANY (TEP)	Unknown UNKNOWN AZ 00000	9	1999	4931	33.7341	-86.1559	7.39		26.54	57.777	
0401900699	SIERRITA MINE	6200 W. DUVAL MINE ROAD GREEN VALLEY AZ 856220527	9	1999	1021	32.1783	-85.0283	400.846		106.411	15.534	
0401900310	ARIZONA PORTLAND CEMENT COMPANY	11115 N.CASA GRANDE HIGHWAY RILLITO AZ 85654	9	1999	3241	32.2861	-85.1697	1639.8		5519	18.714	
881	MOTOROLA INC	1300 N ALMA SCHOOL RD CHANDLER AZ 85224-	9	1999	3674	34.4431	-86.9173	7.268	1.225	9.358	0.48	
0082	IRVINGTON	Not Available UNKNOWN AZ UNKNOWN	9	1999	4911	32.2193	-84.9999	146.77	8.74	2404.97	83.142	
U118	SAGUARO	Not Available UNKNOWN AZ UNKNOWN	9	1999	4911	33.6803	-86.3217	54.79	7.31	558.11	12.856	
0401701020	CHOLLA FLYASH	FOUR CORNERS CHOLLA PLANT JOSEPH CITY AZ 86032	9	1999	1499	32.4163	-84.9957		1.32		0.161	
0401700776	PEN ROB LANDFILL	4 MILES NORTH I-40 ON PORTER D JOSEPH CITY AZ 86032	9	1999	4953	32.4633	-84.9944	3.275		4.136	0.79	
0401700424	ABITIBI CONSOLIDATED SNOWFLAKE DIVISION	15 M.W.OF SNWFLK ON SPUR 277 SNOWFLAKE AZ 85937	9	1999	2611	32.4294	-84.9995	97.8		2291.119	13.119	
0076	HATCH CONST. - STANSTEEL PLT MODLE #732	Unknown UNKNOWN AZ 00000	9	1999	1521	32.4457	-84.9991				6.581	
0027	HATCH CONST.- STANSTEEL PLT MODLE #628	Unknown UNKNOWN AZ 00000	9	1999	1521	32.4309	-84.9761				4.758	
0001	CHOLLA	Not Available UNKNOWN AZ UNKNOWN	9	1999	4911	32.432	-84.9899	915.94	1.32	13183.26	667.137	
0086	GRANITE CONSTRUCTION	Unknown UNKNOWN AZ 00000	9	1999	3272	32.4971	-85.0555				4.531	
0402501199	SELIGMAN COMPRESSOR STATION	9 MI EAST OF SELIGMAN SELIGMAN AZ 85337	9	1999	4922	33.1045	-86.7621	1.16		126.37		
0034	TRANSWESTERN PIPELINE COMPANY	Unknown UNKNOWN AZ 00000	9	1999	4922	32.0446	-86.7956	159.92		1252.38	1.057	
U120	YUCCA	Not Available UNKNOWN AZ UNKNOWN	9	1999	4911	33.2119	-86.809	170.72	6.5	239.63	11.179	
0404	CONDOR SEED PRODUCTION INC.	Unknown UNKNOWN AZ 00000	9	1999	723	33.1054	-86.7578				10.808	
0402702388	COPPER MOUNTAIN LANDFILL	AVENUE 35E & COUNTY 12TH ST. WELLTON AZ 85356	9	1999	4953	33.2048	-86.868	0.016		0	0	
0402700141	YUMA COGENERATION ASSOCIATES	280 N. 27TH DRIVE YUMA AZ 85364	9	1999	4911	33.1028	-86.8007	20.797	6.5	178.216	0.818	
0331	ARIZONA PUBLIC SERVICE COMPANY (APS)	Unknown UNKNOWN AZ 00000	9	1999	4911	33.2836	-86.6917	30.31		106.55	0.469	
0350	UNITED METRO MATERIALS, INC.(49)	Unknown UNKNOWN AZ 00000	9	1999	3273	33.7503	-86.4667			0.55	0.674	
0698	CHEMICAL LIME CO., AKA: CHEMSTAR LIME, I	Unknown UNKNOWN AZ 00000	9	1999	1499	33.1055	-86.8007	866.95		1196.83		
0402101392	BHP COPPER- SAN MANUEL OPERATIONS	200 SOUTH REDDINGTON ROAD SAN MANUEL AZ 85631	9	1999	1021	33.5941	-86.2597	0.604	0.03	3.016	0.032	
0402500864	GRAY WOLF REGIONAL LANDFILL	23355 EAST HIGHWAY 169, MP 11 DEWEY AZ 86327	9	1999	4953	33.2137	-86.7811	4.978		15.157	0.057	
0402500701	PRINTPACK INC	6800 E 2ND ST PRESCOTT VALLEY AZ 86314	9	1999	2671	33.6007	-86.5086	1.26		1.49		
0402500421	PHOENIX CEMENT	CEMENT PLANT RD CLARKDALE AZ 86324	9	1999	3241	33.6031	-86.2639	203.562		2610.53	40.629	
0402500405	PHELPS DODGE BAGDAD, INC.	TERMINUS OF HIGHWAY 96 BAGDAD AZ 86321	9	1999	1021	33.5828	-86.3341	220.581		56.459	108.227	
0326	US VETERAN'S ADMINISTRATION (USVA)	Unknown UNKNOWN AZ 00000	9	1999	4953	33.7684	-86.4871			11.67	0.66	
0037	ASPHALT PAVING & SUPPLY	Unknown UNKNOWN AZ 00000	9	1999	1611	33.5922	-86.2468				1.657	
0401501232	NORTH STAR STEEL ARIZONA	3000 HWY 66 SOUTH KINGMAN AZ 86413	9	1999	3312	32.4346	-84.9845	19.954		48.674	16.111	
0154	WESTERN ROCK PRODUCTS AZTEC QUARRY	Unknown UNKNOWN AZ 00000	9	1999	1499	33.2433	-86.4569	2.68		58.75	0.274	
996	CHAPMAN CHEVROLET ISUZU INC	1717 E BASELINE RD TEMPE AZ 85283-	9	1999	5511	34.6073	-87.0382					
1115	ADVANTAGE BOATS, INC.	Unknown UNKNOWN AZ 00000	9	1999	3732	32.177	-85.0297					
R-07	United Metro Materials - McKellips Concrete Plant	Dobson & McKellips Scottsdale AZ 85256	9	1999	3273	33.1209	-88.1629				0.006	
R-06	CalMat Arizona - Higley Asphalt Plant	Higley & Dobson Mesa AZ 85215	9	1999	2951	33.3179	-87.9045	1.763		2.937	0.76	
R-05	CalMat Arizona - Mesa Asphalt Plant	1900 Longmore Mesa AZ 85201	9	1999	2951	33.3827	-87.9223	3.433		5.754	1.482	
R-04	United Metro Materials - Beeline Asphalt Plant	Beeline Highway & McDowell Rd Scottsdale AZ 85256	9	1999	2951	33.1145	-88.1735	9.099		8.62	0.394	
R-03	North Center Street Landfill	13602 E. Beeline Highway Scottsdale AZ 85256	9	1999	4953	33.3594	-88.0167	21.19		1.13	0.043	
R-09	United Metro Materials - Beeline Concrete Plant	Beeline Highway & McDowell Rd. Scottsdale AZ 85256	9	1999	3273	33.3973	-88.1203				0.071	
R-01	Salt River Landfill	13602 E. Beeline Highway Scottsdale AZ 85256	9	1999	4953	32.6019	-87.3175	18.696		26.163	7.899	
R-10	CalMat Arizona - Mesa Concrete Plant	1900 Longmore Mesa AZ 85201	9	1999	3273	33.2614	-88.0896				0.47	
991	RANDALLS VIP TRAILERS INC	17066 S 54TH ST CHANDLER AZ 85226-	9	1999	3479	34.4953	-86.8303					
983	ISOLA LAMINATE SYSTEMS CORP	165 S PRICE RD CHANDLER AZ 85224-	9	1999	3679	34.5901	-86.9727	12.939		34.784	0.068	
98	PALO VERDE NUCLEAR GENERATING STATION	5801 S WINTERSBURG RD TONOPAH AZ 85354-7529	9	1999	4911	34.6307	-87.0087	20.957	5.903	49.055	12.101	
975	BUSE PRINTING & ADVERTISING	1616 E HARVARD ST PHOENIX AZ 85006-	9	1999	2752	34.628	-87.0993					
971	MECHTRONICS OF ARIZONA CORP	1601 E BROADWAY RD PHOENIX AZ 85040-2499	9	1999	3499	34.6289	-87.0251					
961	BIG SURF	1500 N MCCLINTOCK DR TEMPE AZ 85281-	9	1999	7996	34.6046	-87.0436	1.057		7.517	0.001	
948	NESCO MFG INC	1510 W DRAKE DR TEMPE AZ 85283-	9	1999	3086	34.6605	-86.9694					
R-02	Tri-Cities Landfill	13602 E. Beeline Highway Scottsdale AZ 85256	9	1999	4953	32.447	-87.501	214.5		11.44	0.438	
0177	ARCO PRODUCTS-ROBERT L. & SHIRLEY WALKER	Unknown UNKNOWN AZ 00000	9	1999	5541	31.7921	-85.8224					
1054	YUMA REGIONAL MEDICAL CENTER	Unknown UNKNOWN AZ 00000	9	1999	8062	33.2471	-86.8175	1.31		6.55	0.158	
0401501041	DUTCH FLAT COMPRESSOR STATION	NEAR LAKE HAVASU LAKE HAVASU AZ 86401	9	1999	4922	33.1579	-85.2898	10.065		121.941	0.254	
0401500815	MOJAVE TOPOCK COMPRESSOR STATION	5499 WEST NEEDLE MOUNTAIN ROAD TOPOCK AZ 86436	9	1999	4922	33.2902	-85.474	129.351		113.342	0.141	
0401500522	HACKBERRY COMPRESSOR STATION	18 MILES EAST OF KINGMAN KINGMAN AZ 86471	9	1999	4922	33.1253	-85.5648	3.654		397.63		
0401500229	ARIZONA PROVING GROUND	#1 PROVING GROUND ROAD YUCCA AZ 86438	9	1999	8734	33.1327	-85.36	56.235		10.255	0.025	
0238	MCCULLOCH CORP.	Unknown UNKNOWN AZ 00000	9	1999	3546	33.1509	-85.514			12.08		
R-08	United Metro Materials - Higley Concrete Plant	Higley & Thomas Mesa AZ 85215	9	1999	3273	33.1426	-88.161				1.085	
0178	ARCO PRODUCTS-PRESTIGE STATIONS INC.	Unknown UNKNOWN AZ 00000	9	1999	5541	31.7961	-85.9681					
0402	POTTERS INDUSTRIES, INC.	Unknown UNKNOWN AZ 00000	9	1999	3211	32.4335	-84.9728				3.308	
0131	TRANSWESTERN PIPELINE COMPANY	Unknown UNKNOWN AZ 00000	9	1999	4922	31.865	-86.0096				0.426	
R-16	Salt River Sand & Rock - Beeline Facility	P.O. Box 728 Scottsdale AZ 85256	9	1999	1442	31.7226	-85.8148	16.01		69.87	5.937	
R-15	Salt River Sand & Rock - Dobson Facility	P.O. Box 728 Scottsdale AZ 85256	9	1999	1442	31.752	-85.8725	8.65		37.75	2.399	
R-14	Salt River Sand & Rock - Higley Facility	P.O. Box 728 Scottsdale AZ 85256	9	1999	1442	31.78	-85.982	3.61		15.76	2.285	
R-13	United Metro Materials - Beeline Crushing Plant	Beeline Highway & McDowell Rd. Scottsdale AZ 85256	9	1999	1442	31.7881	-85.9787				2.762	
R-12	Sunward Materials	1901 N. Alma School Rd. Mesa AZ 85201	9	1999	1442	31.7943	-85.9692	2.415		28.269	0.134	
R-11	CalMat Arizona - Higley Concrete Plant	Higley & Dobson Mesa AZ 85215	9	1999	3273	31.7098	-86.1263				0.119	
0236	KINGMAN REGIONAL MEDICAL CENTER	Unknown UNKNOWN AZ 00000	9	1999	8062	31.7673	-85.9695	7.14		21.87	0.454	
1075	91ST AVE WASTEWATER TREATMENT PLANT	5615 S 91ST AVE TOLLESON AZ 85353-	9	1999	4952	34.4446	-86.2708	25.238		30.149	0.427	

'1479" Or "1481" Or "1499" Or "2813" Or "2873" Or "2874" Or "3271" Or "3272" Or "327

FACILITYID	FACILITYNAME	PMPRI	PM10FIL	PM10PRI	PM25FIL	PM25PRI	SO2	VOC
518	MOSAIC PRINTED CIRCUITS LLC							15.976
582	STONE CREEK INC		0.003	0.005	0.001	0.003		19.107
562	PHOENIX NEWSPAPERS INC		0.003	0.013	0.003	0.013	0.001	11.627
552	THORNWOOD FURNITURE MFG		2.315	4.328	1.367	3.379		57.823
545	ROCKFORD CORPORATION							6.864
544	FLEETWOOD HOMES OF ARIZONA INC #21							17.342
532	TRADE PRINTERS INC							10.649
89	UNITED MODULAR		0.003	0.006	0.001	0.004		13.524
52382	OCOTILLO POWER PLANT		5.745	22.334	5.223	21.811	8.447	15.482
69	PHOENIX HEAT TREATING INC		0.027	0.107	0.027	0.107	0.009	14.047
508	SAMUEL LAWRENCE FURNITURE COMPANY		3.287	6.145	1.366	4.223		64.818
458	BRYANT INDUSTRIES INC		0.007	0.014	0.002	0.009		40.321
4384	WESTERN SHUTTER LLC		0.019	0.035	0.007	0.023		19.042
4360	LITHO TECH INC							10.192
43135	ARIZONA PACIFIC SPAS							14.546
4278	SCOTTSDALE SHUTTERS INC							6.332
529	HIGHLAND PRODUCTS INC		0.017	0.069	0.017	0.069	0.006	66.619
779	G & G PRINTERS INC							4.845
3536	HOLSUM BAKERY INC		0.164	0.656	0.164	0.656	0.052	2.493
83	METAL-WELD SPECIALTIES INC							13.702
827	VALLEY INDUSTRIAL PAINTING							10.27
826	LAMINATE TECHNOLOGY CORP		0.043	0.175	0.043	0.175	0.013	11.771
813	KELLY MOORE PAINT CO INC							2.481
790	INTESYS TECHNOLOGIES INC		0.372	0.393	0.372	0.393	0.002	25.049
62	MASTERCRAFT CABINETS INC		0.097	0.186	0.034	0.123	0.001	60.292
782	TREFFERS PRECISION INC							6.215
654	IRONWOOD LITHOGRAPHERS INC							9.624
777	INSULFOAM		0.02	0.08	0.02	0.08	0.007	51.957
744	M E GLOBAL INC		6.56	24.201	5.795	23.431	3.376	22.338
733	PAN-GLO WEST		0.012	0.048	0.012	0.048	0.004	12.844
72	WOODSTUFF MANUFACTURING INC		4.398	8.224	2.348	6.172	0.001	384.734
70	PARKER HANNIFIN CSS DIV/TEMPE PLANT							14.907
693	MUNTERS CORP		0.003	0.014	0.003	0.014	0.001	11.927
41751	GCR TRUCK TIRE CENTER		2.182	3.38	0.994	2.191		14.451
788	KIRKWOOD SHUTTERS LTD		0.124	0.231	0.053	0.161		6.348
3691	SUPREME OIL CO							6.668
419	PARKER HANNIFIN GTFSD							32.154
388	STOROPACK INC		0.003	0.012	0.003	0.012	0.001	8.937
38731	CLAYTON HOMES-EL MIRAGE		0.262	0.305	0.236	0.279		11.364
3802	HOLSUM BAKERY/TEMPE		0.021	0.083	0.021	0.083	0.007	19.796
3773	REDSTONE INDUSTRIES INC							3.057
376	WESTERN PACKAGING							6.781
3966	INTEL CORP-OCOTILLO CAMPUS (FAB 12)		0.188	0.737	0.181	0.73	0.089	15.739
36939	NATURALLY VITAMIN		0.007	0.009	0.007	0.009		7.924
3976	CHOLLA CUSTOM CABINETS INC		0.029	0.054	0.01	0.035		14.148
365	GAYLORD CONTAINER CORP		0.985	1.937	0.472	1.424	0.014	12.26
36485	BILLBOARD POSTER COMPANY INC							22.76
363	THUNDERBIRD FURNITURE		0.051	0.096	0.017	0.061		23.282
36224	EARNHARDT DODGE AUTO BODY		0.002	0.008	0.002	0.008	0.001	10.224
35541	ALLIED TUBE & CONDUIT CORP-PHX OPERATION		0.008	0.033	0.008	0.033	0.004	12.359
355	HONEYWELL INTERNATIONAL INC		3.782	4.468	3.557	4.239	15.541	63.572
354	IMSAMET OF ARIZONA		3.587	16.276	3.326	16.014	0.047	0.427
3744	DESERT SUN FIBERGLASS SYSTEMS LTD							33.645
4028	B & D LITHO INC							10.939
937	THE HEIL COMPANY							9.92
4175	SFPP LP							48.761
4131	ST MICROELECTRONICS		0.062	0.249	0.062	0.249	0.02	24.203
4111	MAGIC WOODS INC							16.49
40927	CASE PRODUCTS		0.097	0.114	0.084	0.1		10.209
4083	CHRIS FISCHER PRODUCTIONS INC		0.038	0.07	0.015	0.048		14.411
3953	OAKCRAFT INC		0.066	0.127	0.023	0.083	0.001	71.879
403	VAW OF AMERICA INC		2.781	12.663	2.341	12.223	0.472	29.409
4182	LEGENDS FURNITURE INC		0.202	0.38	0.085	0.26		80.121
40236	TEAM FORMS							10.152
40233	CITY OF SCOTTSDALE/WATER SERVICES DIV		0.133	0.199	0.133	0.199	0.012	3.589
4023	CREATIVE SHUTTERS INC		0.001	0.003	0	0.001		13.624
40222	HEXCEL SATELLITE PRODUCTS							0.052
4007	PRECISION TRUCK PAINTING & REPAIR INC							11.478
3982	O'NEIL PRINTING INC							16.367
3978	TEAM TWO DESIGN ASSOC INC		0.003	0.006	0.001	0.003		21.579

FACILITYID	FACILITYNAME	PMPRI	PM10FIL	PM10PRI	PM25FIL	PM25PRI	SO2	VOC
4050	PILLSBURY BAKERIES & FOOD SERVICE		0.035	0.073	0.024	0.062	0.003	11.96
0081	EL PASO NATURAL GAS							
0349	UNITED METRO MATERIALS, INC._PLANT # 47		2.71	2.925	2.255	2.469		
0164	SUNBELT REFINING CO. (HUNTWAY REFINING)		0.33	0.511	0.33	0.511	0.11	26.25
0072	BIOSPHERE II, ENERGY CENTRE		6.81	7.3	6.45	6.94	5.7	11.18
0425	TUCSON ELECTRIC POWER COMPANY (TEP)		64.92	122.697	19.67	77.447	112.51	
0401900699	SIERRITA MINE		144.141	159.683	53.682	69.218	59.892	41.84
0401900310	ARIZONA PORTLAND CEMENT COMPANY		239.307	258.02	105.914	124.627	9.941	5.03
881	MOTOROLA INC		3.092	3.573	3.088	3.569	0.113	15.705
0082	IRVINGTON		29.589	112.732	15.318	98.461	2861.6	27.02
U118	SAGUARO		0.867	13.725	0.867	13.725	1.2	15.35
0401701020	CHOLLA FLYASH		0.758	0.916	0.71	0.87		
0401700776	PEN ROB LANDFILL		7.89	8.68	4.594	5.385	0.266	3.13
0401700424	ABITIBI CONSOLIDATED SNOWFLAKE DIVISION		45.739	58.859	17.843	30.962	1892.94	361.189
0076	HATCH CONST. - STANSTEEL PLT MODLE #732		33.07	39.651	10.18	16.761		
0027	HATCH CONST.- STANSTEEL PLT MODLE #628		23.91	28.668	7.36	12.118		
0001	CHOLLA		956.508	1623.644	544.847	1211.983	19062.1	109.88
0086	GRANITE CONSTRUCTION		241.14	245.671	10.8	15.331	57.86	
0402501199	SELIGMAN COMPRESSOR STATION						0.12	0.68
0034	TRANSWESTERN PIPELINE COMPANY		2.16	3.217	1.52	2.577	1.09	57.97
U120	YUCCA		0.193	11.372	0.193	11.372	2.3	13.66
0404	CONDOR SEED PRODUCTION INC.		31.48	42.288	26.02	36.828		
0402702388	COPPER MOUNTAIN LANDFILL		0	0	0	0	0	37.085
0402700141	YUMA COGENERATION ASSOCIATES		12.081	12.899	11.327	12.145	6.509	4.276
0331	ARIZONA PUBLIC SERVICE COMPANY (APS)		24.91	25.379	13.52	13.989	6.07	3.74
0350	UNITED METRO MATERIALS, INC.(49)		8.6	9.274	5.635	6.308		
0698	CHEMICAL LIME CO., AKA: CHEMSTAR LIME, I						1404.61	
0402101392	BHP COPPER- SAN MANUEL OPERATIONS		0.058	0.091	0.058	0.091	0.018	0.159
0402500864	GRAY WOLF REGIONAL LANDFILL		0.701	0.758	0.588	0.646	1.009	6.653
0402500701	PRINTPACK INC		0.11	0.11	0.11	0.11	0.009	51.48
0402500421	PHOENIX CEMENT		534.886	575.51	197.349	237.974	400.9	
0402500405	PHELPS DODGE BAGDAD, INC.		242.332	350.562	110.359	218.582	20.027	41.165
0326	US VETERAN'S ADMINISTRATION (USVA)		0.22	0.88	0.22	0.88	0.15	
0037	ASPHALT PAVING & SUPPLY		15.33	16.987	2.58	4.237		
0401501232	NORTH STAR STEEL ARIZONA		29.125	45.236	25.867	41.978	2.449	1.128
0154	WESTERN ROCK PRODUCTS AZTEC QUARRY		1.15	1.424	0.471	0.745	3.91	4.7
996	CHAPMAN CHEVROLET ISUZU INC							0.871
1115	ADVANTAGE BOATS, INC.							8.91
R-07	United Metro Materials - McKellips Concrete Plant		0.07	0.076	0.02	0.026		
R-06	CalMat Arizona - Higley Asphalt Plant		4.013	4.773	1.38	2.141	2.773	0.216
R-05	CalMat Arizona - Mesa Asphalt Plant		9.127	10.61	3.159	4.641	2.165	0.42
R-04	United Metro Materials - Beeline Asphalt Plant		4.973	5.369	1.746	2.141	13.984	6.705
R-03	North Center Street Landfill		0.427	0.47	0.4	0.443	0.44	8.27
R-09	United Metro Materials - Beeline Concrete Plant		0.825	0.895	0.243	0.312		
R-01	Salt River Landfill		79.501	87.4	53.112	61.01	1.954	19.653
R-10	CalMat Arizona - Mesa Concrete Plant		5.534	6.003	1.627	2.098		
991	RANDALLS VIP TRAILERS INC							7.519
983	ISOLA LAMINATE SYSTEMS CORP		1.147	1.214	1.147	1.214	0.024	6.619
98	PALO VERDE NUCLEAR GENERATING STATION		24.115	36.221	20.291	32.395	0.996	29.697
975	BUSE PRINTING & ADVERTISING							6.691
971	MECHTRONICS OF ARIZONA CORP							1.841
961	BIG SURF		0.025	0.026	0.025	0.026	0.003	0.308
948	NESCO MFG INC							11.894
R-02	Tri-Cities Landfill		4.332	4.77	4.061	4.499	4.46	27.64
0177	ARCO PRODUCTS-ROBERT L. & SHIRLEY WALKER							37.87
1054	YUMA REGIONAL MEDICAL CENTER		0.17	0.328	0.17	0.328	0.1	
0401501041	DUTCH FLAT COMPRESSOR STATION		3.921	4.175	3.921	4.175	0.181	5.21
0401500815	MOJAVE TOPOCK COMPRESSOR STATION		2.171	2.311	2.171	2.311	0.139	26.807
0401500522	HACKBERRY COMPRESSOR STATION						0.256	1.426
0401500229	ARIZONA PROVING GROUND		0.64	0.667	0.6	0.627	0.535	5.27
0238	MCCULLOCH CORP.						2.46	
R-08	United Metro Materials - Higley Concrete Plant		12.742	13.825	3.746	4.831		
0178	ARCO PRODUCTS-PRESTIGE STATIONS INC.							18.93
0402	POTTERS INDUSTRIES, INC.		11.05	14.358	4.99	8.298		
0131	TRANSWESTERN PIPELINE COMPANY		0.87	1.296	0.62	1.046		5.29
R-16	Salt River Sand & Rock - Beeline Facility		71.456	77.39	20.021	25.957	21.19	1.86
R-15	Salt River Sand & Rock - Dobson Facility		28.354	30.75	6.795	9.193	11.45	1.01
R-14	Salt River Sand & Rock - Higley Facility		28.045	30.33	8.159	10.445	4.78	0.42
R-13	United Metro Materials - Beeline Crushing Plant		34.817	37.579	0.318	3.08		
R-12	Sunward Materials		2.73	2.865	1.706	1.842	1.899	3.303
R-11	CalMat Arizona - Higley Concrete Plant		1.395	1.514	0.41	0.529		
0236	KINGMAN REGIONAL MEDICAL CENTER		2.19	2.644	2.19	2.644	0.75	1.87
1075	91ST AVE WASTEWATER TREATMENT PLANT		1.864	2.294	1.561	1.991	24.47	2.744

STATEFIPS	COUNTYFIPS	STATEABBREV	COUNTYNAME	FACILITYID	FACILITYNAME	STREET	CITY	STATE	ZIP	FACILITYADDRESS	EPA REGION
4	27	AZ	YUMA CO	0402700141	YUMA COGENERATION ASSOCIATES	280 N. 27TH DRIVE	YUMA	AZ	85364	280 N. 27TH DRIVE YUMA AZ 85364	9
4	27	AZ	YUMA CO	U120	YUCCA	Not Available	UNKNOWN	AZ	UNKNOWN	Not Available UNKNOWN AZ UNKNOWN	9
4	1	AZ	APACHE CO	0400100059	SALT RIVER PROJECT	6MI/NE ST.JOHNS-HWY191/B-1018	ST. JOHNS	AZ	85936	6MI/NE ST.JOHNS-HWY191/B-1018 ST. JOHNS AZ 85936	9
4	27	AZ	YUMA CO	0331	ARIZONA PUBLIC SERVICE COMPANY (APS)	Unknown	UNKNOWN	AZ	00000	Unknown UNKNOWN AZ 00000	9
4	21	AZ	PINAL CO	U118	SAGUARO	Not Available	UNKNOWN	AZ	UNKNOWN	Not Available UNKNOWN AZ UNKNOWN	9
4	19	AZ	PIMA CO	0082	IRVINGTON	Not Available	UNKNOWN	AZ	UNKNOWN	Not Available UNKNOWN AZ UNKNOWN	9
4	17	AZ	NAVAJO CO	0001	CHOLLA	Not Available	UNKNOWN	AZ	UNKNOWN	Not Available UNKNOWN AZ UNKNOWN	9
4	13	AZ	MARICOPA CO	98	PALO VERDE NUCLEAR GENERATING STATION	5801 S WINTERSBURG RD	TONOPAH	AZ	85354-7529	5801 S WINTERSBURG RD TONOPAH AZ 85354-7529	9
4	13	AZ	MARICOPA CO	52382	OCOTILLO POWER PLANT	1500 E UNIVERSITY DR	TEMPE	AZ	85281-	1500 E UNIVERSITY DR TEMPE AZ 85281-	9
4	13	AZ	MARICOPA CO	3316	SRP AGUA FRIA	7302 W NORTHERN AVE	GLENDALE	AZ	85303-	7302 W NORTHERN AVE GLENDALE AZ 85303-	9
4	13	AZ	MARICOPA CO	3315	SANTAN GENERATING PLANT	1005 S VAL VISTA DR	GILBERT	AZ	85296-	1005 S VAL VISTA DR GILBERT AZ 85296-	9
4	13	AZ	MARICOPA CO	3313	APS WEST PHX POWER PLANT	4606 W HADLEY ST	PHOENIX	AZ	85043-	4606 W HADLEY ST PHOENIX AZ 85043-	9
4	5	AZ	COCONINO CO	0170	US ARMY NAVAJO DEPOT ACTIVITY	Unknown	UNKNOWN	AZ	00000	Unknown UNKNOWN AZ 00000	9
4	5	AZ	COCONINO CO	0004	NAVAJO	Not Available	UNKNOWN	AZ	UNKNOWN	Not Available UNKNOWN AZ UNKNOWN	9
4	3	AZ	COCHISE CO	0400300037	AZ ELECTRIC POWER COOPERATIVE INC	3525 NORTH HIGHWAY 191	COCHISE	AZ	85606	3525 NORTH HIGHWAY 191 COCHISE AZ 85606	9
4	1	AZ	APACHE CO	0400100060	TUCSON ELECTRIC POWER CO-SPRINGERVILLE	OFF RTE191,APP.15 MI SPRINGER	SPRINGERVILLE	AZ	85938	OFF RTE191,APP.15 MI SPRINGER SPRINGERVILLE AZ 85938	9
4	13	AZ	MARICOPA CO	3317	SRP KYRENE STEAM PLANT	7005 S KYRENE RD	TEMPE	AZ	85283-	7005 S KYRENE RD TEMPE AZ 85283-	9
8	123	CO	WELD CO	0023	PUBLIC SERVICE CO FORT SAINT VRAIN PLT	16805 19.5 RD	WELD CNTY	CO	80651	16805 19.5 RD WELD CNTY CO 80651	8
8	77	CO	MESA CO	0035	PUBLIC SERVICE CO FRUITA STA	158 N MESA AVE	FRUITA	CO	815210000	158 N MESA AVE FRUITA CO 815210000	8
8	77	CO	MESA CO	0239	PUBLIC SERVICE CO ROSS RIDGE STATION	SEC 31 T8S R100W	DENVER	CO	80000	SEC 31 T8S R100W DENVER CO 80000	8
8	81	CO	MOFFAT CO	0018	TRI STATE GENERATION CRAIG	2101 S RANNEY	CRAIG	CO	81626	2101 S RANNEY CRAIG CO 81626	8
8	85	CO	MONTROSE CO	0001	TRI STATE GENERATION NUCLA	30739 DD 30 RD	MONTROSE CNTY	CO	81424	30739 DD 30 RD MONTROSE CNTY CO 81424	8
8	87	CO	MORGAN CO	0011	PUBLIC SERVICE CO PAWNEE PLT	14940 RD 24	BRUSH	CO	80723	14940 RD 24 BRUSH CO 80723	8
8	89	CO	Otero County	0004	WEST PLAINS ENERGY - ROCKY FORD STATION	300 S 14TH ST (14TH & WALNUT)	ROCKY FORD	CO	81067	300 S 14TH ST (14TH & WALNUT) ROCKY FORD CO 81067	8
8	99	CO	PROWERS CO	0006	LAMAR UTILITIES BOARD	100 N SECOND ST	LAMAR	CO	810522505	100 N SECOND ST LAMAR CO 810522505	8
8	101	CO	PUEBLO CO	0003	PUBLIC SERVICE CO COMANCHE PLT	2005 LIME RD	PUEBLO	CO	81006	2005 LIME RD PUEBLO CO 81006	8
8	101	CO	PUEBLO CO	0008	WEST PLAINS ENERGY - PUEBLO STATION	105 SOUTH VICTORIA	PUEBLO	CO	81003	105 SOUTH VICTORIA PUEBLO CO 81003	8
8	123	CO	WELD CO	0250	THERMO COGEN PARTNERSHIP FT LUPTON	6501 ROAD 31	FORT LUPTON	CO	80621	6501 ROAD 31 FORT LUPTON CO 80621	8
8	123	CO	WELD CO	0014	PUBLIC SERVICE CO FT LUPTON STATION	SEC 33 T2N R66W	FORT LUPTON	CO	80621	SEC 33 T2N R66W FORT LUPTON CO 80621	8
8	123	CO	WELD CO	0126	THERMO POWER & ELEC INC	510 18TH ST	GREELEY	CO	80631	510 18TH ST GREELEY CO 80631	8
8	77	CO	MESA CO	0002	PUBLIC SERVICE CO CAMEO PLT	NW SEC 34 T10S R98W	PALISADE	CO	81526	NW SEC 34 T10S R98W PALISADE CO 81526	8
8	107	CO	ROUTT CO	0001	PUBLIC SERVICE CO HAYDEN PLT	US HWY 40 - 12795 E YUTE	HAYDEN	CO	81639	US HWY 40 - 12795 E YUTE HAYDEN CO 81639	8
8	13	CO	BOULDER CO	0001	PUBLIC SERVICE CO - VALMONT	1800 N 63RD ST	BOULDER	CO	80301	1800 N 63RD ST BOULDER CO 80301	8
8	69	CO	LARIMER CO	0053	PLATTE RIVER POWER AUTHORITY - RAWHIDE	2700 E RD 82	WELLINGTON	CO	00000-0000	2700 E RD 82 WELLINGTON CO 00000-0000	8
8	123	CO	WELD CO	0412	THERMO GREELEY INC	846 N SIXTH AVE 0.5 MI W OF US	GREELEY	CO	80621-0188	846 N SIXTH AVE 0.5 MI W OF US GREELEY CO 80621-0188	8
8	1	CO	ADAMS CO	0001	PUBLIC SERVICE CO CHEROKEE PLT	6198 FRANKLIN ST	DENVER	CO	802161211	6198 FRANKLIN ST DENVER CO 802161211	8
8	3	CO	Alamosa County	0007	PUBLIC SERVICE CO ALAMOSA PLT	400 WASHINGTON ST	ALAMOSA	CO	81101	400 WASHINGTON ST ALAMOSA CO 81101	8
8	31	CO	DENVER CO	0007	PUBLIC SERVICE CO ZUNI PLT	1335 ZUNI ST	DENVER	CO	802042363	1335 ZUNI ST DENVER CO 802042363	8
8	31	CO	DENVER CO	0008	PUBLIC SERVICE CO - ARAPAHOE	2601 S PLATTE RIVER DR	DENVER	CO	802234210	2601 S PLATTE RIVER DR DENVER CO 802234210	8
8	31	CO	DENVER CO	0041	PUBLIC SERVICE CO DENVER STEAM PLT	19TH ST AT DELGANY ST	DENVER	CO	80202	19TH ST AT DELGANY ST DENVER CO 80202	8
8	41	CO	EL PASO CO	0004	COLORADO SPRINGS UTILITIES-DRAKE PLT	700 S CONEJOS ST	COLORADO SPRINGS	CO	809470001	700 S CONEJOS ST COLORADO SPRINGS CO 809470001	8
8	41	CO	EL PASO CO	0030	COLORADO SPRINGS UTILITIES - NIXON PLT	FOUNTAIN BLVD & US HWY I25	COLORADO SPRINGS	CO	808170000	FOUNTAIN BLVD & US HWY I25 COLORADO SPRINGS CO 808170000	8
8	43	CO	FREMONT CO	0003	WEST PLAINS ENERGY - W.N. CLARK STATION	550 W US HWY 50	CANON CITY	CO	81212	550 W US HWY 50 CANON CITY CO 81212	8
8	45	CO	Garfield County	0057	AMERICAN ATLAS NO 1/COLORADO GREENHOUSE	56 RD 352	RIFLE	CO	81650	56 RD 352 RIFLE CO 81650	8
8	59	CO	JEFFERSON CO	0059	PUBLIC SERVICE CO LOOKOUT CENTER	18201 W 1OTH AVE	GOLDEN	CO	804010000	18201 W 1OTH AVE GOLDEN CO 804010000	8
8	41	CO	EL PASO CO	0003	COLORADO SPRINGS UTILITIES-BIRDSALL PLT	213 NICHOLS BLVD	COLORADO SPRINGS	CO	80907	213 NICHOLS BLVD COLORADO SPRINGS CO 80907	8
8	63	CO	Kit Carson County	0003	TRI STATE GENERATION BURLINGTON	ROAD 50 & 21889 ROAD Z	BURLINGTON	CO	80807	ROAD 50 & 21889 ROAD Z BURLINGTON CO 80807	8
8	59	CO	JEFFERSON CO	1238	KN SERVICES - LAKEWOOD GENERATION FACILI	143 UNION BLVD	LAKEWOOD	CO	80228-1824	143 UNION BLVD LAKEWOOD CO 80228-1824	8
20	165	KS	RUSH CO	00001	LACROSSE MUNICIPAL POWER PLANT	202 E. 9TH	LACROSSE	KS	67548	202 E. 9TH LACROSSE KS 67548	7
20	151	KS	PRATT CO	00005	PRATT-MUNICIPAL POWER PLANT	321 W. 10TH	PRATT	KS	67124	321 W. 10TH PRATT KS 67124	7
20	155	KS	RENO CO	00033	WESTERN RESOURCES, INC. (HEC)	3200 E. 30TH	HUTCHINSON	KS	00000	3200 E. 30TH HUTCHINSON KS 00000	7
20	157	KS	REPUBLIC CO	00016	BELLEVILLE-MUNICIPAL POWER PLANT	810 M ST.	BELLEVILLE	KS	66935	810 M ST. BELLEVILLE KS 66935	7
20	159	KS	RICE CO	00024	STERLING MUNICIPAL POWER PLANT	333 NORTH BROADWAY	STERLING	KS	67579	333 NORTH BROADWAY STERLING KS 67579	7
20	167	KS	RUSSELL CO	00005	RUSSELL-MUNICIPAL POWER PLANT	9TH & ELM	RUSSELL	KS	67665	9TH & ELM RUSSELL KS 67665	7
20	163	KS	Rooks County	00014	STOCKTON-MUNICIPAL POWER PLANT	WEST HWY 24	STOCKTON	KS	67669	WEST HWY 24 STOCKTON KS 67669	7
20	149	KS	POTTAWATOMIE CO	00012	WAMEGO-MUNICIPAL POWER PLANT	3RD & POPLAR	WAMEGO	KS	665470000	3RD & POPLAR WAMEGO KS 665470000	7
20	133	KS	NEOSHO CO	00034	CITY OF ERIE	618 E. 2ND ST.	ERIE	KS	66733	618 E. 2ND ST. ERIE KS 66733	7
20	161	KS	Riley County	00007	KANSAS STATE UNIVERSITY	109 DYKSTRA HALL	MANHATTAN	KS	66502	109 DYKSTRA HALL MANHATTAN KS 66502	7
20	149	KS	POTTAWATOMIE CO	00001	WESTERN RESOURCES, INC. (JEC)	HWY 63 N, ON ACCESS ROAD	ST. MARYS	KS	00000	HWY 63 N, ON ACCESS ROAD ST. MARYS KS 00000	7
20	145	KS	PAWNEE CO	00010	LARNED-MUNICIPAL POWER PLANT	215 MAIN	LARNED	KS	67550	215 MAIN LARNED KS 67550	7
20	143	KS	Ottawa County	00013	MINNEAPOLIS-MUNICIPAL POWER PLANT	110 MARKLEY AVE.	MINNEAPOLIS	KS	67467	110 MARKLEY AVE. MINNEAPOLIS KS 67467	7
20	141	KS	Osborne County	00009	OSBORNE-MUNICIPAL POWER PLANT	N. LOCUST ST.	OSBORNE	KS	67473	N. LOCUST ST. OSBORNE KS 67473	7
20	139	KS	OSAGE CO	00014	OSAGE CITY-MUNICIPAL POWER PLANT	5TH & MAIN	OSAGE CITY	KS	66523	5TH & MAIN OSAGE CITY KS 66523	7
20	139	KS	OSAGE CO	00012	BURLINGAME-MUNICIPAL POWER PLANT	204 W. LINCOLN	BURLINGAME	KS	66413	204 W. LINCOLN BURLINGAME KS 66413	7
20	173	KS	SEDGWICK CO	00012	WESTERN RESOURCES, INC. (GORDON EVANS)	6001 NORTH 151ST ST. WEST	COLWICH	KS	67201	6001 NORTH 151ST ST. WEST COLWICH KS 67201	7
20	133	KS	NEOSHO CO	00047	CITY OF ERIE	121 NORTH POWER DRIVE	ERIE	KS	66733	121 NORTH POWER DRIVE ERIE KS 66733	7
20	191	KS	SUMNER CO	00019	WELLINGTON-MUNICIPAL POWER PLANT	520 S. OLIVE ST.	WELLINGTON	KS	67152	520 S. OLIVE ST. WELLINGTON KS 67152	7
20	133	KS	NEOSHO CO	00030	CITY OF CHANUTE ELEC. DEPT., PLANT #2	1415 NORTH GARFIELD	CHANUTE	KS	66720	1415 NORTH GARFIELD CHANUTE KS 66720	7
20	133	KS	NEOSHO CO	00028	CITY OF CHANUTE ELEC. DEPT., PLANT #3	4302 S. PLUMMER	CHANUTE	KS	66720	4302 S. PLUMMER CHANUTE KS 66720	7
20	131	KS	Nemaha County	00009	SABETHA-MUNICIPAL POWER PLANT	304 N. 11TH ST.	SABETHA	KS	66534	304 N. 11TH ST. SABETHA KS 66534	7
20	137	KS	NORTON CO	00005	NORTON-MUNICIPAL POWER PLANT	SOUTH MUNICIPAL ST.	NORTON	KS	67654	SOUTH MUNICIPAL ST. NORTON KS 67654	7
20	193	KS	THOMAS CO	00001	MIDWEST ENERGY, INC.	NORTH COUNTRY CLUB DRIVE	COLBY	KS	67701	NORTH COUNTRY CLUB DRIVE COLBY KS 67701	7
20	55	KS	FINNEY CO	00026	SUNFLOWER ELECTRIC POWER CORPORATION	WEST END OF ST. JOHN STREET	GARDEN CITY	KS	67846	WEST END OF ST. JOHN STREET GARDEN CITY KS 67846	7
20	125	KS	MONTGOMERY CO	00002	COFFEYVILLE-MUNICIPAL POWER PLANT	7TH & SANTA FE	COFFEYVILLE	KS	67337	7TH & SANTA FE COFFEYVILLE KS 67337	7
20	209	KS	WYANDOTTE CO	00049	BOARD OF PUBLIC UTILITIES - KAW	2015 KANSAS AVE.	KANSAS CITY	KS	00000	2015 KANSAS AVE. KANSAS CITY KS 00000	7
20	209	KS	WYANDOTTE CO	00048	BOARD OF PUBLIC UTILITIES - QUINDARO	3601 N. 12TH	KANSAS CITY	KS	00000	3601 N. 12TH KANSAS CITY KS 00000	7
20	209	KS	WYANDOTTE CO	00008	BOARD OF PUBLIC UTILITIES - NEARMAN	4240 N. 55TH	KANSAS CITY	KS	00000	4240 N. 55TH KANSAS CITY KS 00000	7
20	205	KS	WILSON CO	00018	FREDONIA MUNICIPAL POWER PLANT	ON FALL RIVER	FREDONIA	KS	66736	ON FALL RIVER FREDONIA KS 66736	7
20	205	KS	WILSON CO	00014	NEODESHA-MUNICIPAL POWER PLANT	WEST MAIN STREET	NEODESHA	KS	66757	WEST MAIN STREET NEODESHA KS 66757	7
20	201	KS	Washington County	00024	WASHINGTON-MUNICIPAL POWER PLANT	101 PARK ROAD	WASHINGTON	KS	66968	101 PARK ROAD WASHINGTON KS 66968	7

STATEFIPS	COUNTYFIPS	STATEABBREV	COUNTYNAME	FACILITYID	FACILITYNAME	STREET	CITY	STATE	ZIP	FACILITYADDRESS	EPA REGION
20	201	KS	Washington County	00012	UTILICORP UNITED, INC.	2 MILES NORTH	CLIFTON	KS	66937	2 MILES NORTH CLIFTON KS 66937	7
20	189	KS	STEVENS CO	00020	HUGOTON-MUNICIPAL POWER PLANT (#1)	115 E. 5TH	HUGOTON	KS	67951	115 E. 5TH HUGOTON KS 67951	7
20	193	KS	THOMAS CO	00007	COLBY MUNICIPAL POWER PLANT	120 N. STERLING	COLBY	KS	67701	120 N. STERLING COLBY KS 67701	7
20	173	KS	SEDGWICK CO	00014	WESTERN RESOURCES, INC.-MURRY GILL	6100 WEST 55TH ST. SOUTH	WICHITA	KS	67201	6100 WEST 55TH ST. SOUTH WICHITA KS 67201	7
20	191	KS	SUMNER CO	00056	WELLINGTON CITY POWER PLANT, GAS TURBINE	R. 1	WELLINGTON	KS	671520000	R. 1 WELLINGTON KS 671520000	7
20	191	KS	SUMNER CO	00055	CITY OF OXFORD, MUNICIPAL POWER PLANT	804 N. WATER	OXFORD	KS	67119	804 N. WATER OXFORD KS 67119	7
20	191	KS	SUMNER CO	00025	MULVANE-MUNICIPAL POWER PLANT	120 BOXELDER	MULVANE	KS	67110	120 BOXELDER MULVANE KS 67110	7
20	189	KS	STEVENS CO	00021	HUGOTON-MUNICIPAL POWER PLANT (#2)	1601 S. WASHINGTON	HUGOTON	KS	000000000	1601 S. WASHINGTON HUGOTON KS 000000000	7
20	187	KS	STANTON CO	00009	JOHNSON CITY MUNICIPAL POWER PLANT	402 S. MAIN	JOHNSON CITY	KS	67855	402 S. MAIN JOHNSON CITY KS 67855	7
20	185	KS	Stafford County	00017	STAFFORD-MUNICIPAL POWER PLANT	519 S. BOSTON	STAFFORD	KS	67578	519 S. BOSTON STAFFORD KS 67578	7
20	181	KS	SHERMAN CO	00005	GOODLAND-MUNICIPAL POWER PLANT	17TH & CHERRY	GOODLAND	KS	67735	17TH & CHERRY GOODLAND KS 67735	7
20	177	KS	SHAWNEE CO	00030	WESTERN RESOURCES, INC. (TEC)	2ND & DUPONT RD.	TOPEKA	KS	66542	2ND & DUPONT RD. TOPEKA KS 66542	7
20	175	KS	SEWARD CO	00001	UTILICORP UNITED, INC.	U.S. HWY 54 & CIMARRON RIVER	CIMARRON RIVER STA.	KS	67901	U.S. HWY 54 & CIMARRON RIVER CIMARRON RIVER STA. KS 67901	7
20	199	KS	Wallace County	00005	SHARON SPRINGS MUNICIPAL POWER PLANT	SOUTH HWY 27	SHARON SPRINGS	KS	67758	SOUTH HWY 27 SHARON SPRINGS KS 67758	7
20	15	KS	BUTLER CO	00010	AUGUSTA-MUNICIPAL POWER PLANT (#2)	615 E. 12TH ST.	AUGUSTA	KS	67010	615 E. 12TH ST. AUGUSTA KS 67010	7
20	39	KS	Decatur County	00009	OBERLIN-MUNICIPAL POWER PLANT	SOUTH RODEHAVER STREET	OBERLIN	KS	67749	SOUTH RODEHAVER STREET OBERLIN KS 67749	7
20	37	KS	Crawford County	00006	GIRARD-MUNICIPAL POWER PLANT	309 EAST BUFFALO	GIRARD	KS	66743	309 EAST BUFFALO GIRARD KS 66743	7
20	123	KS	MITCHELL CO	00012	BELOIT-MUNICIPAL POWER PLANT	215 S. CHESTNUT	BELOIT	KS	67420	215 S. CHESTNUT BELOIT KS 67420	7
20	35	KS	COWLEY CO	00006	WINFIELD MUNICIPAL POWER PLANT	WEST 14TH ST.	WINFIELD	KS	67156	WEST 14TH ST. WINFIELD KS 67156	7
20	59	KS	FRANKLIN CO	00006	OTTAWA-MUNICIPAL POWER PLANT	2ND & BEECH STREET	OTTAWA	KS	66067	2ND & BEECH STREET OTTAWA KS 66067	7
20	31	KS	Coffey County	00006	BURLINGTON-MUNICIPAL POWER PLANT	11TH & NIAGARA ST.	BURLINGTON	KS	66839	11TH & NIAGARA ST. BURLINGTON KS 66839	7
20	27	KS	CLAY CO	00007	CLAY CENTER PUBLIC UTILITIES	427 COURT ST.	CLAY CENTER	KS	67432	427 COURT ST. CLAY CENTER KS 67432	7
20	25	KS	CLARK CO	00001	ASHLAND-MUNICIPAL POWER PLANT	NORTH CHESTNUT	ASHLAND	KS	67831	NORTH CHESTNUT ASHLAND KS 67831	7
20	23	KS	Cheyenne County	00009	ST. FRANCIS POWER PLANT	621 WEST 1ST	ST. FRANCIS	KS	67756	621 WEST 1ST ST. FRANCIS KS 67756	7
20	41	KS	DICKINSON CO	00017	WESTERN RESOURCES, INC. - ABILENE ENERGY	3 MILES SE OF TOWN	ABILENE	KS	67410	3 MILES SE OF TOWN ABILENE KS 67410	7
20	21	KS	CHEROKEE CO	00002	EMPIRE DISTRICT ELECTRIC COMPANY (THE)	R. R. 1	RIVERTON	KS	66770	R. R. 1 RIVERTON KS 66770	7
20	35	KS	COWLEY CO	00012	WINFIELD MUNICIPAL POWER PLANT (NEW)	EAST 12TH STREET	WINFIELD	KS	67156	EAST 12TH STREET WINFIELD KS 67156	7
20	15	KS	BUTLER CO	00009	AUGUSTA-MUNICIPAL POWER PLANT (#1)	7TH & RR JUNC.	AUGUSTA	KS	67010	7TH & RR JUNC. AUGUSTA KS 67010	7
20	13	KS	Brown County	00029	CITY OF HORTON	602 E. 15TH ST.	HORTON	KS	66439	602 E. 15TH ST. HORTON KS 66439	7
20	9	KS	BARTON CO	00026	HOISINGTON-MUNICIPAL POWER PLANT	164 S. ELM ST.	HOISINGTON	KS	67544	164 S. ELM ST. HOISINGTON KS 67544	7
20	9	KS	BARTON CO	00025	ELLINWOOD-MUNICIPAL POWER PLANT	201 W. 1ST ST.	ELLINWOOD	KS	67526	201 W. 1ST ST. ELLINWOOD KS 67526	7
20	9	KS	BARTON CO	00002	UTILICORP UNITED, INC.	ARTHUR MULLERGREN STA	GREAT BEND	KS	675300170	ARTHUR MULLERGREN STA GREAT BEND KS 675300170	7
20	9	KS	BARTON CO	00001	MIDWEST ENERGY, INC.	1025 PATTON ROAD	GREAT BEND	KS	67530	1025 PATTON ROAD GREAT BEND KS 67530	7
20	3	KS	Anderson County	00001	GARNETT-MUNICIPAL POWER PLANT	SOUTH WALNUT STREET	GARNETT	KS	66032	SOUTH WALNUT STREET GARNETT KS 66032	7
20	1	KS	ALLEN CO	00019	CITY OF IOLA POWER PLANT	S. WASHINGTON ST.	IOLA	KS	667490000	S. WASHINGTON ST. IOLA KS 667490000	7
20	1	KS	ALLEN CO	00011	CITY OF IOLA POWER PLANT	WEST ON HWY 54	IOLA	KS	66749	WEST ON HWY 54 IOLA KS 66749	7
20	23	KS	Cheyenne County	00008	MIDWEST ENERGY, INC.	R. R. 1	BIRD CITY	KS	67731	R. R. 1 BIRD CITY KS 67731	7
20	105	KS	LINCOLN CO	00013	LINCOLN-MUNICIPAL POWER PLANT	405 W. SOUTH	LINCOLN	KS	67455	405 W. SOUTH LINCOLN KS 67455	7
20	121	KS	MIAMI CO	00001	OSAWATOMIE-MUNICIPAL POWER PLANT	JOHN BROWN PARK	OSAWATOMIE	KS	66064	JOHN BROWN PARK OSAWATOMIE KS 66064	7
20	119	KS	MEADE CO	00013	MEADE-MUNICIPAL POWER PLANT	623 E. CARTHAGE	MEADE	KS	67864	623 E. CARTHAGE MEADE KS 67864	7
20	113	KS	MC PHERSON CO	00046	BOARD OF PUBLIC UTILITIES - #3	S24-T19S-R3W	MCPHERSON	KS	67460	S24-T19S-R3W MCPHERSON KS 67460	7
20	113	KS	MC PHERSON CO	00014	MCPHERSON BOARD OF PUBLIC UTILITIES #2	1128 WEST AVE. A	MCPHERSON	KS	67460	1128 WEST AVE. A MCPHERSON KS 67460	7
20	31	KS	Coffey County	00021	WOLF CREEK NUCLEAR OPERATING CORP.	S7-T21S-R16E	BURLINGTON	KS	66839	S7-T21S-R16E BURLINGTON KS 66839	7
20	107	KS	LINN CO	00005	KANSAS CITY POWER & LIGHT CO.	R. R. 1	LACYGNE	KS	00000	R. R. 1 LACYGNE KS 00000	7
20	41	KS	DICKINSON CO	00034	HERINGTON-MUNICIPAL POWER PLANT	437 S. 5TH	HERINGTON	KS	674490000	437 S. 5TH HERINGTON KS 674490000	7
20	99	KS	Labette County	00001	WESTERN RESOURCES, INC. - NEOSHO ENERGY	8 MI E ON HWY 160	PARSONS	KS	00000	8 MI E ON HWY 160 PARSONS KS 00000	7
20	97	KS	KIOWA CO	00007	GREENSBURG-MUNICIPAL POWER PLANT	400 N. MAIN ST.	GREENSBURG	KS	67054	400 N. MAIN ST. GREENSBURG KS 67054	7
20	95	KS	KINGMAN CO	00004	KINGMAN-MUNICIPAL POWER PLANT	405 WEST SHERMAN	KINGMAN	KS	67068	405 WEST SHERMAN KINGMAN KS 67068	7
20	93	KS	KEARNEY CO	00019	CITY OF LAKIN	111 OSBORN DRIVE	LAKIN	KS	67860	111 OSBORN DRIVE LAKIN KS 67860	7
20	85	KS	Jackson County	00011	HOLTON-MUNICIPAL POWER PLANT	1000 NEW JERSEY	HOLTON	KS	66436	1000 NEW JERSEY HOLTON KS 66436	7
20	77	KS	HARPER CO	00013	ATTICA-MUNICIPAL POWER PLANT	101 N. HARPER	ATTICA	KS	670090000	101 N. HARPER ATTICA KS 670090000	7
20	77	KS	HARPER CO	00002	ANTHONY-MUNICIPAL POWER PLANT	3 MILES SOUTH OF ANTHONY	ANTHONY	KS	67003	3 MILES SOUTH OF ANTHONY ANTHONY KS 67003	7
20	65	KS	GRAHAM CO	00009	HILL CITY-MUNICIPAL POWER PLANT	724 S. POMEROY AVE.	HILL CITY	KS	67642	724 S. POMEROY AVE. HILL CITY KS 67642	7
20	45	KS	DOUGLAS CO	00011	BALDWIN CITY-MUNICIPAL POWER PLANT	605 HIGH STREET	BALDWIN CITY	KS	66006	605 HIGH STREET BALDWIN CITY KS 66006	7
20	57	KS	FORD CO	00001	UTILICORP UNITED, INC.	JUDSON LARGE STATION	DODGE CITY	KS	67801	JUDSON LARGE STATION DODGE CITY KS 67801	7
20	55	KS	FINNEY CO	00023	SUNFLOWER ELECTRIC POWER CORPORATION	S18-T24S-R33W	HOLCOMB	KS	67851	S18-T24S-R33W HOLCOMB KS 67851	7
20	45	KS	DOUGLAS CO	00014	WESTERN RESOURCES, INC.	1250 N. 1800 RD.	LAWRENCE	KS	66044	1250 N. 1800 RD. LAWRENCE KS 66044	7
20	91	KS	JOHNSON CO	00065	GARDNER ENERGY CENTER	1 MILE E. OF GARDNER	GARDNER	KS	66030	1 MILE E. OF GARDNER GARDNER KS 66030	7
20	109	KS	LOGAN CO	00009	OAKLEY-MUNICIPAL POWER PLANT	400 PRICE AVENUE	OAKLEY	KS	67748	400 PRICE AVENUE OAKLEY KS 67748	7
35	1	NM	BERNALILLO CO	3500100011	REEVES GENERATING STATION	4400 Paseo del Norte DR NE	Albuquerque	NM	87109	4400 Paseo del Norte DR NE Albuquerque NM 87109	6
35	45	NM	SAN JUAN CO	0002	FOUR CORNERS	Not Available	UNKNOWN	NM	UNKNOWN	Not Available UNKNOWN NM UNKNOWN	6
35	37	NM	QUAY CO	0002	TUCUMCARI	315 W Railroad Ave	Tucumcari	NM	88401	315 W Railroad Ave Tucumcari NM 88401	6
35	31	NM	MC KINLEY CO	0032	ESCALANTE	4 Mi N Of Prewitt	Prewitt	NM	87045	4 Mi N Of Prewitt Prewitt NM 87045	6
35	25	NM	LEA CO	0054	CUNNINGHAM	12.5 Mi West Of Hobbs	Hobbs	NM	88240	12.5 Mi West Of Hobbs Hobbs NM 88240	6
35	25	NM	LEA CO	0034	MADDOX STATION	8 Mi W. Hobbs on US 62/180	Hobbs	NM	88240	8 Mi W. Hobbs on US 62/180 Hobbs NM 88240	6
35	13	NM	DONA ANA CO	0025	PHYSICAL PLANT BOILERS	Nmsu Campus	Las Cruces	NM	88003	Nmsu Campus Las Cruces NM 88003	6
35	13	NM	DONA ANA CO	0002	RIO GRANDE GENERATING STATION	3501 Doniphan Road	Sunland Park	NM	88063	3501 Doniphan Road Sunland Park NM 88063	6
35	1	NM	BERNALILLO CO	3500100368	COBISA PERSON POWER PROJECT	725 Electric AVE SE	Albuquerque	NM	87105	725 Electric AVE SE Albuquerque NM 87105	6
35	47	NM	SAN MIGUEL CO	0004	LAS VEGAS TURBINE	West National St.	Las Vegas	NM	87701	West National St. Las Vegas NM 87701	6
35	45	NM	SAN JUAN CO	0902	SAN JUAN GENERATING STATION	San Juan Generating Station	Waterflow	NM	87421	San Juan Generating Station Waterflow NM 87421	6
35	7	NM	COLFAX CO	0001	RATON POWER PLANT	940 S. 2nd St	Raton	NM	87740	940 S. 2nd St Raton NM 87740	6
35	45	NM	SAN JUAN CO	0029	ANIMAS PLANT	501 Mccormick School Rd	Farmington	NM	87401	501 Mccormick School Rd Farmington NM 87401	6
32	3	NV	CLARK CO	0466	MOHAVE GENERATING STATION	2700 EDISON WAY	LAUGHLIN	NV	89029	2700 EDISON WAY LAUGHLIN NV 89029	9
32	1	NV	Churchill County	0197	AMOR IV CORP & STILLWATER GEOTHERMAL	5500 SODA LAKE ROAD	FALLON	NV	89406	5500 SODA LAKE ROAD FALLON NV 89406	9
32	1	NV	Churchill County	0756	CAITHNESS DIXIE VALLEY LLC	P O BOX 1270	FALLON	NV	89407-1270	P O BOX 1270 FALLON NV 89407-1270	9
32	3	NV	CLARK CO	0398	CLARK STATION	CLARK STATION	LAS VEGAS	NV	89151	CLARK STATION LAS VEGAS NV 89151	9
32	3	NV	CLARK CO	0400	REID GARDNER STATION	No Address Given	MOAPA	NV	89025	No Address Given MOAPA NV 89025	9
32	13	NV	HUMBOLDT CO	0457	VALMY GENERATING STATION	No Address Given	RENO	NV	89520-0026	No Address Given RENO NV 89520-0026	9
32	15	NV	Lander County	0223	BEOWAWE POWER LLC	1000 POWER PLANT PLACE	BEOWAWE	NV	89821	1000 POWER PLANT PLACE BEOWAWE NV 89821	9
32	19	NV	LYON CO	0091	SIERRA PACIFIC POWER COMPANY	6100 NEIL ROAD	RENO	NV	89520	6100 NEIL ROAD RENO NV 89520	9

STATEFIPS	COUNTYFIPS	STATEABBREV	COUNTYNAME	FACILITYID	FACILITYNAME	STREET	CITY	STATE	ZIP	FACILITYADDRESS	EPA REGION
32	29	NV	STOREY CO	0194	SIERRA PACIFIC POWER	INTERSTATE-80 EAST	SPARKS	NV	00000	INTERSTATE-80 EAST SPARKS NV 00000	9
32	31	NV	WASHOE CO	A01176A	EMPIRE ENERGY, LLC (FRMLY AMOR II)	SECT 21, T29N, R23E	EMPIRE	NV	89405-0000	SECT 21, T29N, R23E EMPIRE NV 89405-0000	9
32	31	NV	WASHOE CO	A90A	STEAMBOAT ENVIROSYSTEMS, LLC, UNITS 1,1A	1010 POWER PLANT DRIVE	RENO	NV	89511-0000	1010 POWER PLANT DRIVE RENO NV 89511-0000	9
32	3	NV	CLARK CO	0399	SUNRISE STATION	6200 VEGAS VALLEY DRIVE	LAS VEGAS	NV	89121	6200 VEGAS VALLEY DRIVE LAS VEGAS NV 89121	9
40	31	OK	COMANCHE CO	1211	CENTRAL AND SOUTH WEST SERVICES, INC.	P.O. Box 660164	Dallas	TX	752660164	P.O. Box 660164 Dallas TX 752660164	6
40	101	OK	MUSKOGEE CO	2209	OKLAHOMA GAS & ELECTRIC	P.O. Box 321, MC C610	Oklahoma City	OK	731010000	P.O. Box 321, MC C610 Oklahoma City OK 731010000	6
40	103	OK	NOBLE CO	2211	OKLAHOMA GAS & ELECTRIC	P.O. Box 321, MC C610	Oklahoma City	OK	731010000	P.O. Box 321, MC C610 Oklahoma City OK 731010000	6
40	79	OK	Le Flore County	1011	AES SHADY POINT, INC.	PO Box 1740	Panama	OK	749510000	PO Box 1740 Panama OK 749510000	6
40	71	OK	KAY CO	2929	OKLAHOMA GAS & ELECTRIC	PO Box 321, MC C610	Oklahoma City	OK	731010000	PO Box 321, MC C610 Oklahoma City OK 731010000	6
40	47	OK	GARFIELD CO	2207	OKLAHOMA GAS & ELECTRIC	P.O. Box 321, MC C610	Oklahoma City	OK	731010000	P.O. Box 321, MC C610 Oklahoma City OK 731010000	6
40	39	OK	CUSTER CO	4152	ONEOK PRODUCER SERVICES	P.O. Box 521120	Tulsa	OK	741521120	P.O. Box 521120 Tulsa OK 741521120	6
40	97	OK	MAYES CO	1799	GRAND RIVER DAM AUTHORITY	P.O. Box 609	Chouteau	OK	743370609	P.O. Box 609 Chouteau OK 743370609	6
40	23	OK	CHOCTAW CO	2700	WESTERN FARMERS ELECTRIC COOP	P.O. Box 429	Anadarko	OK	730050000	P.O. Box 429 Anadarko OK 730050000	6
40	17	OK	CANADIAN CO	2205	OKLAHOMA GAS & ELECTRIC	P.O. Box 321, MC C610	Oklahoma City	OK	731010000	P.O. Box 321, MC C610 Oklahoma City OK 731010000	6
40	15	OK	CADDO CO	2699	WESTERN FARMERS ELECTRIC COOP	Box 429	Anadarko	OK	730050000	Box 429 Anadarko OK 730050000	6
40	15	OK	CADDO CO	1214	CENTRAL AND SOUTH WEST SERVICES, INC.	P.O. Box 660164	Dallas	TX	752660164	P.O. Box 660164 Dallas TX 752660164	6
40	119	OK	PAYNE CO	1244	CITY OF CUSHING	Box 311, 100 Judy Adams Blvd.	Cushing	OK	740230311	Box 311, 100 Judy Adams Blvd. Cushing OK 740230311	6
40	107	OK	Okfuskee County	1216	CENTRAL AND SOUTH WEST SERVICES, INC.	P.O. Box 660164	Dallas	TX	752660164	P.O. Box 660164 Dallas TX 752660164	6
40	109	OK	OKLAHOMA CO	2208	OKLAHOMA GAS & ELECTRIC	P.O. Box 321, MC C610	Oklahoma City	OK	731010000	P.O. Box 321, MC C610 Oklahoma City OK 731010000	6
40	109	OK	OKLAHOMA CO	2212	OKLAHOMA GAS & ELECTRIC	P.O. Box 321, MC C610	Oklahoma City	OK	731270000	P.O. Box 321, MC C610 Oklahoma City OK 731270000	6
40	119	OK	PAYNE CO	1247	STILLWATER POWER	P.O. Box 1449	Stillwater	OK	740760000	P.O. Box 1449 Stillwater OK 740760000	6
40	131	OK	ROGERS CO	1212	CENTRAL AND SOUTH WEST SERVICES, INC.	P.O. Box 660164	Dallas	TX	752660164	P.O. Box 660164 Dallas TX 752660164	6
40	153	OK	WOODWARD CO	2701	WESTERN FARMERS ELECTRIC COOP	P.O. Box 429	Anadarko	OK	730050000	P.O. Box 429 Anadarko OK 730050000	6
40	133	OK	SEMINOLE CO	2210	OKLAHOMA GAS & ELECTRIC	P.O. Box 321, MC C610	Oklahoma City	OK	731010000	P.O. Box 321, MC C610 Oklahoma City OK 731010000	6
40	143	OK	TULSA CO	1213	CENTRAL AND SOUTH WEST SERVICES, INC.	P.O. Box 660164	Dallas	TX	752660164	P.O. Box 660164 Dallas TX 752660164	6
40	143	OK	TULSA CO	1215	CENTRAL AND SOUTH WEST SERVICES, INC.	P.O. Box 660164	Dallas	TX	752660164	P.O. Box 660164 Dallas TX 752660164	6
48	309	TX	MC LENNAN CO	MB0116C	TXU ELECTRIC CO	APPROX 11.5 M E OF WACO	WACO	TX	76701	APPROX 11.5 M E OF WACO WACO TX 76701	6
48	309	TX	MC LENNAN CO	MB0117A	TXU ELECTRIC CO	APPROX. 4.3 MI. S.W., OFF F.M.	WACO	TX	76701	APPROX. 4.3 MI. S.W., OFF F.M. WACO TX 76701	6
48	315	TX	MARION CO	ME0006A	SOUTHWESTERN ELECTRIC POWER CO	12 MI W OF AVINGER	AVINGER	TX	75630	12 MI W OF AVINGER AVINGER TX 75630	6
48	321	TX	MATAGORDA CO	MH0028D	STP NUCLEAROPERATING CO	ON F.M. 521, 8 MILES W. OF WAD	BAY CITY	TX	77404	ON F.M. 521, 8 MILES W. OF WAD BAY CITY TX 77404	6
48	331	TX	MILAM CO	MM0023J	TXU ELECTRIC CO	7 MI SW OF ROCKDALE	ROCKDALE	TX	76567	7 MI SW OF ROCKDALE ROCKDALE TX 76567	6
48	335	TX	MITCHELL CO	MO0014L	TXU ELECTRIC CO	5 MI. S.W. OF COLORADO CITY, T	COLORADO CITY	TX	79512	5 MI. S.W. OF COLORADO CITY, T COLORADO CITY TX 79512	6
48	341	TX	MOORE CO	MR0033U	SOUTHWESTERN PUBLIC SERVICE	5 MI SW ON FM 119	SUNRAY	TX	79086	5 MI SW ON FM 119 SUNRAY TX 79086	6
48	355	TX	NUECES CO	NE0025C	CENTRAL POWER AND LIGHT CO	3501 CALLICOATE ROAD	CORPUS CHRISTI	TX	78410	3501 CALLICOATE ROAD CORPUS CHRISTI TX 78410	6
48	303	TX	LUBBOCK CO	LN3604A	J.R. MASSENGALE	Not Available	UNKNOWN	TX	UNKNOWN	Not Available UNKNOWN TX UNKNOWN	6
48	353	TX	NOLAN CO	ND0054G	EEX POWER SYSTEMS	SOMEWHERE NEAR I. 20 S.E. OF S	SWEETWATER	TX	79556	SOMEWHERE NEAR I. 20 S.E. OF S SWEETWATER TX 79556	6
48	355	TX	NUECES CO	NE0024E	CENTRAL POWER AND LIGHT CO	4301 WALDRON ROAD	CORPUS CHRISTI	TX	78322	4301 WALDRON ROAD CORPUS CHRISTI TX 78322	6
48	343	TX	MORRIS CO	MS0011T	SOUTHWESTERN ELECTRIC POWER CO	OFF HWY 259, 40 M N OF LONGVIE	LONE STAR	TX	75668	OFF HWY 259, 40 M N OF LONGVIE LONE STAR TX 75668	6
48	339	TX	MONTGOMERY CO	MQ0009F	ENTERGY GULF STATES INC	2 MI. W. OF I. 45 N. ON LONGST	WILLIS	TX	77378	2 MI. W. OF I. 45 N. ON LONGST WILLIS TX 77378	6
48	303	TX	LUBBOCK CO	LN0206F	LUBBOCK POWER AND LIGHT	TEXAS TECH. COGENERATION	LUBBOCK	TX	79457	TEXAS TECH. COGENERATION LUBBOCK TX 79457	6
48	303	TX	LUBBOCK CO	LN0081B	SOUTHWESTERN PUBLIC SERVICE CO	SE OF LUBBOCK, TEXAS	LUBBOCK	TX	79401	SE OF LUBBOCK, TEXAS LUBBOCK TX 79401	6
48	303	TX	LUBBOCK CO	LN0057V	LUBBOCK POWER & LIGHT	AT THE INTERSECTION OF U.S. HW	LUBBOCK	TX	79457	AT THE INTERSECTION OF U.S. HW LUBBOCK TX 79457	6
48	299	TX	LLANO CO	LL0006O	LOWER COLORADO RIVER AUTHORITY	7 MI. W. OF MARBLE FALLS, TX.,	MARBLE FALLS	TX	78654	7 MI. W. OF MARBLE FALLS, TX., MARBLE FALLS TX 78654	6
48	293	TX	LIMESTONE CO	LI0027L	RELIANT ENERGY INC	9 MI. N. OF JEWETT, TX., ON F.	JEWETT	TX	75846	9 MI. N. OF JEWETT, TX., ON F. JEWETT TX 75846	6
48	279	TX	LAMB CO	LB0059G	SAVAGE TOLKCORPORATION	9 MILES E OF MULESHOE ON HWY 7	MULESHOE	TX	79347	9 MILES E OF MULESHOE ON HWY 7 MULESHOE TX 79347	6
48	279	TX	LAMB CO	LB0047N	SOUTHWESTERN PUBLIC SERVICE CO	N. OF SUDAN, TEXAS	MULESHOE	TX	79347	N. OF SUDAN, TEXAS MULESHOE TX 79347	6
48	279	TX	LAMB CO	LB0046P	SOUTHWESTERN PUBLIC SERVICE	NORTH OF AMHERST, TX	AMHERST	TX	79312	NORTH OF AMHERST, TX AMHERST TX 79312	6
48	277	TX	Lamar County	LA0045F	TENASKA IIITEXAS PARTNERS	PARIS, TEXAS	PARIS	TX	75460	PARIS, TEXAS PARIS TX 75460	6
48	251	TX	JOHNSON CO	JH0230L	TENASKA IV TEXAS PARTNERS LTD	CLEBURNE INDUSTRIAL PARK	CLEBURNE	TX	76031	CLEBURNE INDUSTRIAL PARK CLEBURNE TX 76031	6
48	355	TX	NUECES CO	NE0026A	CENTRAL POWER AND LIGHT CO	2002 NAVIGATION BOULEVARD	CORPUS CHRISTI	TX	78322	2002 NAVIGATION BOULEVARD CORPUS CHRISTI TX 78322	6
48	453	TX	TRAVIS CO	TH0004D	CITY OF AUSTIN	8003 DECKER LANE	AUSTIN	TX	78724	8003 DECKER LANE AUSTIN TX 78724	6
48	233	TX	HUTCHINSON CO	HW0024U	SOUTHWESTERN PUBLIC SERVICE	S.H. 207, 2 MI. N.	BORGER	TX	79007	S.H. 207, 2 MI. N. BORGER TX 79007	6
48	233	TX	HUTCHINSON CO	HW0081I	SOUTHWESTERN PUBLIC SERVICE CO	2 MI. N.E. OF BORGER ON STATE	BORGER	TX	79007	2 MI. N.E. OF BORGER ON STATE BORGER TX 79007	6
48	253	TX	JONES CO	JI0030K	CENTRAL & SOUTH WEST SERVICES INC	F.M. 2833, 7 MI. N. OF HWY. 35	ABILENE	TX	79601	F.M. 2833, 7 MI. N. OF HWY. 35 ABILENE TX 79601	6
48	449	TX	TITUS CO	TF0012D	SOUTHWESTERN ELECTRIC POWER CO	NORTH TWO MILES ON AN OILED CO	MOUNT PLEASANT	TX	75455	NORTH TWO MILES ON AN OILED CO MOUNT PLEASANT TX 75455	6
48	503	TX	YOUNG CO	YB0017V	TXU ELECTRIC CO	3 MI. NW OF GRAHAM	GRAHAM	TX	76046	3 MI. NW OF GRAHAM GRAHAM TX 76046	6
48	487	TX	WILBARGER CO	WI0025C	WEST TEXAS UTILITIES CO	3.5 MI. S.S.W. OF OKLAUNION, T	OKLAUNION	TX	76373	3.5 MI. S.S.W. OF OKLAUNION, T OKLAUNION TX 76373	6
48	487	TX	WILBARGER CO	WI0002O	WEST TEXAS UTILITIES	US 287 AND MAPLES ST	VERNON	TX	76384	US 287 AND MAPLES ST VERNON TX 76384	6
48	485	TX	WICHITA CO	WH0083W	MIRANT WICHITA FALLS LP	4511 ALLENDALE RD.	WICHITA FALLS	TX	76310	4511 ALLENDALE RD. WICHITA FALLS TX 76310	6
48	481	TX	WHARTON CO	WF0175P	NEWGULF POWER VENTURE INC	1611 WOODALL PROGRESS FREEWAY	NEWGULF	TX	77462	1611 WOODALL PROGRESS FREEWAY NEWGULF TX 77462	6
48	479	TX	WEBB CO	WE0005G	CENTRAL & SOUTHWEST SERVICES INC	0.5 MI. FROM I. 35 & SANTA MAR	LAREDO	TX	78040	0.5 MI. FROM I. 35 & SANTA MAR LAREDO TX 78040	6
48	475	TX	WARD CO	WC0028Q	TXU ELECTRIC CO	600 YUCCA DR., MONAHANS, TX.:	MONAHANS	TX	79756	600 YUCCA DR., MONAHANS, TX.: MONAHANS TX 79756	6
48	469	TX	VICTORIA CO	VC0026O	SOUTH TEXASELECTRIC COOPERATIVE INC	FM 447, 3 M W OF NURSERY	NURSERY	TX	77976	FM 447, 3 M W OF NURSERY NURSERY TX 77976	6
48	469	TX	VICTORIA CO	VC0003D	CENTRAL POWER AND LIGHT CO	1205 C.S. BOTTOM	VICTORIA	TX	77901	1205 C.S. BOTTOM VICTORIA TX 77901	6
48	453	TX	TRAVIS CO	TH0104V	UNIVERSITY OF TEXAS AT AUSTIN	24TH ST. & SAN JACINTO ST.	AUSTIN	TX	78701	24TH ST. & SAN JACINTO ST. AUSTIN TX 78701	6
48	453	TX	TRAVIS CO	TH0006W	CITY OF AUSTIN	2401 HOLLY STREET	AUSTIN	TX	78701	2401 HOLLY STREET AUSTIN TX 78701	6
48	201	TX	HARRIS CO	HG9954A	CALPINE CORPORATION	1400 JEFFERSON ROAD	PASADENA	TX	77506	1400 JEFFERSON ROAD PASADENA TX 77506	6
48	449	TX	TITUS CO	TF0013B	TXU ELECTRIC CO	7 MI. S.W. OF MT. PLEASANT OFF	MOUNT PLEASANT	TX	75455	7 MI. S.W. OF MT. PLEASANT OFF MOUNT PLEASANT TX 75455	6
48	231	TX	HUNT CO	HV0023K	GREENVILLE ELECTRIC SYSTEM	N. OF GREENVILLE NEAR THE INTE	GREENVILLE	TX	75401	N. OF GREENVILLE NEAR THE INTE GREENVILLE TX 75401	6
48	355	TX	NUECES CO	NE0035W	ROBSTOWN UTILITY SYSTEMS	1100 N 4TH STREET	ROBSTOWN	TX	78380	1100 N 4TH STREET ROBSTOWN TX 78380	6
48	441	TX	TAYLOR CO	TB0056E	WEST TEXAS UTILITIES CO	102 E.N. 2ND ST.	ABILENE	TX	79601	102 E.N. 2ND ST. ABILENE TX 79601	6
48	439	TX	TARRANT CO	TA0354E	TXU ELECTRIC CO	AT 4TH AND NORTH HOUSTON STREE	FORT WORTH	TX	76002	AT 4TH AND NORTH HOUSTON STREE FORT WORTH TX 76002	6
48	439	TX	TARRANT CO	TA0353G	TXU ELECTRIC CO	6604 EAST ROSEDALE	FORT WORTH	TX	76002	6604 EAST ROSEDALE FORT WORTH TX 76002	6
48	439	TX	TARRANT CO	TA0352I	TXU ELECTRIC CO	10 MI. N.W. ON FM 1220	FORT WORTH	TX	76002	10 MI. N.W. ON FM 1220 FORT WORTH TX 76002	6
48	401	TX	RUSK CO	RL0020K	TXU ELECTRIC CO	6 MI SW OF TATUM NEAR FM 2658	TATUM	TX	75691	6 MI SW OF TATUM NEAR FM 2658 TATUM TX 75691	6
48	395	TX	ROBERTSON CO	RI0035C	TEXAS NEW MEXICO POWER CO	8 MILES N OF CALVERT ON HWY 6	CALVERT	TX	77837	8 MILES N OF CALVERT ON HWY 6 CALVERT TX 77837	6
48	387	TX	RED RIVER CO	RE0012M	TXU ELECTRIC CO	APPROX 5.4 M SE ON US HWY 271	BOGATA	TX	75417	APPROX 5.4 M SE ON US HWY 271 BOGATA TX 75417	6
48	375	TX	POTTER CO	PG0041R	SOUTHWESTERN PUBLIC SERVICE CO	2.7 MI. N. ON LAKESIDE DR. FRO	AMARILLO	TX	79101	2.7 MI. N. ON LAKESIDE DR. FRO AMARILLO TX 79101	6
48	375	TX	POTTER CO	PG0040T	SOUTHWESTERN PUBLIC SERVICE CO	1.5 MI. N. ON LAKESIDE DRIVE F	AMARILLO	TX	79101	1.5 MI. N. ON LAKESIDE DRIVE F AMARILLO TX 79101	6
48	371	TX	PECOS CO	PE0259K	WEST TEXAS UTILITIES CO	APPROX 5 MILES NW OF FT STOCKT	FORT STOCKTON	TX	79735	APPROX 5 MILES NW OF FT STOCKT FORT STOCKTON TX 79735	6

STATEFIPS	COUNTYFIPS	STATEABBREV	COUNTYNAME	FACILITYID	FACILITYNAME	STREET	CITY	STATE	ZIP	FACILITYADDRESS	EPA REGION
48	367	TX	PARKER CO	PC0005T	BRAZOS ELECTRIC POWER COO	602 WEST LAKE DRIVE	WEATHERFORD	TX	76086	602 WEST LAKE DRIVE WEATHERFORD TX 76086	6
48	363	TX	PALO PINTO CO	PA0003W	BRAZOS ELECTRIC POWER COOPERATIVE IN	PALO PINTO	PALO PINTO	TX	76072	PALO PINTO PALO PINTO TX 76072	6
48	361	TX	ORANGE CO	OC0013O	ENTERGY GULF STATES INC	POWERHOUSE ROAD OFF OF FM 1442	BRIDGE CITY	TX	77611	POWERHOUSE ROAD OFF OF FM 1442 BRIDGE CITY TX 77611	6
48	451	TX	TOM GREEN CO	TG0044C	WEST TEXAS UTILITIES CO	ROUTE 5	SAN ANGELO	TX	76902	ROUTE 5 SAN ANGELO TX 76902	6
48	57	TX	CALHOUN CO	CB0008C	CENTRAL POWER AND LIGHT CO	FM 1593	POINT COMFORT	TX	77978	FM 1593 POINT COMFORT TX 77978	6
48	113	TX	DALLAS CO	DB0253Q	TXU ELECTRIC CO	5770 PARKDALE DRIVE	DALLAS	TX	75201	5770 PARKDALE DRIVE DALLAS TX 75201	6
48	113	TX	DALLAS CO	DB0252S	TXU ELECTRIC CO	2233 MOUNTAIN CREEK PARKWAY	DALLAS	TX	75201	2233 MOUNTAIN CREEK PARKWAY DALLAS TX 75201	6
48	113	TX	DALLAS CO	DB0251U	TXU ELECTRIC CO	14901 NORTHLAKE RD.	DALLAS	TX	75201	14901 NORTHLAKE RD. DALLAS TX 75201	6
48	113	TX	DALLAS CO	DB0249H	TXU ELECTRIC CO	555 BARNES BRIDGE ROAD	DALLAS	TX	75037	555 BARNES BRIDGE ROAD DALLAS TX 75037	6
48	105	TX	CROCKETT CO	CZ0017A	W TX UTILITIES CO	ONE MILE N.E. OF GIRVIN, TEXAS	GIRVIN	TX	79740	ONE MILE N.E. OF GIRVIN, TEXAS GIRVIN TX 79740	6
48	85	TX	COLLIN CO	CP0230L	THERMONETICS INC	2601 NORTH FLOYD ROAD	RICHARDSON	TX	75080	2601 NORTH FLOYD ROAD RICHARDSON TX 75080	6
48	85	TX	COLLIN CO	CP0065C	TXU ELECTRIC CO	APP 3M N OF FRISCO OFF US HWY	FRISCO	TX	75034	APP 3M N OF FRISCO OFF US HWY FRISCO TX 75034	6
48	85	TX	COLLIN CO	CP0026M	GARLAND MUNICIPAL POWER AND LIGHT	WEST END OF C.R. 489, 2 MI. W.	WYLIE	TX	75098	WEST END OF C.R. 489, 2 MI. W. WYLIE TX 75098	6
48	83	TX	Coleman County	CO0003M	CITY OF COLEMAN	201 NORTH COLORADO STREET	COLEMAN	TX	76834	201 NORTH COLORADO STREET COLEMAN TX 76834	6
48	81	TX	COKE CO	CN0005T	WEST TEXAS UTILITIES CO	ON SH 70 4 MI. SO. OF BLACKWEL	ABILENE	TX	79601	ON SH 70 4 MI. SO. OF BLACKWEL ABILENE TX 79601	6
48	227	TX	HOWARD CO	HT0065Q	POWER RESOURCES LTD	3 MI. E. ON I. 20 FROM BIG SPR	BIG SPRING	TX	79721	3 MI. E. ON I. 20 FROM BIG SPR BIG SPRING TX 79721	6
48	71	TX	CHAMBERS CO	CI0012D	RELIANT ENERGY INC	F.M. 1405, APPROX. 2 MI. S. OF	HOUSTON	TX	77001	F.M. 1405, APPROX. 2 MI. S. OF HOUSTON TX 77001	6
48	113	TX	DALLAS CO	DB0384A	GARLAND MUNICIPAL POWER AND LIGHT	525 E AVENUE B	GARLAND	TX	75040	525 E AVENUE B GARLAND TX 75040	6
48	61	TX	CAMERON CO	CD0009B	BROWNSVILLEPUBLIC UTILITIES BOARD	WEST 13TH ST. & POWER PLANT DR	BROWNSVILLE	TX	78520	WEST 13TH ST. & POWER PLANT DR BROWNSVILLE TX 78520	6
48	73	TX	CHEROKEE CO	CJ0026J	TXU ELECTRIC CO	LOCATED ON THE W SHORE OF STRY	DALLAS	TX	75201	LOCATED ON THE W SHORE OF STRY DALLAS TX 75201	6
48	41	TX	BRAZOS CO	BM0032V	TEXAS A & M UNIVERSITY	600 UNIVERSITY DRIVE	COLLEGE STATION	TX	77840	600 UNIVERSITY DRIVE COLLEGE STATION TX 77840	6
48	41	TX	BRAZOS CO	BM0010I	BRYAN MUNICIPAL ELECTRIC SYSTEM	601 ATKINS STREET	BRYAN	TX	77801	601 ATKINS STREET BRYAN TX 77801	6
48	41	TX	BRAZOS CO	BM0009Q	CITY OF BRYAN	5 MI. N.W. OF BRYAN OFF S.H. 6	BRYAN	TX	77801	5 MI. N.W. OF BRYAN OFF S.H. 6 BRYAN TX 77801	6
48	29	TX	BEXAR CO	BG0188E	CITY PUBLICSERVICE BOARD	207 MISSION RD. (AT HIGHLAND B	SAN ANTONIO	TX	78201	207 MISSION RD. (AT HIGHLAND B SAN ANTONIO TX 78201	6
48	29	TX	BEXAR CO	BG0187G	CITY PUBLICSERVICE	9843 PERRIN BEITEL ROAD	SAN ANTONIO	TX	78201	9843 PERRIN BEITEL ROAD SAN ANTONIO TX 78201	6
48	29	TX	BEXAR CO	BG0186I	CITY PUBLICSERVICE	16120 STREICH RD.	SAN ANTONIO	TX	78201	16120 STREICH RD. SAN ANTONIO TX 78201	6
48	29	TX	BEXAR CO	BG0059Q	CITY PUBLICSERVICE BOARD	7800 QUINTANA ROAD	SAN ANTONIO	TX	78201	7800 QUINTANA ROAD SAN ANTONIO TX 78201	6
48	29	TX	BEXAR CO	BG0057UB	CITY PUBLICSERVICE B	9599 GARDNER ROAD	SAN ANTONIO	TX	78201	9599 GARDNER ROAD SAN ANTONIO TX 78201	6
48	29	TX	BEXAR CO	BG0057UA	CITY PUBLICSERVICE B	9599 GARDNER ROAD	SAN ANTONIO	TX	78201	9599 GARDNER ROAD SAN ANTONIO TX 78201	6
48	29	TX	BEXAR CO	BG0057U	CITY PUBLICSERVICE	9599 GARDNER ROAD	SAN ANTONIO	TX	78201	9599 GARDNER ROAD SAN ANTONIO TX 78201	6
48	21	TX	BASTROP CO	BC0015L	LOWER COLORADO RIVER AUTHORITY	FOUR MIES NORTHEAST OF BASTROP	BASTROP	TX	78602	FOUR MIES NORTHEAST OF BASTROP BASTROP TX 78602	6
48	13	TX	ATASCOSA CO	AG0007G	SAN MIGUEL ELCTRC COOPERATIVE INC	11 MI. S., S.H. 16; 6 MI. E.,	CHRISTINE	TX	78012	11 MI. S., S.H. 16; 6 MI. E., CHRISTINE TX 78012	6
48	207	TX	HASKELL CO	HJ0022B	WEST TEXAS UTILITIES CO	P.O. BOX 605 HASKELL 79521	HASKELL	TX	79521	P.O. BOX 605 HASKELL 79521 HASKELL TX 79521	6
48	215	TX	HIDALGO CO	HN0013E	CENTRAL POWER AND LIGHT CO	LOOP 374	MISSION	TX	78572	LOOP 374 MISSION TX 78572	6
48	61	TX	CAMERON CO	CD0013K	CENTRAL POWER AND LIGHT CO	WEST STENGER RD.	SAN BENITO	TX	78586	WEST STENGER RD. SAN BENITO TX 78586	6
48	215	TX	HIDALGO CO	HN0403K	FRONTERA GENERATION LTD PARTNERSHIP	ONE MI. S. OF BUSINESS ROUTE 8	MISSION	TX	78572	ONE MI. S. OF BUSINESS ROUTE 8 MISSION TX 78572	6
48	121	TX	DENTON CO	DF0012T	DENTON MUNICIPAL UTILITIES	1701-A SPENCER ROAD	DENTON	TX	76201	1701-A SPENCER ROAD DENTON TX 76201	6
48	213	TX	HENDERSON CO	HM0017H	TXU ELECTRIC CO	1 MI S FM 764 0.5 MI W	TRINIDAD	TX	75163	1 MI S FM 764 0.5 MI W TRINIDAD TX 75163	6
48	203	TX	HARRISON CO	HH0037F	SOUTHWESTERN ELECTRIC POWER CO	RT 2 BOX 165	HALLSVILLE	TX	75650	RT 2 BOX 165 HALLSVILLE TX 75650	6
48	201	TX	HARRIS CO	HG4955K	RELIANT ENERGY INC	845 SENS ROAD	LA PORTE	TX	77572	845 SENS ROAD LA PORTE TX 77572	6
48	201	TX	HARRIS CO	HG1495V	AES DEEPWATER INC	701 LIGHT COMPANY ROAD	HOUSTON	TX	77001	701 LIGHT COMPANY ROAD HOUSTON TX 77001	6
48	201	TX	HARRIS CO	HG1169O	CALPINE CORPORATION	9602 BAYPORT RD.	PASADENA	TX	77507	9602 BAYPORT RD. PASADENA TX 77507	6
48	201	TX	HARRIS CO	HG0358Q	RELIANT ENERGY INC	IN LA PORTE	LA PORTE	TX	77571	IN LA PORTE LA PORTE TX 77571	6
48	201	TX	HARRIS CO	HG0357S	RELIANT ENERGY INC	16301 W. MONTGOMERY ST.	HOUSTON	TX	77052	16301 W. MONTGOMERY ST. HOUSTON TX 77052	6
48	201	TX	HARRIS CO	HG0356U	RELIANT ENERGY INC	901 LIGHT COMPANY ROAD	PASADENA	TX	77501	901 LIGHT COMPANY ROAD PASADENA TX 77501	6
48	201	TX	HARRIS CO	HG0355W	RELIANT ENERGY INC	19301 OLD GALVESTON ROAD	WEBSTER	TX	77598	19301 OLD GALVESTON ROAD WEBSTER TX 77598	6
48	201	TX	HARRIS CO	HG0354B	RELIANT ENERGY INC	12100 HIRAM CLARKE ROAD.	HOUSTON	TX	77052	12100 HIRAM CLARKE ROAD. HOUSTON TX 77052	6
48	149	TX	FAYETTE CO	FC0018G	LOWER COLORADO RIVER AUTHORITY	7 MI. E. OF LA GRANGE, TX., ON	LA GRANGE	TX	78945	7 MI. E. OF LA GRANGE, TX., ON LA GRANGE TX 78945	6
48	221	TX	HOOD CO	HQ0012T	TXU ELECTRIC CO	P.O. BOX 579	GRANBURY	TX	76048	P.O. BOX 579 GRANBURY TX 76048	6
48	201	TX	HARRIS CO	HG0353D	RELIANT ENERGY INC	12070 OLD BEAUMONT HIGHWAY	HOUSTON	TX	77049	12070 OLD BEAUMONT HIGHWAY HOUSTON TX 77049	6
48	141	TX	EL PASO CO	EE0029T	EL PASO ELECTRIC CO	N.W. OF INTERSECTION OF F.M. 3	EL PASO	TX	79901	N.W. OF INTERSECTION OF F.M. 3 EL PASO TX 79901	6
48	147	TX	FANNIN CO	FB0025U	TX UTILITIES ELECTRIC CO	ON HWY. 1752 N. OF SAVOY, TX.	SAVOY	TX	75479	ON HWY. 1752 N. OF SAVOY, TX. SAVOY TX 75479	6
48	157	TX	FORT BEND CO	FG0020V	RELIANT ENERGY INC	NEAR Y.U. JONES ROAD	FRESNO	TX	77545	NEAR Y.U. JONES ROAD FRESNO TX 77545	6
48	161	TX	FREESTONE CO	FI0020W	TXU ELECTRIC CO	9 MI. N.E. OF FAIRFIELD, TX.	FAIRFIELD	TX	75840	9 MI. N.E. OF FAIRFIELD, TX. FAIRFIELD TX 75840	6
48	167	TX	GALVESTON CO	GB0037T	RELIANT ENERGY INC	5501 HWY 146	HOUSTON	TX	77251	5501 HWY 146 HOUSTON TX 77251	6
48	167	TX	GALVESTON CO	GB0153Q	TEXAS CITY COGENERATION LP	CRNR OF 5TH AVE S AND GRANT AV	TEXAS CITY	TX	77590	CRNR OF 5TH AVE S AND GRANT AV TEXAS CITY TX 77590	6
48	175	TX	GOLIAD CO	GF0002R	CENTRAL SOUTH WEST SERVICES INC	SCHROEDER ROAD (FM 2987)	FANNIN	TX	77960	SCHROEDER ROAD (FM 2987) FANNIN TX 77960	6
48	197	TX	HARDEMAN CO	HE0013G	WEST TEXAS UTILITIES CO	LAKE PAULINE	QUANAH	TX	79252	LAKE PAULINE QUANAH TX 79252	6
48	183	TX	GREGG CO	GJ0043K	SOUTHWESTERN ELECTRIC POWER CO	KNOX LEE POWER PLT.	LONGVIEW	TX	75601	KNOX LEE POWER PLT. LONGVIEW TX 75601	6
48	163	TX	FRIO CO	FJ0012P	MEDINA ELECTRIC COOPERATIVE INC	1.5 MI. N. ON POWER PLANT RD.	PEARSALL	TX	78061	1.5 MI. N. ON POWER PLANT RD. PEARSALL TX 78061	6
48	141	TX	EL PASO CO	EE0157J	EL PASO ELECTRIC CO	651 HAWKINS BLVD.	EL PASO	TX	79901	651 HAWKINS BLVD. EL PASO TX 79901	6
48	185	TX	GRIMES CO	GK0012K	TEXAS MUNICIPAL POWER AGENCY	2 1/2 M N OF CARLOS OFF FM 244	BRYAN	TX	77801	2 1/2 M N OF CARLOS OFF FM 244 BRYAN TX 77801	6
49	53	UT	Washington County	11539	HILDALE CITY COGENERATION FACILITY	1325 West Utah Ave.	Hildale	UT	84784	1325 West Utah Ave. Hildale UT 84784	8
49	47	UT	UINTAH CO	107790	BONANZA	Not Available	UNKNOWN	UT	UNKNOWN	Not Available UNKNOWN UT UNKNOWN	8
49	49	UT	UTAH CO	10795	POWER PLANT	702 North 300 West	Provo	UT	84601	702 North 300 West Provo UT 84601	8
49	49	UT	UTAH CO	10819	WHITEHEAD POWER PLANT	450 West 700 North	Springville	UT	84663	450 West 700 North Springville UT 84663	8
49	53	UT	Washington County	10892	ST. GEORGE CITY POWER PLANT	795 E. Skyline Dr.	St. George	UT	84770	795 E. Skyline Dr. St. George UT 84770	8
49	35	UT	SALT LAKE CO	10355	GADSBY POWER PLANT	1407 West North Temple (rear)	Salt Lake City	UT	84116	1407 West North Temple (rear) Salt Lake City UT 84116	8
49	7	UT	CARBON CO	10096	SUNNYSIDE COGENERATION FACILITY	One Power Plant Road	Sunnyside	UT	84539	One Power Plant Road Sunnyside UT 84539	8
49	49	UT	UTAH CO	10823	PAYSON CITY POWER	1100 N 100 E	Payson	UT	84651	1100 N 100 E Payson UT 84651	8
49	27	UT	MILLARD CO	10327	INTERMOUNTAIN GENERATION STATION	850 W Brush Wellman Rd	Delta	UT	84624	850 W Brush Wellman Rd Delta UT 84624	8
49	15	UT	EMERY CO	10238	HUNTINGTON POWER PLANT	P. O. Box 680	Huntington	UT	84528	P. O. Box 680 Huntington UT 84528	8
49	11	UT	DAVIS CO	10120	POWER PLANT	253 S 200 W	Bountiful	UT	84010	253 S 200 W Bountiful UT 84010	8
49	7	UT	CARBON CO	10081	CARBON POWER PLANT	NA	Helper	UT	84526	NA Helper UT 84526	8
49	5	UT	Cache County	10058	POWER PLANT	305 South 300 West	Logan	UT	84321	305 South 300 West Logan UT 84321	8
49	1	UT	Beaver County	10319	BONNETT-GEOTHERMAL POWER PLANT	#1 Main	Sulphurdale	UT	84713	#1 Main Sulphurdale UT 84713	8
49	35	UT	SALT LAKE CO	10348	ELECTRICAL GENERATION PLANT	157 W 4800 S	Murray	UT	84107	157 W 4800 S Murray UT 84107	8
49	15	UT	EMERY CO	10237	HUNTER POWER PLANT	P.O. Box 569	Castledale	UT	84513	P.O. Box 569 Castledale UT 84513	8
56	45	WY	WESTON CO	00005	BLACK HILLS OSAGE	OSAGE POWER PLANT	OSAGE	WY	82723-0000	OSAGE POWER PLANT OSAGE WY 82723-0000	8
56	37	WY	SWEETWATER CO	01002	PACIFICORP_JIM BRIDGER	PO BOX 158	POINT OF ROCKS	WY	82901-0000	PO BOX 158 POINT OF ROCKS WY 82901-0000	8

STATEFIPS	COUNTYFIPS	STATEABBREV	COUNTYNAME	FACILITYID	FACILITYNAME	STREET	CITY	STATE	ZIP	FACILITYADDRESS	EPA REGION
56	31	WY	PLATTE CO	00001	BASIN ELECTRIC_LARAMIE RIVER STATION	LARAMIE RIVER PLANT	WHEATLAND	WY	82201-0000	LARAMIE RIVER PLANT WHEATLAND WY 82201-0000	8
56	23	WY	LINCOLN CO	00004	PACIFICORP_NAUGHTON POWER PLANT	6.5 MI SW OF KEMMERER, HWY 189	KEMMERER	WY	83101-0000	6.5 MI SW OF KEMMERER, HWY 189 KEMMERER WY 83101-0000	8
56	9	WY	CONVERSE CO	00001	PACIFICORP_DAVE JOHNSTON	1591 TANK FARM ROAD	GLENROCK	WY	82637-0000	1591 TANK FARM ROAD GLENROCK WY 82637-0000	8
56	5	WY	CAMPBELL CO	00063	BLACK HILLS POWER & LGT_SIMPSON 2	UNK	GILLETTE	WY	99999-0000	UNK GILLETTE WY 99999-0000	8
56	5	WY	CAMPBELL CO	00002	BLACK HILLS POWER & LGHT SIMPSON 1	3 MI NE OF GILLETTE	GILLETTE	WY	82718-9716	3 MI NE OF GILLETTE GILLETTE WY 82718-9716	8
56	5	WY	CAMPBELL CO	00046	PACIFICORP_WYODAK	3 MI E OF GILLETTE	GILLETTE	WY	82716-0000	3 MI E OF GILLETTE GILLETTE WY 82716-0000	8

FACILITYID	FACILITYNAME	INVNETORY YEAR	SIC	LATITUDE	LONGITUDE	CO	NH3	NOX	PMCON	PMFIL	PMPRI	PM10FIL	PM10PRI	PM25FIL	PM25PRI	SO2	VOC
0402700141	YUMA COGENERATION ASSOCIATES	1999	4911	33.1028	-86.8007	20.797	6.5	178.216	0.818			12.081	12.899	11.327	12.145	6.509	4.276
U120	YUCCA	1999	4911	33.2119	-86.809	170.72	6.5	239.63	11.179			0.193	11.372	0.193	11.372	2.3	13.66
0400100059	SALT RIVER PROJECT	1999	4911	32.2354	-85.4389	430.8		13127.8	595.47			991.298	1586.768	564.735	1160.203	19997.6	100.4
0331	ARIZONA PUBLIC SERVICE COMPANY (APS)	1999	4911	33.2836	-86.6917	30.31		106.55	0.469			24.91	25.379	13.52	13.989	6.07	3.74
U118	SAGUARO	1999	4911	33.6803	-86.3217	54.79	7.31	558.11	12.856			0.867	13.725	0.867	13.725	1.2	15.35
0082	IRVINGTON	1999	4911	32.2193	-84.9999	146.77	8.74	2404.97	83.142			29.589	112.732	15.318	98.461	2861.6	27.02
0001	CHOLLA	1999	4911	32.432	-84.9899	915.94	1.32	13183.26	667.137			956.508	1623.644	544.847	1211.983	19062.1	109.88
98	PALO VERDE NUCLEAR GENERATING STATION	1999	4911	34.6307	-87.0087	20.957	5.903	49.055	12.101			24.115	36.221	20.291	32.395	0.996	29.697
52382	OCOTILLO POWER PLANT	1999	4911	34.6422	-87.0643	82.787	8.561	555.776	16.585			5.745	22.334	5.223	21.811	8.447	15.482
3316	SRP AGUA FRIA	1999	4911	30.6683	-88.0437	488.738	17.61	3299.612	32.543			15.478	48.023	15.478	48.023	0.715	31.423
3315	SANTAN GENERATING PLANT	1999	4911	30.5544	-88.1697	336.707		1356.641	6.084			123.077	129.162	123.077	129.162	4.031	3.634
3313	APS WEST PHX POWER PLANT	1999	4911	30.7665	-88.0563	101.01		1430.233	3.191			44.485	47.68	44.137	47.332	4.954	25.505
0170	US ARMY NAVAJO DEPOT ACTIVITY	1999	4911	33.9501	-87.7813	0.65		2.98	0.146			0.14	0.286	0.05	0.196	1.28	0.16
0004	NAVAJO	1999	4911	32.2608	-87.79	1939.67	2.71	35275.25	1899.402			1956.637	3856.039	868.815	2768.216	9162.6	232.63
0400300037	AZ ELECTRIC POWER COOPERATIVE INC	1999	4911	32.5176	-87.8133	493.157	3.891	6636.37	348.437			919.308	1267.745	369.674	718.114	5968.965	59.701
0400100060	TUCSON ELECTRIC POWER CO-SPRINGERVILLE	1999	4911	34.6537	-86.6737	785.561	0.98	11730.15	620.45			708.923	1329.374	454.4	1074.858	18387.2	103.6
3317	SRP KYRENE STEAM PLANT	1999	4911	30.6629	-88.0364	39.03	1.091	230.301	2.27			5.759	8.032	5.737	8.01	37.147	1.86
0023	PUBLIC SERVICE CO FORT SAINT VRAIN PLT	1999	4911	38.0874	-107.7103	181.5	1.04	219.25	41.202			2.431	43.634	1.945	43.147	4.2	12.3
0035	PUBLIC SERVICE CO FRUITA STA	1999	4911	39.783	-105.1044	3.4		15.8	0.074			1.5	1.574	1.5	1.574	1.1	0.8
0239	PUBLIC SERVICE CO ROSS RIDGE STATION	1999	4911	37.2715	-107.5657												26.9
0018	TRI STATE GENERATION CRAIG	1999	4911	37.2833	-107.8384	7553.8	1.49	16761.08	969.351	0.03		577.459	1546.81	388.566	1357.918	10662.29	64.7
0001	TRI STATE GENERATION NUCLA	1999	4911	40.5822	-105.0792	140.64	0.1	1039.11	237.412			153.09	390.502	94.45	331.861	1475.81	9.61
0011	PUBLIC SERVICE CO PAWNEE PLT	1999	4911	40.5807	-105.0481	627.6	0.8	5320.72	254.451			162.523	416.973	77.831	332.281	16665.8	75.24
0004	WEST PLAINS ENERGY - ROCKY FORD STATION	1999	4911	37.1133	-104.6762	3.72		34.17	0.105			1.39	1.495	1.303	1.408	1.57	1.62
0006	LAMAR UTILITIES BOARD	1999	4911	39.1365	-108.73	21.9	1.73	301.3	3.315			0.051	3.367	0.051	3.367	0.3	0.8
0003	PUBLIC SERVICE CO COMANCHE PLT	1999	4911	39.0771	-108.5551	701.6	0.91	7079.2	268.325			210.426	478.751	86.737	355.062	13699.9	74.3
0008	WEST PLAINS ENERGY - PUEBLO STATION	1999	4911	39.331	-108.5915	9.13	0.44	108.75	0.762			1.323	2.085	1.241	2.003	1.62	1.77
0250	THERMO COGEN PARTNERSHIP FT LUPTON	1999	4911	38.2325	-104.6218	455.83		599.99	25.157			93.96	119.117	93.944	119.101	10.66	48.6
0014	PUBLIC SERVICE CO FT LUPTON STATION	1999	4911	38.0934	-103.8202	12.2		49.1	0.227			4.6	4.827	4.6	4.827	1.2	2.7
0126	THERMO POWER & ELEC INC	1999	4911	38.143	-102.6128	89.06		386.39	10.757			36.61	47.367	36.609	47.366	1.61	11.33
0002	PUBLIC SERVICE CO CAMEO PLT	1999	4911	39.7942	-105.0644	68.5	0.17	1889.26	96.077			160.029	256.106	68.32	164.396	3045.3	8.2
0001	PUBLIC SERVICE CO HAYDEN PLT	1999	4911	37.5309	-108.9391	369.9	0.55	7217.35	401.476			221.701	623.177	110.747	512.222	6678.4	44.4
0001	PUBLIC SERVICE CO - VALMONT	1999	4911	39.8488	-104.9965	102.75	0.23	1085.46	56.115			56.388	112.503	37.237	93.353	2836.02	14.19
0053	PLATTE RIVER POWER AUTHORITY - RAWHIDE	1999	4911	39.8776	-105.1017	49.9	0.38	4530.65	262.341			78.003	340.343	30.454	292.793	1117.2	38.04
0412	THERMO GREELEY INC	1999	4911	38.2703	-104.5874	97		96	0.36			7.3	7.66	7.3	7.66	0.9	55
0001	PUBLIC SERVICE CO CHEROKEE PLT	1999	4911	34.4893	-119.072	544.5	2.281	12444.76	484.337			251.483	735.82	126.75	611.084	18543	63.65
0007	PUBLIC SERVICE CO ALAMOSA PLT	1999	4911	38.6935	-121.9066	11.9		56.6	0.261			5.3	5.561	5.3	5.561	1.9	2.7
0007	PUBLIC SERVICE CO ZUNI PLT	1999	4911	38.1268	-103.1598	15.4	0.581	165.02	2.034			0.055	2.087	0.052	2.087	2.9	0.7
0008	PUBLIC SERVICE CO - ARAPAHOE	1999	4911	38.0968	-103.091	229.83	1.58	3952.71	135.153			79.431	214.583	43.023	178.172	4166.43	26.91
0041	PUBLIC SERVICE CO DENVER STEAM PLT	1999	4911	40.1614	-105.101	23		316.8	5.07			1.69	6.76	1.69	6.76	0.36	0.83
0004	COLORADO SPRINGS UTILITIES-DRAKE PLT	1999	4911	39.6668	-104.8846	213.08	1.01	5623.96	192.8			231.546	424.347	174.244	367.042	6596	24.43
0030	COLORADO SPRINGS UTILITIES - NIXON PLT	1999	4911	39.6371	-104.894	139.02	0.359	2583.98	129.402			159.14	288.542	118.415	247.818	4601.04	16.43
0003	WEST PLAINS ENERGY - W.N. CLARK STATION	1999	4911	39.5614	-104.9895	327.78	0.04	894.61	50.367			824.656	875.023	792.407	842.771	1197.99	3.28
0057	AMERICAN ATLAS NO 1/COLORADO GREENHOUSE	1999	4911	39.556	-104.4858	105.21		220.65	11.274			35.81	47.084	35.635	46.909	0.53	19.96
0059	PUBLIC SERVICE CO LOOKOUT CENTER	1999	4911	38.8844	-104.721	0.13		0.63	0.005			0.03	0.035	0.025	0.03	0.03	0.05
0003	COLORADO SPRINGS UTILITIES-BIRDSALL PLT	1999	4911	39.6917	-105.0011	14.11	0.67	47.1	2.53			2.84	5.37	2.358	4.888	0.73	0.93
0003	TRI STATE GENERATION BURLINGTON	1999	4911	39.5695	-108.2451	6.3		91.6	0.605			8	8.605	8	8.605	28.6	2.2
1238	KN SERVICES - LAKEWOOD GENERATION FACILI	1999	4911	39.4674	-107.8355	5.64		34.07	1.285			0.01	1.295	0.009	1.295		1.16
00001	LACROSSE MUNICIPAL POWER PLANT	1999	4911	39.5312	-95.3175	0.35		1.64	0.008			0.11	0.118	0.103	0.111	0.1	0.11
00005	PRATT-MUNICIPAL POWER PLANT	1999	4911	41.6106	-90.6079	7.97	0.31	26.61	0.435			0.086	0.521	0.079	0.514	0.08	0.52
00033	WESTERN RESOURCES, INC. (HEC)	1999	4911	37.8843	-95.3153	56.72	3.659	395.63	6.904			1.86	8.764	1.838	8.742	36.37	6.71
00016	BELLEVILLE-MUNICIPAL POWER PLANT	1999	4911	38.17	-95.3	7.42		53.64	0.042			0.61	0.652	0.58	0.622	0.48	1.61
00024	STERLING MUNICIPAL POWER PLANT	1999	4911	38.214	-95.3045	6		23.55	0.337			2.17	2.507	1.84	2.177	0.75	1.51
00005	RUSSELL-MUNICIPAL POWER PLANT	1999	4911	37.24	-98.57	245.49		963.12	13.69			88.18	101.87	74.762	88.45	31.8	61.88
00014	STOCKTON-MUNICIPAL POWER PLANT	1999	4911	39.5312	-95.3175	1.41		10.7	0.004			0.06	0.064	0.058	0.062	0.04	0.28
00012	WAMEGO-MUNICIPAL POWER PLANT	1999	4911	41.6776	-93.5719	13.94		88.12	0.049			0.78	0.829	0.747	0.794	0.51	2.86
00034	CITY OF ERIE	1999	4911	42.0794	-91.5989	3.36		15.47	0.079			1.05	1.129	0.984	1.064	1.02	1.05
00007	KANSAS STATE UNIVERSITY	1999	4911	39.6	-95.11	29.25		92.92	7.862			2.63	10.492	2.627	10.488	0.32	1.89
00001	WESTERN RESOURCES, INC. (JEC)	1999	4911	41.6776	-93.5719	2068.2	2.921	25716.34	1622.411			1478.497	3100.907	779.224	2401.632	58246.89	247.87
00010	LARNED-MUNICIPAL POWER PLANT	1999	4911	41.466	-91.0763	5.38	0.31	30.14	0.567			0.109	0.676	0.093	0.66	1.15	0.66
00013	MINNEAPOLIS-MUNICIPAL POWER PLANT	1999	4911	41.3917	-91.0569	7.5		53.67	0.047			0.67	0.717	0.636	0.683	0.53	1.65
00009	OSBORNE-MUNICIPAL POWER PLANT	1999	4911	41.466	-91.0763	0.35		2.81	0			0.01	0.01	0.01	0.01		0.06
00014	OSAGE CITY-MUNICIPAL POWER PLANT	1999	4911	41.3181	-91.0931	0.01		0.06									
00012	BURLINGAME-MUNICIPAL POWER PLANT	1999	4911	42.0794	-91.5989	2.15		16.16	0.008			0.12	0.128	0.115	0.123	0.08	0.44
00012	WESTERN RESOURCES, INC. (GORDON EVANS)	1999	4911	37.8	-96.86	414.3	15.91	3428.04	28.16			0.679	28.839	0.663	28.825	43.3	27.19
00047	CITY OF ERIE	1999	4911	42.0794	-91.5989	7.47		32.91								0.53	0.96
00019	WELLINGTON-MUNICIPAL POWER PLANT	1999	4911	38.9905	-96.7503	2.88	0.23	10.1	1.504			0.366	1.87	0.366	1.87	0.04	0.12
00030	CITY OF CHANUTE ELEC. DEPT., PLANT #2	1999	4911	40.5963	-91.4162	1.67		12.72	0.005			0.08	0.085	0.077	0.082	0.05	0.34
00028	CITY OF CHANUTE ELEC. DEPT., PLANT #3	1999	4911	40.5963	-91.4162	25.4		172.8	0.215			3	3.215	2.835	3.05	2.6	7.99
00009	SABETHA-MUNICIPAL POWER PLANT	1999	4911	42.4848	-90.804	11.65		76.9	0.117			1.6	1.717	1.51	1.627	1.42	2.8
00005	NORTON-MUNICIPAL POWER PLANT	1999	4911	42.0794	-91.5989	3.5		23.48	0.031			0.44	0.471	0.416	0.447	0.38	0.83
00001	MIDWEST ENERGY, INC.	1999	4911	37.45	-101.35	1.12		4.08	0.007			0.14	0.147	0.14	0.147	0.74	0.13
00026	SUNFLOWER ELECTRIC POWER CORPORATION	1999	4911	39.7335	-85.5875	64.85	1.4	638.29	5.563			6.716	12.278	6.699	12.261	0.48	48.64
00002	COFFEYVILLE-MUNICIPAL POWER PLANT	1999	4911	39.8104	-84.8955	18.13	1.45	49.58	2.568			0.044	2.612	0.044	2.612	0.26	0.63
00049	BOARD OF PUBLIC UTILITIES - KAW	1999	4911	38.15	-97.45	32.27	1.23	165.69	1.975			0.007	1.983	0.007	1.983	62.1	2.1
00048	BOARD OF PUBLIC UTILITIES - QUINDARO	1999	4911	37.1871	-98.0812	198.21	1.88	4198.61	81.03			69.398	150.427	41.934	122.964	6145.05	41.7
00008	BOARD OF PUBLIC UTILITIES - NEARMAN	1999	4911	37.8645	-96.2396	210.97	0.36	3391.68	96.239	1.39		153.606	249.845	97.767	194.004	6356.49	24.52
00018	FREDONIA MUNICIPAL POWER PLANT	1999	4911	37.64	-101.26	1.2		9.08	0.004			0.06	0.064	0.058	0.062	0.04	0.24
00014	NEODESHA-MUNICIPAL POWER PLANT	1999	4911	37.45	-101.35	2.01		9.25	0.048			0.63	0.678	0.591	0.638	0.61	0.63
00024	WASHINGTON-MUNICIPAL POWER PLANT	1999	4911	37.46	-101.49	1.89		12.63	0.018			0.24	0.258	0.226	0.244	0.22	0.44

FACILITYID	FACILITYNAME	INVNETORY YEAR	SIC	LATITUDE	LONGITUDE	CO	NH3	NOX	PMCON	PMFIL	PMPRI	PM10FIL	PM10PRI	PM25FIL	PM25PRI	SO2	VOC
00012	UTILICORP UNITED, INC.	1999	4911	37.55	-101.13	29.01		117.98	0.531			10.6	11.131	10.597	11.128	0.59	5.26
00020	HUGOTON-MUNICIPAL POWER PLANT (#1)	1999	4911	38.8901	-95.3118	0.09		0.12	0.003			0.02	0.023	0.017	0.02	0.01	0.01
00007	COLBY MUNICIPAL POWER PLANT	1999	4911	37.57	-101.2	0.78		4.09	0.015			0.2	0.215	0.188	0.203	0.19	0.22
00014	WESTERN RESOURCES, INC.-MURRY GILL	1999	4911	37.67	-96.97	154.82	10.53	992.09	19.37			6.869	26.24	6.3	25.67	1686.61	13.09
00056	WELLINGTON CITY POWER PLANT, GAS TURBINE	1999	4911	37.56	-101.19	8.22		29.54	0.049			1	1.049	1	1.049	0.05	0.9
00055	CITY OF OXFORD, MUNICIPAL POWER PLANT	1999	4911	37.54	-101.18	2.26		10.41	0.054			0.71	0.764	0.666	0.719	0.69	0.71
00025	MULVANE-MUNICIPAL POWER PLANT	1999	4911	38.9905	-96.7503	1.9		13.77	0.01			0.15	0.16	0.143	0.153	0.12	0.41
00021	HUGOTON-MUNICIPAL POWER PLANT (#2)	1999	4911	38.8901	-95.3118	116.71		222.31	11.835			43.16	54.995	36.597	48.432	10.78	28.59
00009	JOHNSON CITY MUNICIPAL POWER PLANT	1999	4911	38.92	-95.22	5.46		37.82	0.042			0.58	0.622	0.549	0.591	0.5	1.25
00017	STAFFORD-MUNICIPAL POWER PLANT	1999	4911	38.97	-95.26	0.05		0.23	0.001			0.01	0.011	0.009	0.01	0.01	0.01
00005	GOODLAND-MUNICIPAL POWER PLANT	1999	4911	39.75	-94.88	6.58		49.35	0.021			0.35	0.371	0.336	0.357	0.28	1.33
00030	WESTERN RESOURCES, INC. (TEC)	1999	4911	38.87	-97.21	209.06	1.121	2524.63	83.947			142.014	225.961	69.584	153.53	4609.89	20.97
00001	UTILICORP UNITED, INC.	1999	4911	37.228	-96.8517	62.3	1.86	162.3	5.341			2.725	8.066	2.725	8.066	0.37	4.68
00005	SHARON SPRINGS MUNICIPAL POWER PLANT	1999	4911	37.69	-101.2	0.03		0.16	0.001			0.01	0.011	0.009	0.01	0.01	0.01
00010	AUGUSTA-MUNICIPAL POWER PLANT (#2)	1999	4911	39.5296	-86.3776	43.16		100.48	0.062			0.4	0.462	0.339	0.401	0.1	7.44
00009	OBERLIN-MUNICIPAL POWER PLANT	1999	4911	41.6163	-87.0696	0.42		3.1	0.002			0.03	0.032	0.029	0.03	0.02	0.08
00006	GIRARD-MUNICIPAL POWER PLANT	1999	4911	41.4776	-87	17.52		40.84	0.131			0.85	0.981	0.72	0.852	13.52	3.01
00012	BELOIT-MUNICIPAL POWER PLANT	1999	4911	39.8525	-84.91	11.68		27.2	0.088			0.57	0.658	0.483	0.572	9.52	8.06
00006	WINFIELD MUNICIPAL POWER PLANT	1999	4911	38.4581	-87.2636	2.77		9.98	0.016			0.33	0.346	0.33	0.346	0.01	0.3
00006	OTTAWA-MUNICIPAL POWER PLANT	1999	4911	41.6818	-86.3032	34.42		101.91	0.125			1.91	2.035	1.866	1.991	0.08	16.82
00006	BURLINGTON-MUNICIPAL POWER PLANT	1999	4911	37.9896	-86.795	5.15		35.5	0.042			0.58	0.622	0.549	0.591	0.48	1.18
00007	CLAY CENTER PUBLIC UTILITIES	1999	4911	39.2945	-86.7866	12.62		115.15								0.38	8.9
00001	ASHLAND-MUNICIPAL POWER PLANT	1999	4911	38.5573	-86.4813	1.02		4.94	0.023			0.3	0.323	0.281	0.304	0.29	0.31
00009	ST. FRANCIS POWER PLANT	1999	4911	41.395	-85.4236	0.73		7.66	0.017			0.24	0.257	0.226	0.243	0.22	0.33
00017	WESTERN RESOURCES, INC. - ABILENE ENERGY	1999	4911	41.6266	-87.1332	3.61		14.08	0.014			0.29	0.304	0.29	0.304	0.15	0.09
00002	EMPIRE DISTRICT ELECTRIC COMPANY (THE)	1999	4911	41.48	-85.6107	113.88	0.17	1436.41	144.417			101.996	246.413	51.093	195.509	5000.49	14.69
00012	WINFIELD MUNICIPAL POWER PLANT (NEW)	1999	4911	38.3528	-87.2077		0.64	47.96	1.05			0.104	1.156	0.096	1.148	0.3	
00009	AUGUSTA-MUNICIPAL POWER PLANT (#1)	1999	4911	39.4843	-86.4186	4.03		9.48									0.69
00029	CITY OF HORTON	1999	4911	39.9749	-86.8337	6.98		32.12	0.166			2.19	2.356	2.053	2.219	2.13	2.19
00026	HOISINGTON-MUNICIPAL POWER PLANT	1999	4911	39.1765	-86.6249	2.86		19.93	0.021			0.29	0.311	0.274	0.295	0.24	0.64
00025	ELLINWOOD-MUNICIPAL POWER PLANT	1999	4911	40.6688	-86.1068	4.31		32.04	0.019			0.28	0.299	0.268	0.287	0.2	0.9
00002	UTILICORP UNITED, INC.	1999	4911	40.6616	-86.1022	27.64	3.69	287.6	6.34			0.109	6.45	0.109	6.45	0.6	6.33
00001	MIDWEST ENERGY, INC.	1999	4911	40.7726	-86.1291	1.31		8.6	0.012			0.17	0.182	0.16	0.172	0.16	0.31
00001	GARNETT-MUNICIPAL POWER PLANT	1999	4911	41.2942	-86.1357	12.59		35.55	0.11			0.71	0.82	0.601	0.712	2.15	2.03
00019	CITY OF IOLA POWER PLANT	1999	4911	41.3662	-86.3287	6.91		26.13	0.193			1.23	1.423	1.044	1.232	0.06	0.69
00011	CITY OF IOLA POWER PLANT	1999	4911	41.4502	-86.1512	21.97	0.32	42.07	1266.638			9.86	1276.498	9.244	1275.882	0.25	22.83
00008	MIDWEST ENERGY, INC.	1999	4911	41.4326	-85.425	0.39		1.83	0.009			0.12	0.129	0.113	0.122	0.12	0.12
00013	LINCOLN-MUNICIPAL POWER PLANT	1999	4911	37.9374	-87.4916	2.78		12.8	0.066			0.87	0.936	0.816	0.881	0.85	0.87
00001	OSAWATOMIE-MUNICIPAL POWER PLANT	1999	4911	37.9352	-87.3558	2.57		11.84	0.06			0.8	0.86	0.75	0.81	0.78	0.81
00013	MEADE-MUNICIPAL POWER PLANT	1999	4911	40.1981	-87.5275	9.85		77.05	0.016			0.29	0.306	0.29	0.306	1.1	1.92
00046	BOARD OF PUBLIC UTILITIES - #3	1999	4911	40.8352	-85.7375	63.7		32.82	0.217			4.39	4.607	4.39	4.607	0.13	5.46
00014	MCPHERSON BOARD OF PUBLIC UTILITIES #2	1999	4911	39.5327	-87.4282	25.17	0.279	105.86	0.676			3.658	4.334	3.658	4.334	0.18	4.48
00021	WOLF CREEK NUCLEAR OPERATING CORP.	1999	4911	38.0542	-86.6383			28.73									
00005	KANSAS CITY POWER & LIGHT CO.	1999	4911	39.9389	-87.4728	1376.67	3	35236.95	809.158			962.578	1771.736	443.241	1252.4	29919.53	232.87
00034	HERINGTON-MUNICIPAL POWER PLANT	1999	4911	41.6091	-87.0864	7.02		37.88	0.127			1.7	1.827	1.596	1.723	1.63	2
00001	WESTERN RESOURCES, INC. - NEOSHO ENERGY	1999	4911	38.1444	-87.5512	8.65	1.16	496.35	3.449			0.034	3.484	0.034	3.484	0.3	1.98
00007	GREENSBURG-MUNICIPAL POWER PLANT	1999	4911	38.1002	-87.5554	9.84		22.91									6.78
00004	KINGMAN-MUNICIPAL POWER PLANT	1999	4911	37.9892	-87.5876	201.24		364.5	1.947			12.54	14.487	10.631	12.578	0.36	92.49
00019	CITY OF LAKIN	1999	4911	37.9901	-87.5887	3.49		24	0.028			0.39	0.418	0.369	0.396	0.33	0.8
00011	HOLTON-MUNICIPAL POWER PLANT	1999	4911	39.0119	-87.4077	37.58		147.5	0.442			2.85	3.292	2.416	2.859	2.61	38.06
00013	ATTICA-MUNICIPAL POWER PLANT	1999	4911	39.5227	-85.7901	1.18		8.84	0.005			0.07	0.075	0.067	0.072	0.05	0.24
00002	ANTHONY-MUNICIPAL POWER PLANT	1999	4911	39.5091	-85.7892	36.52		85.03								0.04	25.18
00009	HILL CITY-MUNICIPAL POWER PLANT	1999	4911	41.6734	-86.1315	2.63		20.32	0.006			0.1	0.106	0.097	0.103	0.05	0.52
00011	BALDWIN CITY-MUNICIPAL POWER PLANT	1999	4911	38.0021	-87.8416	6.33		34.26	0.114			1.53	1.644	1.436	1.551	1.46	1.79
00001	UTILICORP UNITED, INC.	1999	4911	41.7481	-86.1185	220.31	8.39	623.28	14.287			0.249	14.536	0.249	14.536	1.5	14.42
00023	SUNFLOWER ELECTRIC POWER CORPORATION	1999	4911	39.302	-85.2303	329.28	0.62	4193.96	296.414			60.722	357.137	25.145	321.559	2430.7	52.52
00014	WESTERN RESOURCES, INC.	1999	4911	41.0436	-86.5967	342.16	0.92	5455	316.101			715.564	1031.665	302.84	618.938	3576.7	41.49
00065	GARDNER ENERGY CENTER	1999	4911	40.3871	-86.8545	18.74		67.3	0.112			2.28	2.392	2.28	2.392	0.09	2.05
00009	OAKLEY-MUNICIPAL POWER PLANT	1999	4911	39.3606	-87.4167	2.14		16.96	0.002			0.04	0.042	0.04	0.042		0.41
3500100011	REEVES GENERATING STATION	1999	4911	39.8615	-75.1522	325.41	2.93	451.89	17.526			22.934	40.456	19.054	36.575	0.44	18.43
0002	FOUR CORNERS	1999	4911	40.785	-74.2942	2136.94	3.25	45775.14	1699.444			4415.297	6114.742	2195.896	3895.34	42520.7	255.52
0002	TUCUMCARI	1999	4911	40.5876	-74.243	0.53		2.96	0.005			0.05	0.055	0.045	0.05	0.19	0.05
0032	ESCALANTE	1999	4911	40.562	-74.5222	242.39	2.224	4553.17	236.631			138.827	375.458	67.946	304.578	1514.51	27.39
0054	CUNNINGHAM	1999	4911	40.4527	-74.4026	312.98	22.349	1645.25	41.542			15.327	56.869	15.327	56.869	5	9
0034	MADDOX STATION	1999	4911	40.5667	-74.4292	117.34	12.759	675.26	18.252			4.136	22.388	4.136	22.388	2.04	7
0025	PHYSICAL PLANT BOILERS	1999	4911	40.7445	-74.0731	59		271.89	38.035			24.41	62.445	11.728	49.763	2.38	50.88
0002	RIO GRANDE GENERATING STATION	1999	4911	40.7402	-74.061	853.28	13.741	1066.51	25.034			0.407	25.442	0.407	25.442	2.5	31.78
3500100368	COBISA PERSON POWER PROJECT	1999	4911	39.7127	-75.1597	707		530	2.812			57	59.812	57	59.812	72	34
0004	LAS VEGAS TURBINE	1999	4911	40.9519	-74.2614	0.41		2.64								0.43	
0902	SAN JUAN GENERATING STATION	1999	4911	40.8351	-74.1301	1655.15	2.869	30016.7	1919.005			5764.812	7683.817	3046.467	4965.471	29501.99	200.14
0001	RATON POWER PLANT	1999	4911	40.7412	-74.0335	64.34	0.01	176.31	14.418			4.811	19.23	2.136	16.555	271.3	0.63
0029	ANIMAS PLANT	1999	4911	40.8654	-74.5514	13.89	0.46	84.99	0.812			0.014	0.826	0.014	0.826		54.63
0466	MOHAVE GENERATING STATION	1999	4911	41.23	-95.95	1126.62	2.21	19764.87	913.488			1186.424	2099.912	526.828	1440.318	38639.7	
0197	AMOR IV CORP & STILLWATER GEOTHERMAL	1999	4911	41.42	-96.49	0.51		5.746	0.001			0.039	0.039	0.038	0.039	0.118	34.541
0756	CAITHNESS DIXIE VALLEY LLC	1999	4911	41.25	-95.92	4.38		5.595	0.011			0.453	0.464	0.444	0.455	0.753	0.138
0398	CLARK STATION	1999	4911	41.22	-96.01		4.241	1033.49	8.151			0.319	8.47	0.319	8.47	0.6	
0400	REID GARDNER STATION	1999	4911	41.22	-95.95		0.599	9764.07	454.55			950.144	1404.693	549.804	1004.354	3193.4	
0457	VALMY GENERATING STATION	1999	4911	41.25	-95.93		0.7	6624.56	272.613			129.73	402.343	64.962	337.576	6828.3	0.045
0223	BEOWAWE POWER LLC	1999	4911	41.2	-95.93				0.156			2.495	2.65	2.414	2.57		
0091	SIERRA PACIFIC POWER COMPANY	1999	4911	41.26	-96.06		17.39	2618.75	32.597			0.715	33.312	0.697	33.294	32.1	

FACILITYID	FACILITYNAME	INVNETORY YEAR	SIC	LATITUDE	LONGITUDE	CO	NH3	NOX	PMCON	PMFIL	PMPRI	PM10FIL	PM10PRI	PM25FIL	PM25PRI	SO2	VOC
0194	SIERRA PACIFIC POWER	1999	4911	41.28	-96.04	50.85	18.52	2123.9	62.329			19.553	81.881	19.532	81.86	20.5	59.231
A01176A	EMPIRE ENERGY, LLC (FRMLY AMOR II)	1999	4911	41.26	-95.95												10.39
A90A	STEAMBOAT ENVIROSYSTEMS, LLC, UNITS 1,1A	1999	4911	41.2	-95.96												68
0399	SUNRISE STATION	1999	4911	41.36	-96.05	24.97	2.51	365	8.519			1.637	10.155	1.637	10.155	0.4	0.888
1211	CENTRAL AND SOUTH WEST SERVICES, INC.	1999	4911	39.7055	-80.846	822.88	23.34	4756.86	50.945			0.694	51.639	0.694	51.639	5.4	
2209	OKLAHOMA GAS & ELECTRIC	1999	4911	35.1893	-97.4152	2673.9	6.78	18127.4	501.595			610.96	1112.555	417.276	918.872	29668.7	187.6
2211	OKLAHOMA GAS & ELECTRIC	1999	4911	34.8402	-98.229	1997.5	1.29	14735.06	368.93		80.4	513.221	882.151	335.177	704.108	25138.8	139.9
1011	AES SHADY POINT, INC.	1999	4911	35.2711	-99.8264	1459.48		828.31	54.008			179.953	233.96	112.611	166.619	5259.57	18.19
2929	OKLAHOMA GAS & ELECTRIC	1999	4911	36.5823	-98.2623	1.3		458.54	13.155			5.166	18.321	5.166	18.321	18.2	15.5
2207	OKLAHOMA GAS & ELECTRIC	1999	4911	40.9005	-81.1166	4.96		68.44	0.028			0.572	0.6	0.572	0.6	0.04	0.16
4152	ONEOK PRODUCER SERVICES	1999	4911	41.168	-81.1983	41.6		23.6									15.79
1799	GRAND RIVER DAM AUTHORITY	1999	4911	34.3063	-97.1453	918.23	1.39	13731.1	587.888			546.182	1134.069	343.698	931.586	18355.31	118.28
2700	WESTERN FARMERS ELECTRIC COOP	1999	4911	40.59	-83.1	434.9	0.55	5362.31	165.076			192.266	357.342	130.838	295.914	9575.2	52.16
2205	OKLAHOMA GAS & ELECTRIC	1999	4911	41.69	-83.53	185.9	14.87	3589.47	36.367			0.442	36.808	0.442	36.808	5187.6	6.6
2699	WESTERN FARMERS ELECTRIC COOP	1999	4911	41.3369	-82.1245	742.46	0.59	1832.44	1.354			0.018	1.372	0.018	1.372	3.04	159.26
1214	CENTRAL AND SOUTH WEST SERVICES, INC.	1999	4911	41.7537	-81.1564	434.02	17.211	3346.5	28.669			0.65	29.319	0.642	29.31	3.51	17.42
1244	CITY OF CUSHING	1999	4911	36.1339	-99.4353	44.79		181.24	0.011			0.139	0.15	0.131	0.141	1.73	10.72
1216	CENTRAL AND SOUTH WEST SERVICES, INC.	1999	4911	34.6033	-98.5085	45.29		181.1	1.206			15.964	17.17	15.962	17.168	0.32	0.03
2208	OKLAHOMA GAS & ELECTRIC	1999	4911	35.7292	-99.298	196.7	15.65	1692.2	23.495			1.047	24.543	1.047	24.543	2.4	6.8
2212	OKLAHOMA GAS & ELECTRIC	1999	4911	35.6188	-98.862	3.7		13.3								0.3	
1247	STILLWATER POWER	1999	4911	36.0155	-99.9822		0.1	7.04	0.176			0.009	0.185	0.008	0.184		
1212	CENTRAL AND SOUTH WEST SERVICES, INC.	1999	4911	35.2056	-98.0395	1715.87	34.13	17577.74	404.264			354.824	759.087	239.806	644.07	16088.47	138.35
2701	WESTERN FARMERS ELECTRIC COOP	1999	4911	36.2567	-98.6611	263.68	9.92	806.87	18.469			0.946	19.414	0.946	19.414	1.8	18.15
2210	OKLAHOMA GAS & ELECTRIC	1999	4911	36.6458	-99.4642	824.2	85.661	4344.43	110.864			6.25	117.115	6.25	117.115	11.6	28.9
1213	CENTRAL AND SOUTH WEST SERVICES, INC.	1999	4911	35.8778	-97.8346	1172.58	8.719	3110.24	23.111			0.287	23.397	0.285	23.395	2.43	46.78
1215	CENTRAL AND SOUTH WEST SERVICES, INC.	1999	4911	35.9278	-97.9205	221.39	43.569	4147.58	79.756			1.395	81.151	1.389	81.145	8.91	9.51
MB0116C	TXU ELECTRIC CO	1999	4911	29.7977	-95.2853	2411.41	91.91	15170.18	166.704			2.929	169.632	2.922	169.623	20.33	161.3
MB0117A	TXU ELECTRIC CO	1999	4911	29.772	-95.2777	354.53	13.47	1311.52	22.786			0.451	23.237	0.445	23.228	2.62	26.48
ME0006A	SOUTHWESTERN ELECTRIC POWER CO	1999	4911	29.6222	-95.4189	953.7	0.04	2559.08	67.236			0.002	67.237	0.002	67.237	9	62.46
MH0028D	STP NUCLEAROPERATING CO	1999	4911	29.6444	-95.2594	12.45		46.81	0.086			0.824	0.91	0.744	0.831	0.79	1.99
MM0023J	TXU ELECTRIC CO	1999	4911	29.873	-95.5868	485.99	1.19	9050.84	268.034			1173.611	1441.645	836.22	1104.26	28738.75	77.62
MO0014L	TXU ELECTRIC CO	1999	4911	29.6216	-95.0434	1343.65	51.129	9024.06	90.242			11.213	101.454	11.209	101.45	9.66	95.21
MR0033U	SOUTHWESTERN PUBLIC SERVICE	1999	4911	29.5997	-95.0167	0.15		4.3								0.2	0.17
NE0025C	CENTRAL POWER AND LIGHT CO	1999	4911	29.761	-95.3634	800.3	30.589	2471.7	55.001			0.909	55.908	0.909	55.908	5.9	53.78
LN3604A	J.R. MASSENGALE	1999	4911	29.7309	-95.1515	12.85	0.49	42.84	0.873			0.015	0.886	0.015	0.886	0.095	1.02
ND0054G	EEX POWER SYSTEMS	1999	4911	29.8525	-95.5828	24.11		1106.67	2.223			41.139	43.36	41.139	43.36	11.41	8.17
NE0024E	CENTRAL POWER AND LIGHT CO	1999	4911	29.738	-95.185	1501.9	57.55	2814.44	101.457			6.834	108.292	6.834	108.292	10.7	98.67
MS0011T	SOUTHWESTERN ELECTRIC POWER CO	1999	4911	29.7151	-95.0952	27.66	1.05	121.79	1.346			0.031	1.378	0.031	1.378	0.1	1.81
MQ0009F	ENTERGY GULF STATES INC	1999	4911	29.8335	-95.2493	1217	43.05	2864.53	87.135			1.278	88.413	1.278	88.413	9.1	80.3
LN0206F	LUBBOCK POWER AND LIGHT	1999	4911	29.7258	-95.0194	186.38		78.89	0.408			8.262	8.67	8.262	8.67	0.83	11.27
LN0081B	SOUTHWESTERN PUBLIC SERVICE CO	1999	4911	29.7886	-95.5528	177.08	36.319	3086.15	62.394			6.135	68.529	5.839	68.232	6.92	62.53
LN0057V	LUBBOCK POWER & LIGHT	1999	4911	29.7192	-95.2766	228.5	8.081	582.53	14.307			6.159	20.466	6.159	20.466	1.49	17.46
LL0006O	LOWER COLORADO RIVER AUTHORITY	1999	4911	29.7158	-95.1819	148.8	20.21	1186.58	35.248			2.478	37.725	2.467	37.715	3.76	36.27
LI0027L	RELIANT ENERGY INC	1999	4911	29.6465	-95.064	1700.2	4.5	24867.28	607.401			3509.643	4117.045	2479.881	3087.281	32868.9	227.88
LB0059G	SAVAGE TOLKCORPORATION	1999	4911	29.7556	-95.1004				2.512			29.518	32.03	14.042	16.554		
LB0047N	SOUTHWESTERN PUBLIC SERVICE CO	1999	4911	29.7453	-95.209	1137.15	1.439	13468.26	441.162			201.255	642.416	87.752	528.909	29387.86	141.24
LB0046P	SOUTHWESTERN PUBLIC SERVICE	1999	4911	29.8263	-94.9296	30.69	12.249	782.16	22.131			1.404	23.533	1.397	23.527	2.31	21.07
LA0045F	TENASKA IIITEXAS PARTNERS	1999	4911	29.7027	-95.2601	166.6		1234.89	2.129			31.652	33.78	31.651	33.779	2.24	49.19
JH0230L	TENASKA IV TEXAS PARTNERS LTD	1999	4911	29.6174	-95.0456	28.5		205.62	37.139			14.459	51.598	14.459	51.598	4.94	37.99
NE0026A	CENTRAL POWER AND LIGHT CO	1999	4911	29.6989	-95.381	1133.4	43.14	2578.79	78.992			1.281	80.274	1.281	80.274	8.4	74.2
TH0004D	CITY OF AUSTIN	1999	4911	28.7952	-96.0497	890.65	33.068	1511.65	58.817			6.728	65.545	6.718	65.537	8.88	79.6
HW0024U	SOUTHWESTERN PUBLIC SERVICE	1999	4911	29.4853	-94.5575	1.09		4.4	0.009			0.191	0.2	0.191	0.2	0.01	0.24
HW0081I	SOUTHWESTERN PUBLIC SERVICE CO	1999	4911	31.6921	-101.5619	228.6		694.26	30.983			12.167	43.15	12.167	43.15	3.5	26
JI0030K	CENTRAL & SOUTH WEST SERVICES INC	1999	4911	29.6452	-95.4134	522.2	19.72	1026.71	36.491			0.586	37.076	0.586	37.076	3.9	34.19
TF0012D	SOUTHWESTERN ELECTRIC POWER CO	1999	4911	32.3465	-101.9995	1574.8	2.72	22905.95	619.25			643.401	1262.651	438.749	1057.998	37958.39	188.95
YB0017V	TXU ELECTRIC CO	1999	4911	30.0461	-93.8049	984.32	37.501	5579.42	66.739			1.113	67.854	1.113	67.854	6.91	64.46
WI0025C	WEST TEXAS UTILITIES CO	1999	4911	32.0624	-96.4753	1122.45	1.04	9907.83	588.203			324.917	913.12	221.887	810.09	8801.9	13.65
WI0002O	WEST TEXAS UTILITIES	1999	4911	31.7996	-94.7235	2.56		9.65	0.106			0.194	0.3	0.11	0.217	1.52	0.25
WH0083W	MIRANT WICHITA FALLS LP	1999	4911	31.5733	-94.6495	93.13		425.82	1.84			6.26	8.1	6.26	8.1	1.01	3.35
WF0175P	NEWGULF POWER VENTURE INC	1999	4911	35.8143	-101.9187	2.6		104.16	0.977			0.384	1.36	0.384	1.36	0.1	0.4
WE0005G	CENTRAL & SOUTHWEST SERVICES INC	1999	4911	35.8108	-101.6307	333.8	12.77	726.99	25.095			0.379	25.474	0.379	25.474	3.1	21.8
WC0028Q	TXU ELECTRIC CO	1999	4911	30.3366	-95.4633	1336.55	50.881	12990.41	92.671			7.744	100.415	7.744	100.415	21.03	91.95
VC0026O	SOUTH TEXASELECTRIC COOPERATIVE INC	1999	4911	31.869	-101.7751	16.76	0.519	57.93	0.987			0.989	1.976	0.985	1.974	0.18	2.71
VC0003D	CENTRAL POWER AND LIGHT CO	1999	4911	31.9552	-101.8896	509.6	19.42	1928.61	35.515			0.576	36.091	0.576	36.091	3.7	33.3
TH0104V	UNIVERSITY OF TEXAS AT AUSTIN	1999	4911	29.1431	-95.8912	97.13		684.9	4.148			12.443	16.59	12.398	16.545	0.2	13.26
TH0006W	CITY OF AUSTIN	1999	4911	28.9821	-96.0297	216.94	15.1	706.49	25.277			1.363	26.64	1.359	26.636	2.72	26.41
HG9954A	CALPINE CORPORATION	1999	4911	31.7668	-106.3923	23.8		171.23	3.444			38.096	41.54	38.096	41.54	5.54	24.9
TF0013B	TXU ELECTRIC CO	1999	4911	32.422	-102.1076	1680.89	3.349	20496	1323.375			1698.178	3021.553	1311.562	2634.935	100122	194.14
HV0023K	GREENVILLE ELECTRIC SYSTEM	1999	4911	29.2697	-94.8138	27.85	1.09	78.23	1.727			0.033	1.76	0.033	1.76	0.11	1.8
NE0035W	ROBSTOWN UTILITY SYSTEMS	1999	4911	29.7354	-95.1071	144		345.59	0.906			5.834	6.74	4.947	5.853	0.95	25.35
TB0056E	WEST TEXAS UTILITIES CO	1999	4911	30.9216	-96.1793	4.2	0.16	13.99	0.276			0.005	0.281	0.005	0.281	0.03	0.27
TA0354E	TXU ELECTRIC CO	1999	4911	30.3707	-95.0174	38.5	1.47	346.22	2.542			0.044	2.585	0.044	2.585	0.2	2.52
TA0353G	TXU ELECTRIC CO	1999	4911	30.4123	-94.9636	1228.86	46.729	3333.17	81.668			1.62	83.284	1.609	83.272	13.33	81.7
TA0352I	TXU ELECTRIC CO	1999	4911	30.0004	-94.9536	457.63	17.44	1467.1	30.171			0.526	30.697	0.526	30.696	3.11	29.97
RL0020K	TXU ELECTRIC CO	1999	4911	29.7037	-93.9291	1773.5	4.74	28360.66	975.931			3480.308	4456.24	2486.268	3462.201	111619.38	332.62
RI0035C	TEXAS NEW MEXICO POWER CO	1999	4911	29.8908	-94.0005	617.2	0.69	2537.05	801.658			261.491	1063.149	136.072	937.726	6335.41	11.85
RE0012M	TXU ELECTRIC CO	1999	4911	29.9566	-93.8976	60.68	2.31	538.42	4.216			0.068	4.286	0.068	4.286	0.5	3.98
PG0041R	SOUTHWESTERN PUBLIC SERVICE CO	1999	4911	33.0729	-98.1883	578.2	1.529	12686.97	426.314			301.804	728.118	172.322	598.638	28889.16	132.15
PG0040T	SOUTHWESTERN PUBLIC SERVICE CO	1999	4911	33.0368	-98.1027	55.21	20.6	1478.45	37.504			2.457	39.961	2.457	39.961	3.8	35.51
PE0259K	WEST TEXAS UTILITIES CO	1999	4911	35.9657	-101.6139	0.16		0.63	0.005			0.005	0.01	0.005	0.01	0.01	

FACILITYID	FACILITYNAME	INVNETORY YEAR	SIC	LATITUDE	LONGITUDE	CO	NH3	NOX	PMCON	PMFIL	PMPRI	PM10FIL	PM10PRI	PM25FIL	PM25PRI	SO2	VOC
PC0005T	BRAZOS ELECTRIC POWER COO	1999	4911	32.0026	-97.134	16.3	0.86	78.84	1.544			0.025	1.569	0.025	1.569	0.12	0.57
PA0003W	BRAZOS ELECTRIC POWER COOPERATIVE IN	1999	4911	32.3073	-95.6868	757.13	24.94	1740.08	46.939			11.293	58.231	11.293	58.231	5.8	69.4
OC0013O	ENTERGY GULF STATES INC	1999	4911	29.8521	-97.9647	1852	148.499	9379.67	281.651			14.412	296.06	14.412	296.06	29.7	265.21
TG0044C	WEST TEXAS UTILITIES CO	1999	4911	28.8585	-96.029	19.47	12.53	769.67	22.377			11.503	33.88	11.503	33.88	5.32	17.27
CB0008C	CENTRAL POWER AND LIGHT CO	1999	4911	35.9631	-84.0039	267.6	10.18	808.78	18.422			0.302	18.725	0.302	18.725	2.9	17.5
DB0253Q	TXU ELECTRIC CO	1999	4911	36.0019	-86.5042	205.08	7.81	1363.27	13.714			0.232	13.946	0.232	13.946	1.41	13.42
DB0252S	TXU ELECTRIC CO	1999	4911	35.8367	-86.4033	436.87	36.16	2939.86	68.12			3.531	71.653	3.531	71.653	7.03	62.17
DB0251U	TXU ELECTRIC CO	1999	4911	35.8681	-86.5825	722.64	27.691	2638.29	49.528			1.07	50.598	1.048	50.576	10.52	49.55
DB0249H	TXU ELECTRIC CO	1999	4911	35.8675	-86.4131	1128.64	43.222	2470.95	79.731			1.649	81.38	1.617	81.346	18.82	74.73
CZ0017A	W TX UTILITIES CO	1999	4911	35.9356	-84.3957	266.55	9.67	1100.63	22.827			0.975	23.802	0.975	23.802	2.47	16.9
CP0230L	THERMONETICS INC	1999	4911	36.57	-87.2906	19.56		39.98	0.208			0.304	0.51	0.275	0.482	0.26	6.41
CP0065C	TXU ELECTRIC CO	1999	4911	35.6658	-84.6667	25.4	3.4	138.61	5.802			0.43	6.232	0.426	6.228	1.6	5.82
CP0026M	GARLAND MUNICIPAL POWER AND LIGHT	1999	4911	35.6386	-87.0586	6.2	17.74	1070.18	33.697			0.87	34.567	0.87	34.567	3.5	6.51
CO0003M	CITY OF COLEMAN	1999	4911	35.6414	-87.2453	19.56		78.66								0.47	4.65
CN0005T	WEST TEXAS UTILITIES CO	1999	4911	35.6487	-87.0486	162.3	6.15	413.63	11.386			0.183	11.568	0.183	11.568	1.1	10.63
HT0065Q	POWER RESOURCES LTD	1999	4911	29.4602	-95.0444	30.44		836.59	10.23			30.671	40.9	29.967	40.195	9.64	7.17
CI0012D	RELIANT ENERGY INC	1999	4911	35.7711	-84.3331	3047	116.37	4417.74	206.309			4.105	210.415	4.073	210.382	44.13	201.19
DB0384A	GARLAND MUNICIPAL POWER AND LIGHT	1999	4911	35.36	-85.4306	24.33	0.919	76.33	1.66			0.027	1.688	0.027	1.688	0.07	1.67
CD0009B	BROWNSVILLEPUBLIC UTILITIES BOARD	1999	4911	36.0161	-83.9239	23.15	0.639	181.24	1.679			9.444	11.123	9.444	11.123	1.15	9.39
CJ0026J	TXU ELECTRIC CO	1999	4911	35.4411	-86.7797	429.92	40.319	2862.64	76.82			4.37	81.193	4.34	81.168	9.6	69.6
BM0032V	TEXAS A & M UNIVERSITY	1999	4911	35.95	-83.8614	184.95		539.57	8.554			31.431	39.98	31.382	39.931	7.57	24.36
BM0010I	BRYAN MUNICIPAL ELECTRIC SYSTEM	1999	4911	35.9572	-83.9372	47.7	1.72	169.2	3.076			1.16	4.235	1.16	4.235	0.41	3.19
BM0009Q	CITY OF BRYAN	1999	4911	35.9675	-83.8831	199.7	7.61	380.76	13.231			0.226	13.457	0.226	13.457	1.4	13.22
BG0188E	CITY PUBLICSERVICE BOARD	1999	4911	34.9905	-85.3978	15.2	0.58	107.43	2.369			2.477	4.846	2.058	4.427	0.1	1
BG0187G	CITY PUBLICSERVICE	1999	4911	35.0993	-85.267	139.83	5.319	561.06	20.03			19.108	39.138	15.882	35.912	0.9	9.16
BG0186I	CITY PUBLICSERVICE	1999	4911	35.0538	-85.2063	229.13	30.57	2685.38	54.9			3.656	58.557	3.652	58.553	5.07	66.26
BG0059Q	CITY PUBLICSERVICE BOARD	1999	4911	35.0839	-85.2702	29.55	1.12	234.75	3.801			3.242	7.043	2.695	6.497	0.2	3.87
BG0057UB	CITY PUBLICSERVICE B	1999	4911	35.0508	-85.3316	162.7	15.735	6169.5	421.603			83.639	505.242	34.633	456.236	6120.7	15.7
BG0057UA	CITY PUBLICSERVICE B	1999	4911	35.0628	-85.2636	938.7	25.62	10045.19	351.673			2681.228	3032.901	1297.683	1649.356	24103.29	112.7
BG0057U	CITY PUBLICSERVICE	1999	4911	35.0616	-85.0888	342.53	5.744	2252.54	90.036			27.974	118.009	12.371	102.414	13.43	80.4
BC0015L	LOWER COLORADO RIVER AUTHORITY	1999	4911	35.0531	-85.0856	262.22	35.299	2342.79	60.424			3.146	63.57	3.142	63.567	6.34	120.71
AG0007G	SAN MIGUEL ELCTRC COOPERATIVE INC	1999	4911	35.0434	-85.2665	927	1.17	6771.65	195.634			1629.607	1825.241	1158.809	1354.445	21349.99	17.5
HJ0022B	WEST TEXAS UTILITIES CO	1999	4911	29.6939	-95.714	210.05	7.85	1505.48	16.987			0.233	17.219	0.233	17.219	1.6	13.75
HN0013E	CENTRAL POWER AND LIGHT CO	1999	4911	31.5642	-96.0552	351.1	13.35	1605.45	25.306			0.397	25.702	0.397	25.702	3.4	24.55
CD0013K	CENTRAL POWER AND LIGHT CO	1999	4911	35.9667	-83.8919	426.3	14.811	1405.41	31.067			1.393	32.458	1.393	32.458	3.3	25.6
HN0403K	FRONTERA GENERATION LTD PARTNERSHIP	1999	4911	32.6884	-102.6483	1.6		54.72	0.565			11.455	12.02	11.455	12.02	0.77	
DF0012T	DENTON MUNICIPAL UTILITIES	1999	4911	35.5222	-89.5761	113.34	5.019	597.5	9.478			0.193	9.671	0.193	9.671	1.98	9.26
HM0017H	TXU ELECTRIC CO	1999	4911	31.8257	-96.0568	62.53	8.21	567.22	14.487			1.027	15.513	1.019	15.505	1.96	14.21
HH0037F	SOUTHWESTERN ELECTRIC POWER CO	1999	4911	30.0058	-96.8896	871.09	1.21	8847.46	244.082			896.585	1140.666	619.332	863.412	27781.5	40
HG4955K	RELIANT ENERGY INC	1999	4911	32.4554	-97.0453	261.2		367.77	38.857			15.202	54.059	15.202	54.059	5.1	20
HG1495V	AES DEEPWATER INC	1999	4911	32.927	-96.7648	326.82		3215.97	0.201			1.619	1.82	0.914	1.116	4099.71	6.54
HG1169O	CALPINE CORPORATION	1999	4911	32.789	-96.8209	958.28		1520.77	32.13			40.096	72.226	38.334	70.464	11.6	3.53
HG0358Q	RELIANT ENERGY INC	1999	4911	31.5935	-102.64	279.5	23.691	1192.9	42.034			2.797	44.83	2.797	44.83	4.41	42.62
HG0357S	RELIANT ENERGY INC	1999	4911	31.5985	-102.75	193.5	5.918	1022.04	24.041			125.463	149.504	122.947	146.987	7.91	45.5
HG0356U	RELIANT ENERGY INC	1999	4911	31.5121	-102.6522	25.2	3.49	286.26	6.998			0.104	7.102	0.104	7.102	0.7	6
HG0355W	RELIANT ENERGY INC	1999	4911	31.4917	-102.625	104	15.88	1060.8	28.93			0.948	29.878	0.948	29.878	3.1	27.1
HG0354B	RELIANT ENERGY INC	1999	4911	31.4918	-102.6583	7.94		22.43	0.047			0.983	1.03	0.983	1.03	0.06	0.52
FC0018G	LOWER COLORADO RIVER AUTHORITY	1999	4911	28.6711	-97.7928	1725.04	2.27	19560.76	818.699			5871.842	6690.541	2577.697	3396.395	33182.31	288.36
HQ0012T	TXU ELECTRIC CO	1999	4911	29.363	-94.9328	1617.56	61.54	7974.29	110.275			11.198	121.472	11.198	121.472	11.87	112.17
HG0353D	RELIANT ENERGY INC	1999	4911	31.4298	-102.3806	181.7	12.699	613.96	28.778			19.573	48.351	18.138	46.915	4.1	28.9
EE0029T	EL PASO ELECTRIC CO	1999	4911	32.3418	-102.5542	488.1	35.98	2627.53	65.067			1.068	66.134	1.068	66.134	7	30.35
FB0025U	TX UTILITIES ELECTRIC CO	1999	4911	28.3775	-97.5184	1371.42	52.361	4316.15	95.677			1.775	97.451	1.759	97.436	12.61	91.87
FG0020V	RELIANT ENERGY INC	1999	4911	29.4588	-98.4102	8788.4	47.51	33412.61	1372.752			470.702	1843.455	220.8	1593.557	67583.04	176.6
FI0020W	TXU ELECTRIC CO	1999	4911	29.0021	-95.4081	661.57	2.191	12928.45	1708.297			61.921	1770.217	31.761	1740.061	83771.67	102.24
GB0037T	RELIANT ENERGY INC	1999	4911	29.2305	-95.7312	2801.8	141.159	8671.9	287.326			74.38	361.706	62.467	349.792	26.16	241
GB0153Q	TEXAS CITY COGENERATION LP	1999	4911	29.4016	-95.2531	56.9		3016.47	1.539			31.191	32.73	31.191	32.73	9.47	1.59
GF0002R	CENTRAL SOUTH WEST SERVICES INC	1999	4911	26.9537	-98.2365	634.7	0.79	5572.39	230.166			280.644	510.81	191.499	421.665	22133.79	73.2
HE0013G	WEST TEXAS UTILITIES CO	1999	4911	29.8549	-94.9096	13.26	0.59	44.22	1.055			0.017	1.072	0.017	1.072	0.1	0.87
GJ0043K	SOUTHWESTERN ELECTRIC POWER CO	1999	4911	26.2091	-97.7202	583.97	22.21	1964.07	41.908			2.41	44.318	2.41	44.318	32.8	38.48
FJ0012P	MEDINA ELECTRIC COOPERATIVE INC	1999	4911	29.0146	-95.3682	23.42	0.89	78.07	1.816			0.027	1.843	0.027	1.843	0.17	1.54
EE0157J	EL PASO ELECTRIC CO	1999	4911	27.9411	-97.1199	91.1		112.5	0.611			12.389	13	12.389	13	0.2	
GK0012K	TEXAS MUNICIPAL POWER AGENCY	1999	4911	35.5654	-101.1236	472.2	0.63	5555.03	326.396			242.045	568.441	161.777	488.17	11991.29	56.66
11539	HILDALE CITY COGENERATION FACILITY	1999	4911	34.1611	-99.2922	20.45		42.56	0.164			3.236	3.4	3.236	3.4	1.71	5.52
107790	BONANZA	1999	4911	29.8143	-95.8813	392.44	0.5	5699.93	356.818			125.277	482.095	51.874	408.692	1134.9	47.08
10795	POWER PLANT	1999	4911	29.8102	-95.8897	6.39		15.4								6.61	1.1
10819	WHITEHEAD POWER PLANT	1999	4911	31.6383	-102.893	176.9		161.3								0.02	58.3
10892	ST. GEORGE CITY POWER PLANT	1999	4911	33.9433	-98.5386	7.9		119.4	0.855			11.315	12.17	10.895	11.75	0.03	0.9
10355	GADSBY POWER PLANT	1999	4911	32.2679	-94.7249	153.8	7.1	199.77	17.42			8.664	26.083	7.292	24.709	1.43	15.24
10096	SUNNYSIDE COGENERATION FACILITY	1999	4911	31.2395	-102.888	94.72		460.37	13.163			59.097	72.26	59.077	72.24	1058.57	17.55
10823	PAYSON CITY POWER	1999	4911	31.4577	-103.521	26.26		61.43	1.885			12.145	14.03	10.297	12.183	1.75	57.44
10327	INTERMOUNTAIN GENERATION STATION	1999	4911	36.0337	-100.7268	1312.43	1.67	28260.56	1447.216			495.959	1943.176	245.605	1692.821	3698.31	157.747
10238	HUNTINGTON POWER PLANT	1999	4911	31.6485	-101.7679	739.78	0.989	15018.72	602.753			989.526	1592.279	418.678	1021.432	13901.21	88.37
10120	POWER PLANT	1999	4911	31.1846	-103.0403	23.3		104.6	0.062			0.398	0.46	0.398	0.46	2.26	6.4
10081	CARBON POWER PLANT	1999	4911	32.7728	-97.8064	62.81	0.24	2980.35	97.151			99.161	196.31	45.743	142.893	4388.07	21.563
10058	POWER PLANT	1999	4911	32.1869	-94.3197	0.74		3.54	0.052			0.178	0.23	0.178	0.23	0.22	0.27
10319	BONNETT-GEOTHERMAL POWER PLANT	1999	4911	30.0636	-93.9768	0.18		0.46	0.002			0.028	0.03	0.028	0.03	0.03	0.03
10348	ELECTRICAL GENERATION PLANT	1999	4911	32.1946	-94.9598	0.24		0.32	0.001			0.009	0.01	0.007	0.009	0.01	0.84
10237	HUNTER POWER PLANT	1999	4911	31.154	-101.3447	1057.35	1.499	20305.39	1104.413			1164.229	2268.64	551.898	1656.308	7045.49	127.32
00005	BLACK HILLS OSAGE	1999	4911	45.66	-91.54	60.69	0.06	908.49	90.737			370.757	461.494	78.758	169.495	2592.99	7.29
01002	PACIFICORP_JIM BRIDGER	1999	4911	42.63	-88.63	2738.7	2.968	37991.28	2472.757			3178.359	5651.116	2207.715	4680.467	25784.7	319.4

FACILITYID	FACILITYNAME	INVNETORY YEAR	SIC	LATITUDE	LONGITUDE	CO	NH3	NOX	PMCON	PMFIL	PMPRI	PM10FIL	PM10PRI	PM25FIL	PM25PRI	SO2	VOC
00001	BASIN ELECTRIC_LARAMIE RIVER STATION	1999	4911	45.13	-90.34	1912.56	2.84	17689.07	1503.047			1261.199	2764.246	946.514	2449.562	11067.8	229.23
00004	PACIFICORP_NAUGHTON POWER PLANT	1999	4911	43.74	-87.71	752.8	0.971	13759.54	950.25			893.944	1844.193	805.461	1755.71	21864.6	87.8
00001	PACIFICORP_DAVE JOHNSTON	1999	4911	43.77	-88.1	923.5	1.23	17570.58	689.524			1434.894	2124.418	738.799	1428.322	27915.5	110.7
00063	BLACK HILLS POWER & LGT_SIMPSON 2	1999	4911	46	-91.49	200.6	0.172	815.19	87.205			88.657	175.862	55.879	143.084	641.4	4.8
00002	BLACK HILLS POWER & LGHT SIMPSON 1	1999	4911	45.13	-92.66	31.2	0.07	520.5	14.362			18.265	32.627	11.851	26.213	1008	4.4
00046	PACIFICORP_WYODAK	1999	4911	43.29	-89.73	520.7	0.68	5564.85	385.017			356.305	741.321	223.682	608.7	9082.4	62.4

P200_ STATE_ FIPS	P200_ COUNTY_ FIPS	P200_ SITE_ID	P200_ ORIS_ FACILITY_ CODE	P200_ SIC_ PRIMARY	P200_FACILITY_NAME	P200_ SITE_ DESCRIPTION	P200_ STREET_ LINE_1	P200_ STREET_ LINE_2	P200_ STREET_ LINE_3	P200_CITY	P200_ STATE	P200_ZIP_ CODE	P200_NH3 _EMISSION_ TON_SUM	MATCH_TYPE	MATCH_ MULTIPLE	MATCH_ RATIO	NH3_TO_ APPLY_ EMISSION_ TON_SUM	P300_ STATE_ FIPS	P300_ COUNTY_ FIPS	P300_ SITE_ ID
04	021	0054		0116	MAGMA COPPER BOX 37 SUPERIOR 85273		Unknown			Not Available	AZ	00000	0.03	300_NO_NH3			0.03	04	021	0402101392
04	021	0032		0182	MAGMA METALS COMPANY-SAN MANUEL SMELTER		Unknown			Not Available	AZ	00000	0.63	300_NO_NH3			0.63	04	021	0402100102
04	019	2026		1021	ASARCO PIMA MINE		Unknown			Not Available	AZ	00000	0.18	NONE			0.18			
04	003	0003		2011	CHEMSTAR LIME - DOUGLAS PLANT		Unknown			Not Available	AZ	00000	0.1	300_NO_NH3			0.1	04	003	0400300176
04	005	0009		2421	KAIBAB FOREST PRODUCTS		Unknown			Not Available	AZ	00000	0.06	NONE			0.06			
04	003	0001		2873	APACHE NITROGEN PRODUCTS INC.		Unknown			Not Available	AZ	00000	3.11	300_HAS_NH3			3.11	04	003	0400301143
04	003	0002	160	4911	APACHE STATION		Not Available			Not Available	AZ	NOT AVAIL	3.89	300_NO_NH3			3.89	04	003	0400300037
04	017	0001	113	4911	CHOLLA		Not Available			Not Available	AZ	NOT AVAIL	1.32	300_NO_NH3			1.32	04	017	0401701020
04	001	0003	6177	4911	CORONADO		Not Available			Not Available	AZ	NOT AVAIL	1.02	NONE			1.02			
04	019	0082	126	4911	IRVINGTON		Not Available			Not Available	AZ	NOT AVAIL	8.74	NONE			8.74			
04	005	0004	4941	4911	NAVAJO		Not Available			Not Available	AZ	NOT AVAIL	2.71	NONE			2.71			
04	021	U118	118	4911	SAGUARO		Not Available			Not Available	AZ	NOT AVAIL	7.31	NONE			7.31			
04	001	0004	8223	4911	SPRINGERVILLE		Not Available			Not Available	AZ	NOT AVAIL	0.98	300_NO_NH3			0.98	04	001	0400100060
04	027	U120	120	4911	YUCCA		Not Available			Not Available	AZ	NOT AVAIL	6.5	300_NO_NH3			6.5	04	027	0402700141
32	021	0500		1459	BASIC INC.		Unknown			Not Available	NV	00000	0.17	NONE			0.17			
32	019	0387		3241	NEVADA CEMENT CO		Unknown			Not Available	NV	00000	4.91	300_NO_NH3			4.91	32	019	0387
32	003	0004		3275	GENSTAR BUILDING MATERIALS BLUE DIAMOND		Unknown			Not Available	NV	00000	2.53	NONE			2.53			
32	003	P003	2322	4911	CLARK		Not Available			Not Available	NV	NOT AVAIL	4.24	300_NO_NH3			4.24	32	003	0398
32	019	0001	2330	4911	FORT CHURCHILL		Not Available			Not Available	NV	NOT AVAIL	17.39	300_NO_NH3			17.39	32	019	0091
32	003	P001	2341	4911	MOHAVE		Not Available			Not Available	NV	NOT AVAIL	2.21	300_NO_NH3			2.21	32	003	0466
32	013	5001	8224	4911	NORTH VALMY		Not Available			Not Available	NV	NOT AVAIL	0.7	300_NO_NH3			0.7	32	013	0457
32	003	P002	2324	4911	REID GARDNER		Not Available			Not Available	NV	NOT AVAIL	0.6	300_NO_NH3			0.6	32	003	0400
32	003	P004	2326	4911	SUNRISE		Not Available			Not Available	NV	NOT AVAIL	2.51	300_NO_NH3			2.51	32	003	0399
32	029	0002	2336	4911	TRACY		Not Available			Not Available	NV	NOT AVAIL	18.52	300_NO_NH3			18.52	32	029	0194
										WINNEMUCCA	NV			300_HAS_NH3				32	013	0002

P200_FACILITY_NAME	P300_ ORIS_ FACILITY_ CODE	P300_ SIC_ PRIMARY	P300_FACILITY_NAME	P300_SITE_DESCRIPTION	P300_STREET_LINE_1	P300_ STREET_ LINE_2	P300_ STREET_ LINE_3	P300_CITY	P300_ STATE	P300_ ZIP_CODE	P300_ NH3 _EMISSION_ TON_SUM
MAGMA COPPER BOX 37 SUPERIOR 85273		1021	BHP COPPER- SAN MANUEL OPERATIONS	BHP COPPER- SAN MANUEL OP	200 SOUTH REDDINGTON ROAD			SAN MANUEL	AZ	85631	
MAGMA METALS COMPANY-SAN MANUEL SMELTER		3331	BHP COPPER - SAN MANUEL SMELTER	BHP COPPER - SAN MANUEL S	REDDINGTON ROAD			SAN MANUEL	AZ	85631	
ASARCO PIMA MINE								Not Available	AZ		
CHEMSTAR LIME - DOUGLAS PLANT		3274	CHEMICAL LINE COMPANY - DOUGLAS FACILITY	LIME PROCESSING FACILITY	HIGHWAY 80			DOUGLAS	AZ	85607	
KAIBAB FOREST PRODUCTS									AZ		
APACHE NITROGEN PRODUCTS INC.		2873	APACHE NITROGEN PRODUCTS INC	APACHE NITROGEN PRODUCTS	1436 S. APACHE POWDER RD.			BENSON	AZ	85602	0
APACHE STATION		4911	AZ ELECTRIC POWER COOPERATIVE INC	APACHE GENERATING STATION	3525 NORTH HIGHWAY 191			COCHISE	AZ	85606	
CHOLLA		1499	CHOLLA FLYASH	FLYASH TRANSFER FACILITY	FOUR CORNERS CHOLLA PLANT			JOSEPH CITY	AZ	86032	
CORONADO									AZ		
IRVINGTON									AZ		
NAVAJO									AZ		
SAGUARO									AZ		
SPRINGERVILLE		4911	TUCSON ELECTRIC POWER CO-SPRINGERVILLE	TUCSON ELECTRIC POWER CO-	OFF RTE191,APP.15 MI SPRINGER			SPRINGERVILLE	AZ	85938	
YUCCA		4911	YUMA COGENERATION ASSOCIATES	COGENERATION FACILITY	280 N. 27TH DRIVE			YUMA	AZ	85364	
BASIC INC.								Not Available	NV		
NEVADA CEMENT CO		3241	FERNLEY		No Address Giver			FERNLEY	NV	89408	
GENSTAR BUILDING MATERIALS BLUE DIAMOND									NV		
CLARK		4911	CLARK STATION		CLARK STATION			LAS VEGAS	NV	89151	
FORT CHURCHILL		4911	FORT CHURCHILL STATION		No Address Giver			RENO	NV	89520	
MOHAVE		4911	MOHAVE GENERATING STATION		2700 EDISON WAY			LAUGHLIN	NV	89029	
NORTH VALMY		4911	VALMY GENERATING STATION		No Address Giver			RENO	NV	89520-0026	
REID GARDNER		4911	REID GARDNER STATION		No Address Giver			MOAPA	NV	89025	
SUNRISE		4911	SUNRISE STATION		6200 VEGAS VALLEY DRIVE			LAS VEGAS	NV	89121	
TRACY		4911	TRACY		INTERSTATE-80 EAST			SPARKS	NV	00000	
		2819	none		5505 CYANCO DRIVE			WINNEMUCCA	NV	89445	3.2778

ORISPL	FIPST	FIPSCNY	ORISPL_ In_NEI_V300_ Draft	SiteID_ In_NEI_ V300_ Draft	FIPST_ NUM	FIPSCNY_ NUM	PSTAT ABB	CNTYNAME	PNAME	OPRNAME	OPPRNAME	PCANAME	PL TYPE
50805	04	017			4	17	AZ	NAVAJO	ABITIBI CONSOLIDATED SNOWFLAKE DIVISION	Abitibi Consolidated		Arizona Public Service Co/PCA	NU
141	04	013	141	3316	4	13	AZ	MARICOPA	AGUA FRIA	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist/PCA	UT
160	04	003	160	0400300037	4	3	AZ	COCHISE	APACHE STATION	Arizona Electric Pwr Coop Inc		WAPA - Phoenix (LC)/PCA	UT
54594	04	021	54594	0072	4	21	AZ	PINAL	BIOSPHERE 2 CENTER INC	Biosphere 2 Center Inc		WAPA - Phoenix (LC)/PCA	NU
112	04	025			4	25	AZ	YAVAPAI	CHILDS	Arizona Public Service Co	Pinnacle West Capital Corporation	Arizona Public Service Co/PCA	UT
113	04	017	113	0001	4	17	AZ	NAVAJO	CHOLLA	Arizona Public Service Co	Pinnacle West Capital Corporation	Arizona Public Service Co/PCA	UT
6177	04	001	6177	0400100059	4	1	AZ	APACHE	CORONADO	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist/PCA	UT
143	04	013			4	13	AZ	MARICOPA	CROSSCUT	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist/PCA	UT
152	04	015			4	15	AZ	MOHAVE	DAVIS	USBR-Lower Colorado Region	US Bureau Of Reclamation	WAPA - Phoenix (LC)/PCA	UT
114	04	003			4	3	AZ	COCHISE	DOUGLAS	Arizona Public Service Co	Pinnacle West Capital Corporation	Arizona Public Service Co/PCA	UT
153	04	005			4	5	AZ	COCONINO	GLEN CANYON	USBR-Upper Colorado Region	US Bureau Of Reclamation	WAPA - Rocky Mountains/PCA	UT
54838	04	013			4	13	AZ	MARICOPA	GOULD ELECTRONICS FOIL DIVISION	Japan Energy Corp Ltd		Salt River Proj Ag I & P Dist/PCA	NU
8902	04	015			4	15	AZ	MOHAVE	HOOVER	USBR-Lower Colorado Region	US Bureau Of Reclamation	WAPA - Phoenix (LC)/PCA	UT
145	04	013			4	13	AZ	MARICOPA	HORSE MESA	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist/PCA	UT
55257	04	019			4	19	AZ	PIMA	INA ROAD WATER POLLUTION CONTROL FACILITY	PIMA County Wastewater Manage		Tucson Electric Power Co/PCA	NU
115	04	025			4	25	AZ	YAVAPAI	IRVING	Arizona Public Service Co	Pinnacle West Capital Corporation	Arizona Public Service Co/PCA	UT
126	04	019	126	0082	4	19	AZ	PIMA	IRVINGTON	Tucson Electric Power Co	UniSource Energy Corporation	Tucson Electric Power Co/PCA	UT
147	04	013	147	3317	4	13	AZ	MARICOPA	KYRENE	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist/PCA	UT
148	04	013			4	13	AZ	MARICOPA	MORMON FLAT	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist/PCA	UT
4941	04	005	4941	0004	4	5	AZ	COCONINO	NAVAJO	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist/PCA	UT
54245	04	015			4	15	AZ	MOHAVE	NELSON PLANT GENERATORS	Chemical Lime Co		WAPA - Phoenix (LC)/PCA	NU
6088	04	019			4	19	AZ	PIMA	NORTH LOOP	Tucson Electric Power Co	UniSource Energy Corporation	Tucson Electric Power Co/PCA	UT
116	04	013	116	52382	4	13	AZ	MARICOPA	OCOTILLO	Arizona Public Service Co	Pinnacle West Capital Corporation	Arizona Public Service Co/PCA	UT
6008	04	013	6008	98	4	13	AZ	MARICOPA	PALO VERDE	Arizona Public Service Co	Pinnacle West Capital Corporation	Arizona Public Service Co/PCA	UT
149	04	013			4	13	AZ	MARICOPA	ROOSEVELT	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist/PCA	UT
118	04	021	118	U118	4	21	AZ	PINAL	SAGUARO	Arizona Public Service Co	Pinnacle West Capital Corporation	Arizona Public Service Co/PCA	UT
8068	04	013	8068	3315	4	13	AZ	MARICOPA	SANTAN	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist/PCA	UT
100	04	013			4	13	AZ	MARICOPA	SOUTH CONSOLIDATED	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist/PCA	UT
8223	04	001	8223	0400100060	4	1	AZ	APACHE	SPRINGERVILLE	Tucson Electric Power Co	UniSource Energy Corporation	Tucson Electric Power Co/PCA	UT
50238	04	013			4	13	AZ	MARICOPA	STARWOOD HOTELS RESORTS	Starwood Hotels Resorts		Salt River Proj Ag I & P Dist/PCA	NU
150	04	013			4	13	AZ	MARICOPA	STEWART MTN	Salt River Proj Ag I & P Dist		Salt River Proj Ag I & P Dist/PCA	UT
117	04	013	117	3313	4	13	AZ	MARICOPA	WEST PHOENIX	Arizona Public Service Co	Pinnacle West Capital Corporation	Arizona Public Service Co/PCA	UT
120	04	027	120	U120	4	27	AZ	YUMA	YUCCA	Arizona Public Service Co	Pinnacle West Capital Corporation	Arizona Public Service Co/PCA	UT
54694	04	027			4	27	AZ	YUMA	YUMA COGENERATION ASSOCIATES	Yuma Cogeneration Associates		Arizona Public Service Co/PCA	NU
464	08	003			8	3	CO	ALAMOSA	ALAMOSA	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
10755	08	045			8	45	CO	GARFIELD	AMERICAN ATLAS 1 COGENERATION PLANT	American Atlas #1 Ltd		Public Service Co Of Colorado/PCA	NU
54630	08	037			8	37	CO	EAGLE	AMERICAN GYPSUM COGENERATION	Centex Eagle Gypsum Co LLC		Public Service Co Of Colorado/PCA	NU
6207	08	113			8	113	CO	SAN MIGUEL	AMES	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
465	08	031	465	0008	8	31	CO	DENVER	ARAPAHOE	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
54680	08	013			8	13	CO	BOULDER	BETASSO HYDROELECTRIC PLANT	City of Boulder		Public Service Co Of Colorado/PCA	NU
515	08	069			8	69	CO	LARIMER	BIG THOMPSON	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
512	08	051			8	51	CO	GUNNISON	BLUE MESA	USBR-Upper Colorado Region	US Bureau Of Reclamation	WAPA - Rocky Mountains/PCA	UT
466	08	031			8	31	CO	DENVER	BOULDER	City of Boulder		Public Service Co Of Colorado/PCA	NU
10683	08	087			8	87	CO	MORGAN	BRUSH COGEN PROJECT PHASE 2 BCP	Colorado Cogeneration Operator		Public Service Co Of Colorado/PCA	NU
55209	08	087			8	87	CO	MORGAN	BRUSH IV	Colorado Energy Management LLC		Public Service Co Of Colorado/PCA	NU
10682	08	087			8	87	CO	MORGAN	BRUSH POWER PROJECT PHASE 1 CPP	Colorado Cogeneration Operator		Public Service Co Of Colorado/PCA	NU
6619	08	063			8	63	CO	KIT CARSON	BURLINGTON	Tri-State G & T Assn Inc		WAPA - Rocky Mountains/PCA	UT
467	08	019			8	19	CO	CLEAR CREEK	CABIN CREEK	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
468	08	077	468	0002	8	77	CO	MESA	CAMEO	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
469	08	001	469	0001	8	1	CO	ADAMS	CHEROKEE	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
470	08	101	470	0003	8	101	CO	PUEBLO	COMANCHE	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
6021	08	081	6021	0018	8	81	CO	MOFFAT	CRAIG	Tri-State G & T Assn Inc		WAPA - Rocky Mountains/PCA	UT
6159	08	085			8	85	CO	MONTROSE	CRYSTAL	USBR-Upper Colorado Region	US Bureau Of Reclamation	WAPA - Rocky Mountains/PCA	UT
496	08	029			8	29	CO	DELTA	DELTA	Delta City of		WAPA - Rocky Mountains/PCA	UT
10421	08	117			8	117	CO	SUMMIT	DILLON HYDRO PLANT	Daniel M Nyman		Public Service Co Of Colorado/PCA	NU
54671	08	103			8	103	CO	RIO BLANCO	DRAGON TRAIL GAS PROCESSING PLANT	EnCana Oil & Gas (USA) Inc	EnCana Corporation (Canada)	Public Service Co Of Colorado/PCA	NU
513	08	069			8	69	CO	LARIMER	ESTES	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
518	08	069			8	69	CO	LARIMER	FLATIRON	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
10070	08	035			8	35	CO	DOUGLAS	FOOTHILLS HYDRO PLANT	Denver City & County of		WAPA - Rocky Mountains/PCA	NU
8067	08	001			8	1	CO	ADAMS	FORT LUPTON	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
6112	08	123	6112	0023	8	123	CO	WELD	FORT ST VRAIN	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
471	08	077			8	77	CO	MESA	FRUITA	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
493	08	041	493	0003	8	41	CO	EL PASO	GEORGE BIRDSALL	Colorado Springs City of		WAPA - Rocky Mountains/PCA	UT
472	08	019			8	19	CO	CLEAR CREEK	GEORGETOWN	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
516	08	117			8	117	CO	SUMMIT	GREEN MOUNTAIN	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
525	08	107	525	0001	8	107	CO	ROUTT	HAYDEN	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
54142	08	031			8	31	CO	DENVER	HILLCREST POWERPLANT	Denver City & County of		Public Service Co Of Colorado/PCA	NU
50205	08	067			8	67	CO	LA PLATA	IGNACIO GASOLINE PLANT	Ida West Operating Services		WAPA - Rocky Mountains/PCA	NU
54596	08	123			8	123	CO	WELD	JOHNSTOWN COGENERATION	Colorado Interstate Gas Co		Public Service Co Of Colorado/PCA	NU
508	08	099	508	0006	8	99	CO	PROWERS	LAMAR PLT	Lamar City of		Public Service Co Of Colorado/PCA	UT
509	08	013			8	13	CO	BOULDER	LONGMONT	Longmont City of		Public Service Co Of Colorado/PCA	UT
520	08	077			8	77	CO	MESA	LOWER MOLINA	USBR-Upper Colorado Region	US Bureau Of Reclamation	WAPA - Rocky Mountains/PCA	UT
494	08	041			8	41	CO	EL PASO	MANITOU	Colorado Springs City of		WAPA - Rocky Mountains/PCA	UT
492	08	041	492	0004	8	41	CO	EL PASO	MARTIN DRAKE	Colorado Springs City of		WAPA - Rocky Mountains/PCA	UT
517	08	069			8	69	CO	LARIMER	MARYS LAKE	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
7372	08	083			8	83	CO	MONTEZUMA	MCPHEE	USBR-Upper Colorado Region	US Bureau Of Reclamation	WAPA - Rocky Mountains/PCA	UT
10180	08	001			8	1	CO	ADAMS	METRO WASTEWATER RECLAMATION DISTRICT	Trigen		Public Service Co Of Colorado/PCA	NU
514	08	085			8	85	CO	MONTROSE	MORROW POINT	USBR-Upper Colorado Region	US Bureau Of Reclamation	WAPA - Rocky Mountains/PCA	UT

ORISPL	FIPST	FIPSCNY	ORISPL_ In_NEI_V300_ Draft	SiteID_ In_NEI_ V300_ Draft	FIPST_ NUM	FIPSCNY_ NUM	PSTAT ABB	CNTYNAME	PNAME	OPRNAME	OPPRNAME	PCANAME	PL TYPE
6208	08	065			8	65	CO	LAKE	MOUNT ELBERT	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
10423	08	093			8	93	CO	PARK	NORTH FORK HYDRO PLANT	David A Carpenter		WAPA - Rocky Mountains/PCA	NU
527	08	085	527	0001	8	85	CO	MONTROSE	NUCLA	Tri-State G & T Assn Inc		WAPA - Rocky Mountains/PCA	UT
473	08	077			8	77	CO	MESA	PALISADE	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
6248	08	087	6248	0011	8	87	CO	MORGAN	PAWNEE	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
519	08	069			8	69	CO	LARIMER	POLE HILL	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
460	08	101	460	0008	8	101	CO	PUEBLO	PUEBLO	Aquila Networks-Colorado	Aquila Inc	Public Service Co Of Colorado/PCA	UT
6761	08	069	6761	0053	8	69	CO	LARIMER	RAWHIDE	Platte River Power Authority		Public Service Co Of Colorado/PCA	UT
8219	08	041	8219	0030	8	41	CO	EL PASO	RAY D NIXON	Colorado Springs City of		WAPA - Rocky Mountains/PCA	UT
50267	08	077			8	77	CO	MESA	REDLANDS WATER & POWER CO	Redlands Water & Power Co NUGs	Redlands Water & Power Co	Public Service Co Of Colorado/PCA	NU
6516	08	089			8	89	CO	OTERO	ROCKY FORD	Aquila Networks-Colorado	Aquila Inc	Public Service Co Of Colorado/PCA	UT
495	08	041			8	41	CO	EL PASO	RUXTON	Colorado Springs City of		WAPA - Rocky Mountains/PCA	UT
474	08	015			8	15	CO	CHAFFEE	SALIDA 1	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
475	08	015			8	15	CO	CHAFFEE	SALIDA 2	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
476	08	045			8	45	CO	GARFIELD	SHOSHONE	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
10081	08	035			8	35	CO	DOUGLAS	STRONTIA SPRINGS HYDRO PLANT	Mark T Kirk		Public Service Co Of Colorado/PCA	NU
50435	08	065			8	65	CO	LAKE	SUGARLOAF HYDRO PLANT	STS Hydropower Ltd		Public Service Co Of Colorado/PCA	NU
6206	08	067			8	67	CO	LA PLATA	TACOMA	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
54729	08	103			8	103	CO	RIO BLANCO	TAYLOR DRAW HYDROELECTRIC FACILITY	Rio Blanco Water Conserv Dist		WAPA - Rocky Mountains/PCA	NU
50707	08	123			8	123	CO	WELD	TCP 122	Thermo Cogeneration Partner LP		Public Service Co Of Colorado/PCA	NU
50708	08	123			8	123	CO	WELD	TCP 150	Thermo Cogeneration Partner LP		Public Service Co Of Colorado/PCA	NU
7233	08	041			8	41	CO	EL PASO	TESLA	Colorado Springs City of		WAPA - Rocky Mountains/PCA	UT
50709	08	123			8	123	CO	WELD	THERMO GREELEY INC	Thermo Cogeneration Partner LP		Public Service Co Of Colorado/PCA	NU
50676	08	123			8	123	CO	WELD	THERMO POWER ELECTRIC INC	Thermo Power & Electric Inc		Public Service Co Of Colorado/PCA	NU
7373	08	083			8	83	CO	MONTEZUMA	TOWAOC	USBR-Upper Colorado Region	US Bureau Of Reclamation	WAPA - Rocky Mountains/PCA	UT
10003	08	059			8	59	CO	JEFFERSON	TRIGEN COLORADO ENERGY CORP	Trigen		Public Service Co Of Colorado/PCA	NU
54372	08	013			8	13	CO	BOULDER	UNIVERSITY OF COLORADO	University of Colorado		Public Service Co Of Colorado/PCA	NU
521	08	077			8	77	CO	MESA	UPPER MOLINA	USBR-Upper Colorado Region	US Bureau Of Reclamation	WAPA - Rocky Mountains/PCA	UT
50206	08	067			8	67	CO	LA PLATA	VALLECITO HYDROELECTRIC	Ptarmigan Res & Engy Inc		WAPA - Rocky Mountains/PCA	NU
477	08	013	477	0001	8	13	CO	BOULDER	VALMONT	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
462	08	043	462	0003	8	43	CO	FREMONT	W N CLARK	Aquila Networks-Colorado	Aquila Inc	Public Service Co Of Colorado/PCA	UT
10422	08	049			8	49	CO	GRAND	WILLIAMS FORK HYDRO PLANT	Paul D Penny		WAPA - Rocky Mountains/PCA	NU
478	08	031	478	0007	8	31	CO	DENVER	ZUNI	Public Service Co of Colorado	Xcel Energy Inc	Public Service Co Of Colorado/PCA	UT
1251	20	041			20	41	KS	DICKINSON	ABILENE CT	Westar Energy		Westar Energy/PCA	UT
1258	20	077			20	77	KS	HARPER	ANTHONY	Anthony City of		Aquila Networks - WPK/PCA	UT
1235	20	009	1235	00002	20	9	KS	BARTON	ARTHUR MULLERGREN	Aquila Networks-Kansas	Aquila Inc	Aquila Networks - WPK/PCA	UT
1259	20	025			20	25	KS	CLARK	ASHLAND	Ashland City of		Aquila Networks - WPK/PCA	UT
1262	20	045			20	45	KS	DOUGLAS	BALDWIN	Baldwin City City of		Kansas City Power & Light Co/PCA	UT
1263	20	157			20	157	KS	REPUBLIC	BELLEVILLE	Belleville City of		Aquila Networks - WPK/PCA	UT
1264	20	123			20	123	KS	MITCHELL	BELOIT	Beloit City of		Aquila Networks - WPK/PCA	UT
1224	20	023			20	23	KS	CHEYENNE	BIRD CITY	Midwest Energy Inc		Westar Energy/PCA	UT
1265	20	139			20	139	KS	OSAGE	BURLINGAME	Burlingame City of		Westar Energy/PCA	UT
1266	20	031			20	31	KS	COFFEY	BURLINGTON	Burlington City of		Westar Energy/PCA	UT
1268	20	133					KS	NEOSHO	CHANUTE 2				UT
7018	20	133			20	133	KS	NEOSHO	CHANUTE 3	Chanute City of		Westar Energy/PCA	UT
1230	20	175	1230	00001	20	175	KS	SEWARD	CIMARRON RIVER	Aquila Networks-Kansas	Aquila Inc	Aquila Networks - WPK/PCA	UT
1270	20	027			20	27	KS	CLAY	CLAY CENTER	Clay Center City of		Westar Energy/PCA	UT
8037	20	201			20	201	KS	WASHINGTON	CLIFTON	Aquila Networks-Kansas	Aquila Inc	Aquila Networks - WPK/PCA	UT
1271	20	125	1271	00002	20	125	KS	MONTGOMERY	COFFEYVILLE	Coffeyville City of		Westar Energy/PCA	UT
1225	20	193			20	193	KS	THOMAS	COLBY	Midwest Energy Inc		Westar Energy/PCA	UT
1272	20	193			20	193	KS	THOMAS	COLBY	Colby City of		Sunflower Electric Power Corp/PCA	UT
7013	20	035	7013	00012	20	35	KS	COWLEY	EAST 12TH STREET	Winfield City of		Westar Energy/PCA	UT
1274	20	009			20	9	KS	BARTON	ELLINWOOD	Ellinwood City of		Westar Energy/PCA	UT
1275	20	051					KS	ELLIS	ELLIS				UT
10857	20	205			20	205	KS	WILSON	FREDONIA	Archer Daniels Midland Co		Westar Energy/PCA	NU
1336	20	055	1336	00026	20	55	KS	FINNEY	GARDEN CITY	Sunflower Electric Power Corp		Sunflower Electric Power Corp/PCA	UT
7281	20	091			20	91	KS	JOHNSON	GARDNER	Gardner City of		Kansas City Power & Light Co/PCA	UT
1278	20	003			20	3	KS	ANDERSON	GARNETT MUNICIPAL	Garnett City of		Kansas City Power & Light Co/PCA	UT
1240	20	173	1240	00012	20	173	KS	SEDGWICK	GORDON EVANS EC	Westar Energy		Westar Energy/PCA	UT
1334	20	009			20	9	KS	BARTON	GREAT BEND	Midwest Energy Inc		Westar Energy/PCA	UT
1281	20	097			20	97	KS	KIOWA	GREENSBURG	Greensburg City of		Aquila Networks - WPK/PCA	UT
1283	20	041			20	41	KS	DICKINSON	HERINGTON	Herington City of		Westar Energy/PCA	UT
1285	20	065			20	65	KS	GRAHAM	HILL CITY	Hill City City of		Sunflower Electric Power Corp/PCA	UT
1286	20	009			20	9	KS	BARTON	HOISINGTON	Hoisington City of		Aquila Networks - WPK/PCA	UT
108	20	055	108	00023	20	55	KS	FINNEY	HOLCOMB	Sunflower Electric Power Corp		Sunflower Electric Power Corp/PCA	UT
1287	20	085			20	85	KS	JACKSON	HOLTON	Holton City of		Westar Energy/PCA	UT
1289	20	189			20	189	KS	STEVENS	HUGOTON 1	Hugoton City of		Sunflower Electric Power Corp/PCA	UT
7011	20	189			20	189	KS	STEVENS	HUGOTON 2	Hugoton City of		Sunflower Electric Power Corp/PCA	UT
1248	20	155	1248	00033	20	155	KS	RENO	HUTCHINSON EC	Westar Energy		Westar Energy/PCA	UT
1291	20	001	1291	00011	20	1	KS	ALLEN	IOLA	Iola City of		Westar Energy/PCA	UT
6068	20	149	6068	00001	20	149	KS	POTTAWATOMIE	JEFFREY EC	Westar Energy		Westar Energy/PCA	UT
6579	20	187			20	187	KS	STANTON	JOHNSON	Johnson City of		Sunflower Electric Power Corp/PCA	UT
1233	20	057	1233	00001	20	57	KS	FORD	JUDSON LARGE	Aquila Networks-Kansas	Aquila Inc	Aquila Networks - WPK/PCA	UT
50453	20	209			20	209	KS	WYANDOTTE	KANSAS CITY	Joe Schriner		Kansas City City Of/PCA	NU
10279	20	045			20	45	KS	DOUGLAS	KANSAS RIVER PROJECT	Bowersock Mills Power Co, The		Westar Energy/PCA	NU
54811	20	161			20	161	KS	RILEY	KANSAS STATE UNIVERSITY UTILITIES POWER PLANT	Kansas State University		Westar Energy/PCA	NU
1294	20	209	1294	00049	20	209	KS	WYANDOTTE	KAW	Kansas City City of		Kansas City City Of/PCA	UT
1296	20	095			20	95	KS	KINGMAN	KINGMAN	Kingman City of		Aquila Networks - WPK/PCA	UT

ORISPL	FIPST	FIPSCNY	ORISPL_ In_NEI_V300_ Draft	SiteID_ In_NEI_ V300_ Draft	FIPST_ NUM	FIPSCNY_ NUM	PSTAT ABB	CNTYNAME	PNAME	OPRNAME	OPPRNAME	PCANAME	PL TYPE
1241	20	107	1241	00005	20	107	KS	LINN	LACYGNE	Kansas City Power & Light Co	Great Plains Energy Inc	Kansas City Power & Light Co/PCA	UT
1299	20	145	1299	00010	20	145	KS	PAWNEE	LARNED	Larned City of		Westar Energy/PCA	UT
1250	20	045	1250	00014	20	45	KS	DOUGLAS	LAWRENCE EC	Westar Energy		Westar Energy/PCA	UT
1300	20	105			20	105	KS	LINCOLN	LINCOLN	Lincoln Center City of		Aquila Networks - WPK/PCA	UT
50317	20	173			20	173	KS	SEDGWICK	LOVE BOX CO	Love Box Co Inc		Westar Energy/PCA	NU
1305	20	113	1305	00014	20	113	KS	MCPHERSON	MCPHERSON 2	McPherson City of		Westar Energy/PCA	UT
7515	20	113			20	113	KS	MCPHERSON	MCPHERSON 3	McPherson City of		Westar Energy/PCA	UT
1306	20	119			20	119	KS	MEADE	MEADE	Meade City of		Aquila Networks - WPK/PCA	UT
1307	20	143			20	143	KS	OTTAWA	MINNEAPOLIS	Minneapolis City of		Westar Energy/PCA	UT
1308	20	173			20	173	KS	SEDGWICK	MULVANE	Mulvane City of		Westar Energy/PCA	UT
1242	20	173	1242	00014	20	173	KS	SEDGWICK	MURRAY GILL EC	Westar Energy		Westar Energy/PCA	UT
6064	20	209	6064	00008	20	209	KS	WYANDOTTE	NEARMAN CREEK	Kansas City City of		Kansas City City Of/PCA	UT
1309	20	205			20	205	KS	WILSON	NEODESHA	Neodesha City of		Westar Energy/PCA	UT
1243	20	099	1243	00001	20	99	KS	LABETTE	NEOSHO	Westar Energy		Westar Energy/PCA	UT
1310	20	137			20	137	KS	NORTON	NORTON	Norton City of		Aquila Networks - WPK/PCA	UT
1313	20	139			20	139	KS	OSAGE	OSAGE CITY	Osage City City of		Westar Energy/PCA	UT
1314	20	121			20	121	KS	MIAMI	OSAWATOMIE	Osawatomie City of		Kansas City Power & Light Co/PCA	UT
1315	20	141			20	141	KS	OSBORNE	OSBORNE	Osborne City of		Aquila Networks - WPK/PCA	UT
1261	20	015			20	15	KS	BUTLER	PLANT NO 1	Augusta City of		Westar Energy/PCA	UT
6791	20	015			20	15	KS	BUTLER	PLANT NO 2	Augusta City of		Westar Energy/PCA	UT
1317	20	151	1317	00005	20	151	KS	PRATT	PRATT	Pratt City of		Aquila Networks - WPK/PCA	UT
7447	20	151			20	151	KS	PRATT	PRATT 2	Pratt City of		Aquila Networks - WPK/PCA	UT
1295	20	209	1295	00048	20	209	KS	WYANDOTTE	QUINDARO	Kansas City City of		Kansas City City Of/PCA	UT
50053	20	155					KS	RENO	REPUBLIC PAPERBOARD CO INC				NU
1239	20	021	1239	00002	20	21	KS	CHEROKEE	RIVERTON	Empire District Electric Co		Empire District Electric Co/PCA	UT
1319	20	167			20	167	KS	RUSSELL	RUSSELL	Russell City of		Aquila Networks - WPK/PCA	UT
1320	20	131			20	131	KS	NEMAHA	SABETHA	Sabetha City of		Westar Energy/PCA	UT
1324	20	199			20	199	KS	WALLACE	SHARON SPRING	Sharon Springs City of		Sunflower Electric Power Corp/PCA	UT
1321	20	023			20	23	KS	CHEYENNE	ST FRANCIS	St Francis City of		Sunflower Electric Power Corp/PCA	UT
1322	20	185			20	185	KS	STAFFORD	ST JOHN	St John City of		Westar Energy/PCA	UT
1325	20	185			20	185	KS	STAFFORD	STAFFORD	Stafford City of		Westar Energy/PCA	UT
1326	20	159			20	159	KS	RICE	STERLING	Sterling City of		Westar Energy/PCA	UT
1327	20	163			20	163	KS	ROOKS	STOCKTON	Stockton City of		Aquila Networks - WPK/PCA	UT
1252	20	177	1252	00030	20	177	KS	SHAWNEE	TECUMSEH EC	Westar Energy		Westar Energy/PCA	UT
1328	20	149			20	149	KS	POTTAWATOMIE	WAMEGO	Wamego City of		Westar Energy/PCA	UT
1329	20	201			20	201	KS	WASHINGTON	WASHINGTON	Washington City of		Westar Energy/PCA	UT
7339	20	191			20	191	KS	SUMNER	WELLINGTON CITY	Wellington City of		Westar Energy/PCA	UT
1330	20	191	1330	00019	20	191	KS	SUMNER	WELLINGTON MUNICIPAL	Wellington City of		Westar Energy/PCA	UT
1332	20	035			20	35	KS	COWLEY	WEST 14TH STREET	Winfield City of		Westar Energy/PCA	UT
50169	20	173			20	173	KS	SEDGWICK	WICHITA PLANT	Vulcan Materials Co		Westar Energy/PCA	NU
210	20	031			20	31	KS	COFFEY	WOLF CREEK	Wolf Creek Nuclear Oper Corp		Kansas City Power & Light Co/PCA	UT
2465	35	045	2465	0029	35	45	NM	SAN JUAN	ANIMAS	Farmington City of		WAPA - Rocky Mountains/PCA	UT
54221	35	045			35	45	NM	SAN JUAN	BLANCO COMPRESSOR STATION	El Paso Corporation	El Paso Energy	WAPA - Rocky Mountains/PCA	NU
2453	35	015			35	15	NM	EDDY	CARLSBAD	Southwestern Public Service Co	Xcel Energy Inc	Southwestern Public Service Co/PCA	UT
54667	35	017			35	17	NM	GRANT	CHINO MINES CO	Phelps Dodge Corp		Public Service Co Of NM/PCA	NU
50997	35	031			35	31	NM	MCKINLEY	CINIZA REFINERY	Giant Industries Arizona Inc		Public Service Co Of NM/PCA	NU
50905	35	001			35	1	NM	BERNALILLO	COGENERATION PLANT	University of New Mexico		Public Service Co Of NM/PCA	NU
2454	35	025	2454	0054	35	25	NM	LEA	CUNNINGHAM	Southwestern Public Service Co	Xcel Energy Inc	Southwestern Public Service Co/PCA	UT
6402	35	051			35	51	NM	SIERRA	ELEPHANT BUTTE	USBR-Upper Colorado Region	US Bureau Of Reclamation	WAPA - Rocky Mountains/PCA	UT
87	35	031	87	0032	35	31	NM	MCKINLEY	ESCALANTE	Tri-State G & T Assn Inc		WAPA - Rocky Mountains/PCA	UT
50906	35	001			35	1	NM	BERNALILLO	FORD UTILITIES CENTER	University of New Mexico		Public Service Co Of NM/PCA	NU
2442	35	045	2442	0002	35	45	NM	SAN JUAN	FOUR CORNERS	Arizona Public Service Co	Pinnacle West Capital Corporation	Arizona Public Service Co/PCA	UT
54208	35	023			35	23	NM	HIDALGO	HIDALGO SMELTER	Phelps Dodge Corp		Public Service Co Of NM/PCA	NU
2447	35	047			35	47	NM	SAN MIGUEL	LAS VEGAS	Public Service Co of NM	PNM Resources Inc	Public Service Co Of NM/PCA	UT
2446	35	025	2446	0034	35	25	NM	LEA	MADDOX	Southwestern Public Service Co	Xcel Energy Inc	Southwestern Public Service Co/PCA	UT
54814	35	045			35	45	NM	SAN JUAN	MILAGRO COGENERATION PLANT	Williams Energy		WAPA - Rocky Mountains/PCA	NU
584	35	045			35	45	NM	SAN JUAN	NAVAJO DAM	Farmington City of		WAPA - Rocky Mountains/PCA	UT
54975	35	013			35	13	NM	DONA ANA	NEW MEXICO STATE UNIVERSITY	New Mexico State University		ERCOT ISO/PCA	NU
55312	35	017					NM	GRANT	PHELPS DODGE COBRE MINING CO				NU
54734	35	017			35	17	NM	GRANT	PHELPS DODGE TYRONE INC	Phelps Dodge Corp		Public Service Co Of NM/PCA	NU
2468	35	007	2468	0001	35	7	NM	COLFAX	RATON	Raton Public Service Co		Public Service Co Of Colorado/PCA	UT
2450	35	001	2450	3500100011	35	1	NM	BERNALILLO	REEVES	Public Service Co of NM	PNM Resources Inc	Public Service Co Of NM/PCA	UT
2444	35	013	2444	0002	35	13	NM	DONA ANA	RIO GRANDE	El Paso Electric Co	El Paso Energy	ERCOT ISO/PCA	UT
2451	35	045	2451	0902	35	45	NM	SAN JUAN	SAN JUAN	Public Service Co of NM	PNM Resources Inc	Public Service Co Of NM/PCA	UT
54669	35	045			35	45	NM	SAN JUAN	SAN JUAN BASIN GAS PLANT	Conoco		Public Service Co Of NM/PCA	NU
10339	35	001			35	1	NM	BERNALILLO	SOUTHSIDE WATER RECLAMATION PLANT	Albuquerque City of		Public Service Co Of NM/PCA	NU
2469	35	037			35	37	NM	QUAY	TUCUMCARI	Southwestern Public Service Co	Xcel Energy Inc	Southwestern Public Service Co/PCA	UT
54205	35	045			35	45	NM	SAN JUAN	WILLIAMS FIELD SERVICES KUTZ PLANT	Williams Energy		WAPA - Rocky Mountains/PCA	NU
10671	40	079			40	79	OK	LE FLORE	AES SHADY POINT INC	AES NUGs	AES Corp	Oklahoma Gas & Electric Co/PCA	NU
3006	40	015	3006	2699	40	15	OK	CADDO	ANADARKO	Western Farmers Elec Coop Inc		Western Farmers Elec Coop Inc/PCA	UT
3000	40	119	3000	1247	40	119	OK	PAYNE	BOOMER LAKE STATION	Stillwater Utilities Authority		Grand River Dam Authority/PCA	UT
6415	40	089			40	89	OK	MCCURTAIN	BROKEN BOW	USCE-Tulsa District	US Army Corp Of Engineers	Southwestern Power Admin/PCA	UT
50991	40	097			40	97	OK	MAYES	CALPINE PRYOR INC	Calpine		American Electric Power - West (SPP)/PCA	NU
54702	40	093			40	93	OK	MAJOR	CHANEY DELL PLANT	Western Gas Resources		Western Farmers Elec Coop Inc/PCA	NU
8059	40	031	8059	1211	40	31	OK	COMANCHE	COMANCHE	Public Service Co of Oklahoma	American Electric Power Co Inc	American Electric Power - West (SPP)/PCA	UT
7185	40	071	7185	2929	40	71	OK	KAY	CONOCO	Oklahoma Gas & Electric Co	OGE Energy Corporation	Oklahoma Gas & Electric Co/PCA	UT
2975	40	119			40	119	OK	PAYNE	CUSHING	Cushing City of		Grand River Dam Authority/PCA	UT
2950	40	047			40	47	OK	GARFIELD	ENID	Oklahoma Gas & Electric Co	OGE Energy Corporation	Oklahoma Gas & Electric Co/PCA	UT

ORISPL	FIPST	FIPSCNY	ORISPL_ In_NEI_ V300_ Draft	SiteID_ In_NEI_ V300_ Draft	FIPST_ NUM	FIPSCNY_ NUM	PSTAT ABB	CNTYNAME	PNAME	OPRNAME	OPPRNAME	PCANAME	PL TYPE
6419	40	061			40	61	OK	HASKELL	EUFAULA	USCE-Tulsa District	US Army Corp Of Engineers	Southwestern Power Admin/PCA	UT
3003	40	021			40	21	OK	CHEROKEE	FORT GIBSON	USCE-Tulsa District	US Army Corp Of Engineers	Southwestern Power Admin/PCA	UT
165	40	097	165	1799	40	97	OK	MAYES	GRDA	Grand River Dam Authority		Grand River Dam Authority/PCA	UT
2951	40	109	2951	2208	40	109	OK	OKLAHOMA	HORSESHOE LAKE	Oklahoma Gas & Electric Co	OGE Energy Corporation	Oklahoma Gas & Electric Co/PCA	UT
6772	40	023	6772	2700	40	23	OK	CHOCTAW	HUGO	Western Farmers Elec Coop Inc		Western Farmers Elec Coop Inc/PCA	UT
7545	40	071			40	71	OK	KAY	KAW HYDRO	Oklahoma Municipal Power Auth		American Electric Power - West (SPP)/PCA	UT
2984	40	143			40	143	OK	TULSA	KEYSTONE	USCE-Tulsa District	US Army Corp Of Engineers	Southwestern Power Admin/PCA	UT
2986	40	073			40	73	OK	KINGFISHER	KINGFISHER	Kingfisher City of		Western Farmers Elec Coop Inc/PCA	UT
2991	40	055			40	55	OK	GREER	MANGUM	Mangum City of		Western Farmers Elec Coop Inc/PCA	UT
2980	40	097			40	97	OK	MAYES	MARKHAM	Grand River Dam Authority		Grand River Dam Authority/PCA	UT
3008	40	153	3008	2701	40	153	OK	WOODWARD	MOORELAND	Western Farmers Elec Coop Inc		Western Farmers Elec Coop Inc/PCA	UT
2952	40	101	2952	2209	40	101	OK	MUSKOGEE	MUSKOGEE	Oklahoma Gas & Electric Co	OGE Energy Corporation	Oklahoma Gas & Electric Co/PCA	UT
10362	40	101			40	101	OK	MUSKOGEE	MUSKOGEE MILL	Fort James Operating Co		Oklahoma Gas & Electric Co/PCA	NU
2953	40	017	2953	2205	40	17	OK	CANADIAN	MUSTANG	Oklahoma Gas & Electric Co	OGE Energy Corporation	Oklahoma Gas & Electric Co/PCA	UT
2963	40	131	2963	1212	40	131	OK	ROGERS	NORTHEASTERN	Public Service Co of Oklahoma	American Electric Power Co Inc	American Electric Power - West (SPP)/PCA	UT
54779	40	119			40	119	OK	PAYNE	OKLAHOMA STATE UNIVERSITY	Oklahoma State University		Oklahoma Gas & Electric Co/PCA	NU
2981	40	097			40	97	OK	MAYES	PENSACOLA	Grand River Dam Authority		Grand River Dam Authority/PCA	UT
762	40	071	762	1314	40	71	OK	KAY	PONCA	Ponca City City of		Oklahoma Gas & Electric Co/PCA	UT
52188	40	071			40	71	OK	KAY	PONCA CITY REFINERY	Conoco		Oklahoma Gas & Electric Co/PCA	NU
2997	40	071			40	71	OK	KAY	PONCA DIESEL	Ponca City City of		Oklahoma Gas & Electric Co/PCA	UT
50558	40	109			40	109	OK	OKLAHOMA	POWERSMITH COGEN PROJECT	General Electric Co	General Electric Company	Oklahoma Gas & Electric Co/PCA	NU
4940	40	143	4940	1215	40	143	OK	TULSA	RIVERSIDE	Public Service Co of Oklahoma	American Electric Power Co Inc	American Electric Power - West (SPP)/PCA	UT
2985	40	135			40	135	OK	SEQUOYAH	ROBERT S KERR	USCE-Tulsa District	US Army Corp Of Engineers	Southwestern Power Admin/PCA	UT
2982	40	097			40	97	OK	MAYES	SALINA	Grand River Dam Authority		Grand River Dam Authority/PCA	UT
2956	40	133	2956	2210	40	133	OK	SEMINOLE	SEMINOLE	Oklahoma Gas & Electric Co	OGE Energy Corporation	Oklahoma Gas & Electric Co/PCA	UT
6095	40	103	6095	2211	40	103	OK	NOBLE	SOONER	Oklahoma Gas & Electric Co	OGE Energy Corporation	Oklahoma Gas & Electric Co/PCA	UT
2964	40	015	2964	1214	40	15	OK	CADDO	SOUTHWESTERN	Public Service Co of Oklahoma	American Electric Power Co Inc	American Electric Power - West (SPP)/PCA	UT
3004	40	135			40	135	OK	SEQUOYAH	TENKILLER FERRY	USCE-Tulsa District	US Army Corp Of Engineers	Southwestern Power Admin/PCA	UT
2965	40	143	2965	1213	40	143	OK	TULSA	TULSA	Public Service Co of Oklahoma	American Electric Power Co Inc	American Electric Power - West (SPP)/PCA	UT
50307	40	027			40	27	OK	CLEVELAND	UNIVERSITY OF OKLAHOMA	University of Oklahoma		Oklahoma Gas & Electric Co/PCA	NU
50192	40	089			40	89	OK	MCCURTAIN	VALLIANT OK	Weyerhaeuser Co		American Electric Power - West (SPP)/PCA	NU
50660	40	143			40	143	OK	TULSA	WALTER B HALL RESOURCE RECOVERY FACILITY	Ogden Energy		American Electric Power - West (SPP)/PCA	NU
2987	40	101			40	101	OK	MUSKOGEE	WEBBERS FALLS	USCE-Tulsa District	US Army Corp Of Engineers	Southwestern Power Admin/PCA	UT
2966	40	107			40	107	OK	OKFUSKEE	WELEETKA	Public Service Co of Oklahoma	American Electric Power Co Inc	American Electric Power - West (SPP)/PCA	UT
2958	40	153			40	153	OK	WOODWARD	WOODWARD	Oklahoma Gas & Electric Co	OGE Energy Corporation	Oklahoma Gas & Electric Co/PCA	UT
50198	40	089			40	89	OK	MCCURTAIN	WRIGHT CITY OK	Weyerhaeuser Co		American Electric Power - West (SPP)/PCA	NU
3581	48	187			48	187	TX	GUADALUPE	ABBOTT TP 3	Guadalupe Blanco River Auth		ERCOT ISO/PCA	UT
3517	48	441	3517	TB0056E	48	441	TX	TAYLOR	ABILENE	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
10670	48	201			48	201	TX	HARRIS	AES DEEPWATER INC	AES NUGs	AES Corp	ERCOT ISO/PCA	NU
6128	48	465			48	465	TX	VAL VERDE	AMISTAD DAM & POWER	International Bound & Wtr Comm		ERCOT ISO/PCA	UT
3594	48	453			48	453	TX	TRAVIS	AUSTIN	Lower Colorado River Authority		ERCOT ISO/PCA	UT
54940	48	453			48	453	TX	TRAVIS	AUSTIN STATE HOSPITAL	Austin State Hospital		ERCOT ISO/PCA	NU
4939	48	355	4939	NE0024E	48	355	TX	NUECES	BARNEY M DAVIS	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
10317	48	309			48	309	TX	MCLENNAN	BAYLOR UNIVERSITY COGENERATION	Aramark Corp		ERCOT ISO/PCA	NU
10298	48	201			48	201	TX	HARRIS	BAYOU COGENERATION PLANT	Air Liquide America Corp		ERCOT ISO/PCA	NU
10692	48	201			48	201	TX	HARRIS	BAYTOWN TURBINE GENERATOR PROJECT	Exxon Mobil		ERCOT ISO/PCA	NU
50625	48	245			48	245	TX	JEFFERSON	BEAUMONT REFINERY	Exxon Mobil		Entergy Electric System/PCA	NU
54458	48	461			48	461	TX	UPTON	BENEDUM PLANT	Western Gas Resources		ERCOT ISO/PCA	NU
3497	48	161	3497	FI0020W	48	161	TX	FREESTONE	BIG BROWN	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
10569	48	227			48	227	TX	HOWARD	BIG SPRING TEXAS REFINERY	Fina Oil Chemical Co		ERCOT ISO/PCA	NU
54979	48	227			48	227	TX	HOWARD	BIG SPRING WIND POWER FACILITY	New World Power TX Ren Elec LP		ERCOT ISO/PCA	NU
55064	48	233	55064	HW0081I	48	233	TX	HUTCHINSON	BLACK HAWK STATION	Quixx Power Services		Southwestern Public Service Co/PCA	NU
50067	48	233			48	233	TX	HUTCHINSON	BORGER PLANT	Sid Richardson Carbon Ltd		Southwestern Public Service Co/PCA	NU
50404	48	057			48	57	TX	CALHOUN	BP CHEMICALS GREEN LAKE PLANT	BP Amoco		ERCOT ISO/PCA	NU
7131	48	303			48	303	TX	LUBBOCK	BRANDON STATION	Lubbock City of		Southwestern Public Service Co/PCA	UT
55053	48	497			48	497	TX	WISE	BRIDGEPORT GAS PROCESSING PLANT	Mitchell Gas Services LP		ERCOT ISO/PCA	NU
3558	48	445			48	445	TX	TERRY	BROWNFIELD	Brownfield City of		Southwestern Public Service Co/PCA	UT
3561	48	041	3561	BM0010I	48	41	TX	BRAZOS	BRYAN	Bryan City of		ERCOT ISO/PCA	UT
3595	48	053			48	53	TX	BURNET	BUCHANAN	Lower Colorado River Authority		ERCOT ISO/PCA	UT
3574	48	113	3574	DB0384A	48	113	TX	DALLAS	C E NEWMAN	Garland City of		ERCOT ISO/PCA	UT
52176	48	227			48	227	TX	HOWARD	C R WING COGENERATION PLANT	Power Resources Ltd		ERCOT ISO/PCA	NU
791	48	091			48	91	TX	COMAL	CANYON	Guadalupe Blanco River Auth		ERCOT ISO/PCA	UT
3460	48	071	3460	CI0012D	48	71	TX	CHAMBERS	CEDAR BAYOU	Texas Genco	CenterPoint Energy	ERCOT ISO/PCA	NU
10243	48	355			48	355	TX	NUECES	CELANESE ENGINEERING RESIN INC	Celanese Engineering Resin Inc		ERCOT ISO/PCA	NU
10184	48	453			48	453	TX	TRAVIS	CENTRAL UTILITY PLANT	Minnesota Mining & Mfg Co		ERCOT ISO/PCA	NU
10418	48	039			48	39	TX	BRAZORIA	CHOCOLATE BAYOU PLANT	Solutia Inc		ERCOT ISO/PCA	NU
10154	48	039			48	39	TX	BRAZORIA	CHOCOLATE BAYOU WORKS	BP Amoco		ERCOT ISO/PCA	NU
10741	48	201			48	201	TX	HARRIS	CLEAR LAKE COGENERATION LTD	Calpine		ERCOT ISO/PCA	NU
50815	48	201			48	201	TX	HARRIS	COGEN LYONDELL INC	Dynegy Marketing & Trade	Dynegy Inc	ERCOT ISO/PCA	NU
10804	48	245					TX	JEFFERSON	COGEN POWER LP				NU
3566	48	083			48	83	TX	COLEMAN	COLEMAN	Coleman City of		ERCOT ISO/PCA	UT
6178	48	175	6178	GF0002R	48	175	TX	GOLIAD	COLETO CREEK	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
3500	48	085	3500	CP0065C	48	85	TX	COLLIN	COLLIN	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
6145	48	425			48	425	TX	SOMERVELL	COMANCHE PEAK	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
9	48	141			48	141	TX	EL PASO	COPPER	El Paso Electric Co	El Paso Energy	ERCOT ISO/PCA	UT
50475	48	355			48	355	TX	NUECES	CORPUS CHRISTI PLANT	Occidental Chemical Corp		ERCOT ISO/PCA	NU
10203	48	355			48	355	TX	NUECES	CORPUS CHRISTI REFINERY	Coastal Refining&Marketing Inc		ERCOT ISO/PCA	NU
6243	48	041	6243	BM0009Q	48	41	TX	BRAZOS	DANSBY	Bryan City of		ERCOT ISO/PCA	UT

ORISPL	FIPST	FIPSCNY	ORISPL_ In_NEI_V300_ Draft	SiteID_ In_NEI_ V300_ Draft	FIPST_ NUM	FIPSCNY_ NUM	PSTAT ABB	CNTYNAME	PNAME	OPRNAME	OPPRNAME	PCANAME	PL TYPE
3548	48	453	3548	TH0004D	48	453	TX	TRAVIS	DECKER CREEK	Austin City of		ERCOT ISO/PCA	UT
8063	48	221	8063	HQ0012T	48	221	TX	HOOD	DECORDOVA	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
3461	48	201	3461	HG0356U	48	201	TX	HARRIS	DEEPWATER	Texas Genco	CenterPoint Energy	ERCOT ISO/PCA	NU
50471	48	201			48	201	TX	HARRIS	DEER PARK PLANT	Occidental Chemical Corp		ERCOT ISO/PCA	NU
55399	48	201			48	201	TX	HARRIS	DELAWARE MOUNTAIN WINDFARM	General Electric Wind Energy	General Electric Company	ERCOT ISO/PCA	NU
6416	48	181			48	181	TX	GRAYSON	DENISON	USCE-Tulsa District	US Army Corp Of Engineers	Southwestern Power Admin/PCA	UT
50569	48	121			48	121	TX	DENTON	DFW GAS RECOVERY	DFW Gas Recovery		ERCOT ISO/PCA	NU
3582	48	187			48	187	TX	GUADALUPE	DUNLAP TP 1	Guadalupe Blanco River Auth		ERCOT ISO/PCA	UT
3436	48	057	3436	CB0008C	48	57	TX	CALHOUN	E S JOSLIN	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
3489	48	439	3489	TA0352I	48	439	TX	TARRANT	EAGLE MOUNTAIN	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
3437	48	323			48	323	TX	MAVERICK	EAGLE PASS	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
54943	48	365			48	365	TX	PANOLA	EAST TEXAS GAS PLANT	Duke Energy Power Services	Duke Energy Corporation	American Electric Power - West (SPP)/PCA	NU
54332	48	227			48	227	TX	HOWARD	EAST VEALMOOR GAS PLANT	Vealmoor Gas Plant		OFF-G/PCA	NU
54461	48	467					TX	VAN ZANDT	EDGEWOOD GAS PLANT				NU
50615	48	353			48	353	TX	NOLAN	ENCOGEN ONE	EEX Power Systems		ERCOT ISO/PCA	NU
10072	48	233			48	233	TX	HUTCHINSON	ENGINEERED CARBONS BORGER COGENERATION	Engineered Carbons Inc		Southwestern Public Service Co/PCA	NU
10187	48	361			48	361	TX	ORANGE	ENGINEERED CARBONS ECHO COGENERATION	Engineered Carbons Inc		Entergy Electric System/PCA	NU
10261	48	071			48	71	TX	CHAMBERS	ENTERPRISE PRODUCTS OPERATING LP	Enterprise Products Operatg LP		ERCOT ISO/PCA	NU
54962	48	499			48	499	TX	WOOD	EXXON HAWKINS GAS PLANT	Exxon Mobil		American Electric Power - West (SPP)/PCA	NU
10436	48	201			48	201	TX	HARRIS	EXXON MOBIL CO USA BAYTOWN PP3 PP4	Exxon Mobil		ERCOT ISO/PCA	NU
6410	48	427			48	427	TX	STARR	FALCON DAM & POWER	International Bound & Wtr Comm		ERCOT ISO/PCA	UT
6179	48	149	6179	FC0018G	48	149	TX	FAYETTE	FAYETTE POWER PRJ	Lower Colorado River Authority		ERCOT ISO/PCA	UT
10554	48	057			48	57	TX	CALHOUN	FORMOSA UTILITY VENTURE LTD	Formosa Plastics Corp		ERCOT ISO/PCA	NU
10136	48	157			48	157	TX	FORT BEND	FORT BEND UTILITIES CO	Imperial Co		ERCOT ISO/PCA	NU
4938	48	253	4938	JI0030K	48	253	TX	JONES	FORT PHANTOM	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
3520	48	371			48	371	TX	PECOS	FORT STOCKTON	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
55311	48	039			48	39	TX	BRAZORIA	FREEPORT	BASF		ERCOT ISO/PCA	NU
55098	48	215			48	215	TX	HIDALGO	FRONTERA GENERATION FACILITY	CSW Energy Inc		ERCOT ISO/PCA	NU
54948	48	003			48	3	TX	ANDREWS	FULLERTON PLANT	GPM Gas Services Co		ERCOT ISO/PCA	NU
6136	48	185	6136	GK0012K	48	185	TX	GRIMES	GIBBONS CREEK	Texas Municipal Power Agency		ERCOT ISO/PCA	UT
3490	48	503	3490	YB0017V	48	503	TX	YOUNG	GRAHAM	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
3597	48	053			48	53	TX	BURNET	GRANITE SHOALS	Lower Colorado River Authority		ERCOT ISO/PCA	UT
3464	48	201	3464	HG0353D	48	201	TX	HARRIS	GREENS BAYOU	Texas Genco	CenterPoint Energy	ERCOT ISO/PCA	NU
3583	48	177			48	177	TX	GONZALES	H 4	Guadalupe Blanco River Auth		ERCOT ISO/PCA	UT
3584	48	177			48	177	TX	GONZALES	H 5	Guadalupe Blanco River Auth		ERCOT ISO/PCA	UT
3491	48	439	3491	TA0353G	48	439	TX	TARRANT	HANDLEY	Exelon Generation	Exelon Corporation	ERCOT ISO/PCA	NU
6193	48	375	6193	PG0041R	48	375	TX	POTTER	HARRINGTON	Southwestern Public Service Co	Xcel Energy Inc	Southwestern Public Service Co/PCA	UT
3465	48	201			48	201	TX	HARRIS	HIRAM CLARKE	Texas Genco	CenterPoint Energy	ERCOT ISO/PCA	NU
3549	48	453	3549	TH0006W	48	453	TX	TRAVIS	HOLLY STREET	Austin City of		ERCOT ISO/PCA	UT
50043	48	201			48	201	TX	HARRIS	HOUSTON CHEMICAL COMPLEX BATTLEGROUND SITE	Occidental Chemical Corp		ERCOT ISO/PCA	NU
55313	48	409			48	409	TX	SAN PATRICIO	INGLESIDE COGENERATION	Occidental Chemical Corp		ERCOT ISO/PCA	NU
3598	48	053			48	53	TX	BURNET	INKS	Lower Colorado River Authority		ERCOT ISO/PCA	UT
10425	48	361			48	361	TX	ORANGE	INLAND PAPERBOARD AND PACKAGING	Inland Corp		Entergy Electric System/PCA	NU
7097	48	029	7097	BG0057UB	48	29	TX	BEXAR	J K SPRUCE	San Antonio Public Service Bd		ERCOT ISO/PCA	UT
3438	48	215	3438	HN0013E	48	215	TX	HIDALGO	J L BATES	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
3604	48	303	3604	LN3604A	48	303	TX	LUBBOCK	J ROBERT MASSENGALE	Lubbock City of		Southwestern Public Service Co/PCA	UT
6181	48	029	6181	BG0057UA	48	29	TX	BEXAR	J T DEELY	San Antonio Public Service Bd		ERCOT ISO/PCA	UT
55052	48	081			48	81	TX	COKE	JAMESON GAS PROCESSING PLANT	Mitchell Gas Services LP		ERCOT ISO/PCA	NU
54637	48	245			48	245	TX	JEFFERSON	JCO OXIDES OLEFINS PLANT	Huntsman Corp		Entergy Electric System/PCA	NU
3482	48	303	3482	LN0081B	48	303	TX	LUBBOCK	JONES	Southwestern Public Service Co	Xcel Energy Inc	Southwestern Public Service Co/PCA	UT
3476	48	183	3476	GJ0043K	48	183	TX	GREGG	KNOX LEE	Southwestern Electric Power Co	American Electric Power Co Inc	American Electric Power - West (SPP)/PCA	UT
50026	48	355			48	355	TX	NUECES	KOCH PETROLEUM GROUP LP CORPUS REFINERY	Koch		ERCOT ISO/PCA	NU
3442	48	061	3442	CD0013K	48	61	TX	CAMERON	LA PALMA	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
3502	48	309	3502	MB0117A	48	309	TX	MCLENNAN	LAKE CREEK	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
3452	48	113	3452	DB0249H	48	113	TX	DALLAS	LAKE HUBBARD	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
3521	48	197	3521	HE0013G	48	197	TX	HARDEMAN	LAKE PAULINE	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
3439	48	479	3439	WE0005G	48	479	TX	WEBB	LAREDO	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
3609	48	029	3609	BG0059Q	48	29	TX	BEXAR	LEON CREEK	San Antonio Public Service Bd		ERCOT ISO/PCA	UT
3457	48	339	3457	MQ0009F	48	339	TX	MONTGOMERY	LEWIS CREEK	Entergy Gulf States Inc	Entergy Corporation	Entergy Electric System/PCA	UT
794	48	121			48	121	TX	DENTON	LEWISVILLE	Denton City of		ERCOT ISO/PCA	UT
298	48	293	298	LI0027L	48	293	TX	LIMESTONE	LIMESTONE	Texas Genco	CenterPoint Energy	ERCOT ISO/PCA	NU
3440	48	355	3440	NE0025C	48	355	TX	NUECES	LON C HILL	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
3477	48	343	3477	MS0011T	48	343	TX	MORRIS	LONE STAR	Southwestern Electric Power Co	American Electric Power Co Inc	American Electric Power - West (SPP)/PCA	UT
54971	48	343			48	343	TX	MORRIS	LONE STAR STEEL CO	Lone Star Steel Co		American Electric Power - West (SPP)/PCA	NU
50249	48	005			48	5	TX	ANGELINA	LUFKIN TEXAS	Champion International Corp		ERCOT ISO/PCA	NU
3599	48	053			48	53	TX	BURNET	MARBLE FALLS	Lower Colorado River Authority		ERCOT ISO/PCA	UT
3600	48	453			48	453	TX	TRAVIS	MARSHALL FORD	Lower Colorado River Authority		ERCOT ISO/PCA	UT
6146	48	401	6146	RL0020K	48	401	TX	RUSK	MARTIN LAKE	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
54459	48	461			48	461	TX	UPTON	MIDKIFF PLANT	Western Gas Resources		ERCOT ISO/PCA	NU
3610	48	029	3610	BG0188E	48	29	TX	BEXAR	MISSION ROAD	San Antonio Public Service Bd		ERCOT ISO/PCA	UT
6147	48	449	6147	TF0013B	48	449	TX	TITUS	MONTICELLO	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
3483	48	341			48	341	TX	MOORE	MOORE COUNTY	Southwestern Public Service Co	Xcel Energy Inc	Southwestern Public Service Co/PCA	UT
3492	48	335	3492	MO0014L	48	335	TX	MITCHELL	MORGAN CREEK	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
3557	48	363			48	363	TX	PALO PINTO	MORRIS SHEPPARD	Brazos River Authority		ERCOT ISO/PCA	UT
54976	48	467			48	467	TX	VAN ZANDT	MORTON SALT CO GRAND SALINE	Rohm & Haas Co		American Electric Power - West (SPP)/PCA	NU
3453	48	113	3453	DB0252S	48	113	TX	DALLAS	MOUNTAIN CREEK	Exelon Generation	Exelon Corporation	ERCOT ISO/PCA	NU
55065	48	501			48	501	TX	YOAKUM	MUSTANG STATION	North American Energy Services		Southwestern Public Service Co/PCA	NU
50137	48	481	50137	WF0175P	48	481	TX	WHARTON	NEWGULF	CSW Energy Inc		ERCOT ISO/PCA	NU

ORISPL	FIPST	FIPSCNY	ORISPL_ In_NEI_ V300_ Draft	SiteID_ In_NEI_ V300_ Draft	FIPST_ NUM	FIPSCNY_ NUM	PSTAT ABB	CNTYNAME	PNAME	OPRNAME	OPPRNAME	PCANAME	PL TYPE
3456	48	141	3456	EE0029T	48	141	TX	EL PASO	NEWMAN	El Paso Electric Co	El Paso Energy	ERCOT ISO/PCA	UT
3484	48	375	3484	PG0040T	48	375	TX	POTTER	NICHOLS	Southwestern Public Service Co	Xcel Energy Inc	Southwestern Public Service Co/PCA	UT
3585	48	187			48	187	TX	GUADALUPE	NOLTE	Guadalupe Blanco River Auth		ERCOT ISO/PCA	UT
54972	48	203			48	203	TX	HARRISON	NORIT AMERICAS INC MARSHALL PLANT	Norit Americas Inc		American Electric Power - West (SPP)/PCA	NU
3454	48	113	3454	DB0251U	48	113	TX	DALLAS	NORTH LAKE	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
3493	48	439	3493	TA0354E	48	439	TX	TARRANT	NORTH MAIN	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
54443	48	329			48	329	TX	MIDLAND	NORTH RILEY	Union Oil Co of California		Southwestern Public Service Co/PCA	NU
3627	48	367	3627	PC0005T	48	367	TX	PARKER	NORTH TEXAS	Brazos Electric Power Coop Inc		ERCOT ISO/PCA	UT
3441	48	355	3441	NE0026A	48	355	TX	NUECES	NUECES BAY	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
3611	48	029	3611	BG0057U	48	29	TX	BEXAR	O W SOMMERS	San Antonio Public Service Bd		ERCOT ISO/PCA	UT
3523	48	081	3523	CN0005T	48	81	TX	COKE	OAK CREEK	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
127	48	487	127	WI0025C	48	487	TX	WILBARGER	OKLAUNION	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
54676	48	201			48	201	TX	HARRIS	OYSTER CREEK UNIT VIII	Dow Chemical		ERCOT ISO/PCA	NU
3466	48	167	3466	GB0037T	48	167	TX	GALVESTON	P H ROBINSON	Texas Genco	CenterPoint Energy	ERCOT ISO/PCA	NU
3524	48	207	3524	HJ0022B	48	207	TX	HASKELL	PAINT CREEK	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
3455	48	113	3455	DB0253Q	48	113	TX	DALLAS	PARKDALE	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
10638	48	201			48	201	TX	HARRIS	PASADENA	Air Products		ERCOT ISO/PCA	NU
55047	48	201	55047	HG1169O	48	201	TX	HARRIS	PASADENA COGENERATION LP	Calpine		ERCOT ISO/PCA	NU
3630	48	163	3630	FJ0012P	48	163	TX	FRIO	PEARSALL	Medina Electric Coop Inc		ERCOT ISO/PCA	UT
3494	48	475	3494	WC0028Q	48	475	TX	WARD	PERMIAN BASIN	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
54628	48	141			48	141	TX	EL PASO	PHELPS DODGE REFINING CORP	Phelps Dodge Corp		ERCOT ISO/PCA	NU
7902	48	203	7902	HH0037F	48	203	TX	HARRISON	PIRKEY	Southwestern Electric Power Co	American Electric Power Co Inc	American Electric Power - West (SPP)/PCA	UT
3485	48	279	3485	LB0046P	48	279	TX	LAMB	PLANT X	Southwestern Public Service Co	Xcel Energy Inc	Southwestern Public Service Co/PCA	UT
50973	48	245			48	245	TX	JEFFERSON	PORT ARTHUR REFINERY	Motiva Enterprises LLC		Entergy Electric System/PCA	NU
52108	48	245			48	245	TX	JEFFERSON	PORT ARTHUR REFINERY	Clark Refining & Marketing Inc		Entergy Electric System/PCA	NU
10568	48	245			48	245	TX	JEFFERSON	PORT ARTHUR TEXAS REFINERY	ATOFINA Petrolchemicals Inc		Entergy Electric System/PCA	NU
52131	48	167			48	167	TX	GALVESTON	POWER STATION 3	BP Amoco		ERCOT ISO/PCA	NU
52132	48	167			48	167	TX	GALVESTON	POWER STATION 4	BP Amoco		ERCOT ISO/PCA	NU
4195	48	231	4195	HV0023K	48	231	TX	HUNT	POWERLANE PLANT	Greenville Electric Util Sys		ERCOT ISO/PCA	UT
54364	48	485			48	485	TX	WICHITA	PPG INDUSTRIES INC WORKS 4	PPG Industries Inc		ERCOT ISO/PCA	NU
3525	48	377			48	377	TX	PRESIDIO	PRESIDIO	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
50241	48	141			48	141	TX	EL PASO	PROVIDENCE MEMORIAL HOSPITAL	Tenet Hospital Ltd		ERCOT ISO/PCA	NU
52069	48	057			48	57	TX	CALHOUN	PT COMFORT OPERATIONS	Alcoa NUGS	Alcoa, Inc	ERCOT ISO/PCA	NU
54748	48	245			48	245	TX	JEFFERSON	PT NECHES PLANT	Air Liquide America Corp		Entergy Electric System/PCA	NU
3628	48	363	3628	PA0003W	48	363	TX	PALO PINTO	R W MILLER	Brazos Electric Power Coop Inc		ERCOT ISO/PCA	UT
3576	48	085	3576	CP0026M	48	85	TX	COLLIN	RAY OLINGER	Garland City of		ERCOT ISO/PCA	UT
796	48	121			48	121	TX	DENTON	RAY ROBERTS	Denton City of		ERCOT ISO/PCA	UT
54291	48	355			48	355	TX	NUECES	REYNOLDS METALS CO SHERWIN PLANT	Reynolds Metals Co Sherwin Plt		ERCOT ISO/PCA	NU
52065	48	201			48	201	TX	HARRIS	RHODIA INC HOUSTON PLANT	Aventis		ERCOT ISO/PCA	NU
50054	48	201			48	201	TX	HARRIS	RICE UNIVERSITY	William Marsh Rice University		ERCOT ISO/PCA	NU
54338	48	061			48	61	TX	CAMERON	RIO GRANDE VALLEY SUGAR GROWERS INC	Rio Grande Sugar Growers Co		ERCOT ISO/PCA	NU
3526	48	105	3526	CZ0017A	48	105	TX	CROCKETT	RIO PECOS	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
3503	48	387	3503	RE0012M	48	387	TX	RED RIVER	RIVER CREST	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
3487	48	233			48	233	TX	HUTCHINSON	RIVERVIEW	Southwestern Public Service Co	Xcel Energy Inc	Southwestern Public Service Co/PCA	UT
7200	48	241			48	241	TX	JASPER	ROBERT D WILLIS	USCE-Fort Worth District	US Army Corp Of Engineers	ERCOT ISO/PCA	UT
3608	48	355			48	355	TX	NUECES	ROBSTOWN	Robstown City of		ERCOT ISO/PCA	UT
54253	48	167			48	167	TX	GALVESTON	S&L COGENERATION	Praxair Inc		ERCOT ISO/PCA	NU
3459	48	361	3459	OC0013O	48	361	TX	ORANGE	SABINE	Entergy Gulf States Inc	Entergy Corporation	Entergy Electric System/PCA	UT
10789	48	361			48	361	TX	ORANGE	SABINE RIVER WORKS	E I DuPont De Nemours & Co		Entergy Electric System/PCA	NU
3468	48	201	3468	HG0358Q	48	201	TX	HARRIS	SAM BERTRON	Texas Genco	CenterPoint Energy	ERCOT ISO/PCA	NU
3631	48	469	3631	VC0026O	48	469	TX	VICTORIA	SAM RAYBURN	South Texas Electric Coop Inc		ERCOT ISO/PCA	UT
6413	48	241			48	241	TX	JASPER	SAM RAYBURN	USCE-Fort Worth District	US Army Corp Of Engineers	ERCOT ISO/PCA	UT
3527	48	451	3527	TG0044C	48	451	TX	TOM GREEN	SAN ANGELO	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
7325	48	201	7325	HG4955K	48	201	TX	HARRIS	SAN JACINTO SES	Texas Genco	CenterPoint Energy	ERCOT ISO/PCA	NU
6183	48	013	6183	AG0007G	48	13	TX	ATASCOSA	SAN MIGUEL	San Miguel Electric Coop Inc		ERCOT ISO/PCA	UT
6648	48	331	6648	MM0023J	48	331	TX	MILAM	SANDOW	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
52071	48	331			48	331	TX	MILAM	SANDOW	Alcoa NUGS	Alcoa, Inc	ERCOT ISO/PCA	NU
10167	48	057			48	57	TX	CALHOUN	SEADRIFT COKE LP	Seadrift Coke L P		ERCOT ISO/PCA	NU
50150	48	057			48	57	TX	CALHOUN	SEADRIFT PLANT UNION CARBIDE CORP	Union Carbide		ERCOT ISO/PCA	NU
3616	48	187					TX	GUADALUPE	SEGUIN				UT
50253	48	201			48	201	TX	HARRIS	SHELDON TEXAS	Champion International Corp		ERCOT ISO/PCA	NU
50304	48	201			48	201	TX	HARRIS	SHELL DEER PARK	Shell		ERCOT ISO/PCA	NU
3559	48	061	3559	CD0009B	48	61	TX	CAMERON	SI RAY	Brownsville Public Utils Board		ERCOT ISO/PCA	UT
3601	48	021	3601	BC0015L	48	21	TX	BASTROP	SIM GIDEON	Lower Colorado River Authority		ERCOT ISO/PCA	UT
55000	48	123			48	123	TX	DE WITT	SMALL HYDRO OF TEXAS INC	Small Hydro of Texas Inc		ERCOT ISO/PCA	NU
50141	48	203			48	203	TX	HARRISON	SNIDER INDUSTRIES INC	Snider Industries Inc		American Electric Power - West (SPP)/PCA	NU
6251	48	321			48	321	TX	MATAGORDA	SOUTH TEXAS	Texas Genco	CenterPoint Energy	ERCOT ISO/PCA	NU
50127	48	485			48	485	TX	WICHITA	SOUTHERN ENERGY WICHITA FALLS LP	Vetrotex America		ERCOT ISO/PCA	NU
50263	48	209			48	209	TX	HAYS	SOUTHWEST TEXAS STATE UNIVERSITY COGEN	Southwest Texas State Univ		ERCOT ISO/PCA	NU
4266	48	121	4266	DF0012T	48	121	TX	DENTON	SPENCER	Denton City of		ERCOT ISO/PCA	UT
55390	48	113			48	113	TX	DALLAS	STATE FARM INS CO ISC CENTRAL	Daniel Norris		ERCOT ISO/PCA	NU
3504	48	073	3504	CJ0026J	48	73	TX	CHEROKEE	STRYKER CREEK	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
55015	48	039	55015	BL0622F	48	39	TX	BRAZORIA	SWEENY COGENERATION FACILITY	Sweeny Cogeneration LP		ERCOT ISO/PCA	NU
3469	48	201	3469	HG0357S	48	201	TX	HARRIS	T H WHARTON	Texas Genco	CenterPoint Energy	ERCOT ISO/PCA	NU
50109	48	277			48	277	TX	LAMAR	TENASKA III TEXAS PARTNERS	North American Energy Services		ERCOT ISO/PCA	NU
54817	48	251	54817	JH0230L	48	251	TX	JOHNSON	TENASKA IV TEXAS PARTNERS LTD CLEBURNE COGEN	North American Energy Services		ERCOT ISO/PCA	NU
54097	48	067			48	67	TX	CASS	TEXARKANA MILL	International Paper Co		American Electric Power - West (SPP)/PCA	NU
52088	48	167			48	167	TX	GALVESTON	TEXAS CITY COGENERATION LP	Texas City Cogeneration L P		ERCOT ISO/PCA	NU

ORISPL	FIPST	FIPSCNY	ORISPL_ In_NEI_ V300_ Draft	SiteID_ In_NEI_ V300_ Draft	FIPST_ NUM	FIPSCNY_ NUM	PSTAT ABB	CNTYNAME	PNAME	OPRNAME	OPPRNAME	PCANAME	PL TYPE
52097	48	167					TX	GALVESTON	TEXAS CITY PLANT				NU
50153	48	167			48	167	TX	GALVESTON	TEXAS CITY PLANT UNION CARBIDE CORP	Union Carbide		ERCOT ISO/PCA	NU
50229	48	201			48	201	TX	HARRIS	TEXAS PETROCHEMICALS CORP	Texas Petrochemicals Corp		ERCOT ISO/PCA	NU
52120	48	039			48	39	TX	BRAZORIA	THE DOW CHEMICAL CO TEXAS OPERATIONS	Dow Chemical		ERCOT ISO/PCA	NU
54321	48	245			48	245	TX	JEFFERSON	THE GOODYEAR&TIRE RUBBER CO	Goodyear Tire & Rubber Co		Entergy Electric System/PCA	NU
4937	48	299	4937	LL0006O	48	299	TX	LLANO	THOMAS C FERGUSON	Lower Colorado River Authority		ERCOT ISO/PCA	UT
7030	48	395	7030	RI0035C	48	395	TX	ROBERTSON	TNP ONE	Sempra Energy Resources	Sempra Energy	ERCOT ISO/PCA	NU
6595	48	351			48	351	TX	NEWTON	TOLEDO BEND	Entergy Gulf States Inc	Entergy Corporation	Entergy Electric System/PCA	UT
6194	48	279	6194	LB0047N	48	279	TX	LAMB	TOLK	Southwestern Public Service Co	Xcel Energy Inc	Southwestern Public Service Co/PCA	UT
3586	48	187			48	187	TX	GUADALUPE	TP 4	Guadalupe Blanco River Auth		ERCOT ISO/PCA	UT
3506	48	309	3506	MB0116C	48	309	TX	MCLENNAN	TRADINGHOUSE	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
3507	48	213	3507	HM0017H	48	213	TX	HENDERSON	TRINIDAD	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
3602	48	303	3602	LN0057V	48	303	TX	LUBBOCK	TY COOKE	Lubbock City of		Southwestern Public Service Co/PCA	UT
50118	48	453			48	453	TX	TRAVIS	UNIVERSITY OF TEXAS AT AUSTIN	University of Texas at Austin		ERCOT ISO/PCA	NU
54607	48	113			48	113	TX	DALLAS	UNIVERSITY OF TEXAS AT DALLAS	Win Sam Inc		ERCOT ISO/PCA	NU
54606	48	029			48	29	TX	BEXAR	UNIVERSITY OF TEXAS AT SAN ANTONIO	Thermonetics Div of Win Sam		ERCOT ISO/PCA	NU
3612	48	029	3612	BG0186I	48	29	TX	BEXAR	V H BRAUNIG	San Antonio Public Service Bd		ERCOT ISO/PCA	UT
50121	48	355			48	355	TX	NUECES	VALERO REFINERY	Valero Refining Co		ERCOT ISO/PCA	NU
52013	48	167			48	167	TX	GALVESTON	VALERO REFINING CO TEXAS CITY REFINERY	Valero Refining Co		ERCOT ISO/PCA	NU
52012	48	201			48	201	TX	HARRIS	VALERO REFINING CO TEXAS HOUSTON REFINERY	Valero Refining Co		ERCOT ISO/PCA	NU
3508	48	147	3508	FB0025U	48	147	TX	FANNIN	VALLEY	TXU Generation LLC	TXU Corporation	ERCOT ISO/PCA	NU
3623	48	487			48	487	TX	WILBARGER	VERNON	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
3443	48	469	3443	VC0003D	48	469	TX	VICTORIA	VICTORIA	AEP NUGs	American Electric Power Co Inc	ERCOT ISO/PCA	NU
10790	48	469			48	469	TX	VICTORIA	VICTORIA TEXAS PLANT	E I DuPont De Nemours & Co		ERCOT ISO/PCA	NU
54520	48	439			48	439	TX	TARRANT	VILLAGE CREEK WASTEWATER TREATMENT PLANT	Ft Worth City of		ERCOT ISO/PCA	NU
3470	48	157	3470	FG0020V	48	157	TX	FORT BEND	W A PARISH	Texas Genco	CenterPoint Energy	ERCOT ISO/PCA	NU
3613	48	029	3613	BG0187G	48	29	TX	BEXAR	W B TUTTLE	San Antonio Public Service Bd		ERCOT ISO/PCA	UT
54049	48	465					TX	VAL VERDE	WASHINGTON VENEER DIVISION				NU
52122	48	501			48	501	TX	YOAKUM	WASSON CO2 REMOVAL PLANT	Occidental Chemical Corp		Southwestern Public Service Co/PCA	NU
3471	48	201	3471	HG0355W	48	201	TX	HARRIS	WEBSTER	Texas Genco	CenterPoint Energy	ERCOT ISO/PCA	NU
6139	48	449	6139	TF0012D	48	449	TX	TITUS	WELSH	Southwestern Electric Power Co	American Electric Power Co Inc	American Electric Power - West (SPP)/PCA	UT
55367	48	461			48	461	TX	UPTON	WEST TEXAS WIND ENERGY LLC	Daniel Norris		ERCOT ISO/PCA	NU
54966	48	229			48	229	TX	HUDSPETH	WEST TEXAS WINDPLANT	LG&E Power Services	E.ON (Germany)	ERCOT ISO/PCA	NU
54330	48	201			48	201	TX	HARRIS	WESTHOLLOW TECHNOLOGY CENTER	Shell		ERCOT ISO/PCA	NU
50101	48	241			48	241	TX	JASPER	WESTVACO EVADALE	MeadWestvaco Corp		Entergy Electric System/PCA	NU
6414	48	035			48	35	TX	BOSQUE	WHITNEY	USCE-Fort Worth District	US Army Corp Of Engineers	ERCOT ISO/PCA	UT
3478	48	315	3478	ME0006A	48	315	TX	MARION	WILKES	Southwestern Electric Power Co	American Electric Power Co Inc	American Electric Power - West (SPP)/PCA	UT
55025	48	371			48	371	TX	PECOS	YATES GAS PLANT	Marathon Oil Co		ERCOT ISO/PCA	NU
3641	49	049			49	49	UT	UTAH	AMERICAN FORK	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
3688	49	049			49	49	UT	UTAH	BARTHOLOMEW	Springville City of		Pacificorp-East/PCA	UT
6536	49	001			49	1	UT	BEAVER	BEAVER LOWER HYDRO 1	Beaver City Corp		Pacificorp-East/PCA	UT
3664	49	001			49	1	UT	BEAVER	BEAVER MID HYDRO 2	Beaver City Corp		Pacificorp-East/PCA	UT
7340	49	001			49	1	UT	BEAVER	BEAVER UPPER HYDRO 3	Beaver City Corp		Pacificorp-East/PCA	UT
299	49	001			49	1	UT	BEAVER	BLUNDELL	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
7790	49	047	7790	107790	49	47	UT	UINTAH	BONANZA	Deseret Generation & Tran Coop		Pacificorp-East/PCA	UT
3699	49	017			49	17	UT	GARFIELD	BOULDER	Garkane Power Assn Inc		WAPA - Rocky Mountains/PCA	UT
3665	49	011			49	11	UT	DAVIS	BOUNTIFUL CITY	Bountiful City City of		Pacificorp-East/PCA	UT
6182	49	003			49	3	UT	BOX ELDER	BOX ELDER	Brigham City Corp		Pacificorp-East/PCA	UT
3666	49	003			49	3	UT	BOX ELDER	BRIGHAM CITY	Brigham City Corp		Pacificorp-East/PCA	UT
3644	49	007	3644	10081	49	7	UT	CARBON	CARBON	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
3685	49	021			49	21	UT	IRON	CENTER CREEK	Parowan City Corp		Pacificorp-East/PCA	UT
3646	49	003			49	3	UT	BOX ELDER	CUTLER	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
6404	49	051			49	51	UT	WASATCH	DEER CREEK	USBR-Upper Colorado Region	US Bureau Of Reclamation	WAPA - Rocky Mountains/PCA	UT
4263	49	043			49	43	UT	SUMMIT	ECHO DAM	Bountiful City City of		Pacificorp-East/PCA	UT
6405	49	009			49	9	UT	DAGGETT	FLAMING GORGE	USBR-Upper Colorado Region	US Bureau Of Reclamation	WAPA - Rocky Mountains/PCA	UT
3647	49	039			49	39	UT	SANPETE	FOUNTAIN GREEN	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
3648	49	035	3648	10355	49	35	UT	SALT LAKE	GADSBY	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
10778	49	049			49	49	UT	UTAH	GENEVA STEEL	Geneva Steel		Pacificorp-East/PCA	NU
3651	49	035			49	35	UT	SALT LAKE	GRANITE	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
3634	49	053			49	53	UT	WASHINGTON	GUNLOCK	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
7069	49	053			49	53	UT	WASHINGTON	GUNLOCK HYDRO	St George City of		Pacificorp-East/PCA	UT
7111	49	051			49	51	UT	WASATCH	HEBER CITY	Heber Light & Power Co		Pacificorp-East/PCA	UT
3689	49	049			49	49	UT	UTAH	HOBBLE CREEK	Springville City of		Pacificorp-East/PCA	UT
6165	49	015	6165	10237	49	15	UT	EMERY	HUNTER	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
8069	49	015	8069	10238	49	15	UT	EMERY	HUNTINGTON	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
7034	49	005			49	5	UT	CACHE	HYDRO II	Logan City of		Pacificorp-East/PCA	UT
3675	49	005			49	5	UT	CACHE	HYDRO III	Logan City of		Pacificorp-East/PCA	UT
3668	49	039			49	39	UT	SANPETE	HYDRO PLANT NO 1	Ephraim City of		Pacificorp-East/PCA	UT
925	49	039			49	39	UT	SANPETE	HYDRO PLANT NO 3	Ephraim City of		Pacificorp-East/PCA	UT
7133	49	039			49	39	UT	SANPETE	HYDRO PLANT NO 4	Ephraim City of		Pacificorp-East/PCA	UT
3674	49	005			49	5	UT	CACHE	HYRUM	Hyrum City Corp		Pacificorp-East/PCA	UT
6481	49	027	6481	10327	49	27	UT	MILLARD	INTERMOUNTAIN	Los Angeles City of		Los Angeles Dept of Water & Power/PCA	UT
159	49	051			49	51	UT	WASATCH	LAKE CREEK	Heber Light & Power Co		Pacificorp-East/PCA	UT
6537	49	035			49	35	UT	SALT LAKE	LITTLE COTTONWOOD	Murray City of		Pacificorp-East/PCA	UT
6553	49	057			49	57	UT	WEBER	LITTLE MOUNTAIN	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
10215	49	035			49	35	UT	SALT LAKE	LONE PEAK PARTNERS POWER CO	Snowbird Utilites		Pacificorp-East/PCA	NU
3679	49	041			49	41	UT	SEVIER	LOWER	Monroe City of		Pacificorp-East/PCA	UT
3681	49	039			49	39	UT	SANPETE	LOWER-UNIT	Mt Pleasant City of		Pacificorp-East/PCA	UT

ORISPL	FIPST	FIPSCNY	ORISPL_ In_NEI_V300_ Draft	SiteID_ In_NEI_ V300_ Draft	FIPST_ NUM	FIPSCNY_ NUM	PSTAT ABB	CNTYNAME	PNAME	OPRNAME	OPPRNAME	PCANAME	PL TYPE
1020	49	039			49	39	UT	SANPETE	MANTI LOWER	Manti City of		Pacificorp-East/PCA	UT
3676	49	039			49	39	UT	SANPETE	MANTI UPPER	Manti City of		Pacificorp-East/PCA	UT
7043	49	041			49	41	UT	SEVIER	MONROE PUMPING STA	Monroe City of		Pacificorp-East/PCA	UT
3683	49	035			49	35	UT	SALT LAKE	MURRAY CITY	Murray City of		Pacificorp-East/PCA	UT
3655	49	049			49	49	UT	UTAH	OLMSTEAD	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
3692	49	049			49	49	UT	UTAH	PAYSON	Strawberry Water Users Assn		Pacificorp-East/PCA	UT
7362	49	053			49	53	UT	WASHINGTON	PINE VALLEY	St George City of		Pacificorp-East/PCA	UT
7132	49	057			49	57	UT	WEBER	PINE VIEW DAM	Bountiful City City of		Pacificorp-East/PCA	UT
3656	49	057			49	57	UT	WEBER	PIONEER	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
52119	49	035			49	35	UT	SALT LAKE	PRIMARY CHILDRENS MEDICAL CENTER	Primary Childrens Medical Cntr		Pacificorp-East/PCA	NU
3686	49	049			49	49	UT	UTAH	PROVO	Provo City Corp		Pacificorp-East/PCA	UT
52039	49	053			49	53	UT	WASHINGTON	QUAIL CREEK HYDRO PLANT #1	Washington County Wtr Consv Dt		WAPA - Rocky Mountains/PCA	NU
6538	49	021			49	21	UT	IRON	RED CREEK	Parowan City Corp		Pacificorp-East/PCA	UT
3636	49	053			49	53	UT	WASHINGTON	SAND COVE	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
3658	49	051			49	51	UT	WASATCH	SNAKE CREEK	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
3673	49	051			49	51	UT	WASATCH	SNAKE CREEK	Heber Light & Power Co		Pacificorp-East/PCA	UT
3691	49	049			49	49	UT	UTAH	SPANISH FORK	Strawberry Water Users Assn		Pacificorp-East/PCA	UT
3690	49	049			49	49	UT	UTAH	SPRING CREEK	Springville City of		Pacificorp-East/PCA	UT
7080	49	053			49	53	UT	WASHINGTON	ST GEORGE	St George City of		Pacificorp-East/PCA	UT
3659	49	035			49	35	UT	SALT LAKE	STAIRS	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
50951	49	007			49	7	UT	CARBON	SUNNYSIDE COGENERATION ASSOCIATES	Sunnyside Cogeneration Assoc		Pacificorp-East/PCA	NU
3704	49	013			49	13	UT	DUCHESNE	UINTAH	Moon Lake Electric Assn Inc		WAPA - Rocky Mountains/PCA	UT
7016	49	039			49	39	UT	SANPETE	UNIT 3	Mt Pleasant City of		Pacificorp-East/PCA	UT
7015	49	039			49	39	UT	SANPETE	UNIT 4	Mt Pleasant City of		Pacificorp-East/PCA	UT
3680	49	041			49	41	UT	SEVIER	UPPER	Monroe City of		Pacificorp-East/PCA	UT
7027	49	049			49	49	UT	UTAH	UPPER BARTHOLOMEW	Springville City of		Pacificorp-East/PCA	UT
3643	49	001			49	1	UT	BEAVER	UPPER BEAVER	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
3682	49	039			49	39	UT	SANPETE	UPPER-UNIT	Mt Pleasant City of		Pacificorp-East/PCA	UT
3635	49	053			49	53	UT	WASHINGTON	VEYO	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
55302	49	011			49	11	UT	DAVIS	WASATCH ENERGY SYSTEMS	Davis CSWM & Energy RSSD		Pacificorp-East/PCA	NU
3661	49	057			49	57	UT	WEBER	WEBER	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
7028	49	049			49	49	UT	UTAH	WHITEHEAD	Springville City of		Pacificorp-East/PCA	UT
3705	49	013			49	13	UT	DUCHESNE	YELLOWSTONE	Moon Lake Electric Assn Inc		WAPA - Rocky Mountains/PCA	UT
6409	56	025			56	25	WY	NATRONA	ALCOVA	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
52129	56	041			56	41	WY	UINTA	ANSCHUTZ RANCH EAST	BP Amoco		Pacificorp-East/PCA	NU
55278	56	013			56	13	WY	FREMONT	BEAVER CREEK GAS PLANT	Devon SFS Operating Inc		WAPA - Rocky Mountains/PCA	NU
55134	56	037	55134	00042	56	37	WY	SWEETWATER	BLACKS FORK GAS PROCESSING PLANT	Questar Gas Management Co		Pacificorp-West/PCA	NU
505	56	013			56	13	WY	FREMONT	BOYSEN	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
7317	56	029			56	29	WY	PARK	BUFFALO BILL	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
4158	56	009	4158	00001	56	9	WY	CONVERSE	DAVE JOHNSTON	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
52127	56	029			56	29	WY	PARK	ELK BASIN GASOLINE PLANT	BP Amoco		Pacificorp-West/PCA	NU
4185	56	023			56	23	WY	LINCOLN	FONTENELLE	USBR-Upper Colorado Region	US Bureau Of Reclamation	WAPA - Rocky Mountains/PCA	UT
4176	56	025			56	25	WY	NATRONA	FREMONT CANYON	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
54318	56	037	54318	00002	56	37	WY	SWEETWATER	GENERAL CHEMICAL	General Chemical Corp		Pacificorp-West/PCA	NU
4177	56	031			56	31	WY	PLATTE	GLENDO	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
4178	56	031			56	31	WY	PLATTE	GUERNSEY	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
6408	56	029			56	29	WY	PARK	HEART MOUNTAIN	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
8066	56	037	8066	01002	56	37	WY	SWEETWATER	JIM BRIDGER	PacifiCorp-West	ScottishPower PLC	Pacificorp-West/PCA	UT
4180	56	007			56	7	WY	CARBON	KORTES	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
6204.1	56	031			56	31	WY	PLATTE	LARAMIE RIVER 1	Basin Electric Power Coop-East	Basin Electric Power Coop	WAPA - Upper Great Plains East/PCA	UT
6204.2	56	031			56	31	WY	PLATTE	LARAMIE RIVER 2&3	Basin Electric Power Coop-West	Basin Electric Power Coop	WAPA - Rocky Mountains/PCA	UT
4162	56	023	4162	00004	56	23	WY	LINCOLN	NAUGHTON	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
4150	56	005	4150	00002	56	5	WY	CAMPBELL	NEIL SIMPSON	Black Hills Power & Light	Black Hills Corp	WAPA - Rocky Mountains/PCA	UT
7504	56	005	7504	00063	56	5	WY	CAMPBELL	NEIL SIMPSON II	Black Hills Power & Light	Black Hills Corp	WAPA - Rocky Mountains/PCA	UT
4151	56	045	4151	00005	56	45	WY	WESTON	OSAGE	Black Hills Power & Light	Black Hills Corp	WAPA - Rocky Mountains/PCA	UT
674	56	013			56	13	WY	FREMONT	PILOT BUTTE	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
55203	56	021			56	21	WY	LARAMIE	PONNEQUIN PHASE 1	Energy Unlimited Inc		Public Service Co Of Colorado/PCA	NU
4182	56	007			56	7	WY	CARBON	SEMINOE	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
54472	56	037	54472	00022	56	37	WY	SWEETWATER	SF PHOSPHATES LTD CO	SF Phosphates Ltd Co		Pacificorp-West/PCA	NU
4183	56	029			56	29	WY	PARK	SHOSHONE	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
54374	56	007	54374	00001	56	7	WY	CARBON	SINCLAIR OIL REFINERY	Sinclair Oil Corp		Pacificorp-West/PCA	NU
7541	56	029			56	29	WY	PARK	SPIRIT MOUNTAIN	USBR-Great Plains Region	US Bureau Of Reclamation	WAPA - Upper Great Plains West/PCA	UT
6393	56	023			56	23	WY	LINCOLN	STRAWBERRY CREEK	Lower Valley Energy Inc		Bonneville Power Admin/PCA	UT
7050	56	023			56	23	WY	LINCOLN	VIVA NAUGHTON	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT
6101	56	005	6101	00046	56	5	WY	CAMPBELL	WYODAK	PacifiCorp-East	ScottishPower PLC	Pacificorp-East/PCA	UT

PNAME	PREV UTIL	LAT	LON	NUMBLR	NUMGEN	SOURCEM	PLPRIMFL	PLFFLCTG	CAPFAC	BOILCAP	NAMEPCAP	CHPFLAG	USETHRMO	PWRTOHT	ELCALLOC	PLNUCONN
ABITIBI CONSOLIDATED SNOWFLAKE DIVISION	0	35.2863	110.2885	0	2	E	SUB	C	0.5541	0	70.55	U	3155479			Y
AGUA FRIA	0	33.5569	112.2175	3	6	T,E	GAS	G	0.3803	3672	613.422		0	N/A	N/A	
APACHE STATION	0	32.0556	109.8861	3	6	T	COL	C	0.7062	4515.2	559.142		0	N/A	N/A	
BIOSPHERE 2 CENTER INC	0	32.9836	111.3255	0	2	E	NG	G	0.0932	0	3.048	U	2590			Y
CHILDS	0	34.7053	112.4042	0	1	Z	WT		0.4414	0	5.4		0	N/A	N/A	
CHOLLA	0	34.9414	110.3003	4	4	T	COL	C	0.7017	10506	1105.436		0	N/A	N/A	
CORONADO	0	34.5778	109.2717	2	2	T	COL	C	0.8717	7471.84	821.88		0	N/A	N/A	
CROSSCUT	0	33.35	112.49	0	5	Z	WT		0.0181	0	33		0	N/A	N/A	
DAVIS	0	35.6134	113.6474	0	1	Z	WT		0.5911	0	240		0	N/A	N/A	
DOUGLAS	0	31.8799	109.754	0	1	E	OIL	O	0.0196	0	21.4		0	N/A	N/A	
GLEN CANYON	0	35.6337	112.0444	0	1	Z	WT		0.3642	0	1296		0	N/A	N/A	
GOULD ELECTRONICS FOIL DIVISION	0	33.35	112.49	0	2	E	NG	G	0.0599	0	1.05	U	818			Y
HOOVER	0	35.6134	113.6474	0	1	Z	WT		0.3148	0	1039.4		0	N/A	N/A	
HORSE MESA	0	33.35	112.49	0	2	Z	WT		0.1957	0	129.578		0	N/A	N/A	
INA ROAD WATER POLLUTION CONTROL FACILITY	0	31.9699	111.8899	0	7	E	NG	G	0.4703	0	4.54	U	70733			Y
IRVING	0	34.7053	112.4042	0	1	Z	WT		0.8549	0	1.6		0	N/A	N/A	
IRVINGTON	0	32.16	110.9044	4	6	T,E	COL	C	0.3352	3633.92	558.5		0	N/A	N/A	
KYRENE	0	33.3547	111.9364	2	6	T,E	GAS	G	0.1345	1349.12	334.85		0	N/A	N/A	
MORMON FLAT	0	33.35	112.49	0	2	Z	WT		0.1598	0	57.845		0	N/A	N/A	
NAVAJO	0	36.9125	111.3917	3	3	T	COL	C	0.8574	22072.8	2409.48		0	N/A	N/A	
NELSON PLANT GENERATORS	0	35.6134	113.6474	0	1	E	DFO	O	0.0237	0	2.27		0	N/A	N/A	Y
NORTH LOOP	0	31.9699	111.8899	0	3	E	GAS	G	0.07	0	81		0	N/A	N/A	
OCOTILLO	0	33.4467	111.9417	2	5	T,E	GAS	G	0.2561	2176	333.897		0	N/A	N/A	
PALO VERDE	0	33.35	112.49	0	1	Z	UR		0.8239	0	4209.57		0	N/A	N/A	
ROOSEVELT	0	33.35	112.49	0	1	Z	WT		0.113	0	36.018		0	N/A	N/A	
SAGUARO	0	32.5522	111.2992	2	4	T,E	GAS	G	0.2126	2448	356.25		0	N/A	N/A	
SANTAN	0	33.35	112.49	0	4	E	GAS	G	0.4091	0	414		0	N/A	N/A	
SOUTH CONSOLIDATED	0	33.35	112.49	0	1	Z	WT		0.0882	0	1.4		0	N/A	N/A	
SPRINGERVILLE	0	34.3186	109.1636	2	2	T	COL	C	0.7896	7656.8	849.6		0	N/A	N/A	
STARWOOD HOTELS RESORTS	0	33.35	112.49	0	3	E	NG	G	0.2868	0	1.65	U	11235			Y
STEWART MTN	0	33.35	112.49	0	1	Z	WT		0.2408	0	10.4		0	N/A	N/A	
WEST PHOENIX	0	33.4428	112.1536	0	8	E	GAS	G	0.2244	0	621.75		0	N/A	N/A	
YUCCA	0	33.22	113.94	1	5	T,E	GAS	G	0.153	0	278.66		0	N/A	N/A	
YUMA COGENERATION ASSOCIATES	0	32.7504	114.0678	0	2	E	NG	G	0.8036	0	62.64	U	202460			Y
ALAMOSA	0	37.5541	105.7477	0	2	E	GAS	G	0.0183	0	33.1		0	N/A	N/A	
AMERICAN ATLAS 1 COGENERATION PLANT	0	39.7286	107.5255	0	4	E	NG	G	0.2098	0	85	U	166015			Y
AMERICAN GYPSUM COGENERATION	0	39.6415	106.6443	0	4	E	DFO	O	0.2934	0	9.848	U	1000000			Y
AMES	0	37.9645	108.3899	0	1	Z	WT		0.3152	0	3.6		0	N/A	N/A	
ARAPAHOE	0	39.67	105.0028	4	4	T	COL	C	0.6865	3100.8	232		0	N/A	N/A	
BETASSO HYDROELECTRIC PLANT	0	40.0884	105.3453	0	1	Z	WAT		0.2588	0	3		0	N/A	N/A	Y
BIG THOMPSON	0	40.6281	105.5665	0	1	Z	WT		0.2525	0	4.5		0	N/A	N/A	
BLUE MESA	0	38.7019	106.9407	0	1	Z	WT		0.3184	0	86.4		0	N/A	N/A	
BOULDER	1	39.7114	104.9217	0	1	Z	WT		0.0976	0	20		0	N/A	N/A	Y
BRUSH COGEN PROJECT PHASE 2 BCP	0	40.2627	103.807	0	2	E	NG	G	0.426	0	74	U	810984			Y
BRUSH IV	0	40.2627	103.807	0	2	E	NG	G	0.0469	0	70	U	457013			Y
BRUSH POWER PROJECT PHASE 1 CPP	0	40.2627	103.807	0	3	E	NG	G	0.1369	0	88	A		N/A		Y
BURLINGTON	0	39.3061	102.6048	0	2	E	OIL	O	0.0531	0	129.4		0	N/A	N/A	
CABIN CREEK	0	39.7085	105.6604	0	1	Z	WT		-0.046	0	300		0	N/A	N/A	
CAMEO	0	39.1333	108.3167	2	2	T,E	COL	C	0.9561	0	66		0	N/A	N/A	
CHEROKEE	0	39.8697	104.379	4	6	T	COL	C	0.7575	7386.16	715.5		0	N/A	N/A	
COMANCHE	0	38.2081	104.5747	2	2	T	COL	C	0.6888	6892.48	700		0	N/A	N/A	
CRAIG	0	40.4628	107.59	3	3	T	COL	C	0.8391	12403.2	1339.2		0	N/A	N/A	
CRYSTAL	0	38.4104	108.2795	0	1	Z	WT		0.6754	0	28		0	N/A	N/A	
DELTA	0	38.9431	107.9389	0	7	E	GAS	G	0.014	0	4.957		0	N/A	N/A	
DILLON HYDRO PLANT	0	39.6484	106.1078	0	1	Z	WAT		0.8065	0	1.807		0	N/A	N/A	Y
DRAGON TRAIL GAS PROCESSING PLANT	0	29.8336	95.4383	0	2	E	NG	G	0.4225	0	1.225		0	N/A	N/A	Y
ESTES	0	40.6281	105.5665	0	1	Z	WT		0.2821	0	45		0	N/A	N/A	
FLATIRON	0	40.6281	105.5665	0	2	Z	WT		0.2062	0	94.5		0	N/A	N/A	
FOOTHILLS HYDRO PLANT	0	39.348	104.9944	0	1	Z	WAT		0.4789	0	3.125		0	N/A	N/A	Y
FORT LUPTON	0	39.8697	104.379	0	2	E	GAS	G	0.082	0	78.4		0	N/A	N/A	
FORT ST VRAIN	0	40.501	104.3121	2	3	T	GAS	G	0.5192	1876.8	601		0	N/A	N/A	
FRUITA	0	38.9331	108.2266	0	1	E	GAS	G	0.0142	0	18.65		0	N/A	N/A	
GEORGE BIRDSALL	0	38.83	104.52	3	3	E	GAS	G	0.2164	0	58.823		0	N/A	N/A	
GEORGETOWN	0	39.7085	105.6604	0	1	Z	WT		0.4353	0	1.44		0	N/A	N/A	
GREEN MOUNTAIN	0	39.6484	106.1078	0	1	Z	WT		0.1827	0	26		0	N/A	N/A	
HAYDEN	0	40.4856	107.185	2	2	T	COL	C	0.8098	4017.44	447		0	N/A	N/A	
HILLCREST POWERPLANT	0	39.7114	104.9217	0	1	Z	WAT		0.5636	0	2		0	N/A	N/A	Y
IGNACIO GASOLINE PLANT	0	37.3198	107.9299	0	1	E	NG	G	0.8629	0	6.196	U	2775000			Y
JOHNSTOWN COGENERATION	0	40.501	104.3121	0	1	E	NG	G	0.0742	0	3.3	U	7500			Y
LAMAR PLT	0	37.95	102.4	1	5	E	GAS	G	0.212	0	35	C		N/A		
LONGMONT	0	40.0884	105.3453	0	1	Z	WT		0.1935	0	0.6		0	N/A	N/A	
LOWER MOLINA	0	38.9331	108.2266	0	1	Z	WT		0.302	0	4.86		0	N/A	N/A	
MANITOU	0	38.8248	104.5616	0	1	Z	WT		0.3651	0	5		0	N/A	N/A	
MARTIN DRAKE	0	38.8244	104.8331	3	3	T	COL	C	0.7262	2733.6	294.057		0	N/A	N/A	
MARYS LAKE	0	40.6281	105.5665	0	1	Z	WT		0.6206	0	8.1		0	N/A	N/A	
MCPHEE	0	37.3189	108.5081	0	1	Z	WT		0.5144	0	1.283		0	N/A	N/A	
METRO WASTEWATER RECLAMATION DISTRICT	0	39.8697	104.379	0	4	E	OBG		0.2932	0	4.8	U	624000			Y
MORROW POINT	0	38.4104	108.2795	0	1	Z	WT		0.2074	0	173.334		0	N/A	N/A	

PNAME	PREV UTIL	LAT	LON	NUMBLR	NUMGEN	SOURCEM	PLPRIMFL	PLFFLCTG	CAPFAC	BOILCAP	NAMEPCAP	CHPFLAG	USETHRMO	PWRTOHT	ELCALLOC	PLNUCONN
MOUNT ELBERT	0	39.2179	106.3564	0	1	Z	WT		-0.0523	0	200		0	N/A	N/A	
NORTH FORK HYDRO PLANT	0	39.1311	105.7593	0	1	Z	WAT		0.4121	0	5.5		0	N/A	N/A	Y
NUCLA	0	38.2386	108.5072	1	4	T	COL	C	0.6586	1258	113.88		0	N/A	N/A	
PALISADE	0	38.9331	108.2266	0	1	Z	WT		0.6611	0	3		0	N/A	N/A	
PAWNEE	0	40.2694	103.6933	1	1	T	COL	C	0.7628	5010.24	547		0	N/A	N/A	
POLE HILL	0	40.6281	105.5665	0	1	Z	WT		0.4828	0	38.2		0	N/A	N/A	
PUEBLO	0	38.17	104.51	1	6	E	GAS	G	0.209	0	25		0	N/A	N/A	
RAWHIDE	0	40.8583	105.0269	1	1	T	COL	C	0.7639	2584	293.625		0	N/A	N/A	
RAY D NIXON	0	38.6306	104.7056	3	3	T	COL	C	0.6593	1972	301.66		0	N/A	N/A	
REDLANDS WATER & POWER CO	0	38.9331	108.2266	0	1	Z	WAT		0.7038	0	1.4		0	N/A	N/A	Y
ROCKY FORD	0	37.9543	103.7289	0	5	E	OIL	O	0.0778	0	10		0	N/A	N/A	
RUXTON	0	38.8248	104.5616	0	1	Z	WT		0.1802	0	1.25		0	N/A	N/A	
SALIDA 1	0	38.7401	106.2645	0	1	Z	WT		0.4679	0	0.75		0	N/A	N/A	
SALIDA 2	0	38.7401	106.2645	0	1	Z	WT		0.528	0	0.56		0	N/A	N/A	
SHOSHONE	0	39.7286	107.5255	0	1	Z	WT		0.8454	0	14.4		0	N/A	N/A	
STRONTIA SPRINGS HYDRO PLANT	0	39.348	104.9944	0	1	Z	WAT		0.7471	0	1.025		0	N/A	N/A	Y
SUGARLOAF HYDRO PLANT	0	39.2179	106.3564	0	1	Z	WAT		0.3431	0	2.5		0	N/A	N/A	Y
TACOMA	0	37.3198	107.9299	0	1	Z	WT		0.2178	0	8		0	N/A	N/A	
TAYLOR DRAW HYDROELECTRIC FACILITY	0	39.9376	108.0437	0	1	Z	WAT		0.5928	0	2.3		0	N/A	N/A	Y
TCP 122	0	40.501	104.3121	0	3	E	NG	G	0.6091	0	126	U	168397			Y
TCP 150	0	40.501	104.3121	0	4	E	NG	G	0.536	0	178.22	U	206986			Y
TESLA	0	38.8248	104.5616	0	1	Z	WT		0.274	0	27.64		0	N/A	N/A	
THERMO GREELEY INC	0	40.501	104.3121	0	1	E	NG	G	0.5875	0	37	U	748476			Y
THERMO POWER ELECTRIC INC	0	40.501	104.3121	0	3	E	NG	G	0.6392	0	110.844	U	300454			Y
TOWAOC	0	37.3189	108.5081	0	1	Z	WT		0.232	0	11.495		0	N/A	N/A	
TRIGEN COLORADO ENERGY CORP	0	39.5219	105.2228	0	4	E	SUB	C	0.9406	0	35.4	U	4362151			Y
UNIVERSITY OF COLORADO	0	40.0884	105.3453	0	3	E	NG	G	0.478	0	33	U	36844.7			Y
UPPER MOLINA	0	38.9331	108.2266	0	1	Z	WT		0.2923	0	8.64		0	N/A	N/A	
VALLECITO HYDROELECTRIC	0	37.3198	107.9299	0	3	Z	WAT		0.3156	0	5.844		0	N/A	N/A	Y
VALMONT	0	40.0694	105.2022	1	2	T,E	COL	C	0.7913	1740.8	211.45		0	N/A	N/A	
W N CLARK	0	38.47	105.44	2	2	E	COL	C	0.82	0	38.5		0	N/A	N/A	
WILLIAMS FORK HYDRO PLANT	0	40.0856	106.14	0	1	Z	WAT		0.4229	0	3		0	N/A	N/A	Y
ZUNI	0	39.7375	105.0181	3	2	T	GAS	G	0.089	1672.8	101	U	294000			
ABILENE CT	0	38.8712	97.1354	0	1	E	GAS	G	0.0074	0	77		0	N/A	N/A	
ANTHONY	0	37.1921	98.0754	0	3	E	GAS	G	0.0499	0	11.1		0	N/A	N/A	
ARTHUR MULLERGREN	0	38.4053	98.8694	1	1	T	GAS	G	0.3029	0	81.6		0	N/A	N/A	
ASHLAND	0	37.237	99.8243	0	5	E	OIL	O	0.0007	0	4.975		0	N/A	N/A	
BALDWIN	0	38.8985	95.2785	0	5	E	OIL	O	0.0064	0	7.085		0	N/A	N/A	
BELLEVILLE	0	39.8279	97.6503	0	7	E	GAS	G	0.0265	0	13.125	C		N/A		
BELOIT	0	39.3933	98.209	0	7	E	GAS	G	0.0261	0	19.35		0	N/A	N/A	
BIRD CITY	0	39.7857	101.7305	0	2	E	OIL	O	0.0028	0	4		0	N/A	N/A	
BURLINGAME	0	38.6519	95.7251	0	5	E	GAS	G	0.0323	0	4.594		0	N/A	N/A	
BURLINGTON	0	38.2363	95.7331	0	6	E	GAS	G	0.0371	0	8.5		0	N/A	N/A	
CHANUTE 2							GAS				4					
CHANUTE 3	0	37.5588	95.3066	0	5	E	GAS	G	0.0706	0	32.865		0	N/A	N/A	
CIMARRON RIVER	0	37.0592	100.9322	1	2	T,E	GAS	G	0.1794	0	65		0	N/A	N/A	
CLAY CENTER	0	39.3495	97.1649	0	8	E	GAS	G	0.1047	0	24.6		0	N/A	N/A	
CLIFTON	0	39.7841	97.0872	0	2	E	GAS	G	0.0278	0	88		0	N/A	N/A	
COFFEYVILLE	0	37.0475	95.5436	2	2	T,E	GAS	G	0.1572	0	58.75		0	N/A	N/A	
COLBY	0	39.4061	101.1267	0	1	E	GAS	G	0.0058	0	16		0	N/A	N/A	
COLBY	0	39.3507	101.0555	0	6	E	OIL	O	0.0009	0	17.36		0	N/A	N/A	
EAST 12TH STREET	0	37.2631	97.0717	1	1	T	GAS	G	0.0806	0	26.5		0	N/A	N/A	
ELLINWOOD	0	38.4789	98.756	0	5	E	GAS	G	0.0099	0	8.5		0	N/A	N/A	
ELLIS							COL				5.685					
FREDONIA	0	37.5593	95.7436	0	3	E	NG	G	0.1846	0	4.05	U	51983			Y
GARDEN CITY	0	38.0007	100.6644	1	4	T,E	GAS	G	0.0838	836.4	244		0	N/A	N/A	
GARDNER	0	38.8978	94.8318	0	2	E	GAS	G	0.0253	0	39.2		0	N/A	N/A	
GARNETT MUNICIPAL	0	38.2139	95.2917	0	8	E	OIL	O	0.0139	0	15.492		0	N/A	N/A	
GORDON EVANS EC	0	37.7903	97.5217	4	4	T	GAS	G	0.1404	5059.2	671		0	N/A	N/A	
GREAT BEND	0	38.4789	98.756	0	6	E	GAS	G	0.0077	0	10		0	N/A	N/A	
GREENSBURG	0	37.5583	99.2853	0	5	E	GAS	G	0.0225	0	7.8		0	N/A	N/A	
HERINGTON	0	38.8712	97.1354	0	5	E	OIL	O	0.0344	0	9.74		0	N/A	N/A	
HILL CITY	0	39.3498	99.8827	0	6	E	GAS	G	0.0088	0	7.265		0	N/A	N/A	
HOISINGTON	0	38.4789	98.756	0	5	E	GAS	G	0.0098	0	14.2		0	N/A	N/A	
HOLCOMB	0	37.9319	100.9719	1	1	T	COL	C	0.7251	3400	388		0	N/A	N/A	
HOLTON	0	39.4346	95.7998	0	6	E	GAS	G	0.0456	0	15.37		0	N/A	N/A	
HUGOTON 1	0	37.1919	101.3113	0	2	E	GAS	G	0.0427	0	2.24		0	N/A	N/A	
HUGOTON 2	0	37.1919	101.3113	0	7	E	GAS	G	0.2072	0	19.295		0	N/A	N/A	
HUTCHINSON EC	0	38.0892	97.8717	4	8	T,E	GAS	G	0.0563	2937.6	552		0	N/A	N/A	
IOLA	0	37.9367	95.3544	2	12	E	GAS	G	0.0438	0	38.5		0	N/A	N/A	
JEFFREY EC	0	39.2856	96.1083	3	3	T	COL	C	0.7611	20604	2160		0	N/A	N/A	
JOHNSON	0	37.5633	101.7838	0	7	E	GAS	G	0.0341	0	6.781		0	N/A	N/A	
JUDSON LARGE	0	37.7328	99.9492	1	1	T	GAS	G	0.3402	1496	148.75		0	N/A	N/A	
KANSAS CITY	0	39.0964	94.755	0	1	E	NG	G	0.2761	0	2	U	561371			Y
KANSAS RIVER PROJECT	0	38.8985	95.2785	0	7	Z	WAT		0.6637	0	2.637		0	N/A	N/A	Y
KANSAS STATE UNIVERSITY UTILITIES POWER PLANT	0	39.3049	96.6752	0	2	E	NG	G	0.0519	0	4	U	568000			Y
KAW	0	39.0864	94.6517	2	3	T	GAS	G	0.0568	1122	129		0	N/A	N/A	
KINGMAN	0	37.5589	98.1355	0	8	E	GAS	G	0.2717	0	21.55		0	N/A	N/A	

PNAME	PREV UTIL	LAT	LON	NUMBLR	NUMGEN	SOURCEM	PLPRIMFL	PLFFLCTG	CAPFAC	BOILCAP	NAMEPCAP	CHPFLAG	USETHRMO	PWRTOHT	ELCALLOC	PLNUCONN
LACYGNE	0	38.3481	94.6456	2	2	T	COL	C	0.6426	14848.48	1578		0	N/A	N/A	
LARNED	0	38.2072	99.1428	1	4	E	GAS	G	0.0586	0	19.25		0	N/A	N/A	
LAWRENCE EC	0	39.0078	95.2681	3	4	T	COL	C	0.4976	5537.92	603		0	N/A	N/A	
LINCOLN	0	39.0451	98.2089	0	6	E	OIL	O	0.0019	0	10.65		0	N/A	N/A	
LOVE BOX CO	0	37.6935	97.4801	0	3	E	NG	G	0.1883	0	2.175	U	50400			Y
MCPHERSON 2	0	38.3719	97.6869	1	4	T,E	GAS	G	0.0218	0	197		0	N/A	N/A	
MCPHERSON 3	0	38.3917	97.6479	1	1	T	GAS	G	0.0329	0	115.6		0	N/A	N/A	
MEADE	0	37.2377	100.3708	0	5	E	GAS	G	0.0742	0	8.2		0	N/A	N/A	
MINNEAPOLIS	0	39.1323	97.6504	0	7	E	GAS	G	0.0533	0	10.2		0	N/A	N/A	
MULVANE	0	37.6935	97.4801	0	6	E	GAS	G	0.0251	0	6.29		0	N/A	N/A	
MURRAY GILL EC	0	37.6935	97.4801	4	4	T	GAS	G	0.1225	3604	347		0	N/A	N/A	
NEARMAN CREEK	0	39.1714	94.6958	1	1	T	COL	C	0.7244	2380	261		0	N/A	N/A	
NEODESHA	0	37.5593	95.7436	0	4	E	OIL	O	0.0031	0	8.15		0	N/A	N/A	
NEOSHO	0	37.1917	95.2977	1	3	T	GAS	G	0.0425	0	109		0	N/A	N/A	
NORTON	0	39.7842	99.9034	0	5	E	GAS	G	0.0162	0	11.25		0	N/A	N/A	
OSAGE CITY	0	38.6519	95.7251	0	6	E	GAS	G	0.0279	0	9.45		0	N/A	N/A	
OSAWATOMIE	0	38.5637	94.8373	0	4	E	OIL	O	0.0072	0	7		0	N/A	N/A	
OSBORNE	0	39.3504	98.7677	0	8	E	OIL	O	0.0004	0	8.585		0	N/A	N/A	
PLANT NO 1	0	37.7817	96.8379	0	7	E	GAS	G	0.0222	0	9.742		0	N/A	N/A	
PLANT NO 2	0	37.7817	96.8379	0	3	E	GAS	G	0.0991	0	14		0	N/A	N/A	
PRATT	0	37.6842	98.7947	2	4	E	GAS	G	0.0517	0	23.5		0	N/A	N/A	
PRATT 2	0	37.6478	98.7394	0	1	E	OIL	O	0.0091	0	8		0	N/A	N/A	
QUINDARO	0	39.0878	94.6464	2	8	T,E	COL	C	0.2003	2312	487.97		0	N/A	N/A	
REPUBLIC PAPERBOARD CO INC							GAS				2.5					
RIVERTON	0	37.0667	94.7	2	5	T,E	COL	C	0.3761	0	132.64		0	N/A	N/A	
RUSSELL	0	38.9151	98.7628	0	10	E	GAS	G	0.1176	0	30.383		0	N/A	N/A	
SABETHA	0	39.7834	96.0135	0	10	E	GAS	G	0.0259	0	17.436		0	N/A	N/A	
SHARON SPRING	0	38.9163	101.7622	0	4	E	GAS	G	0.0063	0	3.117		0	N/A	N/A	
ST FRANCIS	0	39.7857	101.7305	0	4	E	OIL	O	0.0062	0	5.9		0	N/A	N/A	
ST JOHN	0	38.0427	98.747	0	3	E	OIL	O	0.0016	0	4.6		0	N/A	N/A	
STAFFORD	0	38.0427	98.747	0	5	E	GAS	G	0.0151	0	5.1		0	N/A	N/A	
STERLING	0	38.3476	98.201	0	4	E	GAS	G	0.0228	0	6.155		0	N/A	N/A	
STOCKTON	0	39.3503	99.3244	0	5	E	OIL	O	-0.0048	0	6.294		0	N/A	N/A	
TECUMSEH EC	0	39.0528	95.5683	2	4	T,E	COL	C	0.5251	2359.6	290		0	N/A	N/A	
WAMEGO	0	39.3463	96.366	0	9	E	GAS	G	0.0308	0	12.995		0	N/A	N/A	
WASHINGTON	0	39.7841	97.0872	0	7	E	GAS	G	0.0066	0	9.136		0	N/A	N/A	
WELLINGTON CITY	0	37.2379	97.4773	0	1	E	GAS	G	0.0726	0	20		0	N/A	N/A	
WELLINGTON MUNICIPAL	0	37.2833	97.4703	1	2	E	GAS	G	0.0683	0	21		0	N/A	N/A	
WEST 14TH STREET	0	37.2631	97.0717	0	1	E	GAS	G	0.0123	0	11		0	N/A	N/A	
WICHITA PLANT	0	37.6935	97.4801	0	1	E	NG	G	0.0659	0	32.7	U	162107			Y
WOLF CREEK	0	38.2363	95.7331	0	1	Z	UR		0.837	0	1235.79		0	N/A	N/A	
ANIMAS	0	36.51	108.33	1	6	E	GAS	G	0.4569	0	50.3		0	N/A	N/A	
BLANCO COMPRESSOR STATION	0	36.5003	108.2327	0	2	E	NG	G	0.9251	0	3		0	N/A	N/A	Y
CARLSBAD	0	32.4827	104.2867	0	1	E	GAS	G	0.0244	0	16.32		0	N/A	N/A	
CHINO MINES CO	0	32.5365	108.3272	0	2	E	NG	G	0.4349	0	46.5		0	N/A	N/A	Y
CINIZA REFINERY	0	35.4809	108.1758	0	2	E	NG	G	0.8167	0	6	U	316880			Y
COGENERATION PLANT	0	35.0442	106.6727	0	1	E	NG	G	0.5867	0	2.5	U	1550000			Y
CUNNINGHAM	0	32.7131	103.3533	4	4	T	GAS	G	0.3195	2754	519.2		0	N/A	N/A	
ELEPHANT BUTTE	0	33.0429	107.17	0	1	Z	WT		0.3713	0	27.945		0	N/A	N/A	
ESCALANTE	0	35.4144	108.0825	1	1	T	COL	C	0.8841	2416.72	233	U	988800			
FORD UTILITIES CENTER	0	35.0442	106.6727	0	1	E	NG	G	0.332	0	1.5	U	508375			Y
FOUR CORNERS	0	36.6906	108.4822	5	5	T	COL	C	0.7509	20461.2	2269.8		0	N/A	N/A	
HIDALGO SMELTER	0	32.0549	108.6283	0	5	E	NG	G	0.1124	0	37.5	U	105.43			Y
LAS VEGAS	0	35.4563	104.6792	0	1	E	OIL	O	0.0227	0	20		0	N/A	N/A	
MADDOX	0	32.7131	103.3017	1	3	T,E	GAS	G	0.3337	1101.6	213		0	N/A	N/A	
MILAGRO COGENERATION PLANT	0	36.5003	108.2327	2	2	T,E	NG	G	0.9426	0	60.8	U	782840			Y
NAVAJO DAM	0	36.5003	108.2327	0	1	Z	WT		0.4934	0	30		0	N/A	N/A	
NEW MEXICO STATE UNIVERSITY	0	32.4202	106.8195	0	1	E	NG	G	0.8461	0	4.75	U	158145			Y
PHELPS DODGE COBRE MINING CO							FO1				1.6					
PHELPS DODGE TYRONE INC	0	32.5365	108.3272	0	15	E	DFO	O	0.1344	0	45.4		0	N/A	N/A	Y
RATON	0	36.6	104.65	2	3	E	COL	C	0.2924	0	12.75	C		N/A		
REEVES	0	35.0442	106.6727	3	3	T	GAS	G	0.165	2108	154		0	N/A	N/A	
RIO GRANDE	0	31.805	106.5475	3	3	T	GAS	G	0.4177	2627.52	266.5		0	N/A	N/A	
SAN JUAN	0	36.8833	108.4833	4	4	T	COL	C	0.7948	17968.32	1779		0	N/A	N/A	
SAN JUAN BASIN GAS PLANT	0	36.5003	108.2327	0	4	E	NG	G	0.9737	0	8.06		0	N/A	N/A	Y
SOUTHSIDE WATER RECLAMATION PLANT	0	35.0442	106.6727	0	2	E	NG	G	0.8867	0	2.27	U	46609			Y
TUCUMCARI	0	35.1724	103.585	0	7	E	OIL	O	0.0007	0	17.45		0	N/A	N/A	
WILLIAMS FIELD SERVICES KUTZ PLANT	0	36.5003	108.2327	0	2	E	NG	G	0.3155	0	4.8	U	69249			Y
AES SHADY POINT INC	0	34.9471	94.7464	0	2	E	SUB	C	0.7568	0	350	U	1453224			Y
ANADARKO	0	35.0844	98.2256	3	6	T,E	GAS	G	0.4596	0	374		0	N/A	N/A	
BOOMER LAKE STATION	0	36.094	96.9874	2	2	E	GAS	G	0.1447	0	22.7		0	N/A	N/A	
BROKEN BOW	0	34.0615	94.8087	0	1	Z	WT		0.1373	0	100		0	N/A	N/A	
CALPINE PRYOR INC	0	36.2925	95.2225	0	7	E	NG	G	0.2606	0	133.2	U	1771682			Y
CHANEY DELL PLANT	0	36.334	98.5319	0	3	E	NG	G	0.4035	0	2.35		0	N/A	N/A	Y
COMANCHE	0	34.5542	98.2061	2	4	T	GAS	G	0.6316	1338.24	280.822		0	N/A	N/A	
CONOCO	0	36.7963	97.106	2	2	T	GAS	G	0.3673	0	66	C		N/A		
CUSHING	0	36.094	96.9874	0	11	E	GAS	G	0.006	0	24.6		0	N/A	N/A	
ENID	0	36.3792	97.7825	0	4	E	GAS	G	0.0085	0	60		0	N/A	N/A	

PNAME	PREV UTIL	LAT	LON	NUMBLR	NUMGEN	SOURCEM	PLPRIMFL	PLFFLCTG	CAPFAC	BOILCAP	NAMEPCAP	CHPFLAG	USETHRMO	PWRTOHT	ELCALLOC	PLNUCONN
EUFAULA	0	35.2581	95.1344	0	1	Z	WT		0.3416	0	90		0	N/A	N/A	
FORT GIBSON	0	35.9	95.0307	0	1	Z	WT		0.393	0	45		0	N/A	N/A	
GRDA	0	36.1889	95.2892	2	2	T	COL	C	0.7101	10336	1010		0	N/A	N/A	
HORSESHOE LAKE	0	35.5089	97.1875	5	4	T	GAS	G	0.1347	7235.2	851		0	N/A	N/A	
HUGO	0	34.0292	95.3167	1	1	T	COL	C	0.793	4284	400		0	N/A	N/A	
KAW HYDRO	0	36.7963	97.106	0	1	Z	WT		0.5482	0	25.6		0	N/A	N/A	
KEYSTONE	0	36.1397	96.0295	0	1	Z	WT		0.5002	0	70		0	N/A	N/A	
KINGFISHER	0	35.9451	97.9419	0	5	E	GAS	G	0.0142	0	9.1		0	N/A	N/A	
MANGUM	0	34.9208	99.5673	0	6	E	GAS	G	0.0272	0	7.635		0	N/A	N/A	
MARKHAM	0	36.2925	95.2225	0	1	Z	WT		0.1393	0	120		0	N/A	N/A	
MOORELAND	0	36.4375	99.2208	3	3	T	GAS	G	0.2514	3424.48	305		0	N/A	N/A	
MUSKOGEE	0	35.7653	95.2883	4	4	T	COL	C	0.6256	17233.92	1889		0	N/A	N/A	
MUSKOGEE MILL	0	35.56	95.408	0	3	E	SUB	C	0.5187	0	114	U	2280000			Y
MUSTANG	0	35.4814	97.675	4	6	T,E	GAS	G	0.1547	5317.6	610		0	N/A	N/A	
NORTHEASTERN	0	36.4222	95.7047	4	5	T,E	COL	C	0.627	14824	1498.68		0	N/A	N/A	
OKLAHOMA STATE UNIVERSITY	0	36.094	96.9874	0	3	E	NG	G	0.1769	0	8	U	286485			Y
PENSACOLA	0	36.2925	95.2225	0	1	Z	WT		0.2661	0	110.9		0	N/A	N/A	
PONCA	0	36.82	97.15	2	2	T	GAS	G	0.0203	0	68.2		0	N/A	N/A	
PONCA CITY REFINERY	0	36.7963	97.106	0	3	E	OG		0.3844	0	18	U	3686236			Y
PONCA DIESEL	0	36.7963	97.106	0	7	E	GAS	G	0.405	0	28.3		0	N/A	N/A	
POWERSMITH COGEN PROJECT	0	35.5514	97.4072	0	2	E	NG	G	0.7275	0	111.51	U	733413			Y
RIVERSIDE	0	35.9858	95.9519	2	3	T,E	GAS	G	0.4228	8840	885.26		0	N/A	N/A	
ROBERT S KERR	0	35.468	94.7817	0	1	Z	WT		0.599	0	110		0	N/A	N/A	
SALINA	0	36.2925	95.2225	0	1	Z	WT		-0.0505	0	288		0	N/A	N/A	
SEMINOLE	0	34.9664	96.7258	3	4	T,E	GAS	G	0.2428	15387.04	1724		0	N/A	N/A	
SOONER	0	36.4544	97.05	2	2	T	COL	C	0.7294	10423.04	1136		0	N/A	N/A	
SOUTHWESTERN	0	35.1014	98.3531	4	4	T,E	GAS	G	0.2676	4392.8	450.992		0	N/A	N/A	
TENKILLER FERRY	0	35.468	94.7817	0	1	Z	WT		0.2937	0	39.1		0	N/A	N/A	
TULSA	0	36.1014	95.9892	3	4	T,E	GAS	G	0.0998	4331.6	443.25		0	N/A	N/A	
UNIVERSITY OF OKLAHOMA	0	35.1534	97.4062	0	4	E	NG	G	0.1003	0	16.8	U	498713			Y
VALLIANT OK	0	34.0615	94.8087	0	1	E	BL		0.3817	0	57.8	U	13092688			Y
WALTER B HALL RESOURCE RECOVERY FACILITY	0	36.1397	96.0295	0	1	E,W	MWC		0.0273	0	16.8	U	18938			Y
WEBBERS FALLS	0	35.56	95.408	0	1	Z	WT		0.4185	0	60		0	N/A	N/A	
WELEETKA	0	35.4644	96.3029	0	4	E	GAS	G	0.0252	0	163		0	N/A	N/A	
WOODWARD	0	36.4837	99.2806	0	1	E	GAS	G	0.0015	0	11		0	N/A	N/A	
WRIGHT CITY OK	0	34.0615	94.8087	0	1	E	WDS		0.6064	0	5	U	1752303			Y
ABBOTT TP 3	0	29.6175	97.9721	0	1	Z	WT		0.3091	0	2.8		0	N/A	N/A	
ABILENE	1	32.3	99.89	2	1	E	GAS	G	0.0729	0	15		0	N/A	N/A	Y
AES DEEPWATER INC	0	29.8336	95.4383	0	1	E	PC	O	0.7707	0	184	U	122143			Y
AMISTAD DAM & POWER	0	29.7652	101.2299	0	1	Z	WT		0.1488	0	66		0	N/A	N/A	
AUSTIN	0	30.3241	97.7711	0	1	Z	WT		0.1965	0	16.136		0	N/A	N/A	
AUSTIN STATE HOSPITAL	0	30.3241	97.7711	0	1	E	NG	G	0.7855	0	1	U	32324			Y
BARNEY M DAVIS	1	27.6064	97.3117	2	2	T	GAS	G	0.6096	6474.96	647.143		0	N/A	N/A	Y
BAYLOR UNIVERSITY COGENERATION	0	31.5536	97.2029	0	1	E	NG	G	0.7205	0	3.447	U	157222			Y
BAYOU COGENERATION PLANT	0	29.8336	95.4383	0	4	E	NG	G	0.9761	0	300	U	11000000			Y
BAYTOWN TURBINE GENERATOR PROJECT	0	29.8336	95.4383	0	4	E	NG	G	0.8039	0	212	U	7007900			Y
BEAUMONT REFINERY	0	29.8641	94.135	0	9	E	NG	G	0.5568	0	204.84	U	1657046			Y
BENEDUM PLANT	0	31.3656	102.0461	0	2	E	NG	G	0.2639	0	2		0	N/A	N/A	Y
BIG BROWN	1	31.8206	96.0547	2	2	T	COL	C	0.8219	10948	1186.8		0	N/A	N/A	Y
BIG SPRING TEXAS REFINERY	0	32.3059	101.4342	0	1	E	NG	G	0.9336	0	1.5	U	6357887			Y
BIG SPRING WIND POWER FACILITY	0	32.3059	101.4342	0	1	Z	WND		0.3332	0	34.32		0	N/A	N/A	Y
BLACK HAWK STATION	0	35.8398	101.3542	2	2	T,E	NG	G	0.6683	0	253.8	U	1000000			Y
BORGER PLANT	0	35.8398	101.3542	0	1	E	OG		0.7054	0	37.5	U	1701698			Y
BP CHEMICALS GREEN LAKE PLANT	0	28.3954	96.6261	0	2	E	OG		0.6315	0	38.8		0	N/A	N/A	Y
BRANDON STATION	0	33.6096	101.8209	0	1	E	GAS	G	0.7484	0	21	C		N/A		
BRIDGEPORT GAS PROCESSING PLANT	0	33.2125	97.6518	0	4	E	NG	G	0.5969	0	1.52		0	N/A	N/A	Y
BROWNFIELD	0	33.1732	102.3346	0	6	E	GAS	G	0.0044	0	21.92		0	N/A	N/A	
BRYAN	0	30.6442	96.3725	4	5	T,E	GAS	G	0.0847	1455.2	138		0	N/A	N/A	
BUCHANAN	0	30.7304	98.1415	0	1	Z	WT		0.0637	0	47.85		0	N/A	N/A	
C E NEWMAN	0	32.9125	96.6228	5	5	T,E	GAS	G	0.0616	0	96.5		0	N/A	N/A	
C R WING COGENERATION PLANT	0	32.3059	101.4342	0	3	E	NG	G	0.6773	0	230.08	U	1039812			Y
CANYON	0	29.816	98.3222	0	1	Z	WT		0.1437	0	6		0	N/A	N/A	
CEDAR BAYOU	1	29.75	94.9256	3	3	T	GAS	G	0.4079	21148	2295		0	N/A	N/A	Y
CELANESE ENGINEERING RESIN INC	0	27.777	97.4878	0	2	E	NG	G	0.7445	0	43.74	U	1465000			Y
CENTRAL UTILITY PLANT	0	30.3241	97.7711	0	3	E	NG	G	0.2534	0	14.46	U	75500			Y
CHOCOLATE BAYOU PLANT	0	29.2062	95.4646	0	4	E	NG	G	0.1901	0	55.3	U	2400036			Y
CHOCOLATE BAYOU WORKS	0	29.2062	95.4646	0	1	E	NG	G	0.7932	0	41	U	1982666			Y
CLEAR LAKE COGENERATION LTD	0	29.8336	95.4383	0	5	E	NG	G	0.8982	0	377	U	239306			Y
COGEN LYONDELL INC	0	29.8336	95.4383	0	7	E	NG	G	0.806	0	564	U	11365650			Y
COGEN POWER LP							WH				5					
COLEMAN	0	31.7606	99.4588	0	9	E	GAS	G	0.0039	0	16.86		0	N/A	N/A	
COLETO CREEK	1	28.7128	97.2142	1	1	T	COL	C	0.966	5710.64	570.057		0	N/A	N/A	Y
COLLIN	1	33.2028	96.8108	1	1	T	GAS	G	0.2172	1564	156.25		0	N/A	N/A	Y
COMANCHE PEAK	1	32.2029	97.7801	0	1	Z	UR		0.8671	0	2430		0	N/A	N/A	Y
COPPER	0	31.6948	106.3128	0	1	E	GAS	G	0.1218	0	80.55		0	N/A	N/A	
CORPUS CHRISTI PLANT	0	27.777	97.4878	0	1	E	NG	G	0.7237	0	45.176	U	2346327			Y
CORPUS CHRISTI REFINERY	0	27.777	97.4878	0	2	E	NG	G	0.8597	0	40	U	2243006			Y
DANSBY	0	30.7217	96.4611	1	1	T	GAS	G	0.3756	1054	105		0	N/A	N/A	

PNAME	PREV UTIL	LAT	LON	NUMBLR	NUMGEN	SOURCEM	PLPRIMFL	PLFFLCTG	CAPFAC	BOILCAP	NAMEPCAP	CHPFLAG	USETHRMO	PWRTOHT	ELCALLOC	PLNUCONN
DECKER CREEK	0	30.3036	97.6128	2	7	T,E	GAS	G	0.2726	7106	932.58		0	N/A	N/A	
DECORDOVA	1	32.4017	97.7186	1	5	T,E	GAS	G	0.4038	7405.2	1157.112		0	N/A	N/A	Y
DEEPWATER	1	29.7231	95.2261	1	1	T	GAS	G	0.1161	1632	187.85		0	N/A	N/A	Y
DEER PARK PLANT	0	29.8336	95.4383	0	4	E	NG	G	0.7939	0	111.06	U	1565872			Y
DELAWARE MOUNTAIN WINDFARM	0	29.8336	95.4383	0	1	Z	WND		0.2863	0	30		0	N/A	N/A	Y
DENISON	0	33.6763	96.6622	0	1	Z	WT		0.3165	0	70		0	N/A	N/A	
DFW GAS RECOVERY	0	33.2075	97.116	0	2	E	LFG		0.8128	0	6		0	N/A	N/A	Y
DUNLAP TP 1	0	29.6175	97.9721	0	1	Z	WT		0.3679	0	3.6		0	N/A	N/A	
E S JOSLIN	1	28.65	96.5417	1	1	T	GAS	G	0.2922	2167.84	234.874		0	N/A	N/A	Y
EAGLE MOUNTAIN	1	32.9058	97.4794	3	3	T	GAS	G	0.1513	6589.2	706.15		0	N/A	N/A	Y
EAGLE PASS	1	28.643	100.3891	0	1	Z	WT		0.4623	0	12		0	N/A	N/A	Y
EAST TEXAS GAS PLANT	0	32.183	94.3071	0	7	E	NG	G	0.5608	0	2.2		0	N/A	N/A	Y
EAST VEALMOOR GAS PLANT	0	32.3059	101.4342	0	7	E	NG	G	0.5076	0	1.925		0	N/A	N/A	N
EDGEWOOD GAS PLANT							GAS				3					
ENCOGEN ONE	0	32.3034	100.4054	0	4	E	NG	G	0.7104	0	265.97	U	1209179			Y
ENGINEERED CARBONS BORGER COGENERATION	0	35.8398	101.3542	0	1	E	OG		0.7178	0	20		0	N/A	N/A	Y
ENGINEERED CARBONS ECHO COGENERATION	0	30.0547	93.9088	0	1	E	OG		0.2438	0	10		0	N/A	N/A	Y
ENTERPRISE PRODUCTS OPERATING LP	0	29.7077	94.6667	0	8	E	NG	G	0.8433	0	25.7	U	874000			Y
EXXON HAWKINS GAS PLANT	0	32.7806	95.4085	0	5	E	NG	G	0.3053	0	7.51		0	N/A	N/A	Y
EXXON MOBIL CO USA BAYTOWN PP3 PP4	0	29.8336	95.4383	0	11	E	NG	G	0.873	0	215	U	10071900			Y
FALCON DAM & POWER	0	26.5177	98.7449	0	1	Z	WT		0.1504	0	31.5		0	N/A	N/A	
FAYETTE POWER PRJ	0	29.9172	96.7506	3	3	T	COL	C	0.8019	15702.56	1690		0	N/A	N/A	
FORMOSA UTILITY VENTURE LTD	0	28.3954	96.6261	0	8	E	NG	G	0.6723	0	652.2	U	12276495			Y
FORT BEND UTILITIES CO	0	29.5254	95.7569	0	4	E	NG	G	0.5046	0	6.155	U	1166338			Y
FORT PHANTOM	1	32.5825	99.6825	2	2	T	GAS	G	0.4489	3404.08	337.322		0	N/A	N/A	Y
FORT STOCKTON	1	30.7119	102.6783	0	1	E	GAS	G	0.0004	0	5		0	N/A	N/A	Y
FREEPORT	0	29.2062	95.4646	0	2	E	NG	G	0.7962	0	92.7	U	8541096			Y
FRONTERA GENERATION FACILITY	0	26.4226	98.2239	2	3	T,E	NG	G	0.338	0	511		0	N/A	N/A	Y
FULLERTON PLANT	0	32.305	102.6376	0	6	E	NG	G	0.5842	0	3		0	N/A	N/A	Y
GIBBONS CREEK	0	30.6167	96.0778	1	1	T	COL	C	0.8444	4488	443.97		0	N/A	N/A	
GRAHAM	1	33.1347	98.6119	2	2	T	GAS	G	0.4124	5780	634.775		0	N/A	N/A	Y
GRANITE SHOALS	0	30.7304	98.1415	0	1	Z	WT		0.1031	0	45		0	N/A	N/A	
GREENS BAYOU	1	29.8208	95.2183	1	7	T,E	GAS	G	0.1162	4153.44	878.4		0	N/A	N/A	Y
H 4	0	29.447	97.4944	0	1	Z	WT		0.3193	0	2.4		0	N/A	N/A	
H 5	0	29.447	97.4944	0	1	Z	WT		0.0132	0	2.4		0	N/A	N/A	
HANDLEY	1	32.7286	97.2192	6	5	T	GAS	G	0.2396	13791.76	1433.35		0	N/A	N/A	Y
HARRINGTON	0	35.2989	101.7475	3	3	T	COL	C	0.8487	10942.56	1080		0	N/A	N/A	
HIRAM CLARKE	1	29.6483	95.4508	0	6	E	GAS	G	0.0236	0	96		0	N/A	N/A	Y
HOLLY STREET	0	30.25	97.7167	4	4	T	GAS	G	0.2547	5032	558		0	N/A	N/A	
HOUSTON CHEMICAL COMPLEX BATTLEGROUND SITE	0	29.8336	95.4383	0	3	E	NG	G	0.8644	0	200	U	4718770			Y
INGLESIDE COGENERATION	0	28.0115	97.5202	0	3	E	NG	G	0.625	0	528	U	11091649			Y
INKS	0	30.7304	98.1415	0	1	Z	WT		0.1037	0	15		0	N/A	N/A	
INLAND PAPERBOARD AND PACKAGING	0	30.0547	93.9088	0	1	E	BL		0.6379	0	48	U	5778000			Y
J K SPRUCE	0	29.3064	98.3203	1	1	T	COL	C	0.832	5191.12	546		0	N/A	N/A	
J L BATES	1	26.2167	98.4083	2	2	T	GAS	G	0.3588	1842.8	166		0	N/A	N/A	Y
J ROBERT MASSENGALE	0	33.61	101.8	6	5	T,E	GAS	G	0.0817	0	107		0	N/A	N/A	
J T DEELY	0	29.3072	98.3228	2	2	T	COL	C	0.7083	7888	892		0	N/A	N/A	
JAMESON GAS PROCESSING PLANT	0	31.8895	100.53	0	3	E	NG	G	0.9353	0	1.25		0	N/A	N/A	Y
JCO OXIDES OLEFINS PLANT	0	29.8641	94.135	0	2	E	NG	G	0.8289	0	77.2	U	2627352			Y
JONES	0	33.5239	101.7397	2	2	T	GAS	G	0.546	4849.76	496		0	N/A	N/A	
KNOX LEE	0	32.3744	94.6431	4	4	T	GAS	G	0.3226	4942.24	458.694		0	N/A	N/A	
KOCH PETROLEUM GROUP LP CORPUS REFINERY	0	27.777	97.4878	0	1	E	NG	G	0.5588	0	55	U	550000			Y
LA PALMA	1	26.1333	97.6389	3	4	T,E	GAS	G	0.2888	2045.44	242.325		0	N/A	N/A	Y
LAKE CREEK	1	31.4633	96.9867	2	5	T,E	GAS	G	0.3198	4216	321.625		0	N/A	N/A	Y
LAKE HUBBARD	1	32.8361	96.5461	2	2	T	GAS	G	0.3281	8602	927.519		0	N/A	N/A	Y
LAKE PAULINE	1	34.3	99.74	4	2	E	GAS	G	0.0677	0	40		0	N/A	N/A	Y
LAREDO	1	27.5667	99.5089	3	3	T	GAS	G	0.4992	1890.4	168.29		0	N/A	N/A	Y
LEON CREEK	0	29.3508	98.575	2	2	T	GAS	G	0.0547	1972	189		0	N/A	N/A	
LEWIS CREEK	0	30.4367	95.5478	2	2	T	GAS	G	0.6005	4588.64	542.8		0	N/A	N/A	
LEWISVILLE	0	33.2075	97.116	0	1	Z	WT		0.0974	0	2.8		0	N/A	N/A	
LIMESTONE	1	31.4222	96.2525	2	2	T	COL	C	0.7936	15014.4	1626.8		0	N/A	N/A	Y
LON C HILL	1	27.85	97.6167	4	4	T	GAS	G	0.3452	5377.44	510.874		0	N/A	N/A	Y
LONE STAR	0	32.9125	94.7131	1	1	T	GAS	G	0.1611	0	40		0	N/A	N/A	
LONE STAR STEEL CO	0	33.1216	94.7358	0	2	E	NG	G	0.0123	0	31.25		0	N/A	N/A	Y
LUFKIN TEXAS	0	31.2763	94.5662	0	6	E	NG	G	0.5576	0	84.926	U	5257304			Y
MARBLE FALLS	0	30.7304	98.1415	0	1	Z	WT		0.0966	0	30		0	N/A	N/A	
MARSHALL FORD	0	30.3241	97.7711	0	1	Z	WT		0.0925	0	102.545		0	N/A	N/A	
MARTIN LAKE	1	32.2606	94.5708	3	3	T	COL	C	0.7926	22032	2379.75		0	N/A	N/A	Y
MIDKIFF PLANT	0	31.3656	102.0461	0	3	E	NG	G	0.5791	0	3.6		0	N/A	N/A	Y
MISSION ROAD	0	29.3975	98.4883	1	1	T	GAS	G	0.0557	1020	114		0	N/A	N/A	
MONTICELLO	1	33.0917	95.0417	3	3	T	COL	C	0.7132	18460.64	1980.05		0	N/A	N/A	Y
MOORE COUNTY	0	35.8377	101.8925	1	1	T	GAS	G	0.1218	0	49		0	N/A	N/A	
MORGAN CREEK	1	32.3361	100.9156	5	11	T,E	GAS	G	0.301	8758.4	1364.223		0	N/A	N/A	Y
MORRIS SHEPPARD	0	32.7596	98.3157	0	1	Z	WT		0.0161	0	25		0	N/A	N/A	
MORTON SALT CO GRAND SALINE	0	32.5966	95.7626	0	1	E	NG	G	0.6421	0	1.5	U	326928			Y
MOUNTAIN CREEK	1	32.7233	96.9361	6	5	T	GAS	G	0.2719	9288.8	958.491		0	N/A	N/A	Y
MUSTANG STATION	0	33.1735	102.8289	2	3	T,E	NG	G	0.5298	0	521.055		0	N/A	N/A	Y
NEWGULF	0	29.2983	96.2438	1	2	T,E	NG	G	0.0366	0	91.25		0	N/A	N/A	Y

PNAME	PREV UTIL	LAT	LON	NUMBLR	NUMGEN	SOURCEM	PLPRIMFL	PLFFLCTG	CAPFAC	BOILCAP	NAMEPCAP	CHPFLAG	USETHRMO	PWRTOHT	ELCALLOC	PLNUCONN
NEWMAN	0	31.9842	106.4319	5	6	T	GAS	G	0.4148	3582.24	568.375		0	N/A	N/A	
NICHOLS	0	35.2831	101.7458	3	3	T	GAS	G	0.2383	4600.88	476		0	N/A	N/A	
NOLTE	0	29.6175	97.9721	0	1	Z	WT		0.2964	0	2.4		0	N/A	N/A	
NORIT AMERICAS INC MARSHALL PLANT	0	32.5618	94.3725	0	1	E	LIG	C	0.6896	0	2	U	2789130			Y
NORTH LAKE	1	32.9506	96.975	3	3	T	GAS	G	0.3093	6840.8	708.605		0	N/A	N/A	Y
NORTH MAIN	1	32.7608	97.3364	1	3	T	GAS	G	0.1429	0	116.25		0	N/A	N/A	Y
NORTH RILEY	0	31.8691	102.0313	0	2	E	NG	G	0.8912	0	2	U	31260			Y
NORTH TEXAS	0	32.7803	97.6953	3	3	T,E	GAS	G	0.0502	0	71		0	N/A	N/A	
NUECES BAY	1	27.8169	97.4167	3	3	T	GAS	G	0.5054	5146.24	513.694		0	N/A	N/A	Y
O W SOMMERS	0	29.3078	98.3244	2	2	T	GAS	G	0.3282	7833.6	892		0	N/A	N/A	
OAK CREEK	1	31.89	100.53	1	1	T	GAS	G	0.4979	0	75		0	N/A	N/A	Y
OKLAUNION	1	34.0825	99.1753	1	1	T	COL	C	0.7667	6664	663.943		0	N/A	N/A	Y
OYSTER CREEK UNIT VIII	0	29.8336	95.4383	0	4	E	NG	G	0.6606	0	498.045	U	7915000			Y
P H ROBINSON	1	29.4869	94.9797	4	4	T	GAS	G	0.4591	21243.2	2314.5		0	N/A	N/A	Y
PAINT CREEK	1	33.0811	99.5778	4	4	T	GAS	G	0.2332	2386.8	218.145		0	N/A	N/A	Y
PARKDALE	1	32.7767	96.7236	3	3	T	GAS	G	0.2057	3910	340.625		0	N/A	N/A	Y
PASADENA	0	29.8336	95.4383	0	1	E	NG	G	0.6074	0	4	U	276646			Y
PASADENA COGENERATION LP	0	29.8336	95.4383	3	5	T,E	NG	G	0.2842	0	760.9	U	1149467			Y
PEARSALL	0	29.0939	99.4122	3	3	E	GAS	G	0.0912	0	66		0	N/A	N/A	
PERMIAN BASIN	1	31.5839	102.9636	2	7	T,E	GAS	G	0.3218	6290	1097.844		0	N/A	N/A	Y
PHELPS DODGE REFINING CORP	0	31.6948	106.3128	0	5	E	NG	G	0.5299	0	19.81	U	301102			Y
PIRKEY	0	32.4606	94.485	1	1	T	COL	C	0.7528	6664	660.402		0	N/A	N/A	
PLANT X	0	34.1661	102.4111	4	4	T	GAS	G	0.2272	4692	434.4		0	N/A	N/A	
PORT ARTHUR REFINERY	0	29.8641	94.135	0	7	E	NG	G	0.6387	0	125.35	U	16653725			Y
PORT ARTHUR REFINERY	0	29.8641	94.135	0	6	E	NG	G	0.6791	0	74.75	U	4709609			Y
PORT ARTHUR TEXAS REFINERY	0	29.8641	94.135	0	1	E	OG		0.7878	0	38.4	U	100000			Y
POWER STATION 3	0	29.3171	94.9773	0	6	E	NG	G	0.3552	0	118.127	U	1217154			Y
POWER STATION 4	0	29.3171	94.9773	0	3	E	NG	G	0.8621	0	191.123	U	9875328			Y
POWERLANE PLANT	0	33.1744	96.1256	3	3	T,E	GAS	G	0	0	84.7		0	N/A	N/A	
PPG INDUSTRIES INC WORKS 4	0	34.0121	98.6874	0	4	E	DFO	O	0.015	0	6.03		0	N/A	N/A	Y
PRESIDIO	1	29.9458	104.386	0	2	E	OIL	O	0.0008	0	2.272		0	N/A	N/A	Y
PROVIDENCE MEMORIAL HOSPITAL	0	31.6948	106.3128	0	2	E	DFO	O	0.0032	0	4.36	U	297			Y
PT COMFORT OPERATIONS	0	28.3954	96.6261	0	4	E	NG	G	0.6603	0	63.1	U	9415173			Y
PT NECHES PLANT	0	29.8641	94.135	0	1	E	NG	G	0.8171	0	38	U	947247.04			Y
R W MILLER	0	32.6581	98.3103	5	5	T	GAS	G	0.3375	4012	603.636		0	N/A	N/A	
RAY OLINGER	0	33.0681	96.4528	3	3	T	GAS	G	0.3594	3595.84	345		0	N/A	N/A	
RAY ROBERTS	0	33.2075	97.116	0	1	Z	WT		0.2127	0	1.2		0	N/A	N/A	
REYNOLDS METALS CO SHERWIN PLANT	0	27.777	97.4878	0	6	E	NG	G	0.7438	0	39	U	4706568			Y
RHODIA INC HOUSTON PLANT	0	29.8336	95.4383	0	2	E	OTS		0.8915	0	6.5	U	1130851			Y
RICE UNIVERSITY	0	29.8336	95.4383	0	2	E	NG	G	0.5298	0	7.106	U	256190			Y
RIO GRANDE VALLEY SUGAR GROWERS INC	0	26.1416	97.5059	0	3	E	AB		0.23	0	7.5	U	2525123			Y
RIO PECOS	1	31.0867	102.3694	2	3	T	GAS	G	0.4316	1441.6	126.968		0	N/A	N/A	Y
RIVER CREST	1	33.3933	95.1467	1	1	T	GAS	G	0.1857	1292	112.5		0	N/A	N/A	Y
RIVERVIEW	0	35.8398	101.3542	0	1	E	GAS	G	0.0282	0	25		0	N/A	N/A	
ROBERT D WILLIS	0	30.6999	93.9944	0	1	Z	WT		0.4958	0	7.2		0	N/A	N/A	
ROBSTOWN	0	27.777	97.4878	0	8	E	GAS	G	0.1684	0	21.071		0	N/A	N/A	
S&L COGENERATION	0	29.3171	94.9773	0	1	E	NG	G	0.6087	0	55	U	1767492			Y
SABINE	0	30.0206	93.8753	5	5	T	GAS	G	0.4748	18126.08	2051.2		0	N/A	N/A	
SABINE RIVER WORKS	0	30.0547	93.9088	0	4	E	NG	G	0.8035	0	105.525	U	4248993			Y
SAM BERTRON	1	29.7297	95.1719	4	6	T,E	GAS	G	0.2437	5372	875.26		0	N/A	N/A	Y
SAM RAYBURN	0	28.79	96.98	1	5	E	GAS	G	0.0512	0	47.7		0	N/A	N/A	
SAM RAYBURN	0	30.6999	93.9944	0	1	Z	WT		0.0813	0	52		0	N/A	N/A	
SAN ANGELO	1	31.3933	100.4922	1	2	T	GAS	G	0.786	811.92	110		0	N/A	N/A	Y
SAN JACINTO SES	1	29.8336	95.4383	2	2	T	GAS	G	0.8849	0	176.4	C		N/A		Y
SAN MIGUEL	0	28.7089	98.4722	1	1	T	COL	C	0.8297	4153.44	410		0	N/A	N/A	
SANDOW	1	30.5642	97.0639	1	1	T	COL	C	0.6874	5610	590.64		0	N/A	N/A	Y
SANDOW	0	30.7839	96.9655	0	3	E	LIG	C	0.8791	0	363		0	N/A	N/A	Y
SEADRIFT COKE LP	0	28.3954	96.6261	0	1	E	OG		0.5954	0	7.6	U	952672			Y
SEADRIFT PLANT UNION CARBIDE CORP	0	28.3954	96.6261	0	8	E	NG	G	0.5806	0	168	U	696378			Y
SEGUIN							OIL				0.5					
SHELDON TEXAS	0	29.8336	95.4383	0	3	E	NG	G	0.2809	0	97.25	U	3877785			Y
SHELL DEER PARK	0	29.8336	95.4383	0	4	E	NG	G	0.8373	0	250	U	21909268			Y
SI RAY	0	25.9131	97.5222	2	4	T,E	GAS	G	0.0868	0	145		0	N/A	N/A	
SIM GIDEON	0	30.1417	97.275	3	3	T	GAS	G	0.3957	5221.04	639		0	N/A	N/A	
SMALL HYDRO OF TEXAS INC	0	29.0987	97.3657	0	3	Z	WAT		0.2268	0	1.767		0	N/A	N/A	Y
SNIDER INDUSTRIES INC	0	32.5618	94.3725	0	1	E	WDS		0.3322	0	5	U	230265			Y
SOUTH TEXAS	1	28.806	95.9432	0	1	Z	UR		0.8049	0	2708.64		0	N/A	N/A	Y
SOUTHERN ENERGY WICHITA FALLS LP	0	34.0121	98.6874	0	4	E	NG	G	0.6925	0	80		0	N/A	N/A	Y
SOUTHWEST TEXAS STATE UNIVERSITY COGEN	0	30.0543	98.0028	0	1	E	NG	G	0.6513	0	6	U	15547			Y
SPENCER	0	33.2042	97.1028	5	5	T,E	GAS	G	0.1697	2310.64	173.945		0	N/A	N/A	
STATE FARM INS CO ISC CENTRAL	0	32.7669	96.7773	0	6	E	DFO	O	0.0016	0	10.95		0	N/A	N/A	Y
STRYKER CREEK	1	31.9381	94.9883	2	7	T,E	GAS	G	0.3799	6596	713.48		0	N/A	N/A	Y
SWEENY COGENERATION FACILITY	0	29.2062	95.4646	3	4	T,E	NG	G	0.6753	0	460	U	5000000			Y
T H WHARTON	1	29.9417	95.5306	1	18	T,E	GAS	G	0.3232	2348.72	1421.52		0	N/A	N/A	Y
TENASKA III TEXAS PARTNERS	0	33.6603	95.583	0	3	E	NG	G	0.6799	0	250	U	697313			Y
TENASKA IV TEXAS PARTNERS LTD CLEBURNE COGEN	0	32.3444	97.3516	1	2	T,E	NG	G	0.629	0	282.6	U	407639			Y
TEXARKANA MILL	0	33.0865	94.3482	0	2	E	BL		0.7758	0	65	U	8056246			Y
TEXAS CITY COGENERATION LP	0	29.3171	94.9773	0	4	E	NG	G	0.895	0	450	U	3541775			Y

PNAME	PREV UTIL	LAT	LON	NUMBLR	NUMGEN	SOURCEM	PLPRIMFL	PLFFLCTG	CAPFAC	BOILCAP	NAMEPCAP	CHPFLAG	USETHRMO	PWRTOHT	ELCALLOC	PLNUCONN
TEXAS CITY PLANT							GAS				41.5					
TEXAS CITY PLANT UNION CARBIDE CORP	0	29.3171	94.9773	0	2	E	NG	G	0.5954	0	96	U	5904004			Y
TEXAS PETROCHEMICALS CORP	0	29.8336	95.4383	0	1	E	NG	G	0.9715	0	35	U	14807288			Y
THE DOW CHEMICAL CO TEXAS OPERATIONS	0	29.2062	95.4646	0	16	E	NG	G	0.5558	0	1378.839	U	20771525			Y
THE GOODYEAR&TIRE RUBBER CO	0	29.8641	94.135	0	5	E	NG	G	0.8067	0	34.877	U	9075322			Y
THOMAS C FERGUSON	0	30.5564	98.3694	1	1	T	GAS	G	0.3707	4153.44	446		0	N/A	N/A	
TNP ONE	1	31.0928	96.6933	2	2	T	COL	C	0.7242	2992	349.2		0	N/A	N/A	Y
TOLEDO BEND	0	30.714	93.732	0	1	Z	WT		0.1451	0	81		0	N/A	N/A	
TOLK	0	34.1847	102.5686	2	2	T	COL	C	0.818	10327.84	1136		0	N/A	N/A	
TP 4	0	29.6175	97.9721	0	1	Z	WT		0.3455	0	2.4		0	N/A	N/A	
TRADINGHOUSE	1	31.5728	96.9644	2	2	T	GAS	G	0.4469	12861.52	1379.7		0	N/A	N/A	Y
TRINIDAD	1	32.1336	96.1019	1	3	T,E	GAS	G	0.1867	2423.52	243.36		0	N/A	N/A	Y
TY COOKE	0	33.5164	101.7917	2	5	T,E	GAS	G	0.3172	0	150.65		0	N/A	N/A	
UNIVERSITY OF TEXAS AT AUSTIN	0	30.3241	97.7711	0	5	E	NG	G	0.3508	0	103.427	U	2156987			Y
UNIVERSITY OF TEXAS AT DALLAS	0	32.7669	96.7773	0	1	E	NG	G	0.0939	0	3.5	U	4577			Y
UNIVERSITY OF TEXAS AT SAN ANTONIO	0	29.4332	98.4635	0	1	E	NG	G	0.1439	0	3.47	U	6243.72			Y
V H BRAUNIG	0	29.2561	98.3814	5	3	T	GAS	G	0.2271	8486.4	894		0	N/A	N/A	
VALERO REFINERY	0	27.777	97.4878	0	3	E	OG		0.4625	0	64.7	U	2729405			Y
VALERO REFINING CO TEXAS CITY REFINERY	0	29.3171	94.9773	0	3	E	NG	G	0.7123	0	39.56	U	1930000			Y
VALERO REFINING CO TEXAS HOUSTON REFINERY	0	29.8336	95.4383	0	2	E	NG	G	0.7196	0	34.296	U	2172128			Y
VALLEY	1	33.6436	96.365	3	3	T	GAS	G	0.3102	10598.48	1175.49		0	N/A	N/A	Y
VERNON	1	34.1135	99.2133	0	5	E	OIL	O	0	0	11.28		0	N/A	N/A	Y
VICTORIA	1	28.7894	97.0103	3	3	T	GAS	G	0.221	4750.48	460.874		0	N/A	N/A	Y
VICTORIA TEXAS PLANT	0	28.8017	96.9749	0	1	E	NG	G	0.9867	0	80	U	2931120			Y
VILLAGE CREEK WASTEWATER TREATMENT PLANT	0	32.7712	97.2911	0	4	E	OBG		0.353	0	4		0	N/A	N/A	Y
W A PARISH	1	29.4833	95.6331	8	9	T,E	COL	C	0.5229	35656.48	3969.12		0	N/A	N/A	Y
W B TUTTLE	0	29.5303	98.4178	4	4	T	GAS	G	0.083	4692	495		0	N/A	N/A	
WASHINGTON VENEER DIVISION							WW				7.5					
WASSON CO2 REMOVAL PLANT	0	33.1735	102.8289	0	1	E	NG	G	0.7311	0	23.4	U	183582			Y
WEBSTER	1	29.5261	95.1081	1	2	T,E	GAS	G	0.1338	3400	426.36		0	N/A	N/A	Y
WELSH	0	33.0403	94.8372	3	3	T	COL	C	0.8036	15475.44	1536.963		0	N/A	N/A	
WEST TEXAS WIND ENERGY LLC	0	31.3656	102.0461	0	1	Z	WND		0.3588	0	75		0	N/A	N/A	Y
WEST TEXAS WINDPLANT	0	31.3158	105.4522	0	1	Z	WND		0.2752	0	33.6		0	N/A	N/A	Y
WESTHOLLOW TECHNOLOGY CENTER	0	29.8336	95.4383	0	1	E	NG	G	1.0351	0	3.725	U	160000			Y
WESTVACO EVADALE	0	30.6999	93.9944	0	3	E	BL		0.876	0	57.74	U	64014894			Y
WHITNEY	0	31.8957	97.6407	0	1	Z	WT		0.0435	0	30		0	N/A	N/A	
WILKES	0	32.8486	94.5469	3	3	T	GAS	G	0.3378	7980.48	807.388		0	N/A	N/A	
YATES GAS PLANT	0	30.7119	102.6783	0	2	E	NG	G	0.5194	0	5.6	U	98000			Y
AMERICAN FORK	0	40.1895	111.5237	0	1	Z	WT		0.7042	0	0.95		0	N/A	N/A	
BARTHOLOMEW	0	40.1895	111.5237	0	1	Z	WT		0.1769	0	1.5		0	N/A	N/A	
BEAVER LOWER HYDRO 1	0	38.3615	113.2123	0	1	Z	WT		0.2142	0	0.275		0	N/A	N/A	
BEAVER MID HYDRO 2	0	38.3615	113.2123	0	1	Z	WT		0.5489	0	0.625		0	N/A	N/A	
BEAVER UPPER HYDRO 3	0	38.3615	113.2123	0	1	Z	WT		0.7462	0	0.65		0	N/A	N/A	
BLUNDELL	0	38.3615	113.2123	0	1	Z	GE		0.6643	0	26.095		0	N/A	N/A	
BONANZA	0	40.0833	109.2833	1	1	T	COL	C	0.8391	4284	400		0	N/A	N/A	
BOULDER	0	37.8449	111.3074	0	1	Z	WT		0.6258	0	4.2		0	N/A	N/A	
BOUNTIFUL CITY	0	40.9611	112.1154	0	7	E	GAS	G	0.1325	0	14.15		0	N/A	N/A	
BOX ELDER	0	41.5004	112.9581	0	1	Z	WT		0.8863	0	0.5		0	N/A	N/A	
BRIGHAM CITY	0	41.5004	112.9581	0	1	Z	WT		0.2217	0	1.2		0	N/A	N/A	
CARBON	0	39.7264	110.8639	2	2	T	COL	C	0.8304	1951.6	188.636		0	N/A	N/A	
CENTER CREEK	0	37.8118	113.2589	0	1	Z	WT		0.0407	0	0.6		0	N/A	N/A	
CUTLER	0	41.5004	112.9581	0	1	Z	WT		0.237	0	30		0	N/A	N/A	
DEER CREEK	0	40.2892	111.242	0	1	Z	WT		0.5754	0	4.95		0	N/A	N/A	
ECHO DAM	0	40.9156	110.82	0	1	Z	WT		0.2054	0	4.5		0	N/A	N/A	
FLAMING GORGE	0	40.8274	109.524	0	1	Z	WT		0.3137	0	151.95		0	N/A	N/A	
FOUNTAIN GREEN	0	39.4228	111.6307	0	1	Z	WT		0.7021	0	0.16		0	N/A	N/A	
GADSBY	0	40.7667	111.9292	3	3	T	GAS	G	0.3258	2713.2	251.636		0	N/A	N/A	
GENEVA STEEL	0	40.1895	111.5237	0	1	E	BFG	C	0.7038	0	50	U	2255819			Y
GRANITE	0	40.6737	111.906	0	1	Z	WT		0.3554	0	2		0	N/A	N/A	
GUNLOCK	0	37.3091	113.4754	0	1	Z	WT		0.2096	0	0.75		0	N/A	N/A	
GUNLOCK HYDRO	0	37.3091	113.4754	0	1	Z	WT		0.1292	0	0.372		0	N/A	N/A	
HEBER CITY	0	40.2892	111.242	0	7	E	GAS	G	0.129	0	6.5		0	N/A	N/A	
HOBBLE CREEK	0	40.1895	111.5237	0	1	Z	WT		0.2869	0	0.3		0	N/A	N/A	
HUNTER	0	39.1667	111.0261	3	3	T	COL	C	0.755	13568.72	1440.568		0	N/A	N/A	
HUNTINGTON	0	39.3792	111.075	2	2	T	COL	C	0.8084	8976	996		0	N/A	N/A	
HYDRO II	0	41.685	111.7887	0	1	Z	WT		0.3115	0	6.6		0	N/A	N/A	
HYDRO III	0	41.685	111.7887	0	2	Z	WT		0.2552	0	2.02		0	N/A	N/A	
HYDRO PLANT NO 1	0	39.4228	111.6307	0	1	Z	WT		0.2671	0	0.2		0	N/A	N/A	
HYDRO PLANT NO 3	0	39.4228	111.6307	0	1	Z	WT		0.1154	0	2.89		0	N/A	N/A	
HYDRO PLANT NO 4	0	39.4228	111.6307	0	1	Z	WT		0.2873	0	0.12		0	N/A	N/A	
HYRUM	0	41.685	111.7887	0	1	Z	WT		0.5861	0	0.5		0	N/A	N/A	
INTERMOUNTAIN	0	39.5108	112.5792	2	2	T	COL	C	0.9177	16592	1640		0	N/A	N/A	
LAKE CREEK	0	40.2892	111.242	0	1	Z	WT		0.3435	0	1.5		0	N/A	N/A	
LITTLE COTTONWOOD	0	40.6737	111.906	0	1	Z	WT		0.1824	0	4.9		0	N/A	N/A	
LITTLE MOUNTAIN	0	41.2499	111.9563	0	1	E	GAS	G	0.4396	0	16	C		N/A		
LONE PEAK PARTNERS POWER CO	0	40.6737	111.906	0	3	E	NG	G	0.8846	0	1.95	U	949805			Y
LOWER	0	38.7739	111.9076	0	1	Z	WT		0.5958	0	0.26		0	N/A	N/A	
LOWER-UNIT	0	39.4228	111.6307	0	1	Z	WT		0.5753	0	0.15		0	N/A	N/A	

PNAME	PREV UTIL	LAT	LON	NUMBLR	NUMGEN	SOURCEM	PLPRIMFL	PLFFLCTG	CAPFAC	BOILCAP	NAMEPCAP	CHPFLAG	USETHRMO	PWRTOHT	ELCALLOC	PLNUCONN
MANTI LOWER	0	39.4228	111.6307	0	1	Z	WT		0.2213	0	1.2		0	N/A	N/A	
MANTI UPPER	0	39.4228	111.6307	0	1	Z	WT		0.3386	0	1.6		0	N/A	N/A	
MONROE PUMPING STA	0	38.7739	111.9076	0	1	Z	WT		0.2032	0	0.1		0	N/A	N/A	
MURRAY CITY	0	40.6737	111.906	0	4	E	GAS	G	0.0016	0	7.2		0	N/A	N/A	
OLMSTEAD	0	40.1895	111.5237	0	1	Z	WT		0.3031	0	10.3		0	N/A	N/A	
PAYSON	0	40.1895	111.5237	0	1	Z	WT		0.5357	0	0.4		0	N/A	N/A	
PINE VALLEY	0	37.3091	113.4754	0	1	Z	WT		0.21	0	0.6		0	N/A	N/A	
PINE VIEW DAM	0	41.2499	111.9563	0	1	Z	WT		0.2454	0	1.8		0	N/A	N/A	
PIONEER	0	41.2499	111.9563	0	1	Z	WT		0.379	0	5		0	N/A	N/A	
PRIMARY CHILDRENS MEDICAL CENTER	0	40.6737	111.906	0	3	E	NG	G	0.5556	0	1.95	U	31509			Y
PROVO	0	40.1895	111.5237	0	5	E	GAS	G	0.1391	0	17.5		0	N/A	N/A	
QUAIL CREEK HYDRO PLANT #1	0	37.3091	113.4754	0	1	Z	WAT		0.4047	0	2.34		0	N/A	N/A	Y
RED CREEK	0	37.8118	113.2589	0	1	Z	WT		0.0287	0	0.6		0	N/A	N/A	
SAND COVE	0	37.3091	113.4754	0	1	Z	WT		0.1704	0	0.8		0	N/A	N/A	
SNAKE CREEK	0	40.2892	111.242	0	1	Z	WT		0.2438	0	1.18		0	N/A	N/A	
SNAKE CREEK	0	40.2892	111.242	0	1	Z	WT		0.4608	0	0.8		0	N/A	N/A	
SPANISH FORK	0	40.1895	111.5237	0	1	Z	WT		0.2343	0	3.75		0	N/A	N/A	
SPRING CREEK	0	40.1895	111.5237	0	1	Z	WT		0.0329	0	0.5		0	N/A	N/A	
ST GEORGE	0	37.3091	113.4754	0	2	E	OIL	O	0.14	0	14		0	N/A	N/A	
STAIRS	0	40.6737	111.906	0	1	Z	WT		0.6049	0	1		0	N/A	N/A	
SUNNYSIDE COGENERATION ASSOCIATES	0	39.6407	110.5648	0	1	E	WOC	C	0.8474	0	58.103		0	N/A	N/A	Y
UINTAH	0	40.3199	110.4395	0	1	Z	WT		0.4894	0	1.2		0	N/A	N/A	
UNIT 3	0	39.4228	111.6307	0	1	Z	WT		0.4455	0	0.225		0	N/A	N/A	
UNIT 4	0	39.4228	111.6307	0	1	Z	WT		0.2878	0	1.25		0	N/A	N/A	
UPPER	0	38.7739	111.9076	0	1	Z	WT		0.4312	0	0.26		0	N/A	N/A	
UPPER BARTHOLOMEW	0	40.1895	111.5237	0	1	Z	WT		0.0662	0	0.2		0	N/A	N/A	
UPPER BEAVER	0	38.3615	113.2123	0	1	Z	WT		0.438	0	2.52		0	N/A	N/A	
UPPER-UNIT	0	39.4228	111.6307	0	1	Z	WT		0.6732	0	0.175		0	N/A	N/A	
VEYO	0	37.3091	113.4754	0	1	Z	WT		0.0648	0	0.5		0	N/A	N/A	
WASATCH ENERGY SYSTEMS	0	40.9611	112.1154	0	1	E	MSW		0.6516	0	1.6	U	985000			Y
WEBER	0	41.2499	111.9563	0	1	Z	WT		0.5408	0	3.85		0	N/A	N/A	
WHITEHEAD	0	40.1895	111.5237	0	3	E	GAS	G	0.0669	0	21		0	N/A	N/A	
YELLOWSTONE	0	40.3199	110.4395	0	1	Z	WT		0.4926	0	0.9		0	N/A	N/A	
ALCOVA	0	42.9662	106.8065	0	1	Z	WT		0.391	0	36		0	N/A	N/A	
ANSCHUTZ RANCH EAST	0	41.2874	110.5468	0	2	E	NG	G	0.6685	0	50.6	U	358000			Y
BEAVER CREEK GAS PLANT	0	43.1348	108.7769	0	2	E	NG	G	0.6957	0	5	U	249884			Y
BLACKS FORK GAS PROCESSING PLANT	0	41.634	108.7785	0	3	E	NG	G	0.3568	0	1.452		0	N/A	N/A	Y
BOYSEN	0	43.1348	108.7769	0	1	Z	WT		0.4169	0	15		0	N/A	N/A	
BUFFALO BILL	0	44.4095	109.8025	0	1	Z	WT		0.4516	0	18		0	N/A	N/A	
DAVE JOHNSTON	0	42.8333	105.7667	4	4	T	COL	C	0.7921	7548	816.772		0	N/A	N/A	
ELK BASIN GASOLINE PLANT	0	44.4095	109.8025	0	2	E	NG	G	0.5623	0	2	U	303046			Y
FONTENELLE	0	42.4468	110.546	0	1	Z	WT		0.6536	0	10		0	N/A	N/A	
FREMONT CANYON	0	42.9662	106.8065	0	1	Z	WT		0.4738	0	66.8		0	N/A	N/A	
GENERAL CHEMICAL	0	41.634	108.7785	0	2	E	SUB	C	0.8626	0	30	U	3789561			Y
GLENDO	0	42.1218	104.9652	0	1	Z	WT		0.2735	0	38		0	N/A	N/A	
GUERNSEY	0	42.1218	104.9652	0	1	Z	WT		0.429	0	6.4		0	N/A	N/A	
HEART MOUNTAIN	0	44.4095	109.8025	0	1	Z	WT		0.3077	0	5		0	N/A	N/A	
JIM BRIDGER	0	41.75	108.8	4	4	T	COL	C	0.7988	21651.2	2311.5		0	N/A	N/A	
KORTES	0	41.717	106.9999	0	1	Z	WT		0.3947	0	36		0	N/A	N/A	
LARAMIE RIVER 1	0	42.1086	104.8711	1	1	T	COL	C	0.8513	5474	570		0	N/A	N/A	
LARAMIE RIVER 2&3	0	42.1086	104.8711	2	2	T	COL	C	0.8513	10948	1100		0	N/A	N/A	
NAUGHTON	0	41.7572	110.5986	3	3	T	COL	C	0.8666	7235.2	707.2		0	N/A	N/A	
NEIL SIMPSON	0	44.25	105.54	1	2	E	COL	C	0.771	0	23.76		0	N/A	N/A	
NEIL SIMPSON II	0	44.2477	105.5462	2	2	T	COL	C	0.7349	0	120		0	N/A	N/A	
OSAGE	0	43.84	104.56	3	3	E	COL	C	0.8121	0	34.5		0	N/A	N/A	
PILOT BUTTE	0	43.1348	108.7769	0	1	Z	WT		0.1872	0	1.6		0	N/A	N/A	
PONNEQUIN PHASE 1	0	41.3275	104.6653	0	1	Z	WND		0.232	0	5.25		0	N/A	N/A	Y
SEMINOE	0	41.717	106.9999	0	1	Z	WT		0.3158	0	45		0	N/A	N/A	
SF PHOSPHATES LTD CO	0	41.634	108.7785	0	1	E	OTS		0.8252	0	11.5	U	1420000			Y
SHOSHONE	0	44.4095	109.8025	0	1	Z	WT		0.8371	0	3		0	N/A	N/A	
SINCLAIR OIL REFINERY	0	41.717	106.9999	0	4	E	OG		0.397	0	3.35	U	2373185			Y
SPIRIT MOUNTAIN	0	44.4095	109.8025	0	1	Z	WT		0.3744	0	4.5		0	N/A	N/A	
STRAWBERRY CREEK	0	42.4468	110.546	0	1	Z	WT		0.723	0	1.5		0	N/A	N/A	
VIVA NAUGHTON	0	42.4468	110.546	0	1	Z	WT		0.1254	0	0.742		0	N/A	N/A	
WYODAK	0	44.2833	105.4	1	1	T	COL	C	0.8402	3565.92	362.07		0	N/A	N/A	

strStateFacilityIdentifier	strSICPrimary	strNAICSPrimary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXYCoordinateType
T$12468	1061	2122	AMERICAN MINERALS INC.		2010 4TH ST. N.E.	DEMING	NM	88031	USA	-107.734	32.27778		LATLON
T$12022	1061	2122	AMERICAN MINERALS INC.		3666 DONIPHAN DR.	EL PASO	TX	79922	USA	-106.552	31.8093		LATLON
0278	1311	211111	AMOCO PROD. CO. - J.B. GARDNER A #1	NATURAL GAS PROCESSING	SW/4 NW/4 SEC 22 T32N R10W	LAPLATA COUNTY	CO	80000	USA	-107.92	37.005	13	LATLON
0280	1311	211111	AMOCO PRODUCTION - EVELYN PAYNE GU #1	NATURAL GAS PROCESSING	SENW SEC 32 T35N R6W	LA PLATA COUNTY	CO	80000	USA	-107.551	37.258	13	LATLON
0083	1311	211111	AMOCO PRODUCTION CO PICNIC FLATS	NATURAL GAS PROCESSING	SE SEC 25 T33N R11W	LA PLATA COUNTY	CO	80000	USA	-107.99	37.0732	13	LATLON
0279	1311	211111	AMOCO PRODUCTION CO - ROBERT DULIN D #1	NATURAL GAS PROCESSING	NW/4 SE/4 SEC. 26 T35N R7W	LAPLATA COUNTY	CO	80000	USA	-107.605	37.2725	13	LATLON
0273	1311	211111	AMOCO PRODUCTION CO GEARHART WELL #1-6	NATURAL GAS PROCESSING	SEC 6 T34N R7W	LA PLATA	CO	00000	USA	-107.678	37.244	13	LATLON
0274	1311	211111	AMOCO PRODUCTION CO LORETT FEDERAL GU #1	NATURAL GAS PROCESSING	SEC 13 T34N R8W	LA PLATA	CO	00000	USA	-107.668	37.1913	13	LATLON
0025	1311	211111	AMOCO PRODUCTION CO WATTENBERG PLT	NATURAL GAS PROCESSING	NE/SE/4 SEC 32 T3S R65W	ADAMS	CO	00000000(	USA	-104.678	39.7448	13	LATLON
0277	1311	211111	AMOCO PRODUCTION CO.- ROBIN FRAZIER A	NATURAL GAS PROCESSING	NW/4 NW/4 SEC 23 T32N R10W	LA PLATA COUNTY	CO	80000	USA	-107.903	37.005	13	LATLON
0444	1311	211111	ANTELOPE ENERGY COMPANY-TERANCE PLANT	OIL & GAS PROCESSING	NW NE SEC 18 T10N R58W	RAYMER N 17 MI OF	CO	00000	USA	-103.897	40.8454	13	LATLON
081230099	1311	211111	ASSOCIATED NATURAL GAS GREELEY PLT	ICE-NG.			CO		USA	-104.853	40.49639		LATLON
081230074	1311	211111	ASSOCIATED NATURAL GAS INC SINGLETREE	ICE-NG.			CO		USA	-104.812	40.14556		LATLON
081230015	1311	211111	ASSOCIATED NATURAL GAS INC SPINDLE PLT	ICE-NG.			CO		USA	-104.882	40.08917		LATLON
081230075	1311	211111	ASSOCIATED NATURAL GAS INC SURREY PLT	ICE-NG.			CO		USA	-104.886	40.01583		LATLON
081230076	1311	211111	ASSOCIATED NATURAL GAS INC WEST SPINDLE	ICE-NG.			CO		USA	-104.886	40.0875		LATLON
081230125	1311	211111	ASSOCIATED NATURAL GAS SPINDLE AIR PLT	ICE-NG.			CO		USA	-104.885	40.0875		LATLON
081230068	1311	211111	ASSOCIATED NATURAL GAS WATTENBERG	ICE-NG.			CO		USA	-104.894	40.12111		LATLON
0145	1311	211111	BARGARTH INC GRAND VALLEY GAS PROC	NATURAL GAS COMRESSION AND	SEC 36 T5S R96W	GARFIELD	CO	81227	USA	-108.112	39.3219	12	LATLON
0089	1311	211111	BARRETT RESOURCES CORP RULISON ANVIL PTS	NATURAL GAS PROCESSING	SEC 29 T6S R94W	RIFLE	CO	81601	USA	-107.91	39.4961	13	LATLON
0029	1311	211111	BITTER CREEK PIPELINES - YENTER C.S.	NATURAL GAS PROCESSING (PLAN	SEC 3 T8N R54W	STERLING	CO	80751	USA	-103.396	40.6909	13	LATLON
0016	1311	211111	BURR OIL & GAS INC. - CROSS CANYON #1		SW/NE SEC 7 T38N R19W	PAPOOSE CANYON GATHERING FIELD	CO	80000	USA	-108.985	37.566	12	LATLON
1189	1311	211111	CASCADE OIL & GAS INC	NAT GAS PROCESSING	NW/4 SECT 11 T1S R64W	ADAMS CNTY	CO	00000000(	USA	-104.518	39.9776	13	LATLON
080330012	1311	211111	CELSIUS ENERGY CO DOVE CREEK PLT	ICE-NG.			CO		USA	-108.87	37.76		LATLON
080810066	1311	211111	CELSIUS ENERGY CO HIAWATHA CO2 EXTR FAC	ICE-NG.			CO		USA	-108.625	40.99028		LATLON
0153	1311	211111	CER CORP MWX-1 GAS WELL	NATURAL GAS PROCESSING PLAN	SW NW 4 SEC 34 T6S R94W	RIFLE	CO	80000	USA	-107.881	39.4833	13	LATLON
0034	1311	211111	CHEVRON USA PRODUCTION CO RANGELY FIELD	CRUDE OIL TERTIARY RECOVERY	100 CHEVRON RD	RANGELY	CO	81648	USA	-108.928	40.1042	12	LATLON
081030055	1311	211111	COLORADO INTERSTATE GAS CO GREASEWOOD				CO		USA	-108.191	39.89694		LATLON
0001	1311	211111	COLORADO INTERSTATE GAS CO KIT CARSON	NATURAL GAS PROCESSING	3073 US HWY 287	KIT CARSON	CO	80825	USA	-102.621	38.673	13	LATLON
0007	1311	211111	COLORADO INTERSTATE GAS CO VILAS C S	NATURAL GAS PROCESSING	SEC 20 T31S R45W	VILAS	CO	80944	USA	-102.472	37.3237	13	LATLON
081030036	1311	211111	CONOCO INC DRAGON TRAIL GAS PROC PLT	ICE-NG.			CO		USA	-108.809	39.83139		LATLON
081030032	1311	211111	CONOCO INC NATURAL GAS WEST DOUGLAS	ICE-NG.			CO		USA	-108.757	39.81111		LATLON
0103	1311	211111	CUSTOM ENERGY CONSTRUCTION INC BUCK PEAK	GAS PROCESSING STATION	SESW SEC 9 T6N R90W	BUCK PEAK GAS PROCESSING STN	CO	00000	USA	-107.498	40.4858	13	LATLON
0099	1311	211111	DUKE ENERGY FIELD SERVICES - GREELEY	NATURAL GAS GATHERING	SEC 25 T5N R66W	WELD COUNTY	CO	00000-000	USA	-104.853	40.4965	13	LATLON
0049	1311	211111	DUKE ENERGY FIELD SERVICES - ROGGEN	NATURAL GAS GATHERING AND PF	35409 COUNTY ROAD 18	WELD COUNTY	CO	00000-000	USA	-104.39	40.1193	13	LATLON
0015	1311	211111	DUKE ENERGY FIELD SERVICES - SPINDLE	NATURAL GAS GATHERING AND PF	0.5 MILES N OF HWY 52	WELD COUNTY	CO	00000-000	USA	-104.883	40.0893	13	LATLON
0036	1311	211111	EL PASO CORPORATION - DRAGON TRAIL GAS	NATURAL GAS PROCESSING (FORI	3606 COUNTY ROAD 116	RANGELY	CO	81648	USA	-108.809	39.8308	12	LATLON
0016	1311	211111	EL PASO CORPORATION - EAST DRAGON TRAIL	FORMERLY CONOCO - NATURAL G	SEC 36 T2S R102W	RANGELY	CO	84108	USA	-108.79	39.8296	12	LATLON
081010098	1311	211111	FUEL RESOURCES DEV SYNHYTEC	ICE-Diesel			CO		USA	-104.714	38.21917		LATLON
0333	1311	211111	GATEWAY PROCESSING CO	GAS TREATING & PROCESSING	NW OF MACK	MESA COUNTY	CO	80000	USA	-108.22	38.931		LATLON
080810124	1311	211111	GRYNBERG PETROLEUM COMPANY SUGAR LOAF	ICE-NG.			CO		USA	-108.683	40.94472		LATLON
080810123	1311	211111	GRYNBERG PETROLEUM COMPANY BLUE GRAVEL	ICE-NG.			CO		USA	-107.651	40.69417		LATLON
0019	1311	211111	HORSESHOE OPERATING INC LA DRY CREEK	NATURAL GAS PROCESSING	SEC 21 T25S R48W	LAS ANIMAS	CO	81054	USA	-102.803	37.8602	13	LATLON
080110018	1311	211111	HORSESHOE OPERATING INC WAGON TRAIL	ICE-NG.			CO		USA	-102.821	38.06417		LATLON
080010501	1311	211111	IRONDALE GAS PROCESSING CO IRONDALE CS2	ICE-NG.			CO		USA	-104.38	39.86694		LATLON
0082	1311	211111	KN GAS GATHERING BLACK SULPHUR LIQUIDS	NATURAL GAS PROCESSING	SEC 20 T2S R97W	RANGELY	CO	81648	USA	-108.305	39.8625	12	LATLON
081030083	1311	211111	KN GAS GATHERING PICEANCE CREEK	ICE-NG.			CO		USA	-108.266	40.04056		LATLON
080050519	1311	211111	KOCH HYDROCARBON CO DENVER CTL PLT	ICE-NG.			CO		USA	-104.354	39.64139		LATLON
080010628	1311	211111	KOCH HYDROCARBON CO KALLSEN PLT	ICE-NG.			CO		USA	-104.333	39.87861		LATLON
080010629	1311	211111	KOCH HYDROCARBON CO LINNEBURG PLT	ICE-NG.			CO		USA	-103.956	39.94056		LATLON
080010627	1311	211111	KOCH HYDROCARBON CO STATE PLT	ICE-NG.			CO		USA	-104.677	39.96222		LATLON
080310950	1311	211111	KOCH HYDROCARBON CO THIRD CREEK PLT	ICE-NG.			CO		USA	-104.697	39.88472		LATLON
080990057	1311	211111	MARATHON OIL CO SNIFF E1	ICE-NG.			CO		USA	-102.784	38.04944		LATLON
080830033	1311	211111	MID AMERICA PIPELINE CO DOLORES STA	Turbine:			CO		USA	-108.433	37.41444		LATLON
0031	1311	211111	MITCHELL ENERGY CORP HELLS HOLE CANYON	NATURAL GAS PROCESSING	SEC 31 T1S R103W	RANGELY	CO	81648	USA	-109.005	39.9236	12	LATLON
0005	1311	211111	MULL DRILLING CO INC SORRENTO FIELD	NATURAL GAS PROCESSING	NE SEC 5 T14S R49W	KIT CARSON	CO	80825	USA	-102.603	38.8709	13	LATLON
080770180	1311	211111	NATL FUEL CORP	ICE-NG.			CO		USA	-108	39.26583		LATLON
081230127	1311	211111	NORTH AMERICAN RESOURCES CO ARISTOCRAT	ICE-NG.			CO		USA	-104.617	40.25		LATLON
0319	1311	211111	NORTH AMERICAN RESOURCES CO FT LUPTON	NATURAL GAS PROCESSING	SE/4 SW/4 SW/4 SEC 11 T2N R66W	FORT LUPTON	CO	80621	USA	-104.739	40.1486	13	LATLON
0950	1311	211111	NORTH AMERICAN RESOURCES CO THIRD CREEK	NATURAL GAS PROCESSING - THIS	SEC 18 T2S R65W	DENVER	CO	80249	USA	-104.749	39.78118	13	LATLON
0628	1311	211111	NORTH AMERICAN RESOURCES CO_ KALLSEN	FORMERLY OWNED BY KOCH HYD	NE NW SEC 16 T2S R62W	STRASBURG OFF I70 N 10 MI OF	CO	00000000(	USA	-104.331	39.8811	13	LATLON
081070047	1311	211111	NORTHERN NATURAL GAS CO ENRON ROUTT NO 1	Turbine:			CO		USA	-107.394	40.29889		LATLON
080770183	1311	211111	PUBLIC SERVICE CO ASBURY	ICE-NG.			CO		USA	-108.647	39.23028		LATLON
0121	1311	211111	PUBLIC SERVICE CO BAXTER STATION	NATURAL GAS PROCESSING	SEC 3 T8S R104W	RIFLE	CO	81650	USA	-108.863	39.3958	12	LATLON
081030016	1311	211111	PUBLIC SERVICE CO DRAGON TRAIL	ICE-NG.			CO		USA	-108.79	39.82972		LATLON
0086	1311	211111	PUBLIC SERVICE CO GREASEWOOD STATION	NATURAL GAS PROCESSING	SEC 5 T2S R96W	MEEKER	CO	81641	USA	-108.192	39.9058	12	LATLON
080770182	1311	211111	PUBLIC SERVICE CO HUNTER CANYON	ICE-NG.			CO		USA	-108.591	39.33139		LATLON
081030056	1311	211111	PUBLIC SERVICE CO INDIAN VALLEY				CO		USA	-108.193	40.10139		LATLON
0087	1311	211111	PUBLIC SERVICE CO NORTH DOUGLAS STATION	NATURAL GAS PROCESSING	62584 HWY 139 SEC18 T1S R101W	RANGELY	CO	81648	USA	-108.774	39.9599	12	LATLON
0122	1311	211111	PUBLIC SERVICE CO RIFLE COMP STA	NATURAL GAS PROCESSING	SEC 18 T6S R93W	GARFIELD CNTY	CO	81650	USA	-107.817	39.5254	13	LATLON
081030048	1311	211111	PUBLIC SERVICE CO WHITE RIVER DOME	ICE-NG.			CO		USA	-108.191	40.09861		LATLON
0024	1311	211111	PUBLIC SERVICE CO WILLIAMS FORK STATION	NATURAL GAS PROCESSING	SEC 23 T2S R78W	GRAND COUNTY	CO	80468	USA	-106.09	39.8626	13	LATLON
081230141	1311	211111	PUBLIC SERVICE CO YOSEMITE	ICE-NG.			CO		USA	-104.886	40.01472		LATLON
0024	1311	211111	QUESTAR EXPLORATION & PROD -CUTTHROAT A	NATURAL GAS PROCESSING	SE SEC 10 T37N R19W	CORTEZ	CO	81321	USA	-108.927	37.4723	12	LATLON
0132	1311	211111	QUESTAR GAS MANAGEMENT - AVALANCHE	NATURAL GAS GATHERING	LOT 9 SEC 18 T12N R91W	MOFFAT	CO	00000	USA	-107.649	40.993	13	LATLON
0135	1311	211111	QUESTAR GAS MANAGEMENT CO E.HIAWATHA	NATURAL GAS PROCESSING	SEC 23 T 12N R100W	MOFFAT	CO	80000000(	USA	-108.182	40.6116	13	LATLON
0131	1311	211111	QUESTAR GAS MANAGEMENT CO SAND HILL	GLYCOL DEHYDRATOR	BAGGS FIELD	CRAIG	CO	81626	USA	-107.621	40.9514	13	LATLON
0006	1311	211111	QUESTAR GAS MANAGEMENT DOVE CREEK PLT	NATURAL GAS PROCESSING - NOT	SEC 5 T40N R18W	DOVE CREEK	CO	81333	USA	-108.865	37.7857	12	LATLON
080330006	1311	211111	QUESTAR PIPELINE CO DOVE CREEK PLT	ICE-NG.			CO		USA	-108.865	37.78556		LATLON
081030037	1311	211111	ROCKY MOUNTAIN NATURAL GAS CO PICEANCE	ICE-NG.			CO		USA	-108.263	40.04333		LATLON
081130007	1311	211111	ROCKY MOUNTAIN NATURAL GAS CO SLICK ROCK	ICE-NG.			CO		USA	-108.893	38.02056		LATLON
081130016	1311	211111	ROCKY MOUNTAIN NATURAL GAS NICHOLAS DRAW	ICE-NG.			CO		USA	-108.819	38.03083		LATLON
0068	1311	211111	ROCKY MTN NATURAL GAS CO BLACK SULPHUR	NATURAL GAS PROCESSING	SEC 19 T2S R97W	MEEKER	CO	81641	USA	-107.856	40.03395	13	LATLON
0108	1311	211111	ROCKY MTN NATURAL GAS CO DEBEQUE C S	NATURAL GAS PROCESSING	SEC 6 T8S R97W	DE BEQUE	CO	81630	USA	-108.26	39.3885	12	LATLON
0037	1311	211111	ROCKY MTN NATURAL GAS CO PICEANCE	NATURAL GAS PROCESSING	SEC 22 T1N R97W	RIO BLANCO	CO	81602	USA	-108.263	40.0435	12	LATLON
0018	1311	211111	ROCKY MTN NATURAL GAS CO WOLF CREEK	NATURAL GAS_PRODUCTION	VARIOUS LOCATIONS T8N R90W	PITKIN COUNTY	CO	80000	USA	-107.407	39.3202	13	LATLON
080870034	1311	211111	ROGGEN GAS PROCESSING CO SITE NAME UNK	ICE-NG.			CO		USA	-104.05	40.46861		LATLON
0018	1311	211111	SHELL CO2 COMPANY - YELLOW JACKET	NATURAL GAS PROCESSING	NW SEC 13 T37N R18W RD U & 14	CORTEZ	CO	81321	USA	-108.787	37.4715	12	LATLON
0020	1311	211111	SHELL CO2 COMPANY, LTD. - HOVENWEEP CO2 SOURCE FIELD	CO2 SOURCE FIELD FACILITY	SW/4 SEC 16 T37N R18W	CORTEZ	CO	81321	USA	-108.862	37.49	12	LATLON

strStateFacilityIdentifier	strSICPrimary	strNAICSPrimary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXYCoordinateType
081230422	1311	211111	SNYDER OIL CO WEST GAS PLT	ICE-NG.			CO		USA	-104.797	40.23361		LATLON
081230049	1311	211111	SNYDER OIL CORP ROGGEN GAS PLT	ICE-NG.			CO		USA	-104.39	40.11944		LATLON
081230111	1311	211111	SNYDER OIL CORP THOMPSON VALLEY GAS PLA	ICE-NG.			CO		USA	-104.941	40.31472		LATLON
080870012	1311	211111	SNYDER OIL CORP VALLERY GAS PLT	ICE-NG.			CO		USA	-103.966	40.22278		LATLON
0098	1311	211111	SOUTHWESTERN PRODUCTION - GILCREST GAS	NATURAL GAS PROCESSING - FOR	13472 WELD COUNTY RD 40	PLATTEVILLE	CO	80651	USA	-104.806	40.2739	13	LATLON
0018	1311	211111	TBI FIELD SERVICES, INC- N DOUGLAS CREEK	NG PROCESSING (FORMERLY WILL	NE SEC 19 T1S R101W	RANGELY	CO	81648	USA	-108.676	40.1336	12	LATLON
0077	1311	211111	TBI FIELD SERVICES, INC. - CLOUGH COMP.	NATURAL GAS PROCESSING (FORI	NE NE SEC 13 T6S R94W	RIFLE, 2 MI W OF	CO	81601	USA	-107.862	39.527	13	LATLON
0020	1311	211111	TBI FIELD SERVICES, INC. - FOUNDATION CR	NG PROCESSING (FORMERLY WILL	SE NE SEC 25 T4S R102W	DURANGO	CO	81648	USA	-108.803	39.6731	12	LATLON
0004	1311	211111	TBI FIELD SERVICES, INC. - GREASEWOOD	NG PROCESSING - (FORMERLY WII	SEC 5 T2S R96W	RANGELY	CO	84108	USA	-108.189	39.9021	12	LATLON
0010	1311	211111	TEXACO E&P INC WILSON CREEK GAS PLT	NATGAS/OIL PROCESSING	SE SE SEC 27 T3N R94W	MEEKER	CO	81641	USA	-107.917	40.194	13	LATLON
0120	1311	211111	TEXACO EXPLOR & PROD - VAN SCHAIK B-3	OIL & GAS PORDUCTION	NE SEC 24 T12N R101W	HIAWATHA VAN SCHAICK B 3	CO	00000	USA	-108.696	40.9852	12	LATLON
0015	1311	211111	TOM BROWN INC - ANDY'S MESA	NATURAL GAS PROCESSING (WAS	SW NE SEC 28 T44N R16W	SAN MIGUEL	CO	00000	USA	-108.64	38.0441	12	LATLON
0065	1311	211111	TOM BROWN INC TAIGA MTN 1-29	FORMERLY KN ENERGY - GASCO N	SEC 29 T1N R103W	RANGELY	CO	81648	USA	-108.981	40.0258	12	LATLON
0015	1311	211111	UNION PACIFIC RES CO ARAPAHOE PLT	NATURAL GAS PROCESSING	SE SEC 27 T14S R42W	KIT CARSON	CO	80825	USA	-102.795	38.76645	13	LATLON
0010	1311	211111	UNION PACIFIC RES CO BLEDSOE RANCH	NATURAL GAS PROCESSING	SEC 1 T13S R51W	KIT CARSON	CO	80825	USA	-103.059	38.9541	13	LATLON
0008	1311	211111	UNION PACIFIC RES CO MT PEARL PLT	NATURAL GAS PROCESSING	NE SEC 35 T13S R48W	KIT CARSON	CO	80825	USA	-102.752	38.8738	13	LATLON
080170014	1311	211111	UNION PACIFIC RESOURCES FRONTERA PLT	ICE-NG.			CO		USA	-102.041	38.795		LATLON
1274	1311	211111	UNITED STATES EXPLOR.-CARLSON 2 32-33	THIS USED TO BE 001/0703 - THAT	SEC 33 T2S R64W	ADAMS	CO	00000	USA	-104.555	39.8329	13	LATLON
081230119	1311	211111	VESSELS GAS PROC LTD FT LUPTON PROC PLT	ICE-NG.			CO		USA	-104.888	40.01639		LATLON
081230367	1311	211111	VESSELS GAS PROCESSING INC	ICE-NG.			CO		USA	-104.995	40.00056		LATLON
081230148	1311	211111	VESSELS GAS PROCESSING LTD SPACE CITY	ICE-NG.			CO		USA	-104.632	40.08139		LATLON
081230132	1311	211111	VESSELS OIL &GAS FT LUPTON FRACTIONATION	ICE-NG.			CO		USA	-104.887	40.01583		LATLON
0468	1311	211111	WALSH PRODUCTION INC - LILLI GAS PROC.	NATURAL GAS PROCESSING	SEC 4 T8N R58W	RAYMER (5.0 M N OF RAYMER)	CO	80000	USA	-103.888	40.6922	13	LATLON
0128	1311	211111	WEST TEXAS GAS dba DAVIS GAS PROCESSING-PICEANCE CRE	PICEANCE CREEK GAS PROCESSIN	SEC 5 & SEC 8, T2S, R96W	23 MI NW OF RIO BLANCO	CO	00000-000	USA	-108.154	39.8985	12	LATLON
080010228	1311	211111	WESTERN GAS RESOURCES INC CABIN CREEK	ICE-NG.			CO		USA	-104.039	39.75222		LATLON
0115	1311	211111	WILDHORSE ENERGY RIFLE BOULTON COMP	NATURAL GAS PROCESSING - FOR	SW NE SEC 25 T7S R92W	RIFLE	CO	80650	USA	-107.616	39.4166	13	LATLON
081030020	1311	211111	WILLIAMS FIELD SVCS FOUNDATION CREEK				CO		USA	-108.803	39.67306		LATLON
081030018	1311	211111	WILLIAMS FIELD SVCS N DOUGLAS SITE	ICE-NG.			CO		USA	-108.72	39.86		LATLON
0011	1311	211111	WILLIFORD ENERGY CO	NATURAL GAS PROCESSING	NWNW SEC 32 T13S R48W	KIT CARSON_7 MI N OF	CO	80825	USA	-102.821	38.8752	13	LATLON
081230098	1311	211111	WINDSOR GAS PROCESSING INC	ICE-NG.			CO		USA	-104.806	40.27389		LATLON
00099	1311	211111	AMOCO PRODUCTION ULYSSES DEHY	NATURAL GAS - DEHYDRATION	ULYSSES DEHY	S5-T29S-R38W	KS	67880	USA	-101.351	37.57915		LATLON
350150024	1311	211111	AGAVE ENERGY/YATES PLANT_____________1M3	ICE-NG.			NM		USA	-104.444	32.71222		LATLON
350150002	1311	211111	AMOCO PROD/EMPIRE ABO GAS PLNT_____126M3	ICE-Diesel			NM		USA	-104.263	32.77167		LATLON
350250001	1311	211111	AMOCO PROD/S HOBBS CO2 INJECT STA___79M3	Turbine:			NM		USA	-103.155	32.66056		LATLON
350390028	1311	211111	APACHE CORP/BEAR CANYON______________814	ICE-NG.			NM		USA	-107.02	36.49		LATLON
350150101	1311	211111	ARCO PERMIAN/EMPIRE ABO INJECTION___12M1	ICE-NG.			NM		USA	-104.259	32.77306		LATLON
350450068	1311	211111	BURLINGTON RES/VALVERDE_______PSDNM728M6	ICE-NG.			NM		USA	-107.956	36.73139		LATLON
350150045	1311	211111	CONOCO/TURKEY TRACK GAS PLANT______457M1	ICE-NG.			NM		USA	-104.04	32.65278		LATLON
350310004	1311	211111	CONOCO/WINGATE FRACTION PLANT_____1313R2	ICE-Diesel			NM		USA	-108.639	35.54278		LATLON
350150102	1311	211111	EL PASO NATL GAS/BURTON FLATS______157M2	ICE-NG.			NM		USA	-104.149	32.56861		LATLON
350250006	1311	211111	EL PASO NATL GAS/JAL #1_____________0007	ICE-NG.			NM		USA	-103.21	32.06611		LATLON
350450042	1311	211111	FIVE OAKS/GALLEGOS CANYON__________131M1	ICE-NG.			NM		USA	-107.843	36.40111		LATLON
350450045	1311	211111	GULF ENERGY PROCESSING/GALLUP PLANT__458	ICE-NG.			NM		USA	-108.387	36.7475		LATLON
350410003	1311	211111	H.L.BROWN JR/BLUITT PLANT____________567	ICE-NG.			NM		USA	-103.183	33.635		LATLON
350250007	1311	211111	J.L.DAVIS GAS PROCESS/DENTON________65M2	ICE-NG.			NM		USA	-103.17	33.04611		LATLON
350390071	1311	211111	NIJECT/SAN JUAN 28-7 UNIT NITRO_____1495	ICE-NG.			NM		USA	-107.532	36.65611		LATLON
350150172	1311	211111	PARKER & PARSLEY/LOVING GAS PLNT____1172	ICE-NG.			NM		USA	-104.075	32.24028		LATLON
350250052	1311	211111	TEXACO/EUNICE NORTH GAS PLANT_______57M3	ICE-NG.			NM		USA	-103.163	32.44972		LATLON
350250051	1311	211111	TEXACO/EUNICE SOUTH GAS PLANT______278M4				NM		USA	-103.158	32.36139		LATLON
350410001	1311	211111	WARREN PETROLEUM/BLUITT GAS PLANT____563	ICE-NG.			NM		USA	-103.238	33.62056		LATLON
350150043	1311	211111	WARREN PETROLEUM/SNYDER RANCH FACIL__228	ICE-NG.			NM		USA	-103.869	32.65139		LATLON
350450247	1311	211111	WESTERN GAS RESOURCES/SAN JUAN RVR____GF	ICE-NG.			NM		USA	-108.368	36.75694		LATLON
0004	1311	211111	Wingate Fraction Plant	NMD986679629 Natl Gas Fraction Pla	6 Mi E Of Gallup	Gallup	NM	87301	USA	-108.639	35.5427	12	LATLON
350050050	1311	211111	YATES PETROLEUM/PATHFINDER AMINE___848M1	ICE-NG.			NM		USA	-104.198	33.42861		LATLON
401370203	1311	211111	MOBIL/SHOLEM ALECHEM GAS PLANT	ICE-NG.			OK		USA	-97.605	34.4225		LATLON
2482	1311	211111	Swift Energy Company Weatherford Facility	3900213 Weatherford Facility			OK		USA	-98.728	35.4851	14	LATLON
483230006	1311	211111	ALKEK GAS PLANT	ICE-NG.			TX		USA	-100.389	28.64302		LATLON
481690005	1311	211111	CEDAR HILL GAS PLANT	ICE-NG.			TX		USA	-101.233	33.09556		LATLON
483230002	1311	211111	CRUDE OIL PRODUCTION	ICE-Diesel			TX		USA	-100.389	28.64302		LATLON
48320	1311	211111	DAVIS GAS PROCESSING				TX		USA	-101.396	33.1635	14	LATLON
AG0002Q	1311	211111	EOG RESOURCES INC JOURDANTON GAS SWEETENING FACI		JOURDANTON GAS SWEETENING FACI	JOURDANTON	TX	78026	USA	-98.5944	28.87301	14	LATLON
483230003	1311	211111	FESSMAN PLANT	ICE-NG.			TX		USA	-100.389	28.64302		LATLON
482250002	1311	211111	LAURA LAVELLE SOUTH	ICE-NG.			TX		USA	-95.3658	31.25965		LATLON
481590004	1311	211111	NEW HOPE GAS PLANT	ICE-NG.			TX		USA	-95.0728	33.23194		LATLON
BI0009J	1311	211111	WEST TEXAS GAS PROCESSING LP		1.3 M N ON PLT RD	GAIL	TX	79738	USA	-101.26	32.57091	14	LATLON
BI0011W	1311	211111	WEST TEXAS GAS PROCESSING LP		2 MILES N OF VEALMOOR ON FM 15	GAIL	TX	79738	USA	-101.6	32.61674	14	LATLON
HT0016G	1311	211111	WEST TEXAS GAS PROCESSING LP		VINCENT RT BOX 132 COAHOMA TX	COAHOMA	TX	79511	USA	-101.353	32.49712	14	LATLON
HT0059L	1311	211111	WEST TEXAS GAS PROCESSING LP		FROM VEALMOOR, TX, 1 MI. S. ON	BIG SPRING	TX	79721	USA	-101.523	32.51563	14	LATLON
484930005	1311	211111	WILSON COUNTY PLANT	ICE-NG.			TX		USA	-98.0678	29.1603		LATLON
490139013	1311	211111	ALTONAH GAS PLANT	ICE-NG.			UT		USA	-110.439	40.3199		LATLON
55529	1311	211111	COASTAL FIELD ALTAMONT EAST				UT		USA	-110.439	40.3199	12	LATLON
55530	1311	211111	COASTAL FIELD ALTAMONT SOUTH				UT		USA	-110.439	40.3199	12	LATLON
55531	1311	211111	COASTAL FIELD ALTAMONT WEST				UT		USA	-110.439	40.3199	12	LATLON
490079095	1311	211111	DEW POINT PLANT	ICE-NG.			UT		USA	-110.565	39.64065		LATLON
490070013	1311	211111	DRUNKARDS WASH	ICE-NG.			UT		USA	-110.86	39.58944		LATLON
55552	1311	211111	GARY-WILLIAMS BLUEBELL GAS PLANT				UT		USA	-110.439	40.3199	12	LATLON
10034	1311	211111	Lisbon Plant-Hook & Ladder	Previously owned by Unocal Corp - Oi			UT		USA	-110.227	37.7491		LATLON
560070006	1311	211111	AMOCO BAIROIL CO2	ICE-Diesel			WY		USA	-107.514	42.22917		LATLON
560130008	1311	211111	AMOCO BEAVER CREEK				WY		USA	-108.314	42.84778		LATLON
560290012	1311	211111	AMOCO PROD CO.-ELK BASIN GAS PLANT	ICE-Diesel			WY		USA	-108.854	44.52944		LATLON
560410006	1311	211111	AMOCO PRODUCTION COMPANY - ANSCHUTZ				WY		USA	-111.041	41.07528		LATLON
560070017	1311	211111	AMOCO PRODUCTION COMPANY - WERTZ PL	ICE-NG.			WY		USA	-107	41.71695		LATLON
5604100006	1311	211111	AMOCO PRODUCTION COMPANY _ ANSCHUTZ	NATURAL GAS PROCESSING	17 MI S OF EVANSTON	EVANSTON	WY	82930	USA	-111.04	41.0755	12	LATLON
560410012	1311	211111	AMOCO WHITNEY CANYON	ICE-Diesel			WY		USA	-110.89	41.45444		LATLON
5600300012	1311	22121	BIG HORN GAS PROCESSING-BYRON GAS PLANT	NATURAL GAS PROCESSING	2 MI W OF BYRON_S29,T56N,R97W	BYRON	WY	82412	USA	-108.553	44.8022	12	LATLON
5601300028	1311	211111	BURLINGTON RESOURCES_LOST CABIN	LOST CABIN	1_1/2 S OF LOST CABIN	LOST CABIN	WY	00000	USA	-107.633	43.28651		LATLON
5604100009	1311	211111	CHEVRON CARTER CREEK	NATURAL GAS PROCESSING	30 MI NNE EVANSTON	EVANSTON	WY	82930	USA	-110.912	41.5735	12	LATLON
560410030	1311	211111	CHEVRON USA - PAINTER RESERVOIR EAST	ICE-NG.			WY		USA	-110.868	41.31194		LATLON
5604100030	1311	211111	CHEVRON USA _ PAINTER RESERVOIR EAST	SWEET GAS PLANT	SECTION 5, T15N, R119W	EVANSTON	WY	82930000(	USA	-110.868	41.3116	12	LATLON

strStateFacilityIdentifier	strSIC Primary	strNAICS Primary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXY Coordinate Type
560070019	1311	211111	CIG RAWLINS COMP	ICE-NG.			WY		USA	-107.058	41.75667		LATLON
5603700014	1311	211111	COLORADO INTER GAS_TABLE ROCK GAS PLANT	NATURAL GAS PROCESSING	TABLE ROCK GAS PLANT	ROCK SPRINGS	WY	82901	USA	-108.418	41.6074	12	LATLON
560290006	1311	211111	COLORADO INTERSTATE GAS - ELK BASIN	ICE-NG.			WY		USA	-109.803	44.40953		LATLON
58193	1311	211111	CONOCO - SHERIDAN				WY		USA	-106.975	44.6637	13	LATLON
560250011	1311	211111	EREC-BALCRON OIL DIV -NORTH GRIEVE	ICE-NG.			WY		USA	-106.806	42.96618		LATLON
560350001	1311	211111	EXXON -LABARGE DEHYDRATION FACILITY	ICE-NG.			WY		USA	-110.349	42.3725		LATLON
560230013	1311	211111	EXXON SHUTE CREEK I	NATURAL GAS PROCESSING	13 MI NE OF OPAL	KEMMERER	WY	83101	USA	-110.087	41.8838	12	LATLON
5602900012	1311	211111	HOWELL PET CORP_ELK BASIN GAS PLANT	NATURAL GAS PROCESSING	SECTION 29, T58N, R99W,	POWELL	WY	82435	USA	-108.854	44.5292	12	LATLON
560430003	1311	211111	INTERENERGY CORP.- HILAND GAS PLANT	ICE-NG.			WY		USA	-107.851	44.03056		LATLON
560090021	1311	211111	INTERLINE GAS (LIGHTNING CREEK)	ICE-NG.			WY		USA	-105.211	43.0392	13	LATLON
560090019	1311	211111	INTERLINE GAS (SOUTH WELL DRAW)	ICE-NG.			WY		USA	-111.037	42.9178	12	LATLON
560410022	1311	211111	KERN RIVER GAS - PAINTER RESERVIOR	Turbine:			WY		USA	-110.547	41.28735		LATLON
560230025	1311	211111	KERN RIVER GAS TRANS. - MUDDY CREEK	ICE-NG.			WY		USA	-110.362	41.69111		LATLON
560410001	1311	211111	KERN RIVER GTC-ANSCHUTZ (CT-742)	ICE-NG.			WY		USA	-111.027	41.06278		LATLON
560130027	1311	211111	KN GAS GATHERING - PAVILLION STATION	ICE-NG.			WY		USA	-108.777	43.1348		LATLON
560070026	1311	211111	NORTHERN GAS CO. - OIL SPRINGS	ICE-NG.			WY		USA	-107	41.71695		LATLON
560230023	1311	211111	NORTHWEST PIPELINE-MUDDY CREEK COMP STN				WY		USA	-110.546	42.44677		LATLON
560290007	1311	211111	OREGON BASIN GAS PLANT OP-184	ICE-NG.			WY		USA	-108.903	44.35278		LATLON
560090026	1311	211111	PHILLIPS PETROLEUM (YOSS)	ICE-NG.			WY		USA	-105.259	43.01		LATLON
560350006	1311	211111	QUESTAR PIPELINE - DRY PINEY	ICE-NG.			WY		USA	-109.834	42.86412		LATLON
5603500006	1311	211111	QUESTAR PIPELINE _ DRY PINEY	QUESTAR PIPELINE _ DRY PI	S11 T27N R114W	NONE	WY	99999	USA	-110.344	42.3492	12	LATLON
560410023	1311	211111	QUESTAR PIPELINE-LEROY STORAGE COMP STN	ICE-NG.			WY		USA	-110.616	41.32972		LATLON
560290005	1311	211111	RALSTON PROCESSING ASSOCIATES	ICE-NG.			WY		USA	-108.899	44.40917		LATLON
5601300008	1311	211111	SANTA FE SNYDER_BEAVER CREEK	NATURAL GAS PROCESSING	13 MI SE OF RIVERTON	RIVERTON	WY	82501	USA	-108.314	42.8474	12	LATLON
560130011	1311	211111	SNYDER OIL CORP.-RIVERTON PLANT	ICE-NG.			WY		USA	-108.343	42.94111		LATLON
T$12143	1311	211111	U.S. DOE NAVAL PETROLEUM RESERVE NO. 3		7290 SALT CREEK RTE.	CASPER	WY	82601132(	USA	-106.25	43.31667		LATLON
560410040	1311	211111	UNIVERSAL RESOURCES CORP - CLEAR CREEK	ICE-NG.			WY		USA	-110.839	41.38028		LATLON
560090039	1311	211111	WESTERN GAS RESOURCES - SPEARHEAD	ICE-NG.			WY		USA	-105.485	42.89442		LATLON
560090033	1311	211111	WESTERN GAS RESOURCES-SOUTH SAND DUNES	ICE-NG.			WY		USA	-105.485	42.89442		LATLON
5603700052	1311	22121	WEXPRO CANYON CREEK/VERMILLION	WEXPRO CANYON CREEK/VERM			WY		USA	-108.778	41.634		LATLON
0069	1321	211112	BEAR PAW ENERGY - WIGGINS GAS PLANT	HYDROCARBON LIQUID RECOVERY	SW SEC 3 T3N R59W	WIGGINS, N OF I-76	CO	80202	USA	-103.971	40.2542	13	LATLON
0183	1321	211112	CALPINE NATURAL GAS (WAS VESSELS OIL & G		SEC 29 T6S R91W	GARFIELD	CO	00000	USA	-107.53	39.727		LATLON
0107	1321	211112	DUKE ENERGY FIELD SERVICES - LUCERNE	NATURAL GAS GATHERING AND PF	31495 WCR 43	WELD COUNTY	CO	00000-000	USA	-104.658	40.4502	13	LATLON
0189	1321	211112	DUKE ENERGY FIELD SERVICES - N ARROWHEAD	NATURAL GAS GATHERING (WAS H	8 MILES W OF CHEYENNE WELLS	CHEYENNE WELLS 8 MI W OF	CO	80217	USA	-102.515	38.6699	13	LATLON
080690274	1321	211112	INDUSTRIAL GAS SERVICES INC WELLINGTON	Turbine:			CO		USA	-105.047	40.77639		LATLON
0473	1321	211112	SW PRODUCTION CO (WAS COSTILLA PETRO)	NATURAL GAS PROCESSING	SEC 27 T5N R64W (S WCR 55 & 54	WELD	CO	80000	USA	-104.312	40.50103	13	LATLON
0006	1321	211112	WILLIAMS FIELD SERVICES IGNACIO B PLT	NATURAL GAS PROCESSING	3746 COUNTY RD 307	DURANGO	CO	81301	USA	-107.784	37.1449	13	LATLON
080670006	1321	211112	WILLIAMS FIELD SVCS IGNACIO B PLT				CO		USA	-107.786	37.13889		LATLON
201750038	1321	211112	ANADARKO PETROLEUM CORP.	ICE-NG.			KS		USA	-101.013	37.15528		LATLON
201710011	1321	211112	KN ENERGY, INC. SUNFLOWER HELIUM PLANT	ICE-NG.			KS		USA	-100.982	38.48306		LATLON
00011	1321	211112	ONEOK FIELD SERVICES COMPANY	NATURAL GAS LIQUIDS	S17-T18S-R33W	SCOTT CITY	KS	67871	USA	-100.99	38.48944		LATLON
200070022	1321	211112	TEXACO PRODUCING, INC.	ICE-NG.			KS		USA	-98.5733	37.25528		LATLON
200770017	1321	211112	TRIDENT NGL, INC.	ICE-NG.			KS		USA	-98.2128	37.37667		LATLON
200950002	1321	211112	TRIDENT NGL, INC.	ICE-NG.			KS		USA	-97.8458	37.65		LATLON
350250018	1321	211112	AMERICAN PROCESSING/HOBBS PLANT____320M3	ICE-NG.			NM		USA	-103.358	32.71306		LATLON
0072	1321	211112	Antelope Ridge Gas Plant	NMD986680163 Natural Gas Processi	20 Mi Sw Of Eunice	Eunice	NM	88231	USA	-103.454	32.2996	13	LATLON
350390027	1321	211112	BENSON-MONTIN-GREER/CANADA OJITOS__914M1	ICE-NG.			NM		USA	-106.901	36.39639		LATLON
0140	1321	211112	Carlsbad Gas Plant	NM0001897628 Natl Gas Process & C	2 Mi NE of Loving	Loving	NM	88256	USA	-104.077	32.3184	13	LATLON
350250004	1321	211112	CONOCO/MALJAMAR GAS PLANT__________319M3	ICE-NG.			NM		USA	-103.768	32.8125		LATLON
350450062	1321	211112	CONOCO/SAN JUAN PLANT______________613M2				NM		USA	-107.959	36.73167		LATLON
0285	1321	211112	Dagger Draw Gas Plant	NMD986678019 Natural Gas Processi	9 Mi Ssw Of Artesia	Artesia	NM	88210	USA	-104.445	32.7183	13	LATLON
350450009	1321	211112	EL PASO NATL GAS/CHACO GAS PLANT__1555M1				NM		USA	-108.12	36.48833		LATLON
350150011	1321	211112	GPM GAS/ARTESIA GAS PLANT__________434M5	ICE-NG.			NM		USA	-104.231	32.7625		LATLON
350150169	1321	211112	GPM GAS/AVALON GASOLINE PLNT______1148M1	ICE-NG.			NM		USA	-104.209	32.5025		LATLON
350250044	1321	211112	GPM GAS/EUNICE GAS PLANT____________44M6				NM		USA	-103.299	32.52056		LATLON
350250046	1321	211112	GPM GAS/LEE GAS PLANT______________276M1	ICE-NG.			NM		USA	-103.514	32.80528		LATLON
350250035	1321	211112	GPM GAS/LINAM RANCH GAS PLANT_______39M2				NM		USA	-103.302	32.69833		LATLON
350150140	1321	211112	HIGHLANDS GATHERING/CARLSBAD PLT___927M3	ICE-NG.			NM		USA	-104.077	32.31806		LATLON
350250072	1321	211112	LG&E/HADSON/ANTELOPE RDG GAS PLNT__401M4	ICE-NG.			NM		USA	-103.45	32.29639		LATLON
350250122	1321	211112	LG&E/HADSON/MINERALS PLANT_________166M1	ICE-NG.			NM		USA	-103.325	32.70806		LATLON
350050014	1321	211112	LIQUID ENERGY/WHITE RANCH_______PSD356M1	ICE-NG.			NM		USA	-103.946	33.46361		LATLON
0004	1321	211112	Maljamar Gas Plant	NMD986680742 Natl Gas Processing	3 Mi S Of Maljamar	Maljamar	NM	88264	USA	-103.769	32.8125	13	LATLON
350150008	1321	211112	MARATHON OIL/INDIAN BSN GAS PLT_PSD295M3	Turbine:			NM		USA	-104.574	32.46639		LATLON
350310023	1321	211112	MERRION OIL & GAS/OJO ENCINO_________936	ICE-NG.			NM		USA	-107.327	35.92556		LATLON
350450196	1321	211112	MERRION OIL & GAS/SNAKE EYES PLANT___950	ICE-NG.			NM		USA	-107.631	36.05417		LATLON
350150035	1321	211112	OXY USA/ABO GAS PROCESSING____G__102,256	ICE-NG.			NM		USA	-104.253	32.78472		LATLON
350150138	1321	211112	PAN ENERGY/BURTON FLATS GAS PLT____913M1	ICE-NG.			NM		USA	-103.721	32.40111		LATLON
350150285	1321	211112	PAN ENERGY/DAGGER DRAW GAS PLT__PSD753M2	ICE-NG.			NM		USA	-104.445	32.71833		LATLON
350150095	1321	211112	PAN ENERGY/PECOS DIAMND GAS PLT___PSD389	ICE-NG.			NM		USA	-104.274	32.76861		LATLON
0062	1321	211112	San Juan Gas Plant	NMD986670297 Natural Gas Processi	61 Cnty Rd 4900, 2 Mi Ne Bloom	Bloomfield	NM	87413000(	USA	-107.964	36.7398	13	LATLON
350250008	1321	211112	SID RICHARDSON GASOLINE/JAL #3______1092				NM		USA	-103.176	32.17417		LATLON
350250009	1321	211112	SID RICHARDSON GASOLINE/JAL #4______70M1	ICE-NG.			NM		USA	-103.195	32.25528		LATLON
350250055	1321	211112	TEXACO/BUCKEYE GASOLINE PLANT_________60	ICE-NG.			NM		USA	-103.508	32.78444		LATLON
350250060	1321	211112	WARREN PETROLEUM/EUNICE GAS PLANT___67M3	ICE-NG.			NM		USA	-103.144	32.42583		LATLON
350250061	1321	211112	WARREN PETROLEUM/MONUMENT PLANT____110M3				NM		USA	-103.308	32.61056		LATLON
350250063	1321	211112	WARREN PETROLEUM/SAUNDERS PLANT____315M1	ICE-NG.			NM		USA	-103.61	33.05694		LATLON
350250064	1321	211112	WARREN PETROLEUM/VADA GAS PLANT____203M1	ICE-NG.			NM		USA	-103.544	33.43417		LATLON
350450026	1321	211112	WILLIAMS FIELD SERV/KUTZ GAS PLANT_301M				NM		USA	-107.954	36.66833		LATLON
350390010	1321	211112	WILLIAMS FIELD SERV/LYBROOK PLANT___81M2				NM		USA	-107.545	36.23194		LATLON
1055	1321	211112	Anadarko Gathering Company-Panther Creek Gas Plant	4900356 Panther Creek Gas Plant			OK		USA	-97.4716	34.7079	14	LATLON
400390351	1321	211112	ANR PRODUCTION CO.	Turbine:			OK		USA	-99.0142	35.63556		LATLON
400370204	1321	211112	ASSOCIATED NATURAL GAS/MILFAY GAS PLANT	ICE-NG.			OK		USA	-96.33	35.9		LATLON
2089	1321	211112	Carrera Gas Compranies, LLC Madill Gas Plant	9500200 Madill Gas Plant	6210 S. Yale, Ste. 1640	Tulsa	OK	74136000(	USA	-96.5918	34.0858	14	LATLON
400070231	1321	211112	CIMARRON GAS HOLDING COMPANY	ICE-NG.			OK		USA	-100.943	36.50167		LATLON
400070385	1321	211112	COLORADO INTERSTATE GAS				OK		USA	-100.397	36.89889		LATLON
400510363	1321	211112	CONOCO INC.	ICE-NG.			OK		USA	-97.7633	35.305		LATLON
400870201	1321	211112	CONOCO/GOLDSBY CONTRAL GAS PLANT	ICE-NG.			OK		USA	-97.5067	35.10167		LATLON
2843	1321	211112	Continental Gas, Inc.Eagle Chief Gas Plant	300300 Eagle Chief Gas Plant			OK		USA	-98.5111	36.6109	14	LATLON
1310	1321	211112	Continental Laverne Gas Processing, LLC Laverne Gas Plant	5900200 Laverne Gas Plant	1437 South Boulder	Tulsa	OK	74119362(	USA	-99.9263	36.7117	14	LATLON

strStateFacilityIdentifier	strSICPrimary	strNAICSPrimary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXYCoordinateType
400070361	1321	211112	CONTINENTAL NATURAL GAS INC.(NICOL				OK		USA	-100.293	36.72583		LATLON
1308	1321	211112	Duke Energy Goldsby Gas Plant	8700201 Goldsby Gas Plant			OK		USA	-97.507	35.1032	14	LATLON
2299	1321	211112	Duke Energy Hillsboro Gas Plant	5100360 Hillsboro Gas Plant			OK		USA	-98.0801	34.9567	14	LATLON
2315	1321	211112	Duke Energy Milfay Gas Plant	3700365 Milfay Gas Plant			OK		USA	-96.5674	35.7695	14	LATLON
2365	1321	211112	Duke Energy West Edmond Gas Plant	8300350 West Edmond Gas Plant			OK		USA	-97.622	35.7535	14	LATLON
2366	1321	211112	Duke Energy West Guthrie	8300201 West Guthrie			OK		USA	-97.4529	35.747	14	LATLON
1481	1321	211112	Enerfin Resources Co. Tecumseh Gas Plant	12500355 Tecumseh Gas Plant			OK		USA	-96.9447	35.2088	14	LATLON
401090130	1321	211112	ENOGEX, INC	ICE-NG.			OK		USA	-97.245	35.43556		LATLON
1488	1321	211112	Enogex, Inc. Calumet Gas Processing Plant	1700351 Calumet Gas Processing Pla	515 Central Park Dr. Ste. 600	Oklahoma City	OK	731050000	USA	-98.1549	35.6665	14	LATLON
2565	1321	211112	Enogex, Inc. Cox City Processing Plant	5100213 Cox City Processing Plant	515 Central Park Dr. Ste. 600	Oklahoma City	OK	731050000	USA	-97.7923	34.7933	14	LATLON
1079	1321	211112	Enogex, Inc. Custer Gas Plant	3900351 Custer Gas Plant	515 Central Park Dr. Ste. 600	Oklahoma City	OK	731050000	USA	-99.0144	35.6369	14	LATLON
400730203	1321	211112	EXXON/DOVER-HENNESSEY	ICE-NG.			OK		USA	-97.9028	36.07194		LATLON
1531	1321	211112	ExxonMobile Production Company Dover Hennessey Gas Plant	7300353 Dover Hennessey Gas Plant			OK		USA	-97.904	36.0729	14	LATLON
1042	1321	211112	GPM Gas Company LLC. Mooreland Plant	15300352 Mooreland Plant	210 Park Ave.	Oklahoma City	OK	731020000	USA	-99.1574	36.4408	14	LATLON
400730220	1321	211112	GPM GAS CORP. KINGFISHER PLANT				OK		USA	-97.7328	35.79083		LATLON
400730224	1321	211112	GPM GAS CORP. OKARCHE PLANT	Turbine:			OK		USA	-98.0856	35.73639		LATLON
400030202	1321	211112	GPM/ALINE BOOSTER	ICE-NG.			OK		USA	-98.3892	36.51444		LATLON
400930218	1321	211112	GPM/CEDAR BOOSTER	ICE-NG.			OK		USA	-98.8214	36.31611		LATLON
400070208	1321	211112	MAPLE GAS CORP.	ICE-NG.			OK		USA	-100.516	36.87306		LATLON
400390358	1321	211112	MOBIL EXPLORATION & PRODUCING U.S.	ICE-NG.			OK		USA	-98.8794	35.82806		LATLON
400190205	1321	211112	MOBIL OIL CO - FOX	ICE-NG.			OK		USA	-97.5094	34.34833		LATLON
401390212	1321	211112	MOBIL OIL CORPORATION WEST HOUGH	ICE-NG.			OK		USA	-101.641	36.90139		LATLON
400030200	1321	211112	NGC ENERGY RESOURCES LIMITED PARTNE	ICE-NG.			OK		USA	-98.2619	36.58194		LATLON
400150205	1321	211112	NGC ENERGY RESOURCES LIMITED PARTNE	ICE-NG.			OK		USA	-98.3267	35.3175		LATLON
400950201	1321	211112	NGC ENERGY RESOURCES LIMITED PARTNE	ICE-NG.			OK		USA	-96.7606	34.11917		LATLON
400470203	1321	211112	NGC ENERGY RESOURCES, L.P.	ICE-NG.			OK		USA	-97.8194	36.42694		LATLON
400950200	1321	211112	NGC ENERGY RESOURCES/MADILL GAS PLANT	ICE-NG.			OK		USA	-96.5903	34.08583		LATLON
400930203	1321	211112	NGC ENERGY, INC/RINGWOOD PLANT	ICE-NG.			OK		USA	-98.2417	36.36556		LATLON
400450201	1321	211112	NORTHERN NATURAL GAS CO.	ICE-NG.			OK		USA	-99.8556	36.45222		LATLON
400070212	1321	211112	NORTHERN NATURAL GAS ELMWOOD	ICE-NG.			OK		USA	-100.523	36.61417		LATLON
401390206	1321	211112	OKLAHOMA GAS PIPELINE CO/TYRONE	ICE-NG.			OK		USA	-101.088	36.99472		LATLON
2523	1321	211112	ONEOK Field Services Co. Antelope Hills Plant	12900203 Antelope Hills Plant			OK		USA	-99.7841	35.8307	14	LATLON
2524	1321	211112	ONEOK Field Services Co. Beaver Gas Plant	700230 Beaver Gas Plant			OK		USA	-100.147	36.5718	14	LATLON
2525	1321	211112	ONEOK Field Services Co. Cimarron Gas Plant	1100208 Cimarron Gas Plant			OK		USA	-98.5417	36.0247	14	LATLON
2526	1321	211112	ONEOK Field Services Co. Custer Gas Plant	3900202 Custer Gas Plant			OK		USA	-98.8918	35.6496	14	LATLON
2527	1321	211112	ONEOK Field Services Co. El Reno Gas Facility	1700203 El Reno Gas Facility			OK		USA	-97.9522	35.6302	14	LATLON
2074	1321	211112	ONEOK Field Services Co. Enid Plant	4700203 Enid Plant			OK		USA	-97.8188	36.4263	14	LATLON
2679	1321	211112	ONEOK Field Services Co. Leedey Plant	12900204 Leedey Plant			OK		USA	-99.4659	35.8092	14	LATLON
2092	1321	211112	ONEOK Field Services Co. Ringwood Gas Plant	9300203 Ringwood Gas Plant			OK		USA	-98.2421	36.3658	14	LATLON
2531	1321	211112	ONEOK Field Services Co. Stephens Plant	13700208 Stephens Plant			OK		USA	-97.7011	34.47	14	LATLON
400530205	1321	211112	ORYX ENERGY	ICE-NG.			OK		USA	-97.9042	36.84639		LATLON
400590200	1321	211112	ORYX ENERGY COMPANY	Turbine:			OK		USA	-99.9256	36.70889		LATLON
401390200	1321	211112	PARKER & PARSLEY				OK		USA	-101.256	36.83417		LATLON
2658	1321	211112	Questar Gas Management Company Beaver Gas Plant	700353 Beaver Gas Plant			OK		USA	-100.953	36.7783	14	LATLON
2509	1321	211112	Spectrum Field Services Velma Gas Plant	13700200 Velma Gas Plant			OK		USA	-97.6919	34.4617	14	LATLON
3082	1321	211112	Superior Pipeline Co. Butler Gas Plant	3903082 Butler Gas Plant			OK		USA	-99.1997	35.6246	14	LATLON
400490219	1321	211112	TEXACO EXPLORATION & PRODUCTION, IN	ICE-NG.			OK		USA	-97.4442	34.81417		LATLON
400850201	1321	211112	TEXACO EXPLORATION & PRODUCTION, IN	ICE-NG.			OK		USA	-97.0281	33.96333		LATLON
2508	1321	211112	Texaco Exploration & Production, Inc. Maysville Gas Plant	4900219 Maysville Gas Plant			OK		USA	-97.4456	34.815	14	LATLON
401370200	1321	211112	TEXACO PRODUCTS - VELMA GAS PLANT	ICE-NG.			OK		USA	-97.6781	34.46083		LATLON
2517	1321	211112	Timberland Gathering & Processing Company Tyrone	13900206 Tyrone			OK		USA	-101.089	36.9973	14	LATLON
400170203	1321	211112	TONKAWA GAS PROCESSING CO.				OK		USA	-97.9517	35.63056		LATLON
401290203	1321	211112	TONKAWA GAS PROCESSING CO.				OK		USA	-99.7833	35.83056		LATLON
401370208	1321	211112	TONKAWA GAS PROCESSING CO.	ICE-NG.			OK		USA	-97.7008	34.46917		LATLON
400390205	1321	211112	TRANSOK, INC.	ICE-NG.			OK		USA	-98.7975	35.73833		LATLON
400630200	1321	211112	TRANSOK, INC.	ICE-NG.			OK		USA	-96.1692	35.1375		LATLON
400830200	1321	211112	TRANSOK, INC.	ICE-NG.			OK		USA	-97.6167	35.89917		LATLON
401290202	1321	211112	TRANSOK, INC.	ICE-NG.			OK		USA	-99.4831	35.74778		LATLON
400470218	1321	211112	TRIDENT NGL, INC.	ICE-NG.			OK		USA	-98.0325	36.17806		LATLON
400470358	1321	211112	TRIDENT NGL, INC.	ICE-NG.			OK		USA	-97.5631	36.36556		LATLON
400730236	1321	211112	TRIDENT NGL, INC.	ICE-NG.			OK		USA	-98.1242	35.79667		LATLON
400710204	1321	211112	TRIDENT NGL, INC/AMBROSE	ICE-NG.			OK		USA	-97.3133	36.82667		LATLON
2946	1321	211112	Tri-Star Energy, LLC Braman Gas Processing Plant	7102946 Braman Gas Processing Plar	101 E. Broadway Ave.	Ponca City	OK	746014302	USA	-97.2406	36.9863	14	LATLON
400070214	1321	211112	WARREN PERTOLEUM COMPANY MOCANE	ICE-NG.			OK		USA	-100.396	36.89889		LATLON
401290204	1321	211112	WARREN PETROLEUM CO., DIVISION CHEV	ICE-NG.			OK		USA	-99.4656	35.80917		LATLON
2683	1321	211112	Westana Gathering Company Chester Gas Plant	15300201 Chester Gas Plant			OK		USA	-98.9789	36.2474	14	LATLON
400930222	1321	211112	WESTERN GAS RESOURCES/CHANEY DELL				OK		USA	-98.2444	36.43222		LATLON
2928	1321	211112	Williams Field Services Co.Dry Trails Gas Plant	13902928 Dry Trails Gas Plant			OK		USA	-101.616	36.9058	14	LATLON
400530211	1321	211112	WILLIAMS NATURAL GAS CO.	ICE-NG.			OK		USA	-97.4778	36.85306		LATLON
SD0048I	1321	211112	ABRAXAS PETROLEUM CORP		5 MI. N. OF SINTON, TX., THEN	SINTON	TX	78387	USA	-97.1295	28.18036	14	LATLON
MQ0303C	1321	211112	ACACIA NATURAL GAS CORP		SPUR 149 AT FM 149	MAGNOLIA	TX	77355	USA	-95.0916	30.02799	15	LATLON
EA0085H	1321	211112	ALLIANT ENERGY DESDEMONA LP		OFF CR 495, 2.5 MILES NE OF DE	DESDEMONA	TX	76445	USA	-98.5167	32.30843	14	LATLON
CF0017D	1321	211112	AMERICAN GATHERING LP		FRM SKELLYTOWN,APPOX 4.5 MI.E	SKELLYTOWN	TX	79080	USA	-101.121	35.56446	14	LATLON
CF0005K	1321	211112	AMERICAN PROCESSING		FROM SWELLYTOWN APPROX. 2.5 MI	PAMPA	TX	79065	USA	-101.136	35.52877	14	LATLON
HL0019O	1321	211112	AMERICAN PROCESSING LP		APPROX. 10 MI. S. ON HWY. 83;	CANADIAN	TX	79014	USA	-100.476	35.73454	14	LATLON
PG0036K	1321	211112	AMERICAN PROCESSING LP		8 MI. S. OF FRITCH, TX., ON ST	FRITCH	TX	79036	USA	-101.639	35.5433	14	LATLON
MR0026R	1321	211112	ANADARKO GATHERING CO		0.75 MI. S. OF HWY. 1913 & 131	SANFORD	TX	70978	USA	-101.63	35.80891	14	LATLON
WF0098I	1321	211112	APACHE CORPORATION		10 MI. S.E. OF PEIRCE @ INTRSN	EL CAMPO	TX	77437	USA	-96.077	29.14636	14	LATLON
480090001	1321	211112	ARCHER CITY PLT	ICE-NG.			TX		USA	-98.6871	33.6156		LATLON
HL0101F	1321	211112	BP AMOCO		4 MI S. OF CANADIAN, TX	CANADIAN	TX	79014	USA	-100.27	35.84	10	LATLON
EA0007E	1321	211112	CANTERA RESOURCES INC		12 MILES NW OF CISCO OFF HWY 6	CISCO	TX	76437	USA	-99.0927	32.50563	14	LATLON
EA0008C	1321	211112	CANTERA RESOURCES INC		6 MI. W. ON F.M. 101	RANGER	TX	76470	USA	-98.7901	32.46883	14	LATLON
PA0009K	1321	211112	CANTERA RESOURCES INC		2 MI. N. ON HWY. 193 FROM I. 2	GORDON	TX	76453	USA	-98.3389	32.53763	14	LATLON
PC0140M	1321	211112	CANTERA RESOURCES INC		2 MI. N.E. OF HWY. 51 SPRINGTO	SPRINGTOWN	TX	76082	USA	-97.6835	32.98432	14	LATLON
481010001	1321	211112	CHALK PLANT	ICE-NG.			TX		USA	-100.258	34.07462		LATLON
480210001	1321	211112	CHEROKEE GATHERING COMPAN	ICE-NG.			TX		USA	-97.3363	30.1029		LATLON
WJ0002I	1321	211112	CITATION OIL & GAS CORP WILLAMAR PLANT		WILLAMAR PLANT NEAR WILLAMAR	LYFORD	TX	78569	USA	-97.5709	26.40943	14	LATLON
CC0005U	1321	211112	CMS TAURUS FIELD SERVICES LP		8 MI. S. OF PUTNAM ON F.M. 880	PUTNAM	TX	76469	USA	-99.1866	32.27621	14	LATLON
FD0003I	1321	211112	CMS TAURUS FIELD SERVICES LP		ON F.M. 3339, 2 MI. S. OF S.H.	HAMLIN	TX	79520	USA	-100.662	32.96172	14	LATLON

strStateFacilityIdentifier	strSIC Primary	strNAICS Primary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXY Coordinate Type
CI0042R	1321	211112	CONOCO INC		1.5 MILES WEST OF HIGHWAY 146	MONT BELVIEU	TX	77580	USA	-94.9188	29.85177	15	LATLON
IA0001R	1321	211112	CONOCO INCORPORATED		7 MI. W. OF MERTZON ON S.H. 67	MERTZON	TX	76941	USA	-100.908	31.18384	14	LATLON
SF0008V	1321	211112	CONOCO INCORPORATED		10.2 M N ON FM 915 0.7 M W ON	ELDORADO	TX	76936	USA	-100.683	30.9914	14	LATLON
SD0022D	1321	211112	CORPUS CHRISTI NAT GAS GPLP		F.M. 136--2 MI. W. FROM S.H. 3	GREGORY	TX	78359	USA	-97.2633	27.93952	14	LATLON
CZ0011M	1321	211112	CROCKETT GAS PROCESSING CO		3 MI. NW. FROM THE HEADQUARTER	OZONA	TX	76943	USA	-101.237	30.73371	14	LATLON
484510003	1321	211112	DOUBLE A GAS PLANT	Turbine:			TX		USA	-100.41	31.35		LATLON
481770001	1321	211112	DUBOSE PLANT	ICE-NG.			TX		USA	-97.3347	29.09194		LATLON
ML0024S	1321	211112	DUKE ENERGY		12.9 MI SE SH 158 5.1 MI S FM	MIDLAND	TX	79701	USA	-101.794	31.85784	14	LATLON
MF0012R	1321	211112	DUKE ENERGY		13 MI. N.W. OF STANTON, OFF OF	TARZAN	TX	79783	USA	-101.968	32.26804	14	LATLON
PB0067I	1321	211112	DUKE ENERGYFIELD SERVICES		COUNTY RD. 306, 1 MI. E. OF HW	CARTHAGE	TX	75633	USA	-94.3432	32.24294	15	LATLON
PB0002N	1321	211112	DUKE ENERGYFIELD SERVICES INC		5 MI. E. ON U.S. HWY. 79	CARTHAGE	TX	75633	USA	-94.2637	32.18816	15	LATLON
SF0001M	1321	211112	DUKE ENERGYFIELD SERVICES INC		13 MI. S. OF CHRISTOVAL ON U.S	CHRISTOVAL	TX	76935	USA	-100.519	31.00091	14	LATLON
SQ0006B	1321	211112	DUKE ENERGYFIELD SERVICES INC		FROM SONORA, TX., 5.5 MI. S.E.	SONORA	TX	76950	USA	-100.589	30.50798	14	LATLON
LE0012W	1321	211112	DUKE ENERGYFIELD SERVICES INC		FM 2437, 12 MI S OF SHERIDAN	SHERIDAN	TX	77475	USA	-96.9501	29.50857	14	LATLON
NE0028T	1321	211112	DUKE ENERGYFIELD SERVICES INC		13 MI. W. OF BISHOP NEAR F.M.	BISHOP	TX	78343	USA	-97.9016	27.68646	14	LATLON
ML0020D	1321	211112	DUKE ENERGYFIELD SERVICES INC		18 MI. S. OF I. 20 ON F.M. 178	MIDLAND	TX	79701	USA	-102.133	31.66262	13	LATLON
PE0024Q	1321	211112	DUKE ENERGYFIELD SERVICES INC		0.5 MI. S OF FM 1450 ON FM 177	COYANOSA	TX	79730	USA	-103.086	31.26842	13	LATLON
PE0025O	1321	211112	DUKE ENERGYFIELD SERVICES INC		7.2 MI. S. OF F.M. 1450 ON F.M	COYANOSA	TX	79730	USA	-103.037	31.18308	13	LATLON
WF0095O	1321	211112	DUKE ENERGYFIELD SERVICES LLC		WARRIOR GAS CO. WHARTON PLANT	EL CAMPO	TX	77437	USA	-96.2096	29.2059	14	LATLON
HW0020F	1321	211112	DUKE ENERGYFIELD SERVICES LLC		NEAR THE WEST END OF 10TH STRE	BORGER	TX	79007	USA	-101.411	35.67427	14	LATLON
HD0055B	1321	211112	DUKE ENERGYFIELD SERVICES LLC		3.5 MI. S. GRUVER, OFF F.M. 20	GRUVER	TX	79040	USA	-101.388	36.19576	14	LATLON
CI0022A	1321	211112	DYNEGY MIDSTREAM SERVICES LP		10119 HWY. 146 N.	MONT BELVIEU	TX	77580	USA	-94.903	29.84173	15	LATLON
CY0018J	1321	211112	DYNEGY MIDSTREAM SERVICES LP		STAR RT., BOX 18, CRANE, TX.	CRANE	TX	79731	USA	-102.641	31.50153	13	LATLON
GA0011C	1321	211112	DYNEGY MIDSTREAM SERVICES LP		8 MI W ON US 62 AND 180 2.4 MI	SEMINOLE	TX	79360	USA	-102.8	32.76063	13	LATLON
GH0007I	1321	211112	DYNEGY MIDSTREAM SERVICES LP		2.5 MI. E. OF LEFORS, TX. ON H	LEFORS	TX	79054	USA	-100.762	35.43211	14	LATLON
GI0012E	1321	211112	DYNEGY MIDSTREAM SERVICES LP		275 & HWY 82 NW OF SHERMAN	SHERMAN	TX	75090	USA	-96.6344	33.68186	14	LATLON
HH0005S	1321	211112	DYNEGY MIDSTREAM SERVICES LP		SOUTH OF INTERSTATE 20 & WEST	WASKOM	TX	75692	USA	-94.0723	32.46927	15	LATLON
HL0008T	1321	211112	DYNEGY MIDSTREAM SERVICES LP		3 MI. S. ON U.S. 60 FROM CANAD	CANADIAN	TX	79014	USA	-100.402	35.86848	14	LATLON
SH0003J	1321	211112	DYNEGY MIDSTREAM SERVICES LP		9 MI NE OF	ALBANY	TX	76430	USA	-99.2175	32.85847	14	LATLON
WG0011M	1321	211112	DYNEGY MIDSTREAM SERVICES LP		10 MI. N. OF I. 40 ON F.M. 144	MCLEAN	TX	79057	USA	-100.5	35.34575	14	LATLON
WN0005E	1321	211112	DYNEGY MIDSTREAM SERVICES LP		S. OF F.M. 1810, 5 MI. W. OF C	CHICO	TX	76030	USA	-97.8775	33.31185	14	LATLON
WN0045P	1321	211112	DYNEGY MIDSTREAM SERVICES LP		1 MI. S. OF RED BUD CHURCH	CHICO	TX	76030	USA	-97.3959	32.98941	14	LATLON
HE0012I	1321	211112	ECHO PRODUCTION INC		ON F.M. 1167, 1 MI. S. OF U.S.	QUANAH	TX	79252	USA	-99.6469	34.25581	14	LATLON
MC0006W	1321	211112	EGS HYDROCARBONS INC		HWY. 72, 1 MI. S. OF HWY. 99,	TILDEN	TX	78072	USA	-98.4572	28.44476	14	LATLON
CB0063R	1321	211112	EL PASO FIELD SERVICES		CORNER OF SAN ANTONIO & MILAM	PORT LAVACA	TX	77979	USA	-96.63	28.4	14	LATLON
MH0039V	1321	211112	EL PASO FIELD SERVICES		1.5 MI. E. OF HWY. 35 ON F.M.	PALACIOS	TX	77465	USA	-96.1827	28.80017	14	LATLON
MH0057T	1321	211112	EL PASO FIELD SERVICES		OYSTER LAKE	PALACIOS	TX	77465	USA	-96.1337	28.61693	14	LATLON
LK0044R	1321	211112	ENRON PROCESSING PROPERTIES INC		ON HWY. 281 NEAR GEORGE WEST	GEORGE WEST	TX	78022	USA	-98.1206	28.36758	14	LATLON
WB0003U	1321	211112	EXXON COMPANY		AT OR NEAR P.O. BOX 276, KATY,	KATY	TX	77449	USA	-95.8772	29.81367	15	LATLON
WC0010M	1321	211112	EXXON COMPANY USA		3 MI. S. ON F.M. 1927	PYOTE	TX	79777	USA	-103.107	31.4882	13	LATLON
WO0009I	1321	211112	EXXON COMPANY USA		F.M. 1795	HAWKINS	TX	75765	USA	-95.1979	32.61159	15	LATLON
HG0234M	1321	211112	EXXON CORPORATION		51210 RED BLUFF-GENOA RD.	PASADENA	TX	77507	USA	-95.1223	29.63141	15	LATLON
RL0007C	1321	211112	EXXON CORPORATION		2 MI. N. AT THE INTERSECTION O	NEW LONDON	TX	75682	USA	-94.9289	32.27045	15	LATLON
KJ0003N	1321	211112	EXXON USA INC KING RANCH		KING RANCH	KINGSVILLE	TX	78363	USA	-98.0583	27.46553	14	LATLON
CB0053U	1321	211112	FORMOSA HYDROCARBONS CO INC		S. OF S.H. 35, W. OF F.M. 1593	POINT COMFORT	TX	77978	USA	-96.5586	28.66372	14	LATLON
GJ0003W	1321	211112	GAS SOLUTIONS		TO CHEROKEE TRACE 1 MI S & 0.3	WHITE OAK	TX	75693	USA	-94.8664	32.50383	15	LATLON
HD0014P	1321	211112	GPM GAS CORPORATION		20 MI. N. OF GRUVER ON TX. 136	GRUVER	TX	79040	USA	-101.35	36.28	14	LATLON
MR0030D	1321	211112	GPM GAS CORPORATION		4 M SW OF DUMAS ON FM 722	DUMAS	TX	79029	USA	-102.028	35.82075	13	LATLON
FC0033K	1321	211112	GPM GAS SERVICES CO		3 MILES NORTH OF THE CITY OF W	WINCHESTER	TX	78964	USA	-96.9867	30.03686	14	LATLON
FC0049S	1321	211112	GPM GAS SERVICES CO		7 MI. N. OF LAGRANGE ON C.R. 1	GIDDINGS	TX	78942	USA	-96.8919	29.99269	14	LATLON
LF0019U	1321	211112	GPM GAS SERVICES CO		GEORGE B. LOFTIN SURVEY ("A-19	GIDDINGS	TX	78942	USA	-96.8077	30.29071	14	LATLON
LF0022I	1321	211112	GPM GAS SERVICES CO		1 MI. N.E. OF GIDDINGS, TX., O	DIME BOX	TX	77853	USA	-96.7743	30.26542	14	LATLON
LF0024E	1321	211112	GPM GAS SERVICES CO		MATTHEW SPARKS LEAGUE "A-18"	GIDDINGS	TX	78942	USA	-96.8603	30.20506	14	LATLON
482250005	1321	211112	GRAPELAND PLANT	Turbine:			TX		USA	-95.3144	31.30278		LATLON
KA0013M	1321	211112	GULF ENERGYGATHERING PROCESSING		10 MI. S. OF RUNGE, TX., ON F.	RUNGE	TX	78151	USA	-97.6316	28.79102	14	LATLON
RG0069H	1321	211112	H & D OPERATING CO		4 MILES SW OF WOODSBORO ON HWY	WOODSBORO	TX	78393	USA	-97.3884	28.20168	14	LATLON
BL0005M	1321	211112	HILCORP ENERGY CO SWEENY		SWEENY	OLD OCEAN	TX	77463	USA	-95.7502	29.0415	15	LATLON
HM0010V	1321	211112	HUNT OIL CO		1 MI NE ON HWY 315	POYNOR	TX	75782	USA	-95.5822	32.08478	15	LATLON
CA0011B	1321	211112	JL DAVIS		6 MI. N.W. OF LULING ON COUNTY	LULING	TX	78648	USA	-97.7282	29.73106	14	LATLON
FJ0045A	1321	211112	JL DAVIS GAS PROC INC		6 MI SSE OF PEARSALL-14.8 MI N	PEARSALL	TX	78061	USA	-99.0309	28.81301	14	LATLON
IA0009B	1321	211112	JL DAVIS GAS PROCESSING INC		ON S.H. 163 10 MI. N. OF	BARNHART	TX	76930	USA	-101.162	31.28765	14	LATLON
RC0001Q	1321	211112	JL DAVIS GAS PROCESSING INC		6 MI. E. OF BIG LAKE, TX.	BIG LAKE	TX	76932	USA	-101.342	31.16433	14	LATLON
CI0005A	1321	211112	KOCH HYDROCARBON CO		1.2 MI. W. OF THE INTERSECTION	MONT BELVIEU	TX	77580	USA	-94.9087	29.85413	15	LATLON
480710032	1321	211112	KOCH HYDROCARBON COMPANY				TX		USA	-94.5428	29.51167		LATLON
482490001	1321	211112	LA GLORIA GAS PLANT				TX		USA	-98.0914	27.16278		LATLON
483130003	1321	211112	MADISONVILLE GAS PROCESSI	ICE-NG.			TX		USA	-95.9293	30.958		LATLON
484030001	1321	211112	MAGASCO COMPRESSOR STN.	ICE-NG.			TX		USA	-93.5831	31.17139		LATLON
35868	1321	211112	MARATHON OIL COMPANY				TX		USA	-100.301	31.2625	14	LATLON
JE0746E	1321	211112	MARINER ENERGY INC		TRAM RD. BETWEEN SHERWOOD DR.	BEAUMONT	TX	77701	USA	-94.1792	30.16773	15	LATLON
LK0001M	1321	211112	MERIT ENERGY CO		ON F.M. 623 IN LIVE OAK CO. NE	OAKVILLE	TX	78060	USA	-98.0132	28.48416	14	LATLON
483630008	1321	211112	MINERAL WELLS PLANT	ICE-NG.			TX		USA	-98.3157	32.7596		LATLON
MQ0335M	1321	211112	MITCHELL ENERGY CORP		4 MI. E. OF F.M. 149, ON F.M.	MAGNOLIA	TX	77355	USA	-95.6401	30.23659	15	LATLON
WN0021G	1321	211112	MITCHELL GAS SERVCS LMTD PARTNERSHIP		3 1/2 M W OF BRIDGEPORT ON HWY	BRIDGEPORT	TX	76026	USA	-97.8076	33.19607	14	LATLON
CN0003A	1321	211112	MITCHELL GAS SERVICES LP		SILVER	SILVER	TX	76949	USA	-100.68	32.04785	14	LATLON
JA0026U	1321	211112	MITCHELL GAS SERVICES LP		ON F.M. 2210, 1 MI. E. OF F.M.	PERRIN	TX	76075	USA	-98.1883	33.07295	14	LATLON
PA0015P	1321	211112	MITCHELL GAS SERVICES LP		2 MI. W. OF LONE CAMP	PALO PINTO	TX	76072	USA	-98.3116	32.66187	14	LATLON
36659	1321	211112	MOBIL EXPLORATION AND PRODUCING US I				TX		USA	-100.867	33.235	14	LATLON
483390032	1321	211112	N.G.P.L.C.O.A. STN. 302	ICE-NG.			TX		USA	-95.1508	30.12028		LATLON
MQ0064U	1321	211112	NATURAL GASPIPELINE CO OF AMERICA		17057 F. M. 1485	NEW CANEY	TX	77357	USA	-95.2514	30.20271	15	LATLON
CZ0024D	1321	211112	NELEH GAS SYSTEMS				TX		USA	-102.221	31.03878	13	LATLON
HW0035P	1321	211112	NORTHERN NATURAL GAS CO		14.4 MI. S., 207; 10.1 MI. W.,	MORSE	TX	79062	USA	-101.514	36.02208	14	LATLON
HP0005E	1321	211112	OCCIDENTAL PERMIAN LTD		3 MI WEST ON FM 303 ON FM 301	SUNDOWN	TX	79372	USA	-102.559	33.4678	13	LATLON
TC0002Q	1321	211112	OCCIDENTAL PERMIAN LTD		29.5 MI. N. ON S.H. 349; 3 MI.	SHEFFIELD	TX	79781	USA	-101.844	30.37381	14	LATLON
GH0001U	1321	211112	ONEOK FIELDSERVICES CO		5 MI. W. OF PAMPA, & 1 MI. N.	PAMPA	TX	79065	USA	-101.035	35.52066	14	LATLON
MR0023A	1321	211112	ONEOK FIELDSERVICES CO		15 MI. E. OF DUMAS ON HYW. 152	DUMAS	TX	79029	USA	-101.696	35.78764	14	LATLON
38108	1321	211112	ORYX ENERGYCOMPANY				TX		USA	-98.06	27.3285	14	LATLON
38517	1321	211112	PANENERGY FIELDS SERVICES INC				TX		USA	-98.1532	27.2766	14	LATLON
PG0035M	1321	211112	PIONEER NATRESOURCES CO		27 MI. N. OF AMARILLO ON HWY.	AMARILLO	TX	79101	USA	-101.894	35.53807	14	LATLON
BE0013Q	1321	211112	PIONEER NATURAL RESOURCES USA INC		2 MI. S. OF PAWNEE ON F.M. 673	PAWNEE	TX	78145	USA	-97.9929	28.62278	14	LATLON

strStateFacilityIdentifier	strSIC Primary	strNAICS Primary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXY Coordinate Type
481690006	1321	211112	PLEASANT VALLEY PLANT	ICE-NG.			TX		USA	-101.021	33.23444		LATLON
AG0024G	1321	211112	PUEBLO MIDSTREAM GAS CORP		HCO3, FM 2924, FASHING	SAN ANTONIO	TX	78232	USA	-98.1803	28.79523	14	LATLON
MF0001W	1321	211112	RAPTOR FACILITIES INC		RT 1 BOX 142A STANTON TX 79782	STANTON	TX	79782	USA	-101.932	32.21152	14	LATLON
39833	1321	211112	ROCKLAND PIPELINE COMPANY				TX		USA	-100.693	31.5918	14	LATLON
482630002	1321	211112	SALT CREEK FIELD GAS PLT	ICE-NG.			TX		USA	-100.521	33.13972		LATLON
482490006	1321	211112	SEELIGSON GAS PLANT	ICE-NG.			TX		USA	-98.0828	27.24139		LATLON
PE0009M	1321	211112	SID RICHARDSON GASOLINE CO		8 MI. S., S.H. 18	GRANDFALLS	TX	79742	USA	-102.888	31.23951	13	LATLON
PE0042O	1321	211112	SID RICHARDSON GASOLINE COMPANY				TX		USA	-102.986	31.18636	13	LATLON
484510011	1321	211112	STRAWN GAS PLANT	ICE-NG.			TX		USA	-100.689	31.3958		LATLON
CG0012C	1321	211112	SULPHUR RIVER GATHERING LP		2 MI. N. OF HWY. 77 & 6 MI. W.	DOUGLASSVILLE	TX	75560	USA	-94.4598	33.2238	15	LATLON
GJ0005S	1321	211112	SULPHUR RIVER GATHERING LP		ON F.M. 2605, 1.5 MI. W. OF F.	LONGVIEW	TX	75605	USA	-94.8299	32.53675	15	LATLON
HM0014N	1321	211112	SULPHUR RIVER GATHERING LP		0.5 MI. N. ON HWY. 90	EUSTACE	TX	75124	USA	-96.039	32.26805	14	LATLON
VB0004M	1321	211112	SULPHUR RIVER GATHERING LP		NEARBY	CANTON	TX	75103	USA	-95.8981	32.62733	15	LATLON
484510008	1321	211112	SUSAN PEAK GAS PLANT	ICE-NG.			TX		USA	-100.689	31.3958		LATLON
RG0054U	1321	211112	TC OIL COMPANY		19 MI. N.E. OF REFUGIO, TX., O	REFUGIO	TX	78377	USA	-97.046	28.50943	14	LATLON
RG0053W	1321	211112	T-C OIL COMPANY		6 MI. N.E. OF REFUGIO, TX.	REFUGIO	TX	78377	USA	-97.0589	28.40712	14	LATLON
PF0049M	1321	211112	TECO GAS PROCESSING CO		16.2 MI. E. OF LIVINGSTON, TX.	LIVINGSTON	TX	77351	USA	-94.7012	30.75699	15	LATLON
SD0072L	1321	211112	TEJAS CORPUS CHRISTI PROCESSING LP		NEAR THE INTERSECTION OF F. M.	PORTLAND	TX	78374	USA	-97.4104	27.88751	14	LATLON
CZ0027U	1321	211112	TEXACO E &P INC		6.5 MI E. ON I. 10, 4.5 MI. S.	OZONA	TX	76943	USA	-101.071	30.63449	14	LATLON
ML0048E	1321	211112	TEXACO EXPLORATION & PRDCTN INC		3.5 MI. E. ON LEASE ROAD	MIDLAND	TX	79701	USA	-102.016	31.84817	13	LATLON
CZ0014G	1321	211112	TEXACO EXPLORATION & PRODUCTION		2 MI. S., S.H. 163	OZONA	TX	76943	USA	-101.206	30.67269	14	LATLON
SO0003G	1321	211112	TEXACO EXPLORATION & PRODUCTION INC				TX		USA	-101.196	31.74186	14	LATLON
EB0069R	1321	211112	TEXACO EXPLORATION AND PRODUCTION IN		501 SOUTHEAST LOOP 338	ODESSA	TX	79760	USA	-102.313	31.86012	13	LATLON
NE0062T	1321	211112	TEXAS CRUDEENERGY INC		OFF WALDRON RD. BTWN. IT & LAG	CORPUS CHRISTI	TX	78322	USA	-97.2791	27.65474	14	LATLON
44263	1321	211112	THE WISER OIL COMPANY				TX		USA	-103.508	31.8293	13	LATLON
482490007	1321	211112	TIJERINA, CANALES,BLUCHER	ICE-NG.			TX		USA	-97.4714	28.03194		LATLON
44278	1321	211112	TONKAWA GASPROCESSING				TX		USA	-95.5285	31.5084	15	LATLON
LK0027R	1321	211112	TONKAWA GASPROCESSING CO		1.8 MI. E. OF U.S. 281, 4.5 S.	THREE RIVERS	TX	78071	USA	-98.1351	28.40499	14	LATLON
BL0004O	1321	211112	TRI-UNION DEVELOPMENT CORP		HASTINGS PLANT	ALVIN	TX	77512	USA	-95.2439	29.50191	15	LATLON
HM0011T	1321	211112	TXU PROCESSING CO		.25 MI W OF FM 1667	TRINIDAD	TX	75163	USA	-96.0854	32.12701	14	LATLON
483390020	1321	211112	U.P. RESOURCES CONROE	ICE-NG.			TX		USA	-95.4633	30.33665		LATLON
VB0011P	1321	211112	UNION OIL COMPANY OF CALIFORNIA		1 MI N OF THE CITY	VAN	TX	75790	USA	-95.6425	32.59353	15	LATLON
PB0003L	1321	211112	UNION PACIFIC RESOURCES		2 MI. W. OF CARTHAGE ON U.S. H	CARTHAGE	TX	75633	USA	-94.4008	32.16103	15	LATLON
MQ0002T	1321	211112	UNION PACIFIC RESOURCES CO		APPROX 6 MI S ON FM 3083	CONROE	TX	77303	USA	-95.3659	30.27968	15	LATLON
HR0018T	1321	211112	VALENCE OPERATING CO		FM 1567 TO 2948 S 2 MI	SULPHUR SPRINGS	TX	75420	USA	-95.4971	32.98774	15	LATLON
OC0151B	1321	211112	VASTAR RESOURCES INC		OFF OF NORTH TRAM ROAD AT THE	VIDOR	TX	77662	USA	-94.0024	30.19632	15	LATLON
484510004	1321	211112	Veribest Gas Plant	ICE-NG.			TX		USA	-100.689	31.3958		LATLON
SG0031P	1321	211112	WEST TEXAS GAS PROCESSING LP		17 MI. S.S.E. OF SNYDER ON S.H	MIDLAND	TX	79701	USA	-100.931	32.85534	14	LATLON
RC0018W	1321	211112	WESTERN GASRESOURCES INC		6.5 M N ON SH 137 2 M W ON CR5	BIG LAKE	TX	76932	USA	-101.647	31.48897	14	LATLON
UB0009T	1321	211112	WESTERN GASRESOURCES INC		7 MI. N., S.H. 349; 8.5 MI. E.	RANKIN	TX	79778	USA	-101.797	31.3399	14	LATLON
481590003	1321	211112	WESTLAND OIL DEVELOPMENT	ICE-NG.			TX		USA	-95.2168	33.1757		LATLON
WI0016D	1321	211112	WG OPERATING INC		3 MILES WEST OF ELECTRA	ELECTRA	TX	76360	USA	-98.9686	34.0436	14	LATLON
HL0076C	1321	211112	WILLIAMS FIELD SERVICES CO		2 MI. S. ON HWY. 3044 & 83 ON	CANADIAN	TX	79014	USA	-100.389	35.7466	14	LATLON
10679	1321	211112	Bridger Lake Plant	facility sold by Dynergy (prev. Warren	T3N, R14E, Sec. 25	Manila	UT	84046	USA	-110.82	40.91557		LATLON
490131003	1321	211112	KOCH HYDROCARBONS - CEDAR RIM PLANT	ICE-NG.			UT		USA	-110.365	40.20028		LATLON
10683	1321	211112	Pineview Gas Plant	Purchased from Union Pacific Resourc	3604 E Chalk Creek Rd	Coalville	UT	84017	USA	-111.163	40.94026		LATLON
10268	1321	211112	San Arroyo Plant	3/98: Ownership transferred from KN E	SE/4 NW/4 Sec. 23, T16S, R25E	Westwater	UT	84515	USA	-109.634	39.0414		LATLON
5603700036	1321	211112	DUKE ENERGY FLD SVCS _ PATRICK DRAW	NGL RECOVERY	7 MI E OF ROCK SPGS	ROCK SPRINGS	WY	82901	USA	-108.502	41.5899	12	LATLON
5604100015	1321	211112	DUKE ENERGY FLD SVCS_EMIGRANT TRAIL	NATURAL GAS TRANSMISSION	EMIGRANT TRAIL PLANT	EVANSTON	WY	82930	USA	-110.091	41.3991	12	LATLON
5604300003	1321	48621	HILAND PARTNERS, LLC_HILAND GAS PLANT	NATURAL GAS PROCESSING			WY		USA	-107.852	44.0302	13	LATLON
5602500020	1321	211112	KINDER MORGAN, INC _ CASPER EXTRACTION	NATURAL GAS TRANSMISSION	1 MILE E. OF EVANSVILLE HWY 20	CASPER	WY	82601	USA	-106.322	42.84456		LATLON
5600900015	1321	211112	KN GAS GATHERING_DOUGLAS GAS PLANT	NATURAL GAS TRANSMISSION	252 HIGHWAY 59, P.O. DRAWER H	DOUGLAS	WY	82635	USA	-105.359	42.7902	13	LATLON
5602900007	1321	211112	MARATHON OIL CO _ OREGON BASIN GAS PLANT	NATURAL GAS PROCESSING	18 MI SE OF CODY_P O BOX 2690	CODY	WY	82414	USA	-108.903	44.3524	12	LATLON
5603700006	1321	211112	MOUNTAIN GAS RESOURCES_GRANGER GAS PLANT	NATURAL GAS PROCESSING	SEC 16,T18N,R111W	GRANGER	WY	82934	USA	-109.953	41.5385	12	LATLON
560430004	1321	211112	UNION OIL COMPANY-WORLAND PLANT #60	ICE-NG.			WY		USA	-107.906	44.13222		LATLON
560370008	1321	211112	UNION PAC BRADY				WY		USA	-108.746	41.38806		LATLON
560410015	1321	211112	UNION PAC EMIGRANT	ICE-NG.			WY		USA	-110.091	41.39944		LATLON
560370026	1321	211112	UNION PAC RESCRS - NORTH BAXTER COMP STN	ICE-NG.			WY		USA	-108.778	41.634		LATLON
5603700008	1321	211112	UNION PAC_BRADY	NGL RECOVERY	30 MI SE ROCK SPGS	ROCK SPRINGS	WY	82901	USA	-108.746	41.388	12	LATLON
560410018	1321	211112	UPRC - LUCKY DITCH GAS PLANT	ICE-NG.			WY		USA	-110.271	41.01944		LATLON
560370006	1321	211112	WESTERN GAS PROCESSORS-GRANGER GAS PLNT	ICE-NG.			WY		USA	-109.953	41.53861		LATLON
560370011	1321	211112	WESTERN GAS RESOURCES - FONTENELLE	ICE-NG.			WY		USA	-109.975	42.05417		LATLON
560050006	1321	211112	WESTERN GAS RESOURCES - KITTY PLANT	ICE-NG.			WY		USA	-105.546	44.24773		LATLON
560090036	1321	211112	WESTERN GAS RESOURCES - SAND DUNES	ICE-NG.			WY		USA	-105.901	43.09083		LATLON
5600500006	1321	211112	WESTERN GAS RESOURCES _ KITTY PLANT	WESTERN GAS RESOURCES _ K	209 N. WORKS	GILLETTE	WY	82716	USA	-105.486	44.29511		LATLON
5600500003	1321	211112	WESTERN GAS RESOURCES_AMOS DRAW PLANT	NATURAL GAS TRANSMISSION	3108 E. 2ND STREET	GILLETTE	WY	82716	USA	-105.9	44.3558	13	LATLON
5600500049	1321	211112	WESTERN GAS_HILIGHT (MD_124)	WESTERN GAS_HILIGHT (MD_1	NW 1/4,SW1/4,S26,T45N,R71W	WRIGHT	WY	00000000(	USA	-105.357	43.8411	13	LATLON
560050049	1321	211112	WESTERN GAS-HILIGHT (MD-124)	ICE-NG.			WY		USA	-105.546	44.24773		LATLON
560070005	1321	211112	WILLIAMS FIELD SERVICES - ECHO SPRINGS				WY		USA	-107	41.71695		LATLON
560230014	1321	211112	WILLIAMS FIELD SVCS-OPAL PLANT				WY		USA	-110.342	41.76778		LATLON
490390007	1411	212311	BENTONITE PRODUCTION	ICE-Diesel			UT		USA	-111.867	39.055		LATLON
00034	1422	212312	ALLEN COUNTY PUBLIC WORKS	ROCK & AGGREGATE CRUSHING	R. 3	S2-T25S-R19E	KS	66751	USA	-95.2979	37.91552		LATLON
00045	1422	212312	APAC KANSAS, INC., SHEARS DIV DODGE CITY	ROCK & AGGREGATE CRUSHING	S5-T27S-R24W	DODGE CITY	KS	67801	USA	-100.021	37.75704		LATLON
00009	1422	212312	APAC-KANSAS, INC., RENO CONST DIVISION	CRUSHED AND BROKEN LIMEST	7100 WEST 167TH ST.	STANLEY EAST QUARRY	KS	66085000(	USA	-94.6678	38.82556		LATLON
00130	1422	212312	APAC-KANSAS, INC., RENO CONST DIVISION	ROCK & AGGREGATE CRUSHING	10203 WEST 167TH ST.	STANLEY WEST QUARRY	KS	66085	USA	-94.6529	38.79999		LATLON
00131	1422	212312	APAC-KANSAS, INC., RENO CONST DIVISION	ROCK & AGGREGATE CRUSHING	162 & GORDON LAKE ROAD	GARDNER QUARRY	KS	66030	USA	-94.9296	38.81565		LATLON
00023	1422	212312	APAC-KANSAS, INC., RENO CONST. DIVISION	ROCK & AGGREGATE CRUSHING	8811 WEST 247TH ST.	LOUISBURG QUARRY	KS	00000000(	USA	-94.6875	38.67893		LATLON
00016	1422	212312	APAC-KANSAS, INC., SHEARS DIVISION	CRUSHED AND BROKEN LIMEST	WEST HWY 14	QUARTZITE QUARRY	KS	00000000(	USA	-98.2089	39.0451		LATLON
00016	1422	212312	APAC-KANSAS, INC., SHEARS DIVISION	ROCK & AGGREGATE CRUSHING	S2-T28S-R12E	FALL RIVER QUARRY	KS	67047	USA	-96.0279	37.60846		LATLON
00030	1422	212312	APAC-KANSAS, INC., SHEARS DIVISION	ROCK & AGGREGATE CRUSHING	3 1/2 MILES SOUTH OF HARTFORD	HARTFORD QUARRY	KS	66854006{	USA	-95.9793	38.27441		LATLON
00019	1422	212312	ASH GROVE AGGREGATES, INC.	ROCK & AGGREGATE CRUSHING	1/2 MI WEST OF AMSTERDAM,MO	LA CYGNE #76	KS	00000000(	USA	-94.733	38.40049		LATLON
00019	1422	212312	ASH GROVE AGGREGATES, INC.	ROCK & AGGREGATE CRUSHING	JCT. 39 & 54	FT. SCOTT EAST #82	KS	00000000(	USA	-94.8509	37.8554		LATLON
00120	1422	212312	ASH GROVE AGGREGATES, INC.	ROCK & AGGREGATE CRUSHING	CEDAR CREEK PARKWAY	CEDAR CREEK #61	KS	00000000(	USA	-94.8317	38.8978		LATLON
00020	1422	212312	BAYER CONSTRUCTION CO., INC.	ROCK & AGGREGATE CRUSHING	7416 TUTTLE CREEK BLVD.	STEVENS QUARRY	KS	66503	USA	-96.7521	39.29102		LATLON
00022	1422	212312	BAYER CONSTRUCTION CO., INC.	ROCK & AGGREGATE CRUSHING	S18&19-T9S-R9E	EBERT QUARRY	KS	00000000(	USA	-96.366	39.3463		LATLON
00024	1422	212312	BAYER CONSTRUCTION CO., INC.	ROCK & AGGREGATE CRUSHING	S4-T9S-R4E	MARTIN QUARRY	KS	67432	USA	-97.1348	39.37493		LATLON
00030	1422	212312	BAYER CONSTRUCTION CO., INC.	ROCK & AGGREGATE CRUSHING	S20-T2S-R9E	SHOTWELL QUARRY	KS	66406	USA	-96.4175	39.8704		LATLON
00007	1422	212312	BYERS & SONS, INC. (HARRY)	CRUSHED AND BROKEN LIMEST	500 N. PLUMMER	CHANUTE	KS	66720	USA	-95.4706	37.68913		LATLON
00043	1422	212312	HARSHMAN CONSTRUCTION L.L.C.	ROCK & AGGRGATE CRUSHING	9423 SW 165TH STREET	SOUTHWEST BUTLER QUARRY	KS	67010	USA	-96.9708	37.67964		LATLON

strStateFacilityIdentifier	strSICPrimary	strNAICSPrimary	strFacilityName	strSiteDescription	strLocationAddress	strCity	strState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXYCoordinateType
00121	1422	212312	HOLLAND CORPORATION, INC.	ROCK & AGGREGATE CRUSHING	23775 W 159TH ST.	OLATHE	KS	66061	USA	-94.8608	38.83988		LATLON
00011	1422	212312	HUNT MIDWEST MINING, INC.	ROCK & AGGREGATE CRUSHING	5 M. WEST ON HWY 166	CEDARVALE	KS	67024	USA	-96.4757	37.12088		LATLON
00020	1422	212312	HUNT MIDWEST MINING, INC.	ROCK & AGGREGATE CRUSHING	18811 W. 271ST ST.	CRAWFORD QUARRY	KS	66071	USA	-94.8032	38.60663		LATLON
00020	1422	212312	HUNT MIDWEST MINING, INC.	ROCK & AGGREGATE CRUSHING	WEST COLONY OFFF K-57 HWY.	SETTLEMYER QUARRY	KS	66015	USA	-95.371	38.07939		LATLON
00021	1422	212312	HUNT MIDWEST MINING, INC.	ROCK & AGGREGATE CRUSHING	SOUTH OF GREELEY ON US HWY 169	SUTTON QUARRY	KS	66033	USA	-95.127	38.36686		LATLON
00022	1422	212312	HUNT MIDWEST MINING, INC.	ROCK & AGGREGATE CRUSHING	WEST OF WELDA	WELDA QUARRY	KS	66091	USA	-95.3527	38.1768		LATLON
00023	1422	212312	HUNT MIDWEST MINING, INC.	ROCK & AGGREGATE CRUSHING	S. OF MOUND CITY ON K-7 HWY.	MOUND CITY QUARRY	KS	66056	USA	-94.814	38.14271		LATLON
00024	1422	212312	HUNT MIDWEST MINING, INC.	ROCK & AGGREGATE CRUSHING	S20-T25S-R24E	FORT SCOTT	KS	000000000(	USA	-94.7015	37.83246		LATLON
00025	1422	212312	HUNT MIDWEST MINING, INC.	ROCK & AGGREGATE CRUSHING	28300 SOUTH US HWY 75	LYNDON QUARRY	KS	66451	USA	-95.6752	38.61903		LATLON
00025	1422	212312	HUNT MIDWEST MINING, INC.	ROCK & AGGREGATE CRUSHING	K-39 HWY	FORT SCOTT-SOUTH	KS	000000000(	USA	-94.7015	37.83246		LATLON
00029	1422	212312	HUNT MIDWEST MINING, INC.	ROCK & AGGREGATE CRUSHING	S. ON U.S. 59 HWY	PRINCETON QUARRY	KS	66078	USA	-95.2677	38.48788		LATLON
00039	1422	212312	HUNT MIDWEST MINING, INC.	ROCK & AGREGATE CRUSHING	1414 EAST 700 ROAD	LAWRENCE	KS	66047	USA	-95.3721	38.9446		LATLON
00040	1422	212312	HUNT MIDWEST MINING, INC.	ROCK & AGGREGATE CRUSHING	80 E. 550 ROAD	GLOBE QUARRY	KS	66524	USA	-95.3989	38.75095		LATLON
00123	1422	212312	HUNT MIDWEST MINING, INC.	ROCK & AGGREGATE CRUSHING	34135 WEST 95TH ST.	SUNFLOWER QUARRY	KS	66018	USA	-94.9804	38.95647		LATLON
00124	1422	212312	JOHNSON COUNTY AGGREGATES	ROCK & AGGREGATE CRUSHING	23555 W. 151ST. ST.	OLATHE QUARRY	KS	66061	USA	-94.8621	38.85451		LATLON
00011	1422	212312	LABETTE COUNTY HIGHWAY DEPT.	CRUSHED AND BROKEN LIMEST	S36-T32S-R19E	OSWEGO	KS	67356000(	USA	-95.1157	37.17144		LATLON
00017	1422	212312	MARTIN MARIETTA MATERIALS, INC	ROCK & AGGREGATE CRUSHING	32306 SOUTH CALIFORNIA	MELVERN QUARRY #349	KS	66510	USA	-95.6374	38.51323		LATLON
00032	1422	212312	MARTIN MARIETTA MATERIALS, INC	ROCK & AGGREGATE CRUSHING	1/2 MI. N. EISENHOWER DR.&US56	NORTH MARION QUARRY #388	KS	66861	USA	-97.0142	38.34863		LATLON
00017	1422	212312	MARTIN MARIETTA MATERIALS, INC.	ROCK & AGGREGATE CRUSHING	HWY 96 EAST	BLAKE QUARRY #328	KS	67137	USA	-96.2274	37.62547		LATLON
00023	1422	212312	MARTIN MARIETTA MATERIALS, INC.	ROCK & AGGREGATE CRUSHING	3000 TABOR VALLEY ROAD	ZEANDALE QUARRY #370	KS	66502	USA	-96.4279	39.1195		LATLON
00023	1422	212312	MARTIN MARIETTA MATERIALS, INC.	ROCK CRUSHER	S13-T16S-R19E	FOGLE QUARRY #376	KS	00000	USA	-95.2825	38.56432		LATLON
00031	1422	212312	MARTIN MARIETTA MATERIALS, INC.	ROCK & CRUSHING EQUIPMENT	2 NORTH 1700 ROAD	BIG SPRINGS QUARRY	KS	66050000(	USA	-95.4821	38.98573		LATLON
00044	1422	212312	MARTIN MARIETTA MATERIALS, INC.	ROCK & AGGREGATE CRUSHING	HWY. K-38	WINFIELD QUARRY #354	KS	67024	USA	-96.8388	37.23763		LATLON
00061	1422	212312	MARTIN MARIETTA MATERIALS, INC.	ROCK & AGGREGATE CRUSHING	1731 UNION ROAD	WOODBINE QUARRY #383	KS	67431	USA	-96.964	38.84736		LATLON
00029	1422	212312	MIDWEST MINERALS, INC.	CRUSHED & BROKEN LIMESTOE	S18-T29S-R16E	ALTOONA QUARRY #24	KS	66710	USA	-95.5903	37.55881		LATLON
00037	1422	212312	MIDWEST MINERALS, INC.	ROCK & AGGREGATE CRUSHING	S30-T30S-R24E	PITTSBURG QUARRY #5	KS	66762	USA	-94.7011	37.40638		LATLON
00049	1422	212312	MIDWEST MINERALS, INC.	ROCK & AGGREGATE CRUSHING	S12-T32S-R19E	PARSONS QUARRY #3	KS	67357	USA	-95.2689	37.34054		LATLON
00071	1422	212312	MIDWEST MINERALS, INC.	ROCK & AGGREGATE CRUSHING	S34-T34S-R17E	COFFEYVILLE QUARRY #16	KS	67337	USA	-95.6253	37.03866		LATLON
00073	1422	212312	MIDWEST MINERALS, INC.	ROCK & AGGREGATE CRUSHING	S9-T32S-R15E	TABLE MOUND QUARRY #26	KS	000000000(	USA	-95.741	37.19285		LATLON
00042	1422	212312	MULBERRY LIMESTONE QUARRY CO.	ROCK & AGGREGATE CRUSHING	S2-T29S-R25E	MULBERRY QUARRY	KS	66756	USA	-94.6419	37.55744		LATLON
00043	1422	212312	MULBERRY LIMESTONE QUARRY CO.	ROCK & AGGREGATE CRUSHING	S25-T28S-R24E	ENGLEVALE QUARRY	KS	000000000(	USA	-94.8525	37.5065		LATLON
00014	1422	212312	N.R. HAMM QUARRY, INC.	ROCK & AGGREGATE CRUSHING	S16-T7S-R12E	HOLTON	KS	000000000(	USA	-95.7314	39.4627		LATLON
00020	1422	212312	N.R. HAMM QUARRY, INC.	ROCK CRUSHING	S32-T7S-R20E	MOONEY CREEK	KS	000000000(	USA	-95.3884	39.2321		LATLON
00022	1422	212312	N.R. HAMM QUARRY, INC.	ROCK CRUSHING	S35&36-T11S-R19E	N. LAWRENCE	KS	000000000(	USA	-95.3884	39.2321		LATLON
00024	1422	212312	N.R. HAMM QUARRY, INC.	ROCK & AGGREGATE CRUSHING	S3&10-T7S-R10E	ONAGA	KS	000000000(	USA	-96.1824	39.47825		LATLON
00027	1422	212312	N.R. HAMM QUARRY, INC.	ROCK & AGGREGATE CRUSHING	S18-T1S-R12E	SENECA	KS	000000000(	USA	-96.0649	39.83569		LATLON
00028	1422	212312	N.R. HAMM QUARRY, INC.	ROCK & AGGREGATE CRUSHING	S36-T5S-R12E	CORNING	KS	000000000(	USA	-96.0703	39.65311		LATLON
00037	1422	212312	N.R. HAMM QUARRY, INC.	ROCK & AGGREGATE CRUSHING	S15-T13S-R21E	EUDORA	KS	000000000(	USA	-95.0851	38.92783		LATLON
00065	1422	212312	N.R. HAMM QUARRY, INC.	ROCK & AGGREGATE CRUSHING	S13-T13S-R3E	CHAPMAN	KS	000000000(	USA	-97.0164	38.96732		LATLON
00034	1422	212312	NELSON QUARRIES, INC.	ROCK & AGGREGATE CRUSHING	S25-T21S-R15E	BURLINGTON QUARRY	KS	000000000(	USA	-95.7468	38.19927		LATLON
00041	1422	212312	NELSON QUARRIES, INC.	ROCK & AGGREGATE CRUSHING	S20-T30S-R24E	PITTSBURG QUARRY	KS	000000000(	USA	-94.8525	37.5065		LATLON
00078	1422	212312	NELSON QUARRIES, INC.	ROCK & AGGREGATE CRUSHING	S15-T31S-R17E	CHERRYVALE QUARRY	KS	000000000(	USA	-95.5438	37.26724		LATLON
00044	1422	212312	NEOSHO COUNTY PUBLIC WORKS DEPT.	ROCK & AGGREGATE CRUSHING	S30-T28S-R19E	NEELY QUARRY	KS	00000	USA	-95.3066	37.55883		LATLON
00033	1422	212312	SCOTT ROCK COMPANY	CRUSHED AND BROKEN LIMEST	1 MI WEST & 1 MI NORTH	SYCAMORE	KS	000000000(	USA	-95.7325	37.33		LATLON
00114	1422	212312	SHAWNEE ROCK COMPANY (PLANT #1)	ROCK & AGGREGATE CRUSHING	151ST STREET	OLATHE	KS	66061	USA	-94.8297	38.89127		LATLON
00231	1422	212312	SHAWNEE ROCK COMPANY (PLANT #3)	ROCK & AGRREGATE CRUSHING	1800 S. 12TH.	BONNER SPRINGS	KS	66012	USA	-94.9075	39.07226		LATLON
00115	1422	212312	SHAWNEE ROCK COMPANY (PLANT #4)	ROCK & AGGREGATE CRUSHING	4875 HOLLIDAY DRIVE	SHAWNEE	KS	66203	USA	-94.7077	39.02012		LATLON
00020	1422	212312	WADE QUARRIES	ROCK & AGGREGATE CRUSHING	S20-T19S-R25E	LA CYGNE	KS	66040	USA	-94.733	38.40049		LATLON
00021	1422	212312	WADE QUARRIES	ROCK & AGGREGATE CRUSHING	S28-T18S-R25E	LOUISBURG	KS	000000000(	USA	-94.6761	38.60332		LATLON
00021	1422	212312	WADE QUARRIES	ROCK & AGGREGATE CRUSHING	S31-T19S-R23E	CADMUS	KS	66026	USA	-94.8631	38.41787		LATLON
490270005	1422	212312	CONTINENTAL LIME				UT		USA	-112.817	38.93972		LATLON
10313	1422	212312	Cricket Mountain Plant	Previous owner: Continental Lime Inc.			UT		USA	-112.586	39.36197		LATLON
0118	1474	212391	AMERICAN SODA LLP - PICEANCE FACILITY	NAHCOLITE SOLUTION MINING	SEC 20 T1S R97W	MEEKER 22 MI WSW OF	CO	00000	USA	-107.856	40.03395	13	LATLON
58196	1474	212391	FMC TRONA				WY		USA	-109.824	41.6013	12	LATLON
5603700010	1474	212391	FMC WYOMING CORP _ SODA ASH PLANT	SODA ASH PRODUCTION	6 MI NE OF GRANGER	GRANGER	WY	82935	USA	-109.899	41.6744	12	LATLON
5603700049	1474	212391	FMC WYOMING CORPORATION-WESTVACO TRONA	FMC WYOMING CORPORATION			WY		USA	-109.466	41.51425		LATLON
5603700002	1474	212391	GENERAL CHEMICAL	SODA ASH PRODUCTION			WY		USA	-109.753	41.5933	12	LATLON
5603700001	1474	212391	OCI (RHONE_POULENC) WYOMING	SODA ASH PRODUCTION			WY		USA	-109.69	41.7141	12	LATLON
5603700005	1474	212391	SOLVAY MINERALS, INC.	SODA ASH PRODUCTION			WY		USA	-109.752	41.531	12	LATLON
490470003	1475	212392	S.F. PHOSPHATES	ICE-Diesel			UT		USA	-109.483	40.59972		LATLON
490570032	1479	212393	GREAT SALT LAKE MINERAL	ICE-Diesel			UT		USA	-112.229	41.23333		LATLON
040250698	1499	2123	CHEMICAL LIME, NELSON PLANT	ICE-Diesel			AZ		USA	-113.311	35.51639		LATLON
0209	2813	325120	DUKE ENERGY - LADDER CREEK HELIUM PLANT	FORMERLY HIGH PLAINS GAS GAT	41707 COUNTY ROAD	CHEYENNE WELLS, 3 MI WSW OF	CO	80000	USA	-102.392	38.7943	13	LATLON
00031	2813	325120	ATOFINA CHEMICALS, INC.	INDUSTRIAL GASES	6040 S. RIDGE ROAD	WICHITA	KS	67202	USA	-97.4252	37.58492		LATLON
201650004	2813	325120	KANSAS REFINED HELIUM COMPANY	ICE-NG.			KS		USA	-99.1067	38.56917		LATLON
200670008	2813	325120	MOBIL EXPLORATION & PRODUCING U.S. INC	ICE-NG.			KS		USA	-101.187	37.57194		LATLON
200670050	2813	325120	PRAXAIR, INC.	ICE-NG.			KS		USA	-101.089	37.64056		LATLON
T$11640	2813	325120	AIR LIQUIDE AMERICA CORP.		11400 BAY AREA BLVD.	PASADENA	TX	77507	USA	-95.05	29.62111		LATLON
T$11721	2813	325120	AIR LIQUIDE AMERICA CORP.		1711 FARM TO MARKET 523	OYSTER CREEK	TX	77541	USA	-95.3333	28.99167		LATLON
HG0010N	2813	325120	AIR PRODUCTS INC		10202 STRANG RD.	LA PORTE	TX	77571	USA	-95.067	29.70155	15	LATLON
MONC4	2813	325120	AIR PRODUCTS, INCORPORATED/HARRIS/HG0011L	Continuous Processes	RTE. 1 10202 STRANG RD.	LA PORTE	TX	77571	USA	-95.44	29.83	0	LATLON
HG1223K	2813	325120	BOC GASES		100 S. AIRHART DRIVE	BAYTOWN	TX	77522	USA	-94.9922	29.74134	15	LATLON
JE0052V	2813	325120	HUNTSMAN CORPORATION		2102 SPUR 136	PORT NECHES	TX	77651	USA	-93.9539	29.84996	15	LATLON
HX2302N	2813	325120	LA PORTE MENTHANOL		11603 STRANG RD	LA PORTE	TX	77572	USA	-95.0619	29.70682	15	LATLON
HX2334A	2813	325120	LINDE GAS INC.		11603 STRANG RD	LA PORTE	TX	77571	USA	-95.0574	29.70675	15	LATLON
T$11739	2813	325120	MATHESON TRI-GAS		1920 W. FAIRMONT PKY.	LA PORTE	TX	77572	USA	-95.0381	29.65333		LATLON
238	2873	325311	KERLEY AG INC.				AZ		USA	-112.107	33.4228	12	LATLON
T$10213	2873	325311	FARMLAND INDS. INC. - LAWRENCE NITROGEN PLANT		1608 N. 1400 RD.	LAWRENCE	KS	66046925(	USA	-95.1997	38.95583		LATLON
T$10374	2873	325311	FARMLAND INDS. INC. DODGE CITY NITROGEN PLANT		3 MILES E. OF DODGE CITY ON U.	DODGE CITY	KS	678011337	USA	-99.9292	37.77667		LATLON
00003	2873	325311	FARMLAND INDUSTRIES, INC. (FERTILIZER)	NITROGENOUS FERTILIZERS	E. HWY 56	DODGE CITY	KS	67801	USA	-99.9272	37.74111		LATLON
350430021	2873	325311	AGRONICS, INC/HUMATES PLANT_______1127M1	ICE-Diesel			NM		USA	-106.948	35.89806		LATLON
T$11018	2873	325311	FARMLAND INDS. INC.		5 MILES E. ON HWY. 412 AN D 1	ENID	OK	73701	USA	-97.7628	36.37972		LATLON
1635	2873	325311	Farmland Industries, Inc.-Enid Nitrogen Plant	Enid Nitrogen Plant			OK		USA	-97.7657	36.3751	14	LATLON
401310704	2873	325311	TERRA NITROGEN	Turbine:			OK		USA	-95.7197	36.21972		LATLON
T$11021	2873	325311	TERRA NITROGEN CORP. WOODWARD COMPLEX		1000 TERRA DR.	WOODWARD	OK	73801	USA	-99.4689	36.43528		LATLON
2495	2873	325311	Terra Nitrogen, Limited Partnership Verdigris Plant	13100704 Verdigris Plant	6606 E. 540 Rd.	Claremore	OK	74017000(	USA	-95.7201	36.2203	15	LATLON
HW0004D	2873	325311	AGRIUM US INC		SOMEWHERE NEAR F.M. ROAD 1551	BORGER	TX	79007	USA	-101.425	35.64532	14	LATLON
T$11681	2873	325311	EL DORADO NITROGEN CO.		8490 W. BAY RD.	BAYTOWN	TX	77520	USA	-94.9253	29.75583		LATLON
T$12138	2873	325311	COASTAL CHEM INC.		8305 OTTO RD.	CHEYENNE	WY	82007	USA	-104.904	41.09583		LATLON

strStateFacilityIdentifier	strSICPrimary	strNAICSPrimary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXYCoordinateType
560210002	2873	325311	COASTAL CHEMICAL	ICE-NG.			WY		USA	-104.913	41.09306		LATLON
HG0534U	2874	325312	AGRIFOS FERTILIZER LP		2001 JACKSON ROAD (DAVIDSON)	PASADENA	TX	77501	USA	-95.2571	29.73725	15	LATLON
T$12154	2874	325312	SF PHOSPHATES LTD. CO.		515 S. HWY. 430	ROCK SPRINGS	WY	82901	USA	-109.235	41.59491		LATLON
5603700022	2874	325312	SF PHOSPHATES, INC	PHOSPHATE FERTILIZER PROD	5 MI SE OF ROCK SPGS	ROCK SPRINGS	WY	82902	USA	-109.128	41.538	12	LATLON
0032	2911	324110	BARTKUS OIL CO	PETROLEUM REFINING	3501 PEARL ST	BOULDER	CO	80301	USA	-105.246	40.0243	13	LATLON
0520	2911	324110	CHIEF PETROLEUM	BULK PETROLEUM PLANT	301 S 10TH ST	COLORADO SPRINGS	CO	80000	USA	-104.842	38.8332	13	LATLON
23-E	2911	324110	Colorado Refining Company		5800 Brighton Blvd.	Commerce City	CO	80022	USA	-104.942	39.80481	0	LATLON
55	2911	324110	Conoco Denver Products Terminal		5601 Brighton Blvd.	Commerce City	CO	80022	USA	-104.946	39.80333	0	LATLON
ESD035	2911	324110	Conoco Inc.		5801 BRIGHTON BLVD.	Commerce City	CO	800223696	USA	-104.941	39.80384	13	LATLON
080770001	2911	324110	LANDMARK PETROLEUM INC	ICE-NG. 96NTI was area source.			CO		USA	-108.757	39.16833		LATLON
0063	2911	324110	REX OIL CO	PETROLEUM REFINING	899 DECATUR ST	DENVER	CO	802043724	USA	-105.021	39.7308	13	LATLON
0035	2911	324110	REX OIL CO INC	PETROLEUM REFINING	431 4TH AVE	LYONS	CO	80540	USA	-105.248	40.0234	13	LATLON
0065	2911	324110	SIEGEL OIL CO	BULK PLANT	1380 ZUNI ST	DENVER	CO	80204	USA	-105.015	39.7371	13	LATLON
ESD036	2911	324110	Ultramar Diamond Shamrock (formerly Total Petroleu		5800 BRIGHTON BLVD	Commerce City	CO	800223613	USA	-104.946	39.80495	13	LATLON
201730020	2911	324110	COASTAL DERBY REFINING CO.	Turbine: 96 nti was an area source.			KS		USA	-97.3147	37.72556		LATLON
200150001	2911	324110	COASTAL DERBY REFINING CO.	ICE-NG. 96NTI was area source.			KS		USA	-96.8592	37.8325		LATLON
ESD050	2911	324110	Cooperative Refining (formerly Farmland Industries	PETROLEUM REFINING	S36-T34S-R16E	Coffeyville	KS	67337	USA	-95.6052	37.04822	15	LATLON
ESD051	2911	324110	Cooperative Refining (formerly National Cooperativ		1391 IRON HORSE ROAD	McPherson	KS	674601404	USA	-97.667	38.34928	14	LATLON
201470001	2911	324110	FARMLAND INDUSTRIES, INC.-REFINERY DIV.	ICE-NG. 96NTI was area source.			KS		USA	-99.3714	39.78694		LATLON
ESD052	2911	324110	Frontier Oil Corp. (formerly El Dorado Refining, f		1401 S. DOUGLAS ROAD	El Dorado	KS	67042	USA	-96.8796	37.79681	14	LATLON
200150004	2911	324110	TEXACO REFINING & MARKETING, INC.	ICE-NG. 96NTI was area source.			KS		USA	-96.8667	37.79917		LATLON
200350004	2911	324110	TOTAL PETROLEUM, INC.				KS		USA	-97.1314	37.075		LATLON
0008	2911	324110	Ciniza Refinery	Petroleum Refinery	17 Mi E Of Gallup On I-40	Gallup	NM	87301	USA	-108.425	35.4887	12	LATLON
ESD091	2911	324110	Giant Refining Co.		#50 County Road 4990	Bloomfield	NM	87413	USA	-107.976	36.70039	13	LATLON
ESD092	2911	324110	Giant Refining Co.		17 Mi E Of Gallup On I-40	Gallup	NM	87301	USA	-108.425	35.50724	12	LATLON
T$12478	2911	324110	LEA REFINING CO.		SOUTH OF LOVINGTON	LOVINGTON	NM	88260	USA	-103.3	32.87944		LATLON
T$12476	2911	324110	NAVAJO REFINING CO.		501 E. MAIN ST.	ARTESIA	NM	88210	USA	-104.396	32.85139		LATLON
T$12459	2911	324110	SAN JUAN REFINING CO.		NO. 50 COUNTY RD. 4990	BLOOMFIELD	NM	87413	USA	-107.972	36.69722		LATLON
T$12490	2911	324110	FORELAND REFINING- TONOPAH REFY.		HWY. 6, 6 MILES E. OF TONOPAHA	TONOPAH	NV	89049	USA	-117.1	38.06667		LATLON
400810001	2911	324110	ALLIED MATLS-REFINER	ICE-NG. 96NTI was area source.			OK		USA	-97.0725	35.635		LATLON
T$11123	2911	324110	CONOCO INC. - PONCA CITY REFY.		1000 S. PINE ST.	PONCA CITY	OK	746017501	USA	-97.0869	36.69305		LATLON
2477	2911	324110	Sun Company Inc.	Refinery - 1700 South Union			OK		USA	-96.0249	36.14	14	LATLON
23-D	2911	324110	TRI Petroleum, Inc. Ardmore Refinery	1900509 Ardmore Refinery	825 E. Cameron	Ardmore	OK	73401	USA	-97.1359	34.17472	0	LATLON
ESD103	2911	324110	Ultramar/Diamond Shamrock (formerly Total Petroleu		BYPASS 142	Ardmore	OK	73402	USA	-97.1034	34.20234	14	LATLON
2782	2911	324110	Wynnewood Refining Company	4900507 Wynnewood Refining Facility			OK		USA	-97.1673	34.635	14	LATLON
ESD110	2911	324110	AGE Refining & Manufacturing		7811 S. PRESA	San Antonio	TX	782233547	USA	-98.4601	29.34916	14	LATLON
ESD111	2911	324110	Alon Israel (formerly Fina Oil & Chemical Co.)		I-H 20 AT REFINERY RD.	Big Spring	TX	79720	USA	-101.47	32.24	14	LATLON
HT0011Q	2911	324110	ALON USA LP		ON THE FRONTAGE ROAD OF I20 EA	BIG SPRING	TX	79721	USA	-101.424	32.27038	14	LATLON
JE0005H	2911	324110	ATOFINA PETROCHEMICALS INC		32ND STREET & HWY. 366	PORT ARTHUR	TX	77640	USA	-93.8954	29.95857	15	LATLON
HG0130C	2911	324110	BASIS PETROLEUM INC		9701 MANCHESTER	HOUSTON	TX	77262	USA	-95.2621	29.72616	15	LATLON
481670050	2911	324110	BASIS PETROLEUM, INC.				TX		USA	-94.5439	29.22083		LATLON
10-C	2911	324110	Big Spring Refinery		IH 20 at Refinery Road	Big Spring	TX	79721	USA	-101.415	32.28444	0	LATLON
T$11755	2911	324110	BP AMOCO TEXAS CITY BUSINESS UNIT		2401 5TH AVE. S.	TEXAS CITY	TX	77590	USA	-94.925	29.37444		LATLON
27-H	2911	324110	Chevron El Paso Refinery (North Facility)		6501 Trowbridge	El Paso	TX	79905	USA	-106.402	31.77099	0	LATLON
ESD115	2911	324110	Citgo		1801 NUECES BAY BLVD.	Corpus Christi	TX	78407	USA	-97.4882	27.81323	14	LATLON
T$11904	2911	324110	CITGO REFINING & CHEMICALS CO. L.P. - EAST PLANT		1801 NUECES BAY BLVD.	CORPUS CHRISTI	TX	78407	USA	-97.4278	27.80917		LATLON
ESD116	2911	324110	Coastal Refining & Marketing Inc.		1300 CANTWELL LANE	Corpus Christi	TX	78407	USA	-97.4432	27.81263	14	LATLON
24-C	2911	324110	Corpus Christi East Refinery		1700 Nueces Bay Blvd.	Corpus Christi	TX	78407	USA	-97.4222	27.80611	0	LATLON
24-B	2911	324110	Corpus Christi West Refinery		Suntide and Up River Roads	Corpus Christi	TX	78410	USA	-97.5278	27.83055	0	LATLON
ESD117	2911	324110	Crown Central Petroleum Corp.		111 RED BLUFF RD.	Pasadena	TX	77506	USA	-95.2073	29.72599	15	LATLON
T$11702	2911	324110	DEER PARK REFINING L.P.		5900 HWY. 225	DEER PARK	TX	77536	USA	-95.1292	29.72139		LATLON
MR0008T	2911	324110	DIAMOND SHAMROCK REFINING CO LP		6701 FM 119	SUNRAY	TX	79086	USA	-101.89	35.95423	14	LATLON
LK0009T	2911	324110	DIAMOND SHAMROCK REFINING CO LP		301 LEROY STREET	THREE RIVERS	TX	78071	USA	-98.1843	28.45563	14	LATLON
20-A	2911	324110	Exxon Baytown Refinery		2800 Decker Drive	Baytown	TX	77522	USA	-94.9927	29.75505	0	LATLON
ESD119	2911	324110	ExxonMobil Corp. (formerly Mobil)		E. END OF BURT ST.	Beaumont	TX	77704	USA	-94.0716	30.07583	15	LATLON
26-A	2911	324110	Houston Refinery		9701 Manchester	Houston	TX	77012	USA	-95.2531	29.72333	0	LATLON
NE0122D	2911	324110	KOCH PETROLEUM GROUP LP		SUNTIDE AND UP RIVER ROADS	CORPUS CHRISTI	TX	78322	USA	-97.4418	27.80693	14	LATLON
SK0022A	2911	324110	LA GLORIA OIL AND GAS CO		1702 EAST COMMERCE ST.	TYLER	TX	75701	USA	-95.2693	32.36675	15	LATLON
ESD121	2911	324110	LaGloria Oil & Gas Co.		1702 E. COMMERCE ST.	Tyler	TX	75702	USA	-95.2728	32.36735	15	LATLON
HG0048L	2911	324110	LYONDELL-CITGO REFINING LP		12000 LAWNDALE	HOUSTON	TX	77252	USA	-95.2512	29.70939	15	LATLON
ESD123	2911	324110	Marathon Ashland Petrol. LCC		1320 LOOP 197 S.	Texas City	TX	77590	USA	-94.9066	29.37657	15	LATLON
23-F	2911	324110	McKee Plants		HCR 1, Box 36	Sunray	TX	79086	USA	-101.873	35.95167	0	LATLON
12-D	2911	324110	Mobil Beaumont Refinery		End of Burt Street	Beaumont	TX	77701	USA	-94.0703	30.06389	0	LATLON
ESD124	2911	324110	Motiva Enterprises (formerly Star)		2100 HOUSTON AVE.	Port Arthur	TX	776403399	USA	-93.9582	29.87322	15	LATLON
JE0095D	2911	324110	MOTIVA ENTERPRISES LLC		AT THE NORTH END OF HOUSTON AV	PORT ARTHUR	TX	77640	USA	-93.9527	29.88934	15	LATLON
BL0042G	2911	324110	PHILLIPS 66CO		HWY 35 AND 524 AT OLD OCEAN	SWEENY	TX	77480	USA	-95.7637	29.07126	15	LATLON
16-D	2911	324110	Phillips Borger Refinery & NGL Center		Spur 119 North Borger Refinery	Borger	TX	79007	USA	-101.368	35.69722	0	LATLON
JE0042B	2911	324110	PREMCOR REFINING GROUP		1801 S. GULFWAY DRIVE	PORT ARTHUR	TX	77640	USA	-93.9552	29.85866	15	LATLON
ESD127.5	2911	324110	Pride Refining Inc.		1210 N. 4TH ST	Abilene	TX	79604	USA	-99.7671	32.54485	14	LATLON
27-G	2911	324110	Refinery Holding Co. Refinery (South Facility)		6500 Trowbridfe	El Paso	TX	79905	USA	-106.402	31.7703	0	LATLON
ESD128	2911	324110	Shell -Deer Park Refining Limited Partnership		5900 HWY. 225	Deer Park	TX	77536	USA	-95.1163	29.72406	15	LATLON
HG0659W	2911	324110	SHELL OIL CO		HWY 225 W OF BATTLEGROUND RD	DEER PARK	TX	77536	USA	-95.1155	29.72356	15	LATLON
ESD128.5	2911	324110	Specified Fuels & Chemicals (formerly Howell Hydro		1201 S. SHELDON RD		TX	775300429	USA	-95.1	29.76851	15	LATLON
16-A	2911	324110	Sweeny Refinery and Petrochemical Complex		Hwy 35 and 524 at Old Ocean	Sweeny	TX	77480	USA	-95.7467	29.06889	0	LATLON
21-G	2911	324110	Texas City Refinery		1320 Loop 197 South	Texas City	TX	77590	USA	-94.9114	29.40593	0	LATLON
T$11850	2911	324110	THREE RIVERS REFY.		301 LEROY ST.	THREE RIVERS	TX	78071	USA	-98.1903	28.45667		LATLON
ESD129	2911	324110	Trifinery Petrol. Srvc. (formerly Neste Trifinery)		6600 UP RIVER ROAD	Corpus Christi	TX	78409	USA	-97.4927	27.81925	14	LATLON
ESD131	2911	324110	Ultramar/Diamond Shamrock Corp.		6701 FM 119	Sunray	TX	790869705	USA	-101.882	35.96259	14	LATLON
ESD130	2911	324110	Ultramar/Diamond Shamrock Corp.		301 LEROY ST.	Three Rivers	TX	78071	USA	-98.1884	28.45739	14	LATLON
ESD133	2911	324110	Valero (formerly Basis Petroleum, Inc.)		9701 MANCHESTER	Houston	TX	77012	USA	-95.2372	29.57851	15	LATLON
GB0073P	2911	324110	VALERO REFINING CO - TEXAS		LOOP 197 SOUTH @ 14TH ST.	TEXAS CITY	TX	77590	USA	-94.8944	29.3733	15	LATLON
ESD132	2911	324110	Valero Refining Co.		5900 UP RIVER RD.	Corpus Christi	TX	78407	USA	-97.5265	27.89656	14	LATLON
T$12204	2911	324110	BIGWEST OIL L.L.C.		333 W. CENTER ST.	NORTH SALT LAKE	UT	84054	USA	-111.906	40.86667		LATLON
ESD135	2911	324110	BP (formerly Amoco Oil Co.)		474 W. 900 N.	Salt Lake City	UT	841031494	USA	-111.903	40.79073	12	LATLON
ESD136	2911	324110	Chevron USA		2351 N. 1100 W.	Salt Lake City	UT	84116	USA	-111.924	40.82801	12	LATLON
490470053	2911	324110	CHEVRON USA PRODUCING CO	Turbine: 96 nti was an area source.			UT		USA	-109.302	40.20306		LATLON
490470007	2911	324110	CITATION OIL AND GAS (PREV. EXXON)	ICE-NG. 96NTI was area source.			UT		USA	-109.371	40.30417		LATLON
10122	2911	324110	Flying J Refinery (Big West Oil Co.)	NA	333 W Center St	N Salt Lake	UT	84054	USA	-111.924	40.84199		LATLON
490130100	2911	324110	GARY REFINERY	ICE-NG. 96NTI was area source.			UT		USA	-110.22	40.36056		LATLON

strStateFacilityIdentifier	strSIC Primary	strNAICS Primary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXY Coordinate Type
490430004	2911	324110	NGC ENERGY RESOURCES	ICE-NG. 96NTI was area source.			UT		USA	-111.368	40.90889		LATLON
490470017	2911	324110	NORTHWEST PIPELINE	Turbine: 96 nti was an area source.			UT		USA	-109.333	40.56889		LATLON
490130027	2911	324110	PENNZOIL				UT		USA	-110.018	40.28		LATLON
490130053	2911	324110	PG & E RESOURCES COMPANY	ICE-NG. 96NTI was area source.			UT		USA	-110.02	40.04472		LATLON
490110013	2911	324110	PHILLIPS PETROLEUM	ICE-NG. 96NTI was area source.			UT		USA	-111.908	40.8925		LATLON
ESD139	2911	324110	Phillips Petroleum Co.		393 South 800 West	Woods Cross	UT	84087714	USA	-111.901	40.88746	12	LATLON
490439078	2911	324110	PINEVIEW FIELD	ICE-NG. 96NTI was area source.			UT		USA	-110.82	40.91557		LATLON
490430010	2911	324110	PINEVIEW GAS PLANT	ICE-NG. 96NTI was area source.			UT		USA	-110.82	40.91557		LATLON
10335	2911	324110	Salt Lake City Refinery	Modify AO DAQE-053-97	474 West 900 North	Salt Lake City	UT	84103	USA	-111.904	40.78906		LATLON
10119	2911	324110	Salt Lake Refinery	NA	2351 N 1100 W	Salt Lake City	UT	84125	USA	-111.921	40.81955		LATLON
ESD137	2911	324110	Silver Eagle Refining Inc. (formerly Inland Refini		2355 S. 1100 W.	Woods Cross	UT	84087	USA	-111.91	40.86698	12	LATLON
490431001	2911	324110	UNION PACIFIC RESOURCES-YELLOW CREEK	ICE-NG. 96NTI was area source.			UT		USA	-111.154	40.94528		LATLON
490070034	2911	324110	US FUEL CO	ICE-Diesel 96 NTI was area source			UT		USA	-111.011	39.49139		LATLON
5602100001	2911	324110	FRONTIER REFINING, INC.	PETROLEUM REFINING	2700 EAST 5TH STREET	CHEYENNE	WY	82007	USA	-104.787	41.128	13	LATLON
ESD150	2911	324110	Little America Refining Co.				WY		USA	-106.264	42.85974	13	LATLON
T$12156	2911	324110	SILVER EAGLE REFINING		2990 COUNTY RD. 180	EVANSTON	WY	82930	USA	-110.807	41.26056		LATLON
60-C	2911	324110	Sinclair, Little America Refinery		5700 East Highway 20-26	Casper	WY	82609	USA	-106.28	42.83902	0	LATLON
60-A	2911	324110	Sinclair, Wyoming Refinery		100 East Lincoln Highway	Sinclair	WY	82334	USA	-107.056	41.78889	0	LATLON
T$12150	2911	324110	WYOMING REFINING CO.		740 W. MAIN ST.	NEWCASTLE	WY	82701	USA	-104.216	43.84972		LATLON
080011182	3211	327211	CAPITOL GLASS & ALUMINUM CORP	ICE-NG. 96NTI was area source.			CO		USA	-104.848	39.76389		LATLON
0008	3221	327213	ROCKY MOUNTAIN BOTTLE CO	GLASS CONTAINERS MFG	10619 W 50TH AVE	WHEAT RIDGE	CO	80033	USA	-105.116	39.7857	13	LATLON
0326	3229	327212	FIBERON INC	FIBERGLASS FABRICATION	337 HICKORY ST	FORT COLLINS	CO	80524-110	USA	-105.083	40.603	13	LATLON
080311259	3229	327212	ROCKY MOUNTAIN SCIENTIFIC GLASS BLOWING	ICE-NG. 96NTI was area source.			CO		USA	-104.929	39.68028		LATLON
0401900310	3241	32731	ARIZONA PORTLAND CEMENT COMPANY	CEMENT PRODUCTION	11115 N.CASA GRANDE HIGHWAY	RILLITO	AZ	85654	USA	-111.149	32.40915	12	LATLON
0003	3241	327310	CEMEX, INC. - LYONS CEMENT PLANT	CEMENT, HYDRAULIC (FORMERLY	5134 UTE HWY	LYONS	CO	00000-000	USA	-105.229	40.209	13	LATLON
0001	3241	327310	HOLNAM INC PORTLAND PLANT	PORTLAND CEMENT MFG	3500 HWY 120	FLORENCE	CO	81226	USA	-105.017	38.3872	13	LATLON
0002	3241	327310	HOLNAM INC_FORT COLLINS PLANT	CEMENT, HYDRAULIC	4629 N OVERLAND TRL	LAPORTE (LA PORTE)	CO	00000-000	USA	-105.141	40.6524	13	LATLON
T$10266	3241	327310	ASH GROVE CEMENT CO.		1801 N. SANTA FE	CHANUTE	KS	66720	USA	-95.4631	37.69778		LATLON
T$10268	3241	327310	LAFARGE CORP. (INCLD SYSTECH ENVIRONMENTAL)		S. CEMENT RD.	FREDONIA	KS	66736	USA	-95.8217	37.50945		LATLON
T$10273	3241	327310	MONARCH CEMENT CO.		449 1200 ST.	HUMBOLDT	KS	66748100(	USA	-95.4417	37.80056		LATLON
T$12442	3241	327310	RIO GRANDE PORTLAND CEMENT CORP.		11783 STATE HWY. 337	TIJERAS	NM	87059	USA	-106.39	35.07222		LATLON
BG0259G	3241	327310	ALAMO CEMENT CO II LTD		6055 W. GREEN MOUNTAIN ROAD	SAN ANTONIO	TX	78201	USA	-98.3756	29.61184	14	LATLON
BG0045E	3241	327310	CAPITOL CEMENT DIV CAPITOL AGGREGATE		11551 NACOGDOCHES ROAD	SAN ANTONIO	TX	78201	USA	-98.4207	29.54637	14	LATLON
T$11980	3241	327310	LONE STAR IND. INC. MARYNEAL PLANT		202 CR 306 FARM RD. 608	MARYNEAL	TX	79535	USA	-100.458	32.25		LATLON
ND0014S	3241	327310	LONE STAR INDUSTRIES INC		0.5 MI. N.W. ON F.M. 608	MARYNEAL	TX	79535	USA	-100.459	32.25113	14	LATLON
T$11385	3241	327310	NORTH TEXAS CEMENT CO. LLP.		900 GIFCO RD.	MIDLOTHIAN	TX	76065052(	USA	-97.0083	32.52083		LATLON
EB0121R	3241	327310	SOUTHDOWN INC		1200 SMITH STREET, SUITE 2400	ODESSA	TX	79761	USA	-102.545	31.74667	13	LATLON
T$12011	3241	327310	SOUTHWESTERN PORTLAND CEMENT		13 MILES W. OF ODESSA I-20 EXI	PENWELL	TX	79776	USA	-102.541	31.75111		LATLON
CS0022K	3241	327310	SUNBELT CEMENT OF TEXAS LP		AT THE INTERSECTION OF WALD &	NEW BRAUNFELS	TX	78130	USA	-98.2524	29.69211	14	LATLON
318	3241	327310	Texas Industries, Inc.	TXD007349327	245 WARD ROAD	Midlothian	TX	76065	USA	-97.0285	32.46378	0	LATLON
T$11924	3241	327310	TEXAS-LEHIGH CEMENT CO.		701 CEMENT PLANT RD.	BUDA	TX	78610061(	USA	-97.8533	30.07111		LATLON
ED0066B	3241	327310	TXI OPERATIONS LIMITED PARTNERSHIP		2.5 MI. W. OF MIDLOTHIAN, TX.,	MIDLOTHIAN	TX	76065	USA	-97.0255	32.46194	14	LATLON
CS0018B	3241	327310	TXI OPERATIONS LP		7781 FM 1102	NEW BRAUNFELS	TX	78132	USA	-98.0412	29.80478	14	LATLON
5600100002	3241	327310	MOUNTAIN CEMENT CO	CEMENT, HYDRAULIC			WY		USA	-105.603	41.2689	13	LATLON
BSCP20	3251	327121	Clinton-Campbell Contractor, Inc	Phoenix Brick Yard	1814 South 7th Ave	Phoenix	AZ	85007	USA	-112.084	33.42083		LATLON
0043	3251	327	DENVER BRICK CO	MANUFACTURE AND SELL FACE BI	401 SANTA FE RD	CASTLE ROCK	CO	80104	USA	-104.867	39.3757	13	LATLON
T$12069	3251	327	ROBINSON BRICK CO.	BRICK MANUFACTURING	1845 W. DARTHMOUTH AVE.	ENGLEWOOD	CO	80110130	USA	-105.007	39.6625		LATLON
BSCP116	3251	327121	Summit Pressed Brick and Tile Co	Brick Plant and Storange Yard	13 th and Erie St	Pueblo	CO	81001	USA	-104.595	38.28083		LATLON
BSCP39	3251	327121	Summit Pressed Brick and Tile Co	Lakewood Brick and Tile Co	1325 Jay St	Lakewood	CO	80214	USA	-105.064	39.7375		LATLON
BSCP155	3251	327121	The Denver Brick Co	The Denver Brick Co	401 North Santa Fe Rd	Castle Rock	CO	80104	USA	-104.856	39.37889		LATLON
00004	3251	327	ACME BRICK COMPANY	BRICK AND STRUCTURAL CLAY	1915 AVENUE L	KANOPOLIS	KS	67454	USA	-98.1478	38.71083		LATLON
00009	3251	327	CLOUD CERAMICS (DIV. GENERAL FINANCE)	BRICK MANUFACTURING	R. R. 3	CONCORDIA	KS	66901000(	USA	-97.6842	39.59167		LATLON
BSCP158	3251	327121	General Finance, Inc	Cloud Ceramics	RR 3 P.O. Box 369	Concordia	KS	66901	USA	-97.658	39.56749		LATLON
BSCP92	3251	327121	Justin Industries	Acme Brick-Kanopolis Plant	1915 Arenia L	Kanopolis	KS	67454	USA	-98.1506	38.71222		LATLON
BSCP93	3251	327121	Justin Industries	Acme Brick-Weir Plant	South Washington St	Weir	KS	66781	USA	-94.7286	37.28556		LATLON
BSCP175NR	3251	327121	Kansas Brick and Tile Co	Kansas Brick and Tile Co	Highway 281	Hoisington	KS	67544	USA	-98.7842	38.53603		LATLON
BSCP2	3251	327121	American Eagle Brick Co	American Eagle Brick Co	1000 McNutt Rd	Sunland Park	NM	88063	USA	-106.542	31.78889		LATLON
BSCP38	3251	327121	Hoffman Enterprises, Inc	Kinney Brick Co	100 Prosperity SE	Albuquerque	NM	87105	USA	-106.659	35.01473		LATLON
PC0001E	3251	327	ACME BRICK COMPANY		BENNETT PLANT	MILLSAP	TX	76066	USA	-98.0536	32.715	14	LATLON
T$11307	3251	327	BORAL BRICKS INC. HENDERSON PLANT		1309 KILGORE DR.	HENDERSON	TX	75652	USA	-94.8033	32.18083		LATLON
T$11314	3251	327	BORAL BRICKS INC. MARSHALL PLANT		1700 N. FRANKLIN ST.	MARSHALL	TX	75670	USA	-94.3678	32.555		LATLON
BSCP21	3251	327121	D'Hanis Clay Products, Inc	dba D'Hanis Brick and Tile	7734 County Rd No. 429	D'Hanis	TX	78850	USA	-99.2794	29.33028		LATLON
BSCP153	3251	327121	Elgin-Butler Brick Co	Elgin Butler Brick	FM 696 (P.O. Box 546)	Elgin	TX	78621	USA	-97.2894	30.32167		LATLON
BSCP70	3251	327121	Hanson, PLC	US Brick - Mineral Wells Plant	500 N.E. 14th Ave	Mineral Wells	TX	76067	USA	-98.1258	32.81556		LATLON
BSCP77	3251	327121	Hanson, PLC	US Brick-Elgin Plant	Rt.6, Box 338	Elgin	TX	78621	USA	-97.3397	30.31643		LATLON
BSCP118	3251	327121	Justin Industries	Texas Clay	West Bartlett St	Malakoff	TX	75148	USA	-96.0208	32.16555		LATLON
BSCP125	3251	327121	Justin Industries	Acme Brick-Bridgeport Plant	102 Main St	Bridgeport	TX	76426	USA	-97.7744	33.20945		LATLON
BSCP126	3251	327121	Justin Industries	Acme Brick-Garrison Plant	257 Brickyard Rd	Garrison	TX	75946	USA	-94.5089	31.83917		LATLON
BSCP128	3251	327121	Justin Industries	Acme Brick-San Felipe Plant	562 Peter San Felip Rd	Sealy	TX	77474	USA	-96.1397	29.82889		LATLON
BSCP151	3251	327121	Justin Industries	Acme Brick-Bennett Tunnel Plant	2350 Bennett Rd	Milsap	TX	76066	USA	-98.0517	32.68333		LATLON
BSCP97	3251	327121	Justin Industries	Acme Brick-Denton Tunnel Plant	220 E Danels Plant	Denton	TX	76205	USA	-97.1347	33.18639		LATLON
BSCP98	3251	327121	Justin Industries	Acme Brick-Elgin Tunnel Plants	FM Road 696	Elgin	TX	78621	USA	-97.2933	30.31917		LATLON
BSCP99	3251	327121	Justin Industries	Acme Brick-McQueeney Plant	FM I25	McQueeney	TX	78123	USA	-98.0397	29.5725		LATLON
BSCP160NR	3251	327121	Snyder Brick and Tile	Snyder Brick and Tile	901 East US Highway 180	Snyder	TX	79549	USA	-100.906	32.71685		LATLON
BSCP121	3251	327121	Texas Industries	Athens Brick Mineral Wells Plant	7510 Hwy 180 East	Mineral Wells	TX	76080	USA	-97.3502	32.61335		LATLON
HM0003S	3251	327	TEXAS INDUSTRIES INC		FR 31 GO 2495 E.4 & S .4 ON OI	ATHENS	TX	75751	USA	-95.8224	32.20379	15	LATLON
46461	3251	327	WILLIAMSBURG BRICK COMPANY				TX		USA	-95.1039	32.9806	15	LATLON
DB1073N	3253	327122	AMERICAN MARAZZI TILE INC		359 CLAY ROAD	SUNNYVALE	TX	75182	USA	-96.5625	32.76681	14	LATLON
CC48	3253	327122	Dal-Tile Corporation	Tile Plant	10399 Silver Springs Road	Conroe	TX	77303	USA	-95.4672	30.39083		LATLON
CC50	3253	327122	Dal-Tile Corporation	Tile Plant	12001 Railroad Drive	El Paso	TX	79934	USA	-106.355	31.95278		LATLON
DB0242V	3253	327122	DAL-TILE CORPORATION		7834 HAWN FREEWAY	DALLAS	TX	75037	USA	-96.6879	32.71733	14	LATLON
CC72	3253	327122	Huntington/Pacfic Ceramics, Inc.	Tile Plant	3600 Conway	Ft. Worth	TX	76111	USA	-97.2954	32.76771		LATLON
CC73	3253	327122	Huntington/Pacific Ceramics, Inc.	Tile Plant	U.S. Hwy 167 West	Mt. Vernon	TX	75457	USA	-95.2433	33.18528		LATLON
CC205	3253	327122	Lone Star Ceramics Mfg. Co.	Tile Plant	2408 Fruitland Street	Farmers Branch	TX	75234	USA	-96.9092	32.93528		LATLON
9611	3255	327124	ADIENCE INC				CO		USA	-105.23	38.442	13	LATLON
0459	3255	327124	COORSTEK, INC	INDUSTRIAL CERAMIC MANUFACTU	16000 N TABLE MOUNTAIN PKWY	GOLDEN	CO	80403	USA	-105.177	39.7829	13	LATLON
0017	3255	327124	DFC CERAMICS	CLAY REFRACTORIES	515 S NINTH ST	CANON CITY	CO	81212	USA	-105.231	38.4393	13	LATLON
0012	3255	327124	VESUVIUS USA	REFRACTORIES MANUFACTURING	309 S 11TH ST	CANON CITY	CO	81212	USA	-105.23	38.442	13	LATLON
BSCP106	3259	327123	MCP Industries, Inc	Mission Clay Products Phoenix	4850 W. Buckeye Rd	Phoenix	AZ	85043	USA	-112.163	33.43684		LATLON

strStateFacilityIdentifier	strSIC Primary	strNAICS Primary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXY Coordinate Type
BSCP108	3259	327123	MCP Industries, Inc	Mission Clay Products Pittsburg	900 E. 2nd	Pittsburg	KS	66762	USA	-94.6917	37.35833		LATLON
BSCP109	3259	327123	MCP Industries, Inc	Mission Clay Products Saspamco	Old Corpus Christi Rd	Elmendorf	TX	78112	USA	-98.3	29.2375		LATLON
CC15	3261	327111	American Standard, Inc.	Sanitaryware Plant	6615 W. Boston Rd	Chandler	AZ	85226	USA	-111.957	33.30245		LATLON
CC92	3261	327111	Falcon Building Products, Inc. (Mansfield)	Sanitaryware Plant	Highway 259 North	Kilgore	TX	75663	USA	-94.8486	32.40333		LATLON
CC203	3261	327111	Kohler Co	Sanitaryware Plant	4601 Highway 377 South	Brownwood	TX	76801	USA	-98.9972	31.66389		LATLON
CC38	3262	327112	CR/PL, L.L.C.	Sanitaryware Plant	Highway 6 South	Hearne	TX	77859	USA	-96.5943	30.87724		LATLON
0007	3264	327113	COORS CERAMICS CO ELECTRONICS DIV	PORCELAIN ELECTRIC.SUPPLY	17750 W 32ND AVE	GOLDEN	CO	80401	USA	-105.201	39.7649	13	LATLON
0024	3264	327113	COORSTEK GRAND JUNCTION	CERAMIC SUBSTRATE / FURRULE /	2449 RIVER RD	GRAND JUNCTION	CO	81505	USA	-108.596	39.0852	12	LATLON
0437	3264	327113	COORSTEK, INC.	CERAMIC SPECIALITIES (FORMERL	4545 MCINTYRE ST	GOLDEN	CO	80403	USA	-105.174	39.7694	13	LATLON
308	3271	327331	QUALITY BLOCK INC				AZ		USA	-112.225	33.68333		LATLON
490350200	3271	327331	BRICK MANUFACTURING PLANT	ICE-Diesel			UT		USA	-112.014	40.59389		LATLON
490439045	3271	327331	HENIFER MINE	ICE-Diesel			UT		USA	-111.472	41.025		LATLON
490499046	3271	327331	POWELL MINE (UTAH SITE #1)	ICE-Diesel			UT		USA	-111.927	40.33		LATLON
490459043	3271	327331	SMILE MINE	ICE-Diesel			UT		USA	-112.191	40.08889		LATLON
T$12328	3272	327	MONIERLIFETILE L.L.C.		1832 S. 51ST AVE.	PHOENIX	AZ	85043	USA	-112.169	33.43528		LATLON
0411	3272	327	DENVER ARCHITECHURAL PRECAST INC	MFG PRECAST CONCRETE	8200 E 96TH AVE	HENDERSON	CO	80640852	USA	-104.891	39.8704	13	LATLON
0053	3272	327	ROCKY MOUNTAIN PRESTRESS ARCHITECTURAL	ARCHITECTURAL CONCRETE MFG	301 W 60TH PL	DENVER	CO	80216101	USA	-104.982	39.8047	13	LATLON
0081	3272	327	STRESSCON CORP	CONCRETE PRODUCTS, INC.	3210 ASTROZON BLVD	COLORADO SPRINGS	CO	80910	USA	-104.772	38.7808	13	LATLON
00097	3272	327	RICH MIX PRODUCTS, INC.- KANSAS DIVISION	CONSTRUCTION SAND AND GRA	6500 W. 21ST	WICHITA	KS	67212	USA	-97.4181	37.72333		LATLON
DB0374D	3272	327	FRITZ INDUSTRIES INC		500 SAM HOUSTON ROAD	MESQUITE	TX	75149	USA	-96.675	32.75562	14	LATLON
T$11169	3272	327	GIFFORD-HILL AMERICAN		1004 N. MAC ARTHUR BLVD.	GRAND PRAIRIE	TX	75050	USA	-96.9558	32.76639		LATLON
490410012	3272	327	COX ROCK PRODUCTS - AURORA PLANT	ICE-Diesel			UT		USA	-111.908	38.7739		LATLON
490390001	3272	327	COX ROCK PRODUCTS - MT PLEASANT CONCRETE	ICE-Diesel			UT		USA	-111.631	39.42275		LATLON
490350088	3272	327	HOBUSCH PIT	ICE-Diesel			UT		USA	-111.861	40.58111		LATLON
490110049	3272	327	WEBER SAND AND GRAVEL L-6	ICE-Diesel			UT		USA	-112.115	40.9611		LATLON
400	3273	327320	CALMAT OF ARIZONA				AZ		USA	-112.25	33.85556		LATLON
401	3273	327320	CALMAT OF ARIZONA				AZ		USA	-112.072	33.70833		LATLON
403	3273	327320	CALMAT OF AZ PLANT #3				AZ		USA	-112.447	33.78889		LATLON
404	3273	327320	CALMAT OF AZ/SUN CITY PLANT				AZ		USA	-112.517	34.02778		LATLON
411	3273	327320	CENTURY MATERIALS, INC.				AZ		USA	-112.492	33.725		LATLON
413	3273	327320	CHANDLER READY MIX				AZ		USA	-112.381	33.68611		LATLON
304	3273	327320	PHOENIX REDI MIX				AZ		USA	-112.253	33.69167		LATLON
339	3273	327320	SUNWARD MATERIALS				AZ		USA	-112.522	33.82222		LATLON
340	3273	327320	SUNWARD MATERIALS (BCW CEMENT CO.)				AZ		USA	-112.439	33.55556		LATLON
367	3273	327320	UNITED METRO (TANNER)				AZ		USA	-112.661	33.70833		LATLON
0672	3273	327320	KIEWIT WESTERN CO	AGGREGATE STORAGE AND HOT M	2401 PICADILLY RD	AURORA	CO	80019361	USA	-104.734	39.7521	13	LATLON
0103	3273	327320	QUIKRETE OF DENVER HOLDINGS INC	PAVING MIXTURES AND BLOCK	6200 BRYANT ST	DENVER	CO	80221205	USA	-105.019	39.811	13	LATLON
0010	3273	327320	TRANSIT MIX CONCRETE	READY-MIXED CONCRETE	444 E COSTILLA ST	COLORADO SPRINGS	CO	80903	USA	-104.817	38.8278	13	LATLON
0400300176	3274	32741	CHEMICAL LINE COMPANY - DOUGLAS FACILITY	LIME PROCESSING FACILITY	HIGHWAY 80	DOUGLAS	AZ	85607	USA	-109.735	31.36357	12	LATLON
0261	3274	327410	PILOT PEAK		3950 SOUTH 700 EAST SUITE 301	SALT LAKE CITY	NV	84107	USA	-114.22	40.82477	11	LATLON
BJ0001T	3274	327410	CHEMICAL LIME LTD		7 M S.W. OF CLIFTON, TEX., ON	CLIFTON	TX	76634	USA	-97.5973	31.70845	14	LATLON
490450005	3274	327410	GRANTSVILLE PLANT	ICE-Diesel			UT		USA	-112.55	40.685		LATLON
490350373	3274	327410	HERCULES COMPOSITE MATERIALS	ICE-Diesel			UT		USA	-111.906	40.6737		LATLON
490450035	3274	327410	USPCI - MERR	ICE-Diesel			UT		USA	-113.09	40.93056		LATLON
080370029	3275	327420	EAGLE GYPSUM PRODUCTS WALLBOARD PLT				CO		USA	-106.899	39.64583		LATLON
00021	3275	327420	G-P GYPSUM CORPORATION	GYPSUM PRODUCTS	2127 HIGHWAY 77	BLUE RAPIDS	KS	66411	USA	-96.645	39.70444		LATLON
T$10977	3275	327420	UNITED DESIGN CORP. NOBLE FAC.		1600 N. MAIN	NOBLE	OK	73068	USA	-97.4056	35.15694		LATLON
10654	3275	327420	Sigurd Plant	81 North State Street (across the stree	81 N. State Street	Sigurd	UT	84657	USA	-111.967	38.83921		LATLON
5600300001	3275	327420	GEORGIA PACIFIC_GYPSUM PLANT	GYPSUM WALLBOARD MFG	15 MI SE OF LOVELL	LOVELL	WY	82431	USA	-108	44.7529	13	LATLON
T$12314	3281	327991	AVONTI MFG. INC.		941 W. DEER VALLEY RD.	PHOENIX	AZ	85027	USA	-112.126	33.85083		LATLON
T$12342	3281	327991	MESA FULLY FORMED INC.		1111 S. SIRRINE	MESA	AZ	85210878	USA	-111.831	33.39389		LATLON
T$12434	3281	327991	MOUNTAIN MARBLE MFG. INC.		7359 E. SECOND ST.	PRESCOTT VALLEY	AZ	86314735	USA	-112.317	34.58556		LATLON
0131	3281	327991	MANSTONE	MARBLE PRODUCT MFG	105 TALAMINE CT	COLORADO SPRINGS	CO	80907	USA	-104.824	38.8792	13	LATLON
0286	3281	327991	ROCKY MOUNTAIN CULTURED MARBLE INC	MANUFACTURE OF CULTURED MA	832 E LINCOLN AVE	FORT COLLINS	CO	80524	USA	-105.055	40.5885	13	LATLON
T$11300	3281	327991	ALDON MARBLE MFG. CO.		FM 349 & FM 2011	LONGVIEW	TX	75603	USA	-94.7567	32.40417		LATLON
T$11438	3291		NORTON CO.		2770 W. WASHINGTON ST.	STEPHENVILLE	TX	76401	USA	-98.2361	32.20278		LATLON
T$11914	3291		NORTON CO.		1505 MORNINGSIDE RD.	BROWNSVILLE	TX	78521769	USA	-97.4399	25.90414		LATLON
455	3295	2123	HARBORLITE CORP, SUPERIOR PLANT				AZ		USA	-111.128	33.2833	12	LATLON
040271006	3295	2123	YUMA COUNTY DEPT PUBLIC WORKS C&S PLANT				AZ		USA	-114.494	32.75833		LATLON
0004	3295	2123	MWCA INC	SCORIA BRIQ/AQUA PAINT	RD P & RD 12 0.4 MI N OF	SAN ACACIO	CO	81152000	USA	-105.575	37.1907	13	LATLON
00015	3295	2123	MICRO-LITE, L.L.C.	MINERALS, GROUND OR TREAT	WEST MICRO-LITE STREET	BUFFALO	KS	00000	USA	-95.6971	37.70861		LATLON
NB0037F	3295	2123	TXI OPERATIONS LP		2 MI. N. OF STREETMAN, TX., NE	STREETMAN	TX	75859	USA	-96.3488	31.91539	14	LATLON
T$12365	3296	327993	OWENS-CORNING ELOY PLANT		1825 W. BATTAGLIA RD.	ELOY	AZ	85231	USA	-111.628	32.66833		LATLON
0168	3296	327993	MESA FIBERGLASS INC	FIBERGLASS FABRICATION	6471 E 49TH AVE	COMMERCE CITY	CO	80022450	USA	-104.914	39.7857	13	LATLON
00001	3296	327993	CERTAIN TEED CORPORATION	MINERAL WOOL	103 FUNSTON ROAD	KANSAS CITY	KS	00000	USA	-94.6114	39.14305		LATLON
00036	3296	327993	JOHNS MANVILLE	MINERAL WOOL	1465 17TH AVENUE	MCPHERSON	KS	67460	USA	-97.6117	38.38583		LATLON
00010	3296	327993	OWENS CORNING	MINERAL WOOL	300 SUNSHINE ROAD	KANSAS CITY	KS	66115	USA	-94.6156	39.14667		LATLON
34651	3296	327993	SCHULLER INTL. INC.				KS		USA	-97.615	38.38639		LATLON
T$11455	3296	327993	AMERICAN ROCKWOOL INC.		NO. 1 JACKRABBIT RD.	NOLANVILLE	TX	76559	USA	-97.5686	31.075		LATLON
JH0025O	3296	327993	JOHNS MANVILLE INTERNATIONAL INC		200 WEST INDUSTRIAL BLVD.	CLEBURNE	TX	76031	USA	-97.397	32.38778	14	LATLON
AA0044U	3296	327993	OWEN CORNING		5476 S.H. 294	PALESTINE	TX	75801	USA	-95.761	31.65535	15	LATLON
ED0051O	3296	327993	OWENS-CORNING		3700 N.I. 35 E.	WAXAHACHIE	TX	75165	USA	-96.8501	32.43925	14	LATLON
T$11220	3296	327993	OWENS-CORNING		3700 N INTERSTATE HWY. 35E	WAXAHACHIE	TX	75165	USA	-96.85	32.43917		LATLON
HG1766N	3296	327993	ROCK WOOL MANUFACTURING CO		3290 SOUTH LOOP EAST	HOUSTON	TX	77021	USA	-95.3172	29.69829	15	LATLON
BF0107S	3296	327993	THERMAFIBER LLC		1 JACKRABBIT RD.	NOLANVILLE	TX	76558	USA	-97.5695	31.07524	14	LATLON
0106	3299	327	VISICOM LABORATORIES DBA MICROLITHICS CO	CIRCUIT BOARD MANUFACTURING	17301 W COLFAX AVE STE 100 152	GOLDEN	CO	80401	USA	-105.166	39.7316	13	LATLON
T$11847	3299	327	KAMAL INC. VENETIAN MARBLE (DBA)		13310 WESTERN OAK	HELOTES	TX	78023410	USA	-98.6619	29.56556		LATLON
BM0026Q	3299	327	NORTON CHEMICAL PROCESS PRODUCTS COR		BRAZOS COUNTY INDUSTRIAL PARK	BRYAN	TX	77801	USA	-96.4086	30.66233	14	LATLON
MQ0106G	3299	327	SCAN-PAC MFG INC		31502 SUGAR BEND DRIVE	MAGNOLIA	TX	77355	USA	-95.46	30.34	15	LATLON
RL0086D	3299	327	TROY MFG TEXAS INC		200 PRESTON ROAD-PRESTON INDUS	HENDERSON	TX	75652	USA	-94.8182	32.19677	15	LATLON
0401501232	3312	331111	NORTH STAR STEEL ARIZONA	STEEL MILL	3000 HWY 66 SOUTH	KINGMAN	AZ	86413	USA	-114.091	35.13795	11	LATLON
0048	3312	331	CF&I STEEL L P DBA ROCKY MTN STEEL MILLS	BLAST FURNACES AND STEEL	2100 S. FREEWAY	PUEBLO	CO	81004	USA	-104.613	38.237	13	LATLON
1144	3312	331	CONSOLIDATED STEEL SVC	STEEL FABRICATOR	3700 S WINDERMERE ST	ENGLEWOOD	CO	80110	USA	-105.002	39.6479	13	LATLON
T$11138	3312	331	ACKER INDS. INC.		301 N WEWOKA AVE.	WEWOKA	OK	74884222	USA	-96.4911	35.16028		LATLON
2453	3312	331	Sheffield Steel	14300010 2300 South Highway 97			OK		USA	-96.1185	36.1324	14	LATLON
T$11048	3312	331	SHEFFIELD STEEL CORP.		2300 S. HWY. 97	SAND SPRINGS	OK	74063	USA	-96.1186	36.11861		LATLON
EE0011P	3312	331	BORDER STEEL INC		IH-10 & VINTON ROAD	EL PASO	TX	79901	USA	-106.584	31.96589	13	LATLON
T$11384	3312	331	CHAPARRAL STEEL MIDLOTHIAN L.P.		300 WARD RD.	MIDLOTHIAN	TX	76065965	USA	-97.0417	32.46389		LATLON
ED0011D	3312	331	CHAPARRAL STEEL MIDLOTHIAN LP		U.S. HWY. 67 @ WARD RD., IN MI	MIDLOTHIAN	TX	76065	USA	-97.0375	32.45792	14	LATLON

strStateFacilityIdentifier	strSIC Primary	strNAICS Primary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXY Coordinate Type
CI0170H	3312	331	JINDAL UNITED STEEL CORP		5200 E. MCKINNEY ROAD, SUITE 1	BAYTOWN	TX	77520	USA	-94.8956	29.68826	15	LATLON
MS0008I	3312	331	LONE STAR STEEL CO		HIGHWAY 259 SOUTH	LONE STAR	TX	75668	USA	-94.74	33.12	15	LATLON
T$11311	3312	331	LONE STAR STEEL CO.		HWY. 259 S.	LONE STAR	TX	75668100(	USA	-94.7167	32.9		LATLON
55404	3312	331	LONE STAR STEEL COMPANY				TX		USA	-94.718	32.9142	15	LATLON
OC0011S	3312	331	NORTH STAR STEEL OF TEXAS		OLD HIGHWAY 90	ROSE CITY	TX	77662	USA	-94.0786	30.08556	15	LATLON
GL0028H	3312	331	STRUCTURAL METALS INC		STEEL MILL ROAD	SEGUIN	TX	78155	USA	-98.0328	29.57685	14	LATLON
T$12209	3312	331	GENEVA STEEL		10 S. GENEVA RD. BIN 10	VINEYARD	UT	84058	USA	-111.74	40.29639		LATLON
T$12268	3312	331	NUCOR STEEL - A DIV. OF NUCOR CORP.		7825 W. 21200 N.	PLYMOUTH	UT	84330	USA	-112.189	41.87695		LATLON
5603700003	3312	331	P4 PRODUCTION_ROCK SPRINGS FACILITY	ROTARY COKING			WY		USA	-109.22	41.5241	12	LATLON
T$12467	3331	331411	PHELPS DODGE HIDALGO INC.		9 MILES S. OF HWY. 9 ALONG SME	PLAYAS	NM	88009	USA	-108.543	31.77111		LATLON
350230003	3331	331411	PHELPS DODGE/HIDALGO SMELTER________59M1	Turbine:			NM		USA	-108.529	31.77528		LATLON
T$11966	3331	331411	ASARCO INC. AMARILLO COPPER REFY.		7901 N. HWY. 136	AMARILLO	TX	79107020(	USA	-101.734	35.28528		LATLON
EE0007G	3331	331411	ASARCO INCORPORATED		2301 WEST PAISANO DRIVE	EL PASO	TX	79901	USA	-106.523	31.78263	13	LATLON
PG0005V	3331	331411	ASARCO INCORPORATED		8 MI. N.E. OF AMARILLO, TX., O	AMARILLO	TX	79101	USA	-101.733	35.28257	14	LATLON
EE0067L	3331	331411	PHELPS DODGE EL PASO OPERATIONS		6999 NORTH LOOP ROAD	EL PASO	TX	79998	USA	-106.392	31.76683	13	LATLON
15076	3331	331411	KENNECOTT - UTAH POWER PLANT AND				UT		USA	-112.117	40.7		LATLON
T$12197	3331	331411	KENNECOTT UTAH COPPER SMELTER & REFY.		12000 W. 2100 S., & 11500 W. 2	MAGNA	UT	84044	USA	-112.197	40.72167		LATLON
10346	3331	331411	Smelter, Refinery	Refinery precious metals facility, smelt	12000 West 2100 South	Magna	UT	84044	USA	-112.083	40.70026		LATLON
T$11456	3334	331312	ALCOA		FM 1786 OFF RTE. 79	ROCKDALE	TX	76567	USA	-97.0886	30.63417		LATLON
MM0001T	3334	331312	ALUMINUM COMPANY OF AMERICA		5 MI. S. OF U.S. HWY. 79 AT IN	ROCKDALE	TX	76567	USA	-97.0729	30.56841	14	LATLON
00002	3341	331	TOWER METAL PRODUCTS	SECONDARY NONFERROUS META	301 NORTH HILL	FORT SCOTT	KS	66701	USA	-94.6988	37.8389		LATLON
T$11049	3341	331	IMCO RECYCLING INC.		1508 N. 8TH ST.	SAPULPA	OK	74066	USA	-96.1317	36.01694		LATLON
T$11114	3341	331	WABASH ALLOYS L.L.C.		100 E. APEX RD.	CHECOTAH	OK	74426	USA	-95.5417	35.4		LATLON
T$11028	3341	331	ZINC CORP. OF AMERICA		HWY. 123 & ELEVENTH ST.	BARTLESVILLE	OK	74003	USA	-95.9936	36.74167		LATLON
T$11852	3341	331	ALCOA INC. SAN ANTONIO WORKS		14555 OLD CORPUS CHRISTI RD.	ELMENDORF	TX	78112	USA	-98.3789	29.2775		LATLON
T$11283	3341	331	ALUMAX MILL PRODS. INC.		300 ALUMAX DR.	TEXARKANA	TX	75501	USA	-94.1422	33.45139		LATLON
47835	3341	331	COLUMBIA ALUMINUM PROCESSORS				TX		USA	-96.4494	32.925	14	LATLON
T$11212	3341	331	ECS REFINING TEXAS L.L.C.		106 TEJAS DR.	TERRELL	TX	75160	USA	-96.3133	32.72585		LATLON
CP0029G	3341	331	EXIDE CORPORATION		SOUTH FIFTH STREET	FRISCO	TX	75034	USA	-96.8335	33.13477	14	LATLON
T$11520	3341	331	FABRICATED PRODS./LONE STAR		9200 MARKET ST. RD.	HOUSTON	TX	77029	USA	-95.2637	29.76901		LATLON
BL0029V	3341	331	GULF CHEMICAL & METALLURGICAL CORP		302 MIDWAY ROAD	FREEPORT	TX	77541	USA	-95.3382	28.95808	15	LATLON
T$11469	3341	331	GULF REDUCTION CORP. - ESPERSON DIV. OF U.S. ZINC		6020 ESPERSON ST.	HOUSTON	TX	77010	USA	-95.3125	29.74333		LATLON
T$11478	3341	331	GULF REDUCTION CORP. - GREENWOOD METAL DIV. OF U.S		310 N. GREENWOOD	HOUSTON	TX	77011	USA	-95.3125	29.74694		LATLON
490350006	3341	331	UTAH METAL WORKS	ICE-NG.			UT		USA	-111.769	40.79944		LATLON
13374	4911	2211	AGUA FRIA				AZ		USA	-112.217	33.55667		LATLON
13068-A	4911	2211	Apache Station	0079600000-0	10 Miles South of Interst	Cochise	AZ		USA	-109.926	32.03034		LATLON
040131025	4911	2211	APS-CC PLANT PHOENIX	Turbine:			AZ		USA	-112.157	33.44444		LATLON
040131507	4911	2211	APS-OCOTILLO POWER PLANT	Turbine:			AZ		USA	-111.912	33.42222		LATLON
313	4911	2211	APS-OCOTILLO POWER PLANT				AZ		USA	-111.912	33.4225	12	LATLON
324	4911	2211	APS-WEST PHOENIX POWER PLANT				AZ		USA	-112.158	33.4447	12	LATLON
T$12400	4911	2211	ARIZONA ELECTRIC POWER COOPERATIVE INC.		HWY. 191 4 MILES S.	COCHISE	AZ	85606	USA	-109.892	32.06167		LATLON
040030037	4911	2211	ARIZONA ELECTRIC POWER COOPERATIVE, INC.	Turbine:			AZ		USA	-109.893	32.06167		LATLON
040131009	4911	2211	ARIZONA NUCLEAR POWER PROJECT	ICE-Diesel			AZ		USA	-113.433	33.65		LATLON
040030123	4911	2211	ARIZONA PUBLIC SERVICE COMPANY (APS)	Turbine:			AZ		USA	-109.552	31.36333		LATLON
040270331	4911	2211	ARIZONA PUBLIC SERVICE COMPANY (APS)	Turbine:			AZ		USA	-114.709	32.72139		LATLON
040210033	4911	2211	ARIZONA PUBLIC SERVICE, SAGUARO PLANT	ICE-NG.			AZ		USA	-111.3	32.55167		LATLON
0400300037	4911	221112	AZ ELECTRIC POWER COOPERATIVE INC	APACHE GENERATING STATION	3525 NORTH HIGHWAY 191	COCHISE	AZ	85606	USA	-109.89	32.06176	12	LATLON
13700-A	4911	2211	Cholla Power Plant	0008030000-0	Cholla Power Plant I-40 F	Joseph City	AZ	86032	USA	-110.364	35.1869		LATLON
13712	4911	2211	CORONADO				AZ		USA	-109.272	34.57778		LATLON
13712-A	4911	2211	Coronado	0615720000-0	10 Miles NorthEast of Str	Saint John's	AZ	85936	USA	-109.377	34.50642		LATLON
040131007	4911	2211	GROVE COGENERATION PROJECT	ICE-NG.			AZ		USA	-112.116	33.58389		LATLON
13135	4911	2211	IRVINGTON				AZ		USA	-110.904	32.15972		LATLON
13135-A	4911	2211	Irvington	0242110000-0	3950 East Irvington Rd	Tuscon	AZ	85714	USA	-110.907	32.16294		LATLON
13160	4911	2211	KYRENE				AZ		USA	-111.936	33.35444		LATLON
13568	4911	2211	NAVAJO				AZ		USA	-111.392	37.52361		LATLON
13568-A	4911	2211	Navajo	0165720000-0	Highway 98; 5 Miles East	Page	AZ	86040	USA	-111.46	36.91629		LATLON
13248	4911	2211	OCOTILLO				AZ		USA	-111.942	33.44667		LATLON
98	4911	221113	PALO VERDE NUCLEAR GENERATING STATION	FORMERLY AZ NUCLEAR POWER, !	5801 S WINTERSBURG RD	TONOPAH	AZ	85354-752	USA	-112.875	33.39567	12	LATLON
040190076	4911	2211	PIMA CO. WASTE WATER	ICE-NG.			AZ		USA	-110.869	32.15111		LATLON
13308	4911	2211	SAGUARO				AZ		USA	-111.299	32.55194		LATLON
040131500	4911	2211	SANTAN GENERATING PLANT_(SRP)	Turbine:			AZ		USA	-111.748	33.33028		LATLON
318	4911	2211	SANTAN GENERATING PLANT_(SRP)				AZ		USA	-111.748	33.3306	12	LATLON
040131006	4911	2211	SCOTTSDALE PRINCESS RESORT HOTEL	ICE-NG.			AZ		USA	-111.908	33.64806		LATLON
322	4911	2211	SCOTTSDALE PRINCESS RESORT HOTEL				AZ		USA	-112.522	34.08889		LATLON
13638	4911	2211	SPRINGERVILLE				AZ		USA	-109.163	34.31833		LATLON
13638-A	4911	2211	Springerville	0242110000-0	12 Miles North of Springe	Tuscon	AZ	85714	USA	-109.522	35.24095		LATLON
3316	4911	221112	SRP AGUA FRIA	FORMER SITE ID 1215	7302 W NORTHERN AVE	GLENDALE	AZ	85303-	USA	-112.216	33.55593	12	LATLON
040131215	4911	2211	SRP-AGUA FRIA PWR PL	Turbine:			AZ		USA	-112.216	33.55389		LATLON
0400100060	4911	22111	TUCSON ELECTRIC POWER CO-SPRINGERVILLE	TUCSON ELECTRIC POWER CO-	OFF RTE191,APP.15 MI SPRINGER	SPRINGERVILLE	AZ	85938	USA	-109.164	34.31857	12	LATLON
13387	4911	2211	YUMA AXIS				AZ		USA	-113.94	33.21972		LATLON
080450057	4911	2211	AMERICAN ATLAS NO 1				CO		USA	-107.708	39.51917		LATLON
13079	4911	2211	Arapahoe	0154660000-0	2601 South Platte River D	Denver	CO	80223-	USA	-105.001	39.66833		LATLON
13391	4911	2211	Cameo	0154660000-0	NW 1/4 SEC34 T10D R98W	Palisade	CO	81526-	USA	-108.317	39.13306		LATLON
13400	4911	2211	CHEROKEE	0154660000-0	6198 Franklin Street	Denver	CO	80216-	USA	-105.966	39.80806		LATLON
080410030	4911	2211	COLORADO SPRINGS NIXON	Turbine:			CO		USA	-104.709	38.63306		LATLON
0030	4911	2211	COLORADO SPRINGS UTILITIES - NIXON PLT	ELECTRICAL POWER	FOUNTAIN BLVD & US HWY I25	COLORADO SPRINGS	CO	80817000(	USA	-104.706	38.6329	13	LATLON
0004	4911	2211	COLORADO SPRINGS UTILITIES-DRAKE PLT	ELECTRICAL POWER	700 S CONEJOS ST	COLORADO SPRINGS	CO	80947000	USA	-104.831	38.8242	13	LATLON
13410	4911	2211	Comanche	0154660000-0	2005 Lime Road	Pueblo	CO	81006-	USA	-104.574	38.20806		LATLON
13418-A	4911	2211	Craig	0301510000-0	2101 South Ranney	Craig	CO	81626	USA	-107.772	40.6362		LATLON
13091	4911	2211	GEORGE BIRDSALL				CO		USA	-104.52	38.82972		LATLON
13112	4911	2211	Hayden	0154660000-0	12795 East Ute	Hayden	CO	81639-	USA	-107.258	40.49484		LATLON
1238	4911	2211	KN SERVICES - LAKEWOOD GENERATION FACILI	RECIPROCATING COMPRESSOR EI	143 UNION BLVD	LAKEWOOD	CO	80228-182	USA	-105.133	39.7154	13	LATLON
13168	4911	2211	LAMAR				CO		USA	-102.401	37.95028		LATLON
080990006	4911	2211	LAMAR UTILITIES BOARD	ICE-Diesel			CO		USA	-102.615	38.09028		LATLON
13194	4911	2211	Martin Drake	0039890000-0	700 South Conejos Street	Colorado Springs	CO	80903	USA	-104.833	38.82417		LATLON
11589-A	4911	2211	Nucla		30799 DD 30 Road	Nucla	CO	81424	USA	-108.506	38.24238		LATLON
13259	4911	2211	Pawnee	0154660000-0	14940 County Rd 24	Brush	CO	80723-	USA	-103.693	40.26917		LATLON
081230321	4911	2211	PHOENIX POWER PARTNERS	Turbine:			CO		USA	-104.686	40.40972		LATLON
11170	4911	2211	PLATTE RIVER POWER AUTH RAWHIDE	0151430000-0	2700 E RD 82	LARIMER CNTY	CO	80549	USA	-105.047	40.8408	13	LATLON

strStateFacilityIdentifier	strSIC Primary	strNAICS Primary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXY Coordinate Type
0053	4911	2211	PLATTE RIVER POWER AUTHORITY - RAWHIDE	ELECTRICAL POWER	2700 E RD 82	WELLINGTON	CO	00000-000	USA	-105.047	40.8408	13	LATLON
0008	4911	2211	PUBLIC SERVICE CO - ARAPAHOE	ELECTRICAL GENERATION	2601 S PLATTE RIVER DR	DENVER	CO	80223421(	USA	-105	39.6695	13	LATLON
0001	4911	2211	PUBLIC SERVICE CO - VALMONT	ELECTRICAL GENERATION	1800 N 63RD ST	BOULDER	CO	80301	USA	-105.206	40.0162	13	LATLON
0007	4911	2211	PUBLIC SERVICE CO ALAMOSA PLT	ELECTRICAL POWER	400 WASHINGTON ST	ALAMOSA	CO	81101	USA	-105.883	37.4655	13	LATLON
080030007	4911	2211	PUBLIC SERVICE CO ALAMOSA STA	Turbine:			CO		USA	-105.883	37.46556		LATLON
080310008	4911	2211	PUBLIC SERVICE CO ARAPAHOE	ICE-Diesel			CO		USA	-104.999	39.66972		LATLON
080770002	4911	2211	PUBLIC SERVICE CO CAMEO	ICE-Diesel			CO		USA	-108.315	39.14861		LATLON
0002	4911	2211	PUBLIC SERVICE CO CAMEO PLT	ELECTRICAL POWER	NW SEC 34 T10S R98W	PALISADE	CO	81526	USA	-108.315	39.1484	12	LATLON
8653	4911	2211	PUBLIC SERVICE CO CHEROKEE PLANT				CO		USA	-104.968	39.8056	13	LATLON
0001	4911	2211	PUBLIC SERVICE CO CHEROKEE PLT	ELECTRICAL GENERATION	6198 FRANKLIN ST	DENVER	CO	80216121	USA	-104.968	39.8056	13	LATLON
081010003	4911	2211	PUBLIC SERVICE CO COMANCHE	ICE-Diesel			CO		USA	-104.571	38.21111		LATLON
0003	4911	2211	PUBLIC SERVICE CO COMANCHE PLT	ELECTRICAL POWER	2005 LIME RD	PUEBLO	CO	81006	USA	-104.571	38.2107	13	LATLON
0023	4911	2211	PUBLIC SERVICE CO FORT SAINT VRAIN PLT	ELECTRICAL POWER	16805 19.5 RD	WELD CNTY	CO	80651	USA	-104.874	40.2434	13	LATLON
080770035	4911	2211	PUBLIC SERVICE CO FRUITA	Turbine:			CO		USA	-108.732	39.15972		LATLON
0035	4911	2211	PUBLIC SERVICE CO FRUITA STA	ELECTRICAL POWER	158 N MESA AVE	FRUITA	CO	81521000(	USA	-108.733	39.16	12	LATLON
081230014	4911	2211	PUBLIC SERVICE CO FT LUPTON	Turbine:			CO		USA	-104.772	40.10028		LATLON
0014	4911	2211	PUBLIC SERVICE CO FT LUPTON STATION	ELECTRICAL POWER	SEC 33 T2N R66W	FORT LUPTON	CO	80621	USA	-104.772	40.1	13	LATLON
081230023	4911	2211	PUBLIC SERVICE CO FT ST VRAIN				CO		USA	-104.874	40.24333		LATLON
11193	4911	2211	PUBLIC SERVICE CO HAYDEN				CO		USA	-107.185	40.4858	13	LATLON
0001	4911	2211	PUBLIC SERVICE CO HAYDEN PLT	ELECTRICAL POWER	US HWY 40 - 12795 E YUTE	HAYDEN	CO	81639	USA	-107.185	40.4858	13	LATLON
080590059	4911	2211	PUBLIC SERVICE CO LOOKOUT CTR	ICE-Diesel			CO		USA	-105.202	39.73361		LATLON
080870011	4911	2211	PUBLIC SERVICE CO PAWNEE	ICE-Diesel			CO		USA	-103.683	40.21889		LATLON
0011	4911	2211	PUBLIC SERVICE CO PAWNEE PLT	ELECTRICAL POWER	14940 RD 24	BRUSH	CO	80723	USA	-103.684	40.2189	13	LATLON
8661	4911	2211	PUBLIC SERVICE CO VALMONT				CO		USA	-105.206	40.0162	13	LATLON
8662	4911	2211	PUBLIC SERVICE CO ZUNI				CO		USA	-105.015	39.7362	13	LATLON
T$12092	4911	2211	RAWHIDE ENERGY STATION		2700 E. COUNTY RD. 82	WELLINGTON	CO	80549210$	USA	-105.024	40.85944		LATLON
9748-A	4911	2211	Ray D. Nixon	0039890000-0	14020 Ray Nixon Rd exit 1	Fountain	CO	80817	USA	-104.691	38.64485		LATLON
0250	4911	2211	THERMO COGEN PARTNERSHIP FT LUPTON	ELECTRICAL AND STEAM GENERAT	6501 ROAD 31	FORT LUPTON	CO	80621	USA	-104.772	40.1063	13	LATLON
0412	4911	2211	THERMO GREELEY INC	ELECTRIC POWER GENERATION	846 N SIXTH AVE	GREELEY	CO	80621-018	USA	-104.686	40.443	13	LATLON
0126	4911	2211	THERMO POWER & ELEC INC	COGENERATION ELECTRICITY - sa	510 18TH ST	GREELEY	CO	80631	USA	-104.687	40.4097	13	LATLON
081250001	4911	2211	TRI STATE GENERATION & TRANSMISSION ASSN	Turbine:			CO		USA	-102.242	40.07917		LATLON
0003	4911	2211	TRI STATE GENERATION BURLINGTON	ELECTRICAL POWER PLANT	ROAD 50 & 21889 ROAD Z	BURLINGTON	CO	80807	USA	-102.241	39.3286	13	LATLON
0018	4911	2211	TRI STATE GENERATION CRAIG	COAL FIRED ELECTRICAL POWER (	2101 S RANNEY	CRAIG	CO	81626	USA	-107.591	40.4639	13	LATLON
0001	4911	2211	TRI STATE GENERATION NUCLA	COAL FIRED ELECTRIC GENERATI(	30739 DD 30 RD	MONTROSE CNTY	CO	81424	USA	-108.517	38.2474	12	LATLON
T$12135	4911	2211	TRI-STATE GENERATION & TRANSMISSION - CRAIG STATIO		2201 RANNEY ST.	CRAIG	CO	81626	USA	-107.59	40.46444		LATLON
T$12125	4911	2211	TRI-STATE GENERATION & TRANSMISSION - NUCLA STATIO		30739 DD 30 RD.	NUCLA	CO	81424	USA	-108.506	38.24238		LATLON
13363	4911	2211	Valmont	0154660000-0	1800 North 63rd Street	Boulder	CO	80301-	USA	-105.206	40.01735		LATLON
081010008	4911	2211	WEST PLAINS ENERGY PUEBLO	ICE-Diesel			CO		USA	-104.614	38.26528		LATLON
0003	4911	2211	WEST PLAINS ENERGY - W.N. CLARK STATION	ELECTRICAL POWER	550 W US HWY 50	CANON CITY	CO	81212	USA	-105.238	38.4393	13	LATLON
080890004	4911	2211	WEST PLAINS ENERGY ROCKY FORD PLT	ICE-Diesel			CO		USA	-103.713	38.04917		LATLON
13388	4911	2211	ZUNI				CO		USA	-105.018	39.73722		LATLON
200330001	4911	2211	ANR PIPELINE CO.				KS		USA	-99.3772	37.47806		LATLON
200770002	4911	2211	ANTHONY-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-98.0894	37.17306		LATLON
13110	4911	2211	ARTHUR MULLERGREN				KS		USA	-98.8692	38.40528		LATLON
200250001	4911	2211	ASHLAND-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-99.8114	37.21722		LATLON
200770013	4911	2211	ATTICA-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-98.2881	37.27667		LATLON
200150009	4911	2211	AUGUSTA-MUNICIPAL POWER PLANT (#1)	ICE-NG.			KS		USA	-97.0419	37.69694		LATLON
200150010	4911	2211	AUGUSTA-MUNICIPAL POWER PLANT (#2)	ICE-NG.			KS		USA	-97.0419	37.69667		LATLON
200450011	4911	2211	BALDWIN-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-95.1783	38.79556		LATLON
201570016	4911	2211	BELLEVILLE-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-97.6603	39.85167		LATLON
201230012	4911	2211	BELOIT-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-98.1531	39.49444		LATLON
00008	4911	2211	BOARD OF PUBLIC UTILITIES - NEARMAN	ELECTRICAL SERVICES	4240 N. 55TH	KANSAS CITY	KS	00000	USA	-94.7056	39.15639		LATLON
00048	4911	2211	BOARD OF PUBLIC UTILITIES - QUINDARO	ELECTRICAL SERVICES	3601 N. 12TH	KANSAS CITY	KS	00000	USA	-94.6414	39.14833		LATLON
202090048	4911	2211	BOARD OF PUBLIC UTILITIES - QUINDARO	Turbine:			KS		USA	-94.6406	39.14972		LATLON
201390012	4911	2211	BURLINGAME-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-95.8064	38.75222		LATLON
200310006	4911	2211	BURLINGTON-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-95.7117	38.18972		LATLON
13404	4911	2211	CIMARRON RIVER				KS		USA	-100.932	37.05917		LATLON
201330030	4911	2211	CITY OF CHANUTE ELEC. DEPT.- N. GARFIELD	ICE-NG.			KS		USA	-95.4508	37.67389		LATLON
201330028	4911	2211	CITY OF CHANUTE ELEC. DEPT.- S. PLUMMER	ICE-NG.			KS		USA	-95.4006	37.68833		LATLON
201330002	4911	2211	CITY OF CHANUTE ELEC. DEPT.-S. SANTA FE	ICE-Diesel			KS		USA	-95.4006	37.68833		LATLON
200930019	4911	2211	CITY OF LAKIN	ICE-NG.			KS		USA	-101.285	37.95222		LATLON
201910055	4911	2211	CITY OF OXFORD, MUNICIPAL POWER PLANT	ICE-Diesel			KS		USA	-97.1731	37.26806		LATLON
200270007	4911	2211	CLAY CENTER-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-97.1456	39.39556		LATLON
13406	4911	2211	COFFEYVILLE		7TH & SANTA FE	COFFEYVILLE	KS	67337	USA	-95.5433	37.04722		LATLON
201930007	4911	2211	COLBY-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-101.127	39.40583		LATLON
13446	4911	2211	EAST 12TH STREET PLA				KS		USA	-97.0717	37.26306		LATLON
200090025	4911	2211	ELLINWOOD-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-98.6278	38.39528		LATLON
00002	4911	2211	EMPIRE DISTRICT ELECTRIC COMPANY (THE)	ELECTRICAL SERVICES	R. R. 1	RIVERTON	KS	66770	USA	-94.6986	37.07167		LATLON
202050018	4911	2211	FREDONIA-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-95.76	37.53556		LATLON
200910065	4911	2211	GARDNER ENERGY CENTER	Turbine:			KS		USA	-94.9256	38.80833		LATLON
200030001	4911	2211	GARNETT-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-95.2481	38.26917		LATLON
200370006	4911	2211	GIRARD-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-94.7947	37.52528		LATLON
201810005	4911	2211	GOODLAND-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-101.797	39.34778		LATLON
13098	4911	2211	GORDON EVANS				KS		USA	-97.5217	37.79028		LATLON
200970007	4911	2211	GREENSBURG-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-99.3242	37.64056		LATLON
200410034	4911	2211	HERINGTON-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-96.9969	38.68306		LATLON
201530011	4911	2211	HERNDON-MUNICIPAL POWER PLANT	ICE-Diesel			KS		USA	-100.871	39.91667		LATLON
200650009	4911	2211	HILL CITY-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-99.9117	39.39194		LATLON
200090026	4911	2211	HOISINGTON-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-98.7764	38.51528		LATLON
13121	4911	2211	HOLCOMB				KS		USA	-100.972	37.93167		LATLON
13121-A	4911	2211	Holcomb	0183150000-0	2440 Holcomb Lane	Holcomb	KS	67851-043	USA	-100.992	37.92702		LATLON
200850011	4911	2211	HOLTON-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-95.7417	39.465		LATLON
201890020	4911	2211	HUGOTON-MUNICIPAL POWER PLANT (#1)	ICE-NG.			KS		USA	-101.352	37.18194		LATLON
201890021	4911	2211	HUGOTON-MUNICIPAL POWER PLANT (#2)	ICE-NG.			KS		USA	-101.352	37.18194		LATLON
13132	4911	2211	HUTCHINSON				KS		USA	-97.8694	38.09417		LATLON
13134	4911	2211	IOLA				KS		USA	-95.3542	37.93667		LATLON
200010011	4911	2211	IOLA-MUNICIPAL POWER PLANT (#1)				KS		USA	-95.3542	37.93639		LATLON
200010019	4911	2211	IOLA-MUNICIPAL POWER PLANT (#2)	ICE-Diesel			KS		USA	-95.4225	37.93056		LATLON
13509	4911	2211	JEFFREY ENERGY CENTE				KS		USA	-96.1083	39.28528		LATLON

strStateFacilityIdentifier	strSICPrimary	strNAICSPrimary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXYCoordinateType
13509-A	4911	2211	Jeffrey Energy Center	0002250000-0	25905 Jeffrey Rd	Saint Marys	KS	66536	USA	-96.1128	39.28223		LATLON
200830005	4911	2211	JETMORE-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-99.9317	38.11583		LATLON
201870009	4911	2211	JOHNSON CITY MUN. POWER PLANT	ICE-NG.			KS		USA	-101.764	37.56556		LATLON
13153	4911	2211	JUDSON LARGE		E. HWY 154	DODGE CITY	KS	67801	USA	-99.9492	37.73278		LATLON
201070005	4911	2211	KANSAS CITY POWER & LIGHT CO.	ICE-Diesel			KS		USA	-94.6431	38.34667		LATLON
201730079	4911	2211	KANSAS GAS AND ELECTRIC CO.-WICHITA STA.	Turbine:			KS		USA	-97.2808	37.66389		LATLON
00007	4911	2211	KANSAS STATE UNIVERSITY	COLLEGES AND UNIVERSITIES	109 DYKSTRA HALL	MANHATTAN	KS	66502	USA	-96.5825	39.19417		LATLON
13154	4911	2211	KAW				KS		USA	-94.6517	39.08639		LATLON
200950004	4911	2211	KINGMAN-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-98.1742	37.68139		LATLON
200410017	4911	2211	KPL GAS SERVICE (AEC)	Turbine:			KS		USA	-97.2494	38.93306		LATLON
201550033	4911	2211	KPL GAS SERVICE (HEC)	Turbine:			KS		USA	-97.8694	38.09417		LATLON
201770030	4911	2211	KPL GAS SERVICE (TEC)	Turbine:			KS		USA	-95.5689	39.05444		LATLON
13526	4911	2211	LA CYGNE				KS		USA	-94.6456	38.34806		LATLON
13526-A	4911	2211	La Cygne	0100000000-0	RR 1	LaCygne	KS	66040-980	USA	-94.845	38.2133		LATLON
201650001	4911	2211	LACROSSE MUNICIPAL POWER PLANT				KS		USA	-99.3647	38.56889		LATLON
13172	4911	2211	LARNED				KS		USA	-99.1428	38.20694		LATLON
201450010	4911	2211	LARNED-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-99.1428	38.20694		LATLON
13174	4911	2211	LAWRENCE				KS		USA	-95.2681	39.00778		LATLON
13174-A	4911	2211	Lawrence	0002250000-0	1250 North 1800 Rd	Lawrence	KS	66044	USA	-95.2708	39.00079		LATLON
201050013	4911	2211	LINCOLN-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-98.1953	39.07417		LATLON
13198	4911	2211	MCPHERSON 2				KS		USA	-97.6867	38.37167		LATLON
201130014	4911	2211	MCPHERSON BOARD OF PUBLIC UTILITIES #2	Turbine:			KS		USA	-97.6867	38.37167		LATLON
201190013	4911	2211	MEADE-MUNICIPAL POWER PLANT				KS		USA	-100.359	37.38639		LATLON
200090001	4911	2211	MIDWEST ENERGY, INC.	ICE-NG.			KS		USA	-98.8108	38.39556		LATLON
200230008	4911	2211	MIDWEST ENERGY, INC.	ICE-Diesel			KS		USA	-101.644	39.75722		LATLON
200510012	4911	2211	MIDWEST ENERGY, INC.	ICE-NG.			KS		USA	-99.3181	38.86694		LATLON
201930001	4911	2211	MIDWEST ENERGY, INC.				KS		USA	-101.127	39.40583		LATLON
201430013	4911	2211	MINNEAPOLIS-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-97.7478	39.1575		LATLON
201910025	4911	2211	MULVANE-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-97.2369	37.45917		LATLON
13563	4911	2211	MURRAY GILL				KS		USA	-97.4133	37.42806		LATLON
23422-A	4911	2211	Nearman Creek	0099960000-0	4240 North 55th Street	Kansas City	KS	66104-127	USA	-94.7057	39.15488		LATLON
202050014	4911	2211	NEODESHA-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-95.6103	37.42333		LATLON
201370005	4911	2211	NORTON-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-99.955	39.85556		LATLON
201090009	4911	2211	OAKLEY-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-100.942	39.11917		LATLON
200390009	4911	2211	OBERLIN-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-100.613	39.83417		LATLON
201390014	4911	2211	OSAGE CITY-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-95.8019	38.6375		LATLON
201210001	4911	2211	OSAWATOMIE-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-94.9117	38.52444		LATLON
201410009	4911	2211	OSBORNE-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-98.7525	39.46833		LATLON
200590006	4911	2211	OTTAWA-MUNICIPAL POWER PLANT				KS		USA	-95.2481	38.63833		LATLON
13276	4911	2211	PRATT				KS		USA	-98.7944	37.68417		LATLON
201510005	4911	2211	PRATT-MUNICIPAL POWER PLANT	ICE-Diesel			KS		USA	-98.7944	37.68417		LATLON
13278-A	4911	2211	Quindaro	0099960000-0	3601 North 12th Street	Kansas City	KS	66104-510	USA	-94.6411	39.14855		LATLON
201730128	4911	2211	RITCHIE SAND, INC.	ICE-NG.			KS		USA	-97.4614	37.77528		LATLON
13299	4911	2211	RIVERTON				KS		USA	-94.6983	37.07167		LATLON
13299-A	4911	2211	Riverton	0058600000-0	Highway 66	Riverton	KS	66713	USA	-94.7353	37.02401		LATLON
201670005	4911	2211	RUSSELL-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-98.9031	38.91722		LATLON
201310009	4911	2211	SABETHA-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-95.8342	39.89778		LATLON
201990005	4911	2211	SHARON SPRINGS-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-101.815	38.88306		LATLON
200230009	4911	2211	ST. FRANCIS-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-101.908	39.76556		LATLON
201850015	4911	2211	ST. JOHN-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-98.8117	38.03194		LATLON
201850017	4911	2211	STAFFORD-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-98.6467	38.00306		LATLON
201590024	4911	2211	STERLING MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-98.2592	38.24806		LATLON
201630014	4911	2211	STOCKTON-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-99.3322	39.46806		LATLON
200550026	4911	2211	SUNFLOWER ELECTRIC POWER CORPORATION	Turbine:			KS		USA	-100.894	37.96917		LATLON
13347	4911	2211	TECUMSEH				KS		USA	-95.5689	39.05444		LATLON
13347-A	4911	2211	Tecumseh	0002250000-0	2nd and Dupont Rd	Tecumseh	KS	66542	USA	-95.5663	39.0516		LATLON
201490012	4911	2211	WAMEGO-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-96.3069	39.19722		LATLON
202010024	4911	2211	WASHINGTON-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-97.0778	39.82917		LATLON
13376	4911	2211	WELLINGTON				KS		USA	-97.4703	37.28306		LATLON
201910056	4911	2211	WELLINGTON CITY POWER PLANT, GAS TURBINE	Turbine:			KS		USA	-97.3644	37.27139		LATLON
201910019	4911	2211	WELLINGTON-MUNICIPAL POWER PLANT	ICE-NG.			KS		USA	-97.4703	37.28306		LATLON
201750001	4911	2211	WEST PLAINS ENERGY	Turbine:			KS		USA	-100.932	37.05917		LATLON
202010012	4911	2211	WEST PLAINS ENERGY				KS		USA	-97.3092	39.58694		LATLON
23413	4911	2211	WEST PLAINS ENERGY				KS		USA	-98.8694	38.4052	14	LATLON
00014	4911	2211	WESTERN RESOURCES, INC.	ELECTRICAL SERVICES	1250 N. 1800 RD.	LAWRENCE	KS	66044	USA	-95.2836	39.00056		LATLON
00033	4911	2211	WESTERN RESOURCES, INC. (HEC)	ELECTRICAL SERVICES	3200 E. 30TH	HUTCHINSON	KS	00000	USA	-97.8764	38.08639		LATLON
200350006	4911	2211	WINFIELD MUNICIPAL POWER PLANT (OLD)	Turbine:			KS		USA	-97.0717	37.26306		LATLON
13438	4911	2211	ANIMAS				NM		USA	-108.33	36.50972		LATLON
350450029	4911	2211	CITY OF FARMINGTON/ANIMAS PLANT___1061R1	Turbine:			NM		USA	-108.193	36.72806		LATLON
13423	4911	2211	CUNNINGHAM				NM		USA	-103.353	32.71306		LATLON
0032	4911	2211	Escalante	NMD980335624 233mw Coal-fired Ge	4 Mi N Of Prewitt	Prewitt	NM	87045	USA	-108.081	35.416	12	LATLON
13086	4911	2211	FOUR CORNERS				NM		USA	-108.482	36.69056		LATLON
13086-A	4911	2211	Four Corners	0008030000-0	End of County Road 6675	Fruitland	NM	87416-035	USA	-108.436	36.75341		LATLON
T$12460	4911	2211	FOUR CORNERS STEAM ELECTRIC STATION		COUNTY RD. 6675	FRUITLAND	NM	87416	USA	-108.482	36.69139		LATLON
350250028	4911	2211	LEA COUNTY ELEC COOP/CUNNINGHAM_______GF	Turbine:			NM		USA	-103.32	32.97833		LATLON
350230001	4911	2211	LORDSBURG LTD/REPOWERING PRJCT___PSD90M1	Turbine:			NM		USA	-108.694	32.33778		LATLON
13189	4911	2211	MADDOX				NM		USA	-103.302	32.71306		LATLON
350310027	4911	2211	MERRION OIL & GAS/PAPERS WASH ELEC_949M1	ICE-NG.			NM		USA	-107.325	35.85333		LATLON
350130025	4911	2211	NMSU/PHYSICAL PLANT BOILERS_________1640	Turbine:			NM		USA	-106.753	32.27944		LATLON
0025	4911	2211	Physical Plant Boilers	NM0001424126 Electric & Steam Gen	Nmsu Campus	Las Cruces	NM	88003	USA	-106.753	32.2798	13	LATLON
350470004	4911	2211	PUBLIC SERV CO NM/LAS VEGAS GEN STA___GF	Turbine:			NM		USA	-105.232	35.60528		LATLON
12917	4911	2211	RATON				NM		USA	-104.651	36.60139		LATLON
13288	4911	2211	REEVES				NM		USA	-106.5	36.33306		LATLON
13603	4911	2211	RIO GRANDE				NM		USA	-106.547	31.80444		LATLON
0002	4911	2211	Rio Grande Generating Station	NMD980622971 Electric Power Gener	3501 Doniphan Road	Sunland Park	NM	88063	USA	-106.546	31.8017	13	LATLON
13618	4911	2211	SAN JUAN				NM		USA	-108.483	36.88306		LATLON
13618-A	4911	2211	San Juan	0154730000-0	County Road 6800 - 1.5 Mi	Waterflow	NM	87421	USA	-108.482	36.7616		LATLON
350490017	4911	2211	SANTA FE COGEN ASSOC_________________620	ICE-NG.			NM		USA	-106.048	35.55583		LATLON
350250054	4911	2211	SOUTHWESTERN PUBL SERV/CUNNINGH PSD622M1				NM		USA	-103.356	32.7175		LATLON

strStateFacilityIdentifier	strSIC Primary	strNAICS Primary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXY Coordinate Type
350250034	4911	2211	SOUTHWESTERN PUBL SERV/MADDOX STN____747	Turbine:			NM		USA	-103.303	32.71694		LATLON
350370002	4911	2211	SOUTHWESTERN PUBL SERV/TUCUMCARI___586M1	ICE-Diesel			NM		USA	-103.737	35.175		LATLON
1011	4911	2211	AES Shady Point, Inc.	7900701 Cogeneration Plant			OK		USA	-94.6466	35.1972	15	LATLON
13427	4911	2211	ANADARKO				OK		USA	-98.2256	35.08417		LATLON
13313	4911	2211	BOOMER LAKE				OK		USA	-96.9872	36.09389		LATLON
400310703	4911	2211	CENTRAL AND SOUTH WEST SERVICES, IN	ICE-NG.			OK		USA	-98.3242	34.54306		LATLON
1211	4911	2211	Central and South West Services, Inc. - Comanche Power Station	3100703 PSO - Comanche Power Sta			OK		USA	-98.3246	34.5435	14	LATLON
1212	4911	2211	Central and South West Services, Inc. - Northeastern Power Statio	13100705 PSO - Northeastern Power			OK		USA	-95.6992	36.426	15	LATLON
1213	4911	2211	Central and South West Services, Inc. - Riverside/Jenks Power Sta	14300036 PSO - Riverside/Jenks Pow			OK		USA	-95.9566	35.9995	15	LATLON
1214	4911	2211	Central and South West Services, Inc. - Southwestern Power Station	1500703 PSO - Southwestern Power S			OK		USA	-98.3523	35.1009	14	LATLON
1215	4911	2211	Central and South West Services, Inc. - Tulsa Power Station	14300009 PSO - Tulsa Power Station			OK		USA	-95.9903	36.1159	15	LATLON
1216	4911	2211	Central and South West Services, Inc. - Weleetka Power Station	10700700 PSO - Weleetka Power Stat			OK		USA	-96.1357	35.3261	14	LATLON
13411	4911	2211	COMANCHE				OK		USA	-98.3242	34.54306		LATLON
1799	4911	2211	Grand River Dam Authority	9700710 Chouteau - Coal Fired Comp			OK		USA	-95.2898	36.1913	15	LATLON
13103	4911	2211	GRDA				OK		USA	-95.2892	36.18889		LATLON
13103-A	4911	2211	GRDA	0074900000-0	4 Miles East on State Hig	Chouteau	OK	74337	USA	-95.3303	36.19272		LATLON
13488	4911	2211	HORSESHOE LAKE				OK		USA	-97.1794	35.50222		LATLON
13492-A	4911	2211	Hugo	0204470000-0	4 Miles West of Ft.	Towson	OK		USA	-95.3167	34.0292		LATLON
13213	4911	2211	MOORELAND				OK		USA	-99.2206	36.7375		LATLON
13224	4911	2211	MUSKOGEE				OK		USA	-95.2953	35.76722		LATLON
13566-A	4911	2211	Muskogee	0140630000-0	5501 Three Forks Road	Muskogee	OK	74434	USA	-95.2961	35.7713		LATLON
13225	4911	2211	MUSTANG				OK		USA	-97.6747	35.48139		LATLON
13241	4911	2211	NORTHEASTERN				OK		USA	-95.6981	36.43194		LATLON
13241-A	4911	2211	Northeastern	0154740000-0	Jct. Highway US 169 / O	Oologah	OK	74053	USA	-95.7118	36.43913		LATLON
T$11045	4911	2211	NORTHEASTERN STATION		JCT. HWY. US 169/OK 88	OOLOGAH	OK	74053	USA	-95.7008	36.43167		LATLON
401090052	4911	2211	OG & E TINKER	Turbine:			OK		USA	-97.9006	35.24		LATLON
400470702	4911	2211	OG&E	Turbine:			OK		USA	-97.8742	36.36917		LATLON
401090010	4911	2211	OG&E-HORSESHOE PLANT	ICE-NG.			OK		USA	-97.1792	35.50833		LATLON
401330702	4911	2211	OG&E-SEMINOLE POWER PLANT	Turbine:			OK		USA	-96.7247	34.96556		LATLON
2209	4911	2211	Oklahoma Gas & Electric	10100704 Muskogee			OK		USA	-95.2869	35.7619	15	LATLON
2211	4911	2211	Oklahoma Gas & Electric	10300700 Sooner			OK		USA	-97.0517	36.4542	14	LATLON
13269	4911	2211	PONCA				OK		USA	-97.1506	36.82		LATLON
401070700	4911	2211	PUBLIC SERVICE CO.				OK		USA	-96.1308	35.32583		LATLON
13297	4911	2211	RIVERSIDE				OK		USA	-95.9517	35.98556		LATLON
13624	4911	2211	SEMINOLE				OK		USA	-96.7256	34.96639		LATLON
13637	4911	2211	SOONER				OK		USA	-97.0497	36.45417		LATLON
13637-A	4911	2211	Sooner	0140630000-0	Intersection of Highway 1	Red Rock	OK	74651	USA	-97.1214	36.46992		LATLON
13331	4911	2211	SOUTHWESTERN				OK		USA	-98.3531	35.10139		LATLON
13356	4911	2211	TULSA				OK		USA	-95.9906	36.11639		LATLON
2700	4911	2211	Western Farmers Electric Coop Hugo	2300702 Hugo			OK		USA	-95.3197	34.0136	15	LATLON
13244-A	4911	2211	Big Brown	0443720000-0	FM 2570 11 Miles NE of F	Fairfield	TX	75840-	USA	-96.1494	31.72349		LATLON
481610004	4911	2211	BIG BROWN STATION	ICE-Diesel			TX		USA	-96.1418	31.712		LATLON
T$11331	4911	2211	BIG BROWN STEAM ELECTRIC STATION & LIGNITE MINE		11 MI E. OF FAIRFIELD ON FM 25	FAIRFIELD	TX	75840	USA	-96.0561	31.82056		LATLON
PA0003W	4911	2211	BRAZOS ELECTRIC POWER COOPERATIVE IN		PALO PINTO	PALO PINTO	TX	76072	USA	-98.3085	32.65814	14	LATLON
HG1169O	4911	2211	CALPINE CORPORATION		9602 BAYPORT RD.	PASADENA	TX	77507	USA	-95.0653	29.62571	15	LATLON
GF0002R	4911	2211	CENTRAL SOUTH WEST SERVICES INC		SCHROEDER ROAD (FM 2987)	FANNIN	TX	77960	USA	-97.2142	28.7129	14	LATLON
480830002	4911	2211	CITY OF COLEMAN	ICE-NG.			TX		USA	-99.4588	31.76063		LATLON
BG0057U	4911	2211	CITY PUBLICSERVICE		9599 GARDNER ROAD	SAN ANTONIO	TX	78201	USA	-98.3203	29.30802	14	LATLON
13705	4911	2211	COLETO CREEK				TX		USA	-97.2142	28.71278		LATLON
13705-A	4911	2211	Coleto Creek	0032780000-0	FM 2987	Fannin	TX	77960	USA	-97.2163	28.73652		LATLON
484250001	4911	2211	COMANCHE PEAK POWER PLANT	ICE-Diesel			TX		USA	-97.4714	32.17528		LATLON
13456	4911	2211	GIBBONS CREEK				TX		USA	-96.1375	30.61667		LATLON
13456-A	4911	2211	Gibbons Creek	0187150000-0	2-1/2 Miles North of Carl		TX		USA	-96.0778	30.6167		LATLON
T$11304	4911	2211	H.W. PIRKEY POWER PLANT		2400 FM RD. 3251	HALLSVILLE	TX	75650	USA	-94.4828	32.4625		LATLON
13157	4911	2211	KNOX LEE				TX		USA	-94.6431	32.37417		LATLON
T$11951	4911	2211	L.C.R.A. FAYETTE POWER PROJECT		6549 POWER PLANT RD.	LA GRANGE	TX	78945	USA	-96.7531	29.91917		LATLON
13178	4911	2211	LIMESTONE				TX		USA	-96.2553	31.42306		LATLON
T$11333	4911	2211	LIMESTONE ELECTRIC GENERATING STATION		FM39 AT FM80	JEWETT	TX	75846	USA	-96.2617	31.41083		LATLON
55505	4911	2211	LOWER COLORADO RIVER AUTHORITY		FOUR MIES NORTHEAST OF BASTROP	BASTROP	TX	78602	USA	-97.2723	30.0616	14	LATLON
FC0018G	4911	2211	LOWER COLORADO RIVER AUTHORITY		7 MI. E. OF LA GRANGE, TX., ON	LA GRANGE	TX	78945	USA	-96.7506	29.91745	14	LATLON
T$11320	4911	2211	MARTIN LAKE STEAM ELECTRIC STATION & LIGNITE		8850 FM 2658 N.	TATUM	TX	75691	USA	-94.5758	32.26111		LATLON
484490004	4911	2211	MONTICELLO STATION	ICE-Diesel			TX		USA	-95.02	33.05444		LATLON
T$11277	4911	2211	MONTICELLO STEAM ELECTRIC STATION & LIGNITE MINE		OFF FM 127 8MI.S.W. OF MT. P	MOUNT PLEASANT	TX	75455	USA	-95.0417	33.09167		LATLON
13232	4911	2211	NEWMAN				TX		USA	-106.431	31.98306		LATLON
T$12027	4911	2211	NEWMAN POWER STATION		4900 STAN ROBERTS SR. BLVD.	EL PASO	TX	79934	USA	-106.395	31.93399		LATLON
481410028	4911	2211	NEWMAN STATION	Turbine:			TX		USA	-106.223	31.45306		LATLON
T$11892	4911	2211	O.W. SOMMERS/J.T. DEELY/J.K. SPRUCE GENERATING COM		9599 GARDNER RD.	SAN ANTONIO	TX	78263	USA	-98.3358	29.32028		LATLON
13580	4911	2211	OKLAUNION				TX		USA	-99.1753	34.14028		LATLON
13580-A	4911	2211	Oklaunion	0204040000-0	12567 FM Road 3430	Vernon	TX	76384-	USA	-99.3004	34.15378		LATLON
T$11436	4911	2211	OKLAUNION POWER STATION		12567 FM RD. 3430	VERNON	TX	76384	USA	-99.1769	34.08333		LATLON
13257	4911	2211	PAINT CREEK				TX		USA	-99.5778	33.08083		LATLON
13265	4911	2211	PIRKEY				TX		USA	-94.4678	32.44556		LATLON
13265-A	4911	2211	Pirkey	0176980000-0	2400 Farm Road 3251	Hallsville	TX	75650	USA	-94.5817	32.53524		LATLON
HT0065Q	4911	2211	POWER RESOURCES LTD		3 MI. E. ON I. 20 FROM BIG SPR	BIG SPRING	TX	79721	USA	-101.422	32.27277	14	LATLON
FG0020V	4911	2211	RELIANT ENERGY INC		NEAR Y.U. JONES ROAD	FRESNO	TX	77545	USA	-95.6341	29.47652	15	LATLON
LI0027L	4911	2211	RELIANT ENERGY INC		9 MI. N. OF JEWETT, TX., ON F.	JEWETT	TX	75846	USA	-96.2534	31.42341	14	LATLON
13616	4911	2211	SAM SEYMOUR				TX		USA	-96.7542	29.925		LATLON
13616-A	4911	2211	Sam Seymour	0112690000-0	6549 Power Plant Rd	La Grange	TX	78945	USA	-96.8755	29.91007		LATLON
13617	4911	2211	SAN ANGELO				TX		USA	-100.492	31.39306		LATLON
484510007	4911	2211	SAN ANGELO POWER STATION	Turbine:			TX		USA	-100.064	31.42167		LATLON
13619	4911	2211	SAN MIGUEL				TX		USA	-98.4719	28.70889		LATLON
13619-A	4911	2211	San Miguel	0166240000-0		Jourdanton	TX	78026-	USA	-98.4722	28.7089		LATLON
AG0007G	4911	2211	SAN MIGUEL ELCTRC COOPERATIVE INC		11 MI. S., S.H. 16; 6 MI. E.,	CHRISTINE	TX	78012	USA	-98.4723	28.70915	14	LATLON
483310002	4911	2211	SANDOW STATION	ICE-Diesel			TX		USA	-96.9655	30.78385		LATLON
T$11457	4911	2211	SANDOW STEAM ELECTRIC STATION		7 MI S.W. OF ROCKDALE OFF FM	ROCKDALE	TX	76567	USA	-97.012	30.65274		LATLON
13325	4911	2211	SIM GIDEON				TX		USA	-97.2708	30.06056		LATLON
VC0026O	4911	2211	SOUTH TEXASELECTRIC COOPERATIVE INC		FM 447, 3 M W OF NURSERY	NURSERY	TX	77976	USA	-97.1359	28.89386	14	LATLON
GJ0043K	4911	2211	SOUTHWESTERN ELECTRIC POWER CO		KNOX LEE POWER PLT.	LONGVIEW	TX	75601	USA	-94.6422	32.37419	15	LATLON
HH0037F	4911	2211	SOUTHWESTERN ELECTRIC POWER CO		RT 2 BOX 165	HALLSVILLE	TX	75650	USA	-94.4679	32.44564	15	LATLON

strStateFacilityIdentifier	strSIC Primary	strNAICS Primary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXY Coordinate Type
ME0006A	4911	2211	SOUTHWESTERN ELECTRIC POWER CO		12 MI W OF AVINGER	AVINGER	TX	75630	USA	-94.5468	32.84868	15	LATLON
TF0012D	4911	2211	SOUTHWESTERN ELECTRIC POWER CO		NORTH TWO MILES ON AN OILED CO	MOUNT PLEASANT	TX	75455	USA	-94.8457	33.05838	15	LATLON
LB0047N	4911	2211	SOUTHWESTERN PUBLIC SERVICE CO		N. OF SUDAN, TEXAS	MULESHOE	TX	79347	USA	-102.575	34.18164	13	LATLON
PG0041R	4911	2211	SOUTHWESTERN PUBLIC SERVICE CO		2.7 MI. N. ON LAKESIDE DR. FRO	AMARILLO	TX	79101	USA	-101.746	35.29962	14	LATLON
T$11964	4911	2211	SOUTHWESTERN PUBLIC SERVICE CO. HARRINGTON STATI		N. LAKESIDE & HWY. 136	AMARILLO	TX	79108	USA	-101.747	35.29944		LATLON
T$11974	4911	2211	SOUTHWESTERN PUBLIC SERVICE CO. - TOLK STATION		8 MI S.W. EARTH	SUDAN	TX	79371	USA	-102.569	34.18472		LATLON
13343	4911	2211	T C FERGUSON				TX		USA	-98.3692	30.55639		LATLON
GB0153Q	4911	2211	TEXAS CITY COGENERATION LP		CRNR OF 5TH AVE S AND GRANT AV	TEXAS CITY	TX	77590	USA	-94.9416	29.37886	15	LATLON
RI0035C	4911	2211	TEXAS NEW MEXICO POWER CO		8 MILES N OF CALVERT ON HWY 6	CALVERT	TX	77837	USA	-96.6956	31.09322	14	LATLON
13351	4911	2211	TOLK STATION				TX		USA	-102.574	34.18139		LATLON
FB0025U	4911	2211	TX UTILITIES ELECTRIC CO		ON HWY. 1752 N. OF SAVOY, TX.	SAVOY	TX	75479	USA	-96.3673	33.63033	14	LATLON
HQ0012T	4911	2211	TXU ELECTRIC CO				TX		USA	-97.688	32.40537	14	LATLON
CP0065C	4911	2211	TXU ELECTRIC CO		APP 3M N OF FRISCO OFF US HWY	FRISCO	TX	75034	USA	-96.8133	33.19956	14	LATLON
DB0249H	4911	2211	TXU ELECTRIC CO		555 BARNES BRIDGE ROAD	DALLAS	TX	75037	USA	-96.5454	32.83763	14	LATLON
HM0017H	4911	2211	TXU ELECTRIC CO		1 MI S FM 764 0.5 MI W	TRINIDAD	TX	75163	USA	-96.1011	32.12639	14	LATLON
DB0251U	4911	2211	TXU ELECTRIC CO		14901 NORTHLAKE RD.	DALLAS	TX	75201	USA	-96.9746	32.95025	14	LATLON
DB0252S	4911	2211	TXU ELECTRIC CO		2233 MOUNTAIN CREEK PARKWAY	DALLAS	TX	75201	USA	-96.936	32.72499	14	LATLON
DB0253Q	4911	2211	TXU ELECTRIC CO		5770 PARKDALE DRIVE	DALLAS	TX	75201	USA	-96.7227	32.77844	14	LATLON
CJ0026J	4911	2211	TXU ELECTRIC CO		LOCATED ON THE W SHORE OF STRY	DALLAS	TX	75201	USA	-94.9895	31.94187	15	LATLON
RE0012M	4911	2211	TXU ELECTRIC CO		APPROX 5.4 M SE ON US HWY 271	BOGATA	TX	75417	USA	-95.1549	33.40181	15	LATLON
TF0013B	4911	2211	TXU ELECTRIC CO		7 MI. S.W. OF MT. PLEASANT OFF	MOUNT PLEASANT	TX	75455	USA	-95.0374	33.09243	15	LATLON
RL0020K	4911	2211	TXU ELECTRIC CO		6 MI SW OF TATUM NEAR FM 2658	TATUM	TX	75691	USA	-94.5702	32.26071	15	LATLON
FI0020W	4911	2211	TXU ELECTRIC CO		9 MI. N.E. OF FAIRFIELD, TX.	FAIRFIELD	TX	75840	USA	-96.0549	31.82158	14	LATLON
TA0352I	4911	2211	TXU ELECTRIC CO		10 MI. N.W. ON FM 1220	FORT WORTH	TX	76002	USA	-97.4794	32.90547	14	LATLON
TA0354E	4911	2211	TXU ELECTRIC CO		AT 4TH AND NORTH HOUSTON STREE	FORT WORTH	TX	76002	USA	-97.3365	32.76111	14	LATLON
TA0353G	4911	2211	TXU ELECTRIC CO		6604 EAST ROSEDALE	FORT WORTH	TX	76002	USA	-97.222	32.72918	14	LATLON
YB0017V	4911	2211	TXU ELECTRIC CO		3 MI. NW OF GRAHAM	GRAHAM	TX	76046	USA	-98.6123	33.13643	14	LATLON
MM0023J	4911	2211	TXU ELECTRIC CO		7 MI SW OF ROCKDALE	ROCKDALE	TX	76567	USA	-97.0581	30.5681	14	LATLON
MB0117A	4911	2211	TXU ELECTRIC CO		APPROX. 4.3 MI. S.W., OFF F.M.	WACO	TX	76701	USA	-96.9853	31.46673	14	LATLON
MO0014L	4911	2211	TXU ELECTRIC CO		5 MI. S.W. OF COLORADO CITY, T	COLORADO CITY	TX	79512	USA	-100.916	32.3346	14	LATLON
WC0028Q	4911	2211	TXU ELECTRIC CO		600 YUCCA DR., MONAHANS, TX.:	MONAHANS	TX	79756	USA	-102.957	31.58346	13	LATLON
13368	4911	2211	W A PARISH				TX		USA	-95.6317	29.48389		LATLON
13368-A	4911	2211	W A Parish	0089010000-0	2500 Y.U. Jones Road	Thompsons	TX	77481-	USA	-95.7641	29.5695		LATLON
481570011	4911	2211	W. A. PARISH STATION	Turbine:			TX		USA	-95.2514	29.47167		LATLON
T$11617	4911	2211	W.A. PARISH ELECTRIC GENERATING STATION		Y.U. JONES RD.	THOMPSON	TX	77481	USA	-95.6342	29.47528		LATLON
13675	4911	2211	WELSH				TX		USA	-94.8456	33.05806		LATLON
WI0025C	4911	2211	WEST TEXAS UTILITIES CO		3.5 MI. S.S.W. OF OKLAUNION, T	OKLAUNION	TX	76373	USA	-99.1802	34.083	14	LATLON
13379	4911	2211	WILKES		TWELVE MI. W. OF AVINGER	AVINGER	TX	75630	USA	-94.5467	32.84833		LATLON
12922	4911	2211	Bonanza	0402300000-0	12500 East 25500 South	Vernal	UT	84078	USA	-109.283	40.08306		LATLON
T$12223	4911	2211	BONANZA POWER PLANT		12500 E. 25500 S.	VERNAL	UT	84078	USA	-109.284	40.08639		LATLON
12997	4911	2211	Carbon	0143540000-0	Highway 6 & 91 3 Miles No	Price	UT	84526	USA	-110.864	39.72639		LATLON
10081	4911	2211	Carbon Power Plant	two fossil fuel fired electric	NA	Helper	UT	84526	USA	-110.852	39.66883		LATLON
490470001	4911	2211	DESERET - BONANZA	ICE-Diesel			UT		USA	-109.317	40.1177	0	LATLON
490350044	4911	2211	ELECTRICAL GENERATION PLANT	ICE-NG.			UT		USA	-111.906	40.6737		LATLON
10355	4911	2211	Gadsby Power Plant	three natural gas fired electr	1407 West North Temple (rear)	Salt Lake City	UT	84116	USA	-111.93	40.77138		LATLON
11539	4911	2211	Hildale City Cogeneration Facility	As of 11/15/95 not yet operating	1325 West Utah Ave.	Hildale	UT	84784	USA	-113.14	37.2278		LATLON
12799	4911	2211	Hunter	0143540000-0	Utah Highway 10 3 Miles S	Castledale	UT	84513	USA	-111.019	39.21085		LATLON
10237	4911	2211	Hunter Power Plant	Hunter thermal electric genera			UT		USA	-111.019	39.21085		LATLON
12800	4911	2211	Huntington	0143540000-0	Highway 31 10 Miles West	Huntington	UT	84528	USA	-111.075	39.37917		LATLON
10238	4911	2211	Huntington Power Plant	Huntington thermal electric ge			UT		USA	-110.963	39.32856		LATLON
10327	4911	2211	Intermountain Generation Station	8 miles north of Delta on Hwy 6, then 8	850 W Brush Wellman Rd	Delta	UT	84624	USA	-112.568	39.49323		LATLON
490579088	4911	2211	LITTLE MOUNTAIN COGENERATION FACILITY	Turbine:			UT		USA	-111.956	41.24985		LATLON
13088	4911	2211	PACIFCORP GADSBY				UT		USA	-111.929	40.76667		LATLON
10120	4911	2211	Power Plant	ICE-NG.	253 S 200 W	Bountiful	UT	84010	USA	-111.885	40.88658		LATLON
490490018	4911	2211	PROVO CITY POWER CO.	ICE-NG.			UT		USA	-111.666	40.2625		LATLON
490530011	4911	2211	ST GEORGE POWER	ICE-Diesel			UT		USA	-113.66	37.12861		LATLON
10892	4911	2211	St. George City Power Plant	diesel powered electrical plant	795 E. Skyline Dr.	St. George	UT	84770	USA	-113.565	37.11274		LATLON
T$12281	4911	2211	SUNNYSIDE COGENERATION ASSOCIATES	50951	ONE POWER PLANT RD.	SUNNYSIDE	UT	84539	USA	-110.392	39.54722		LATLON
490490072	4911	2211	WHITEHEAD POWER PLANT	ICE-NG.			UT		USA	-111.619	40.17611		LATLON
5603100001	4911	2211	BASIN ELECTRIC_LARAMIE RIVER STATION	POWER PLANT	LARAMIE RIVER PLANT	WHEATLAND	WY	82201	USA	-104.877	42.1119	13	LATLON
T$12151	4911	2211	BHPL-OSAGE POWER PLANT		3363 HWY. 16	OSAGE	WY	82723	USA	-104.41	43.97167		LATLON
5604500005	4911	2211	BLACK HILLS OSAGE	POWER PLANT	OSAGE POWER PLANT	OSAGE	WY	82723	USA	-104.408	43.9672	13	LATLON
5600500002	4911	2211	BLACK HILLS POWER & LGHT SIMPSON 1	POWER PLANT	3 MI NE OF GILLETTE	GILLETTE	WY	82718971(	USA	-105.387	44.2867	13	LATLON
58184-A	4911	2211	BLACK HILLS POWER & LGT-SIMPSON 2	0195450000-0	13151 Highway 51 HCR # 81	Gillette	WY	82718-971	USA	-105.499	44.25329		LATLON
13722	4911	2211	DAVE JOHNSTON				WY		USA	-105.767	42.83306		LATLON
13722-A	4911	2211	Dave Johnston	0143540000-0	1951 Tank Farm Road Coal	Glenrock	WY	82637	USA	-105.848	42.87368		LATLON
T$12140	4911	2211	LARAMIE RIVER STATION		347 GRAYROCKS RD.	WHEATLAND	WY	82201134(	USA	-104.881	42.10833		LATLON
58145-A	4911	2211	Laramie River Station	0013070000-0	347 Grayrocks Rd	Wheatland	WY	82201	USA	-104.882	42.10436		LATLON
13228	4911	2211	Naughton	0143540000-0	7 Miles SouthWest of Kemm	Kemmerer	WY	83101	USA	-110.543	41.79367		LATLON
T$12159	4911	2211	PACIFICORP, NAUGHTON POWER PLANT		5 MI. SO., HWY. 189`	KEMMERER	WY	83101	USA	-110.599	41.75722		LATLON
5600900001	4911	2211	PACIFICORP_DAVE JOHNSTON	POWER PLANT	1591 TANK FARM ROAD	GLENROCK	WY	82637	USA	-105.775	42.843	13	LATLON
5603701002	4911	2211	PACIFICORP_JIM BRIDGER	POWER PLANT			WY		USA	-108.795	41.7375	12	LATLON
5602300004	4911	221112	PACIFICORP_NAUGHTON POWER PLANT	POWER PLANT	6.5 MI SW OF KEMMERER, HWY 189	KEMMERER	WY	83101	USA	-110.596	42.8489	12	LATLON
5600500046	4911	2211	PACIFICORP_WYODAK	POWER PLANT	3 MI E OF GILLETTE	GILLETTE	WY	82716	USA	-105.386	44.2903	13	LATLON
58233-A	4911	2211	PACIFICORP-JIM BRIDGER	0143540000-0	35 Miles East of Rock Spr	Point of Rocks	WY	82942	USA	-108.957	41.6029	12	LATLON
58137-A	4911	2211	Wyodak	0143540000-0	48 Wyodak Road (Garner La	Gillette	WY	82716	USA	-105.385	44.28926		LATLON
T$12153	4911	2211	WYODAK PLANT		48 WYODAK RD.	GILLETTE	WY	82718	USA	-105.385	44.28926		LATLON
1639	3211	327211	Visteon	14300035 Tulsa Glass Plant	5555 S. 129th	Tulsa	OK	74134000(	USA	-95.8318	36.0835	15	LATLON
1057	3221	327213	Anchor Glass Container Corporation	11100703 Henryetta (Plant #15)			OK		USA	-95.9694	35.4476	15	LATLON
1144	3221	327213	Bartlett-Collins Glass Company	3700700 Sapulpa	620 S Linden PO Box 1288	Sapulpa	OK	74067000(	USA	-96.1037	35.9929	14	LATLON
1826	3241	327310	Holnam, Inc.	12300701 Ada Plant	1100 West 18th Street	Ada	OK	74820000(	USA	-96.6933	34.773	14	LATLON
401310703	3241	327310	BLUE CIRCLE CEMENT (LaFarge?)	ICE-Diesel 96 NTI was area source		Tulsa	OK		USA	-95.8131	36.19417		LATLON
T$11100	3241	327310	LONE STAR IND. INC. PRYOR CEMENT PLANT		5 MILES E. HWY. 20 & 2 MILES S	PRYOR	OK	74361	USA	-95.2217	36.27194		LATLON
BSCP134	3251	327121	Commercial Brick Corp	Commercial Brick Corp	Old Hwy 270	Wewoka	OK	74884	USA	-96.5458	35.175		LATLON
BSCP76	3251	327121	Scott Jewett Truck Line, Inc	Mangum Brick	2316 N Louis Tittle Ave	Mangum	OK	73554	USA	-99.5	34.9		LATLON
BSCP95	3251	327121	Justin Industries	Acme Brick-Oklahoma City Plant	500 E. Memorial Rd	Oklahoma City	OK	73114	USA	-97.6336	35.6025		LATLON
BSCP96	3251	327121	Justin Industries	Acme Brick-Tulsa Plant	4103 Dawson Rd	Tulsa	OK	74115	USA	-95.93	36.18		LATLON
T$11108	3251	327	BORAL BRICKS INC. - MUSKOGEE PLANT		3101 W. 53RD ST. S.	MUSKOGEE	OK	74401	USA	-95.4	35.69167		LATLON
CC87	3253	327122	Laufen International	Tile Plant	4942 E. 66th Street, N.	Tulsa	OK	74117-180	USA	-95.9218	36.24933		LATLON

strStateFacilityIdentifier	strSIC Primary	strNAICS Primary	strFacilityName	strSiteDescription	strLocationAddress	strCity	srtState	strZipCode	strCountry	dblXCoordinate	dblYCoordinate	intUTMZone	strXY Coordinate Type
T$10977	3275	327420	UNITED DESIGN CORP. NOBLE FAC.		1600 N. MAIN	NOBLE	OK	73068	USA	-97.4056	35.15694		LATLON
1219	3295	2123	Chandler Materials Co.	14300900 2100 N. 145th E Ave (Aggre	5805 E. 15th St.	Tulsa	OK	74112000(	USA	-95.8206	36.1853	15	LATLON
10303	3241	327310	Ash Grove Leamington Cement Plant	Subject to MACT (40 CFR 63 Subpart	Hwy 132	Leamington	UT	84638	USA	-112.815	39.6627		LATLON
490290001	3241	327310	HOLNAM INC.-Devil Slide Plant	ICE-Diesel 96 NTI was area source	6055 E. Croydon Rd	Morgan	UT	84050	USA	-111.514	41.06778		LATLON
BSCP154	3251	327121	Pacific Coast Building Products	Interstate Brick Co	9780 South 5200 West	West Jordan	UT	84088	USA	-112.061	40.59444		LATLON
BSCP71	3251	327121	Interpace Industries Inc	Interpace Industries Inc	736 W. Harrisville Rd	Ogden	UT	84412	USA	-111.994	41.28388		LATLON
490450051	3255	327124	A.P.GREEN REFRACTORIES - SILICA STONE QU	ICE-Diesel 96 NTI was area source			UT		USA	-113.106	40.49005		LATLON
490490007	3255	327124	A.P.GREEN REFRACTORIES - LEHI PLANT	ICE-NG. 96NTI was area source.			UT		USA	-111.524	40.1895		LATLON

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117	AZ-0040	APS WEST PHOENIX	Arizona Public Service	MARICOPA	CHAS SPELL	P.O. BOX 53933, MAIL STATION 4120	PHOENIX	AZ	85072	602-750-1383		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		8604356 S99-023	4911
117	AZ-0040	APS WEST PHOENIX	Arizona Public Service	MARICOPA	CHAS SPELL	P.O. BOX 53933, MAIL STATION 4120	PHOENIX	AZ	85072	602-750-1383		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		8604356 S99-023	4911
117	AZ-0040	APS WEST PHOENIX	Arizona Public Service	MARICOPA	CHAS SPELL	P.O. BOX 53933, MAIL STATION 4120	PHOENIX	AZ	85072	602-750-1383		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		8604356 S99-023	4911
117	AZ-0040	APS WEST PHOENIX	Arizona Public Service	MARICOPA	CHAS SPELL	P.O. BOX 53933, MAIL STATION 4120	PHOENIX	AZ	85072	602-750-1383		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		8604356 S99-023	4911
117	AZ-0040	APS WEST PHOENIX	Arizona Public Service	MARICOPA	CHAS SPELL	P.O. BOX 53933, MAIL STATION 4120	PHOENIX	AZ	85072	602-750-1383		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		8604356 S99-023	4911
117	AZ-0040	APS WEST PHOENIX	Arizona Public Service	MARICOPA	CHAS SPELL	P.O. BOX 53933, MAIL STATION 4120	PHOENIX	AZ	85072	602-750-1383		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		8604356 S99-023	4911
55282	AZ-0035	DUKE ENERGY ARLINGTON VALLEY	DUKE ENERGY ARLINGTON VALLEY	MARICOPA	RUFUS KELLAM	P.O. BOX 26	ARLINGTON	AZ	85322	623-882-2223		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE LIEB	(602) 506-6738		V99-014	4911
55282	AZ-0035	DUKE ENERGY ARLINGTON VALLEY	DUKE ENERGY ARLINGTON VALLEY	MARICOPA	RUFUS KELLAM	P.O. BOX 26	ARLINGTON	AZ	85322	623-882-2223		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE LIEB	(602) 506-6738		V99-014	4911
55282	AZ-0035	DUKE ENERGY ARLINGTON VALLEY	DUKE ENERGY ARLINGTON VALLEY	MARICOPA	RUFUS KELLAM	P.O. BOX 26	ARLINGTON	AZ	85322	623-882-2223		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE LIEB	(602) 506-6738		V99-014	4911
55282	AZ-0035	DUKE ENERGY ARLINGTON VALLEY	DUKE ENERGY ARLINGTON VALLEY	MARICOPA	RUFUS KELLAM	P.O. BOX 26	ARLINGTON	AZ	85322	623-882-2223		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE LIEB	(602) 506-6738		V99-014	4911
55282	AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	DUKE ENERGY ARLINGTON VALLEY	MARICOPA	RUFUS KELLAM	P.O. BOX 27	ARLINGTON	AZ	85322	623-882-2223		9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		S01-004	4911
55282	AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	DUKE ENERGY ARLINGTON VALLEY	MARICOPA	RUFUS KELLAM	P.O. BOX 27	ARLINGTON	AZ	85322	623-882-2223		9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		S01-004	4911
55282	AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	DUKE ENERGY ARLINGTON VALLEY	MARICOPA	RUFUS KELLAM	P.O. BOX 27	ARLINGTON	AZ	85322	623-882-2223		9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		S01-004	4911
55282	AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	DUKE ENERGY ARLINGTON VALLEY	MARICOPA	RUFUS KELLAM	P.O. BOX 27	ARLINGTON	AZ	85322	623-882-2223		9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		S01-004	4911
55282	AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	DUKE ENERGY ARLINGTON VALLEY	MARICOPA	RUFUS KELLAM	P.O. BOX 27	ARLINGTON	AZ	85322	623-882-2223		9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		S01-004	4911
55282	AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	DUKE ENERGY ARLINGTON VALLEY	MARICOPA	RUFUS KELLAM	P.O. BOX 27	ARLINGTON	AZ	85322	623-882-2223		9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		S01-004	4911
55282	AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	DUKE ENERGY ARLINGTON VALLEY	MARICOPA	RUFUS KELLAM	P.O. BOX 27	ARLINGTON	AZ	85322	623-882-2223		9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		S01-004	4911
55282	AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	DUKE ENERGY ARLINGTON VALLEY	MARICOPA	RUFUS KELLAM	P.O. BOX 27	ARLINGTON	AZ	85322	623-882-2223		9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		S01-004	4911
55507	AZ-0038	GILA BEND POWER GENERATING STATION	GILA BEND POWER GENERATING STATION	MARICOPA	JOHN WASHBURN	5949 SHERRY LANE, SUITE 1900	DALLAS	TX	75225	214 210 5000		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A. LIEB	(602) 506-6738		V00-001	4911
55507	AZ-0038	GILA BEND POWER GENERATING STATION	GILA BEND POWER GENERATING STATION	MARICOPA	JOHN WASHBURN	5949 SHERRY LANE, SUITE 1900	DALLAS	TX	75225	214 210 5000		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A. LIEB	(602) 506-6738		V00-001	4911
55507	AZ-0038	GILA BEND POWER GENERATING STATION	GILA BEND POWER GENERATING STATION	MARICOPA	JOHN WASHBURN	5949 SHERRY LANE, SUITE 1900	DALLAS	TX	75225	214 210 5000		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A. LIEB	(602) 506-6738		V00-001	4911
55507	AZ-0038	GILA BEND POWER GENERATING STATION	GILA BEND POWER GENERATING STATION	MARICOPA	JOHN WASHBURN	5949 SHERRY LANE, SUITE 1900	DALLAS	TX	75225	214 210 5000		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A. LIEB	(602) 506-6738		V00-001	4911
55372	AZ-0034	HARQUAHALA GENERATING PROJECT	HARQUAHALA GENERATING CO.	MARICOPA		HARQUAHALA VALLEY ROAD	TONOPAH	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		V99-015	
55372	AZ-0034	HARQUAHALA GENERATING PROJECT	HARQUAHALA GENERATING CO.	MARICOPA		HARQUAHALA VALLEY ROAD	TONOPAH	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		V99-015	
55372	AZ-0034	HARQUAHALA GENERATING PROJECT	HARQUAHALA GENERATING CO.	MARICOPA		HARQUAHALA VALLEY ROAD	TONOPAH	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		V99-015	
55372	AZ-0034	HARQUAHALA GENERATING PROJECT	HARQUAHALA GENERATING CO.	MARICOPA		HARQUAHALA VALLEY ROAD	TONOPAH	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		V99-015	
55372	AZ-0034	HARQUAHALA GENERATING PROJECT	HARQUAHALA GENERATING CO.	MARICOPA		HARQUAHALA VALLEY ROAD	TONOPAH	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		V99-015	
	AZ-0022	INTEL CORPORATION	INTEL CORPORATION			OLD PRICE RD ALIGNMENT	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		93-0046	3674
	AZ-0022	INTEL CORPORATION	INTEL CORPORATION			OLD PRICE RD ALIGNMENT	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		93-0046	3674
	AZ-0022	INTEL CORPORATION	INTEL CORPORATION			OLD PRICE RD ALIGNMENT	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		93-0046	3674
	AZ-0022	INTEL CORPORATION	INTEL CORPORATION			OLD PRICE RD ALIGNMENT	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		93-0046	3674
	AZ-0022	INTEL CORPORATION	INTEL CORPORATION			OLD PRICE RD ALIGNMENT	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE A. LIEB	(602) 506-6738		93-0046	3674
	AZ-0032	INTEL CORPORATION	INTEL CORPORATION			4500 S. DOBSON RD	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE LIEB	(602) 506-6738		96-0743	3674
	AZ-0032	INTEL CORPORATION	INTEL CORPORATION			4500 S. DOBSON RD	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE LIEB	(602) 506-6738		96-0743	3674
	AZ-0032	INTEL CORPORATION	INTEL CORPORATION			4500 S. DOBSON RD	CHANDLER	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE LIEB	(602) 506-6738		96-0743	3674

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147	AZ-0041	KYRENE GENERATING STATION, SALT RIVER PROJECT	KYRENE GENERATING STATION	MARICOPA	CHRIS JANICK	P.O.BOX 5205, MAIL STATION PAB352	PHOENIX	AZ	85072	602-236-5374		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V95-009	4911
147	AZ-0041	KYRENE GENERATING STATION, SALT RIVER PROJECT	KYRENE GENERATING STATION	MARICOPA	CHRIS JANICK	P.O.BOX 5205, MAIL STATION PAB352	PHOENIX	AZ	85072	602-236-5374		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V95-009	4911
147	AZ-0041	KYRENE GENERATING STATION, SALT RIVER PROJECT	KYRENE GENERATING STATION	MARICOPA	CHRIS JANICK	P.O.BOX 5205, MAIL STATION PAB352	PHOENIX	AZ	85072	602-236-5374		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V95-009	4911
55481	AZ-0033	MESQUITE GENERATING STATION	MESQUITE POWER LLC	MARICOPA		37600 WEST ELLIOT ROAD	ARLINGTON	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE LIEB	(602) 506-6738		V99-017	4911
55481	AZ-0033	MESQUITE GENERATING STATION	MESQUITE POWER LLC	MARICOPA		37600 WEST ELLIOT ROAD	ARLINGTON	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE LIEB	(602) 506-6738		V99-017	4911
55481	AZ-0033	MESQUITE GENERATING STATION	MESQUITE POWER LLC	MARICOPA		37600 WEST ELLIOT ROAD	ARLINGTON	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE LIEB	(602) 506-6738		V99-017	4911
55481	AZ-0033	MESQUITE GENERATING STATION	MESQUITE POWER LLC	MARICOPA		37600 WEST ELLIOT ROAD	ARLINGTON	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE LIEB	(602) 506-6738		V99-017	4911
55481	AZ-0033	MESQUITE GENERATING STATION	MESQUITE POWER LLC	MARICOPA		37600 WEST ELLIOT ROAD	ARLINGTON	AZ				9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	DALE LIEB	(602) 506-6738		V99-017	4911
	AZ-0027	MINNESOTA METHANE	MINNESOTA METHANE	MARICOPA		2800 S. 27TH AVE.	PHOENIX	AZ	-85009			9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	LYNN APOSTLE	(602) 506-6760		95-0241	4959
	AZ-0027	MINNESOTA METHANE	MINNESOTA METHANE	MARICOPA		2800 S. 27TH AVE.	PHOENIX	AZ	-85009			9	AZ002	MARICOPA CO AIR POLLUTION CONTROL, AZ	LYNN APOSTLE	(602) 506-6760		95-0241	4959
	AZ-0042	NORTHWEST REGIONAL LANDFILL	NORTHWEST REGIONAL LANDFILL	MARICOPA	DAVE BEARDEN	19401 WEST DEER VALLEY	SURPRISE	AZ	85374	602-708-9815		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V97016	4953
	AZ-0042	NORTHWEST REGIONAL LANDFILL	NORTHWEST REGIONAL LANDFILL	MARICOPA	DAVE BEARDEN	19401 WEST DEER VALLEY	SURPRISE	AZ	85374	602-708-9815		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V97016	4953
	AZ-0042	NORTHWEST REGIONAL LANDFILL	NORTHWEST REGIONAL LANDFILL	MARICOPA	DAVE BEARDEN	19401 WEST DEER VALLEY	SURPRISE	AZ	85374	602-708-9815		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V97016	4953
	AZ-0042	NORTHWEST REGIONAL LANDFILL	NORTHWEST REGIONAL LANDFILL	MARICOPA	DAVE BEARDEN	19401 WEST DEER VALLEY	SURPRISE	AZ	85374	602-708-9815		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V97016	4953
55306	AZ-0037	PANDA GILA RIVER	TPS Arizona Operations, PANDA GILA RIVER	MARICOPA	DAN BAERMAN	P.O. BOX 798	GILA BEND	AZ	85337	928-683-0111		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V99-018	4911
55306	AZ-0037	PANDA GILA RIVER	TPS Arizona Operations, PANDA GILA RIVER	MARICOPA	DAN BAERMAN	P.O. BOX 798	GILA BEND	AZ	85337	928-683-0111		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V99-018	4911
55306	AZ-0037	PANDA GILA RIVER	TPS Arizona Operations, PANDA GILA RIVER	MARICOPA	DAN BAERMAN	P.O. BOX 798	GILA BEND	AZ	85337	928-683-0111		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V99-018	4911
55306	AZ-0037	PANDA GILA RIVER	TPS Arizona Operations, PANDA GILA RIVER	MARICOPA	DAN BAERMAN	P.O. BOX 798	GILA BEND	AZ	85337	928-683-0111		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V99-018	4911
55455	AZ-0036	PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	PINNACLE WEST ENERGY CORP.	MARICOPA	CHRIS CHITTESLER	400 N. 5TH ST.	PHOENIX	AZ	85004	602-407-7807		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V99-013	4911
55455	AZ-0036	PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	PINNACLE WEST ENERGY CORP.	MARICOPA	CHRIS CHITTESLER	400 N. 5TH ST.	PHOENIX	AZ	85004	602-407-7807		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V99-013	4911
55455	AZ-0036	PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	PINNACLE WEST ENERGY CORP.	MARICOPA	CHRIS CHITTESLER	400 N. 5TH ST.	PHOENIX	AZ	85004	602-407-7807		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V99-013	4911
55455	AZ-0036	PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	PINNACLE WEST ENERGY CORP.	MARICOPA	CHRIS CHITTESLER	400 N. 5TH ST.	PHOENIX	AZ	85004	602-407-7807		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V99-013	4911

ORIS_CODE	RBLCID	FACILITY	COMPANY	COUNTY	CONTACT	ADDRESS	CITY	STATE	ZIP	PHONE	EMAIL	REGION	AGENCY CODE	AGENCYNAME	AGENCY CONTACT	AGENCY PHONE	AGENCY EMAIL	PERMITNUM	SIC
55455	AZ-0036	PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	PINNACLE WEST ENERGY CORP.	MARICOPA	CHRIS CHITTESLER	400 N. 5TH ST.	PHOENIX	AZ	85004	602-407-7807		9	AZ001	ARIZONA DEPT OF ENV QUAL, OFC OF AIR QUA	DALE A LIEB	(602) 506-6738		V99-013	4911
55522	AZ-0045	PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	PPL SUNDANCE ENERGY, LLC	PINAL	PAT THEMIG	P.O. BOX 38	COLSTRIP	MT	59323	303-237-6943	PJTHEMIG@PPLMT.COM	9	AZ004	PINAL CO AIR QUALITY CONTROL DIST, AZ	DONALD GABRIELSON	520-866-6929		V20613.000	4911
55522	AZ-0045	PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	PPL SUNDANCE ENERGY, LLC	PINAL	PAT THEMIG	P.O. BOX 38	COLSTRIP	MT	59323	303-237-6943	PJTHEMIG@PPLMT.COM	9	AZ004	PINAL CO AIR QUALITY CONTROL DIST, AZ	DONALD GABRIELSON	520-866-6929		V20613.000	4911
55522	AZ-0045	PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	PPL SUNDANCE ENERGY, LLC	PINAL	PAT THEMIG	P.O. BOX 38	COLSTRIP	MT	59323	303-237-6943	PJTHEMIG@PPLMT.COM	9	AZ004	PINAL CO AIR QUALITY CONTROL DIST, AZ	DONALD GABRIELSON	520-866-6929		V20613.000	4911
55522	AZ-0045	PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	PPL SUNDANCE ENERGY, LLC	PINAL	PAT THEMIG	P.O. BOX 38	COLSTRIP	MT	59323	303-237-6943	PJTHEMIG@PPLMT.COM	9	AZ004	PINAL CO AIR QUALITY CONTROL DIST, AZ	DONALD GABRIELSON	520-866-6929		V20613.000	4911
55129	AZ-0044	SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	SALT RIVER PROJECT	PINAL	CHRIS JANICK	P.O. BOX 52025, PAB 352	PHOENIX	AZ	85072	602-236-3407		9	AZ004	PINAL CO AIR QUALITY CONTROL DIST, AZ	DALE A LIEB	(602) 506-6738		V20610.000	4911
55129	AZ-0044	SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	SALT RIVER PROJECT	PINAL	CHRIS JANICK	P.O. BOX 52025, PAB 352	PHOENIX	AZ	85072	602-236-3407		9	AZ004	PINAL CO AIR QUALITY CONTROL DIST, AZ	DALE A LIEB	(602) 506-6738		V20610.000	4911
55129	AZ-0044	SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	SALT RIVER PROJECT	PINAL	CHRIS JANICK	P.O. BOX 52025, PAB 352	PHOENIX	AZ	85072	602-236-3407		9	AZ004	PINAL CO AIR QUALITY CONTROL DIST, AZ	DALE A LIEB	(602) 506-6738		V20610.000	4911
55129	AZ-0044	SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	SALT RIVER PROJECT	PINAL	CHRIS JANICK	P.O. BOX 52025, PAB 352	PHOENIX	AZ	85072	602-236-3407		9	AZ004	PINAL CO AIR QUALITY CONTROL DIST, AZ	DALE A LIEB	(602) 506-6738		V20610.000	4911
55129	AZ-0044	SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	SALT RIVER PROJECT	PINAL	CHRIS JANICK	P.O. BOX 52025, PAB 352	PHOENIX	AZ	85072	602-236-3407		9	AZ004	PINAL CO AIR QUALITY CONTROL DIST, AZ	DALE A LIEB	(602) 506-6738		V20610.000	4911

FACILITY	NAICS	AIRSID	EPAID	UTMZONE	XCOORD	YCOORD	RCVD DATE	PERMIT DATE	STARTUP DATE	VERIFY DATE	ENTRY DATE	LAST UPDATE	NEW_ MOD	PUBLIC HEAR	FUEL	EMISSSOURCES	ABATEMENT
APS WEST PHOENIX	221112	3313					9/15/1999	5/26/2000	3/15/2003		11/10/2003	11/21/2003	M	Y	NATURAL GAS	COMBINED CYCLE UNITS	OXIDATION CATALYST
APS WEST PHOENIX	221112	3313					9/15/1999	5/26/2000	3/15/2003		11/10/2003	11/21/2003	M	Y	NATURAL GAS	COMBINED CYCLE UNITS	OXIDATION CATALYST
APS WEST PHOENIX	221112	3313					9/15/1999	5/26/2000	3/15/2003		11/10/2003	11/21/2003	M	Y	NATURAL GAS	COMBINED CYCLE UNITS	OXIDATION CATALYST
APS WEST PHOENIX	221112	3313					9/15/1999	5/26/2000	3/15/2003		11/10/2003	11/21/2003	M	Y	NATURAL GAS	COMBINED CYCLE UNITS	OXIDATION CATALYST
APS WEST PHOENIX	221112	3313					9/15/1999	5/26/2000	3/15/2003		11/10/2003	11/21/2003	M	Y	NATURAL GAS	COMBINED CYCLE UNITS	OXIDATION CATALYST
APS WEST PHOENIX	221112	3313					9/15/1999	5/26/2000	3/15/2003		11/10/2003	11/21/2003	M	Y	NATURAL GAS	COMBINED CYCLE UNITS	OXIDATION CATALYST
DUKE ENERGY ARLINGTON VALLEY	21112						7/27/1999	12/14/2000	3/19/2002		11/10/2003	11/21/2003	N	Y	NATURAL GAS	COMBINED CYCLE UNITS	SCR
DUKE ENERGY ARLINGTON VALLEY	21112						7/27/1999	12/14/2000	3/19/2002		11/10/2003	11/21/2003	N	Y	NATURAL GAS	COMBINED CYCLE UNITS	SCR
DUKE ENERGY ARLINGTON VALLEY	21112						7/27/1999	12/14/2000	3/19/2002		11/10/2003	11/21/2003	N	Y	NATURAL GAS	COMBINED CYCLE UNITS	SCR
DUKE ENERGY ARLINGTON VALLEY	21112						7/27/1999	12/14/2000	3/19/2002		11/10/2003	11/21/2003	N	Y	NATURAL GAS	COMBINED CYCLE UNITS	SCR
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	221112	43063		12	323852	3690212	9/1/2001	11/12/2003			1/8/2004	1/29/2004	M	N	NATURAL GAS	COMBINED CYCLE UNITS	SCR & OXIDATION CATALYST
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	221112	43063		12	323852	3690212	9/1/2001	11/12/2003			1/8/2004	1/29/2004	M	N	NATURAL GAS	COMBINED CYCLE UNITS	SCR & OXIDATION CATALYST
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	221112	43063		12	323852	3690212	9/1/2001	11/12/2003			1/8/2004	1/29/2004	M	N	NATURAL GAS	COMBINED CYCLE UNITS	SCR & OXIDATION CATALYST
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	221112	43063		12	323852	3690212	9/1/2001	11/12/2003			1/8/2004	1/29/2004	M	N	NATURAL GAS	COMBINED CYCLE UNITS	SCR & OXIDATION CATALYST
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	221112	43063		12	323852	3690212	9/1/2001	11/12/2003			1/8/2004	1/29/2004	M	N	NATURAL GAS	COMBINED CYCLE UNITS	SCR & OXIDATION CATALYST
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	221112	43063		12	323852	3690212	9/1/2001	11/12/2003			1/8/2004	1/29/2004	M	N	NATURAL GAS	COMBINED CYCLE UNITS	SCR & OXIDATION CATALYST
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	221112	43063		12	323852	3690212	9/1/2001	11/12/2003			1/8/2004	1/29/2004	M	N	NATURAL GAS	COMBINED CYCLE UNITS	SCR & OXIDATION CATALYST
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	221112	43063		12	323852	3690212	9/1/2001	11/12/2003			1/8/2004	1/29/2004	M	N	NATURAL GAS	COMBINED CYCLE UNITS	SCR & OXIDATION CATALYST
GILA BEND POWER GENERATING STATION	221112						2/29/2000	5/15/2002			11/10/2003	11/21/2003	N		NATURAL GAS	COMBINED CYCLE COMBUSTION TURBINE (3)/ STEAM TURBINE (1)	SELECTIVE CATALYTIC REDUCTION (SCR), OXIDATION CATALYST
GILA BEND POWER GENERATING STATION	221112						2/29/2000	5/15/2002			11/10/2003	11/21/2003	N		NATURAL GAS	COMBINED CYCLE COMBUSTION TURBINE (3)/ STEAM TURBINE (1)	SELECTIVE CATALYTIC REDUCTION (SCR), OXIDATION CATALYST
GILA BEND POWER GENERATING STATION	221112						2/29/2000	5/15/2002			11/10/2003	11/21/2003	N		NATURAL GAS	COMBINED CYCLE COMBUSTION TURBINE (3)/ STEAM TURBINE (1)	SELECTIVE CATALYTIC REDUCTION (SCR), OXIDATION CATALYST
GILA BEND POWER GENERATING STATION	221112						2/29/2000	5/15/2002			11/10/2003	11/21/2003	N		NATURAL GAS	COMBINED CYCLE COMBUSTION TURBINE (3)/ STEAM TURBINE (1)	SELECTIVE CATALYTIC REDUCTION (SCR), OXIDATION CATALYST
HARQUAHALA GENERATING PROJECT				12	303.6	3705.8	9/8/1999	2/15/2001	11/30/2002		4/19/2001	4/23/2002	N				
HARQUAHALA GENERATING PROJECT				12	303.6	3705.8	9/8/1999	2/15/2001	11/30/2002		4/19/2001	4/23/2002	N				
HARQUAHALA GENERATING PROJECT				12	303.6	3705.8	9/8/1999	2/15/2001	11/30/2002		4/19/2001	4/23/2002	N				
HARQUAHALA GENERATING PROJECT				12	303.6	3705.8	9/8/1999	2/15/2001	11/30/2002		4/19/2001	4/23/2002	N				
HARQUAHALA GENERATING PROJECT				12	303.6	3705.8	9/8/1999	2/15/2001	11/30/2002		4/19/2001	4/23/2002	N				
INTEL CORPORATION	334413							4/10/1994	4/1/1995		5/16/1994	12/18/2001					
INTEL CORPORATION	334413							4/10/1994	4/1/1995		5/16/1994	12/18/2001					
INTEL CORPORATION	334413							4/10/1994	4/1/1995		5/16/1994	12/18/2001					
INTEL CORPORATION	334413							4/10/1994	4/1/1995		5/16/1994	12/18/2001					
INTEL CORPORATION	334413							4/10/1994	4/1/1995		5/16/1994	12/18/2001					
INTEL CORPORATION	334413							9/1/1996			10/21/1996	12/18/2001					
INTEL CORPORATION	334413							9/1/1996			10/21/1996	12/18/2001					
INTEL CORPORATION	334413							9/1/1996			10/21/1996	12/18/2001					

FACILITY	NAICS	AIRSID	EPAID	UTMZONE	XCOORD	YCOORD	RCVD DATE	PERMIT DATE	STARTUP DATE	VERIFY DATE	ENTRY DATE	LAST UPDATE	NEW_ MOD	PUBLIC HEAR	FUEL	EMISSSOURCES	ABATEMENT
KYRENE GENERATING STATION, SALT RIVER PROJECT	221112	3317					8/15/2000	3/14/2001	4/16/2002		11/10/2003	11/26/2003	N	Y	NATURAL GAS	COMBINED CYCLE SYSTEM	SCR, OXIDATION CATALYST
KYRENE GENERATING STATION, SALT RIVER PROJECT	221112	3317					8/15/2000	3/14/2001	4/16/2002		11/10/2003	11/26/2003	N	Y	NATURAL GAS	COMBINED CYCLE SYSTEM	SCR, OXIDATION CATALYST
KYRENE GENERATING STATION, SALT RIVER PROJECT	221112	3317					8/15/2000	3/14/2001	4/16/2002		11/10/2003	11/26/2003	N	Y	NATURAL GAS	COMBINED CYCLE SYSTEM	SCR, OXIDATION CATALYST
MESQUITE GENERATING STATION	221111, 221112, 221113, 221119, 221121, 221122			12	326.6	369	11/24/1999	3/22/2001	6/1/2003		4/16/2001	8/20/2002	N				
MESQUITE GENERATING STATION	221111, 221112, 221113, 221119, 221121, 221122			12	326.6	369	11/24/1999	3/22/2001	6/1/2003		4/16/2001	8/20/2002	N				
MESQUITE GENERATING STATION	221111, 221112, 221113, 221119, 221121, 221122			12	326.6	369	11/24/1999	3/22/2001	6/1/2003		4/16/2001	8/20/2002	N				
MESQUITE GENERATING STATION	221111, 221112, 221113, 221119, 221121, 221122			12	326.6	369	11/24/1999	3/22/2001	6/1/2003		4/16/2001	8/20/2002	N				
MESQUITE GENERATING STATION	221111, 221112, 221113, 221119, 221121, 221122			12	326.6	369	11/24/1999	3/22/2001	6/1/2003		4/16/2001	8/20/2002	N				
MINNESOTA METHANE	488119, 56291, 56171, 562998							11/12/1995	12/15/1995		10/31/1995	12/18/2001					
MINNESOTA METHANE	488119, 56291, 56171, 562998							11/12/1995	12/15/1995		10/31/1995	12/18/2001					
NORTHWEST REGIONAL LANDFILL	562212	1879					6/15/1997	10/27/2003	6/15/1988		11/18/2003	12/4/2003	M	N	LANDFILL GAS	ENCLOSED FLARE, INTERNAL COMBUSTION ENGINE	
NORTHWEST REGIONAL LANDFILL	562212	1879					6/15/1997	10/27/2003	6/15/1988		11/18/2003	12/4/2003	M	N	LANDFILL GAS	ENCLOSED FLARE, INTERNAL COMBUSTION ENGINE	
NORTHWEST REGIONAL LANDFILL	562212	1879					6/15/1997	10/27/2003	6/15/1988		11/18/2003	12/4/2003	M	N	LANDFILL GAS	ENCLOSED FLARE, INTERNAL COMBUSTION ENGINE	
NORTHWEST REGIONAL LANDFILL	562212	1879					6/15/1997	10/27/2003	6/15/1988		11/18/2003	12/4/2003	M	N	LANDFILL GAS	ENCLOSED FLARE, INTERNAL COMBUSTION ENGINE	
PANDA GILA RIVER	221112	444439					12/29/1999	2/23/2001	3/7/2003		11/10/2003	11/21/2003	N		NATURAL GAS	COMBINED CYCLE UNITS	SCR AND CATALYTIC OXIDATION
PANDA GILA RIVER	221112	444439					12/29/1999	2/23/2001	3/7/2003		11/10/2003	11/21/2003	N		NATURAL GAS	COMBINED CYCLE UNITS	SCR AND CATALYTIC OXIDATION
PANDA GILA RIVER	221112	444439					12/29/1999	2/23/2001	3/7/2003		11/10/2003	11/21/2003	N		NATURAL GAS	COMBINED CYCLE UNITS	SCR AND CATALYTIC OXIDATION
PANDA GILA RIVER	221112	444439					12/29/1999	2/23/2001	3/7/2003		11/10/2003	11/21/2003	N		NATURAL GAS	COMBINED CYCLE UNITS	SCR AND CATALYTIC OXIDATION
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	221112	42956					7/14/1999	12/2/2000	4/9/2002		11/10/2003	11/21/2003	N	Y	NATURAL GAS	COMBINED CYCLE UNITS	SCR
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	221112	42956					7/14/1999	12/2/2000	4/9/2002		11/10/2003	11/21/2003	N	Y	NATURAL GAS	COMBINED CYCLE UNITS	SCR
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	221112	42956					7/14/1999	12/2/2000	4/9/2002		11/10/2003	11/21/2003	N	Y	NATURAL GAS	COMBINED CYCLE UNITS	SCR
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	221112	42956					7/14/1999	12/2/2000	4/9/2002		11/10/2003	11/21/2003	N	Y	NATURAL GAS	COMBINED CYCLE UNITS	SCR

FACILITY	NAICS	AIRSID	EPAID	UTMZONE	XCOORD	YCOORD	RCVD DATE	PERMIT DATE	STARTUP DATE	VERIFY DATE	ENTRY DATE	LAST UPDATE	NEW_ MOD	PUBLIC HEAR	FUEL	EMISSSOURCES	ABATEMENT
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	221112	42956					7/14/1999	12/2/2000	4/9/2002		11/10/2003	11/21/2003	N	Y	NATURAL GAS	COMBINED CYCLE UNITS	SCR
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	221112	4.02E+08					10/4/2000	7/25/2001	7/17/2002	10/9/2002	4/5/2004	4/15/2004	N	Y	NATURAL GAS	SIMPLE CYCLE COMBUSTION TURBINES	SELECTIVE CATALYTIC REDUCTION (SCR) WITH AMMONIA INJECTION, CATALYTIC OXIDIZER.
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	221112	4.02E+08					10/4/2000	7/25/2001	7/17/2002	10/9/2002	4/5/2004	4/15/2004	N	Y	NATURAL GAS	SIMPLE CYCLE COMBUSTION TURBINES	SELECTIVE CATALYTIC REDUCTION (SCR) WITH AMMONIA INJECTION, CATALYTIC OXIDIZER.
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	221112	4.02E+08					10/4/2000	7/25/2001	7/17/2002	10/9/2002	4/5/2004	4/15/2004	N	Y	NATURAL GAS	SIMPLE CYCLE COMBUSTION TURBINES	SELECTIVE CATALYTIC REDUCTION (SCR) WITH AMMONIA INJECTION, CATALYTIC OXIDIZER.
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	221112	4.02E+08					10/4/2000	7/25/2001	7/17/2002	10/9/2002	4/5/2004	4/15/2004	N	Y	NATURAL GAS	SIMPLE CYCLE COMBUSTION TURBINES	SELECTIVE CATALYTIC REDUCTION (SCR) WITH AMMONIA INJECTION, CATALYTIC OXIDIZER.
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	221112	4.02E+08					2/18/1999	9/10/1999	4/7/2001		4/5/2004	4/19/2004	N	Y	NATURAL GAS	COMBUSTION TURBINES WITH DUCT BURNERS	SELECTIVE CATALYTIC REDUCTION
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	221112	4.02E+08					2/18/1999	9/10/1999	4/7/2001		4/5/2004	4/19/2004	N	Y	NATURAL GAS	COMBUSTION TURBINES WITH DUCT BURNERS	SELECTIVE CATALYTIC REDUCTION
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	221112	4.02E+08					2/18/1999	9/10/1999	4/7/2001		4/5/2004	4/19/2004	N	Y	NATURAL GAS	COMBUSTION TURBINES WITH DUCT BURNERS	SELECTIVE CATALYTIC REDUCTION
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	221112	4.02E+08					2/18/1999	9/10/1999	4/7/2001		4/5/2004	4/19/2004	N	Y	NATURAL GAS	COMBUSTION TURBINES WITH DUCT BURNERS	SELECTIVE CATALYTIC REDUCTION
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	221112	4.02E+08					2/18/1999	9/10/1999	4/7/2001		4/5/2004	4/19/2004	N	Y	NATURAL GAS	COMBUSTION TURBINES WITH DUCT BURNERS	SELECTIVE CATALYTIC REDUCTION

FACILITY	NARRATIVE	NOTES	PROCESS	PROC TYPE	SCC	FUEL	THRUPUT	THRUPUT UNIT	COMP VERIFY	STACK TEST	INSPECTION	CALCULATED
APS WEST PHOENIX	POWER PLANT	Major modification. BACT/LAER required for PM, VOC and CO. NOx netted out.	TURBINE, COMBINED CYCLE, DUCT BURNER, NAT GAS, CC4	15.21	20100201	NATURAL GAS	130	MW	Y	Y	N	N
APS WEST PHOENIX	POWER PLANT	Major modification. BACT/LAER required for PM, VOC and CO. NOx netted out.	TURBINE, COMBINED CYCLE, DUCT BURNER, NAT GAS, CC4	15.21	20100201	NATURAL GAS	130	MW	Y	Y	N	N
APS WEST PHOENIX	POWER PLANT	Major modification. BACT/LAER required for PM, VOC and CO. NOx netted out.	TURBINE, COMBINED CYCLE, DUCT BURNER, NAT GAS, CC4	15.21	20100201	NATURAL GAS	130	MW	Y	Y	N	N
APS WEST PHOENIX	POWER PLANT	Major modification. BACT/LAER required for PM, VOC and CO. NOx netted out.	TURBINE, COMBINED CYCLE, DUCT BURNER, NAT GAS, CC5	15.21	20100201	NATURAL GAS	530	MW	Y	Y	N	N
APS WEST PHOENIX	POWER PLANT	Major modification. BACT/LAER required for PM, VOC and CO. NOx netted out.	TURBINE, COMBINED CYCLE, DUCT BURNER, NAT GAS, CC5	15.21	20100201	NATURAL GAS	530	MW	Y	Y	N	N
APS WEST PHOENIX	POWER PLANT	Major modification. BACT/LAER required for PM, VOC and CO. NOx netted out.	TURBINE, COMBINED CYCLE, DUCT BURNER, NAT GAS, CC5	15.21	20100201	NATURAL GAS	530	MW	Y	Y	N	N
DUKE ENERGY ARLINGTON VALLEY	POWER PLANT		TURBINE, COMBINED CYCLE	15.21	20100201	NATURAL GAS	255	MW	Y	Y	N	Y
DUKE ENERGY ARLINGTON VALLEY	POWER PLANT		TURBINE, COMBINED CYCLE	15.21	20100201	NATURAL GAS	255	MW	Y	Y	N	Y
DUKE ENERGY ARLINGTON VALLEY	POWER PLANT		TURBINE, COMBINED CYCLE	15.21	20100201	NATURAL GAS	255	MW	Y	Y	N	Y
DUKE ENERGY ARLINGTON VALLEY	POWER PLANT		TURBINE, COMBINED CYCLE	15.21	20100201	NATURAL GAS	255	MW	Y	Y	N	Y
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	POWER PLANT		TURBINE, COMBINED CYCLE & DUCT BURNER	15.21	20100201	NATURAL GAS	325	MW	N	N	N	N
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	POWER PLANT		TURBINE, COMBINED CYCLE & DUCT BURNER	15.21	20100201	NATURAL GAS	325	MW	N	N	N	N
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	POWER PLANT		TURBINE, COMBINED CYCLE & DUCT BURNER	15.21	20100201	NATURAL GAS	325	MW	N	N	N	N
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	POWER PLANT		TURBINE, COMBINED CYCLE & DUCT BURNER	15.21	20100201	NATURAL GAS	325	MW	N	N	N	N
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	POWER PLANT		TURBINE, COMBINED CYCLE	15.21	20100201	NATURAL GAS	325	MW	N	N	N	N
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	POWER PLANT		TURBINE, COMBINED CYCLE	15.21	20100201	NATURAL GAS	325	MW	N	N	N	N
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	POWER PLANT		TURBINE, COMBINED CYCLE	15.21	20100201	NATURAL GAS	325	MW	N	N	N	N
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	POWER PLANT		TURBINE, COMBINED CYCLE	15.21	20100201	NATURAL GAS	325	MW	N	N	N	N
GILA BEND POWER GENERATING STATION	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER, NATURAL GAS	15.21	20100201	NATURAL GAS	170	MW	Y	N	N	Y
GILA BEND POWER GENERATING STATION	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER, NATURAL GAS	15.21	20100201	NATURAL GAS	170	MW	Y	N	N	Y
GILA BEND POWER GENERATING STATION	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER, NATURAL GAS	15.21	20100201	NATURAL GAS	170	MW	Y	N	N	Y
GILA BEND POWER GENERATING STATION	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER, NATURAL GAS	15.21	20100201	NATURAL GAS	170	MW	Y	N	N	Y
HARQUAHALA GENERATING PROJECT		THERE ARE 3 NATURAL GAS FIRED TURBINES, SIEMENS-WESTINGHOUSE SW501G (240 MW EACH) AND THREE STEAM TURBINES (121 MW EACH). THERE IS NO SUPPLEMENTARY DUCT FIRING. SCR AND OXIDATION CATALYSTS FOR EMISSION CONTROLS	COMBINED CYCLE, NATURAL GAS	15.21	2-01-002-01	NATURAL GAS	2362	MMBTU/H	N	N	N	N
HARQUAHALA GENERATING PROJECT		THERE ARE 3 NATURAL GAS FIRED TURBINES, SIEMENS-WESTINGHOUSE SW501G (240 MW EACH) AND THREE STEAM TURBINES (121 MW EACH). THERE IS NO SUPPLEMENTARY DUCT FIRING. SCR AND OXIDATION CATALYSTS FOR EMISSION CONTROLS	COMBINED CYCLE, NATURAL GAS	15.21	2-01-002-01	NATURAL GAS	2362	MMBTU/H	N	N	N	N
HARQUAHALA GENERATING PROJECT		THERE ARE 3 NATURAL GAS FIRED TURBINES, SIEMENS-WESTINGHOUSE SW501G (240 MW EACH) AND THREE STEAM TURBINES (121 MW EACH). THERE IS NO SUPPLEMENTARY DUCT FIRING. SCR AND OXIDATION CATALYSTS FOR EMISSION CONTROLS	COMBINED CYCLE, NATURAL GAS	15.21	2-01-002-01	NATURAL GAS	2362	MMBTU/H	N	N	N	N
HARQUAHALA GENERATING PROJECT		THERE ARE 3 NATURAL GAS FIRED TURBINES, SIEMENS-WESTINGHOUSE SW501G (240 MW EACH) AND THREE STEAM TURBINES (121 MW EACH). THERE IS NO SUPPLEMENTARY DUCT FIRING. SCR AND OXIDATION CATALYSTS FOR EMISSION CONTROLS	COMBINED CYCLE, NATURAL GAS	15.21	2-01-002-01	NATURAL GAS	2362	MMBTU/H	N	N	N	N
HARQUAHALA GENERATING PROJECT		THERE ARE 3 NATURAL GAS FIRED TURBINES, SIEMENS-WESTINGHOUSE SW501G (240 MW EACH) AND THREE STEAM TURBINES (121 MW EACH). THERE IS NO SUPPLEMENTARY DUCT FIRING. SCR AND OXIDATION CATALYSTS FOR EMISSION CONTROLS	COMBINED CYCLE, NATURAL GAS	15.21	2-01-002-01	NATURAL GAS	2362	MMBTU/H	N	N	N	N
INTEL CORPORATION			BOILERS, 5	13.31	10200602	NATURAL GAS	50	MMBTU/HR	F	F	F	F
INTEL CORPORATION			BOILERS, 5	13.31	10200602	NATURAL GAS	50	MMBTU/HR	F	F	F	F
INTEL CORPORATION			PHOTORESIST OPERATIONS	99.011	40100399		0		F	F	F	F
INTEL CORPORATION			GENERATORS, BACKUP, 5	17.13	20200202	NATURAL GAS	2220	BHP	F	F	F	F
INTEL CORPORATION			GENERATORS, BACKUP, 5	17.13	20200202	NATURAL GAS	2220	BHP	F	F	F	F
INTEL CORPORATION		PROJECT XL PERMIT	SEMICONDUCTOR MANUFACTURING	99.011	3-13-999-99		0		F	F	F	F
INTEL CORPORATION		PROJECT XL PERMIT	BOILERS, GENERATORS	16.11	1-02-005-02		0		F	F	F	F
INTEL CORPORATION		PROJECT XL PERMIT	BOILERS (10)	13.31	1-02-005-02		54	MMBTU	F	F	F	F

FACILITY	NARRATIVE	NOTES	PROCESS	PROC TYPE	SCC	FUEL	THRUPUT	THRUPUT UNIT	COMP VERIFY	STACK TEST	INSPECTION	CALCULATED
KYRENE GENERATING STATION, SALT RIVER PROJECT	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER, NAT GAS	15.21	20100201	NATURAL GAS	175	MW	Y	Y	N	N
KYRENE GENERATING STATION, SALT RIVER PROJECT	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER, NAT GAS	15.21	20100201	NATURAL GAS	175	MW	Y	Y	N	N
KYRENE GENERATING STATION, SALT RIVER PROJECT	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER, NAT GAS	15.21	20100201	NATURAL GAS	175	MW	Y	Y	N	N
MESQUITE GENERATING STATION		FACILITY WILL HAVE FOUR GE 7FA TURBINES - 180 MW EA. (WITH POWER AUGMENTATION). EACH TURBINE HAS A HEAT RECOVERY STEAM GENERATOR (HRSG) WITH DUCT BURNER. EACH DUCT BURNER HAS A MAX. HEAT INPUT OF 592.6 MMBTU/H (HHV). STEAM FROM THE FOUR HRSGS IS ROUTED TO TWO STEAM TURBINES (290 MW EACH.) TOTAL NOMINAL OUTPUT FOR THE FACILITY IS 1300 MW.	TURBINE, COMBINED CYCLE, NATURAL GAS	15.21	20100201	NATURAL GAS	1923	MMBTU/H	N	N	N	N
MESQUITE GENERATING STATION		FACILITY WILL HAVE FOUR GE 7FA TURBINES - 180 MW EA. (WITH POWER AUGMENTATION). EACH TURBINE HAS A HEAT RECOVERY STEAM GENERATOR (HRSG) WITH DUCT BURNER. EACH DUCT BURNER HAS A MAX. HEAT INPUT OF 592.6 MMBTU/H (HHV). STEAM FROM THE FOUR HRSGS IS ROUTED TO TWO STEAM TURBINES (290 MW EACH.) TOTAL NOMINAL OUTPUT FOR THE FACILITY IS 1300 MW.	TURBINE, COMBINED CYCLE, NATURAL GAS	15.21	20100201	NATURAL GAS	1923	MMBTU/H	N	N	N	N
MESQUITE GENERATING STATION		FACILITY WILL HAVE FOUR GE 7FA TURBINES - 180 MW EA. (WITH POWER AUGMENTATION). EACH TURBINE HAS A HEAT RECOVERY STEAM GENERATOR (HRSG) WITH DUCT BURNER. EACH DUCT BURNER HAS A MAX. HEAT INPUT OF 592.6 MMBTU/H (HHV). STEAM FROM THE FOUR HRSGS IS ROUTED TO TWO STEAM TURBINES (290 MW EACH.) TOTAL NOMINAL OUTPUT FOR THE FACILITY IS 1300 MW.	TURBINE, COMBINED CYCLE, NATURAL GAS	15.21	20100201	NATURAL GAS	1923	MMBTU/H	N	N	N	N
MESQUITE GENERATING STATION		FACILITY WILL HAVE FOUR GE 7FA TURBINES - 180 MW EA. (WITH POWER AUGMENTATION). EACH TURBINE HAS A HEAT RECOVERY STEAM GENERATOR (HRSG) WITH DUCT BURNER. EACH DUCT BURNER HAS A MAX. HEAT INPUT OF 592.6 MMBTU/H (HHV). STEAM FROM THE FOUR HRSGS IS ROUTED TO TWO STEAM TURBINES (290 MW EACH.) TOTAL NOMINAL OUTPUT FOR THE FACILITY IS 1300 MW.	TURBINE, COMBINED CYCLE, NATURAL GAS	15.21	20100201	NATURAL GAS	1923	MMBTU/H	N	N	N	N
MESQUITE GENERATING STATION		FACILITY WILL HAVE FOUR GE 7FA TURBINES - 180 MW EA. (WITH POWER AUGMENTATION). EACH TURBINE HAS A HEAT RECOVERY STEAM GENERATOR (HRSG) WITH DUCT BURNER. EACH DUCT BURNER HAS A MAX. HEAT INPUT OF 592.6 MMBTU/H (HHV). STEAM FROM THE FOUR HRSGS IS ROUTED TO TWO STEAM TURBINES (290 MW EACH.) TOTAL NOMINAL OUTPUT FOR THE FACILITY IS 1300 MW.	TURBINE, COMBINED CYCLE, NATURAL GAS	15.21	20100201	NATURAL GAS	1923	MMBTU/H	N	N	N	N
MINNESOTA METHANE		COMPANY SELLS ENGINES TO MUNICIPAL LANDFILLS TO DESTROY LANDFILL GAS VIA COGENERATION.	ENGINES, COGENERATION (4)	17.15	2-01-008-02	LANDFILL GAS	800	KW	F	F	F	F
MINNESOTA METHANE		COMPANY SELLS ENGINES TO MUNICIPAL LANDFILLS TO DESTROY LANDFILL GAS VIA COGENERATION.	ENGINES, COGENERATION (4)	17.15	2-01-008-02	LANDFILL GAS	800	KW	F	F	F	F
NORTHWEST REGIONAL LANDFILL	MUNICIPAL LANDFILL		FLARE, ENCLOSED	19.32	50100410	LANDFILL GAS			N	N	N	N
NORTHWEST REGIONAL LANDFILL	MUNICIPAL LANDFILL		FLARE, ENCLOSED	19.32	50100410	LANDFILL GAS			N	N	N	N
NORTHWEST REGIONAL LANDFILL	MUNICIPAL LANDFILL		INTERNAL COMBUSTION ENGINE	17.15	20100802	LANDFILL GAS	1410	HP	N	N	N	N
NORTHWEST REGIONAL LANDFILL	MUNICIPAL LANDFILL		INTERNAL COMBUSTION ENGINE	17.15	20100802	LANDFILL GAS	1410	HP	N	N	N	N
PANDA GILA RIVER	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER	15.21	20100201	NATURAL GAS	170	MW	Y	Y	N	Y
PANDA GILA RIVER	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER	15.21	20100201	NATURAL GAS	170	MW	Y	Y	N	Y
PANDA GILA RIVER	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER	15.21	20100201	NATURAL GAS	170	MW	Y	Y	N	Y
PANDA GILA RIVER	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER	15.21	20100201	NATURAL GAS	170	MW	Y	Y	N	Y
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER	15.21	20100201	NATURAL GAS	175	MW	Y	Y	N	Y
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER	15.21	20100201	NATURAL GAS	175	MW	Y	Y	N	Y
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER	15.21	20100201	NATURAL GAS	175	MW	Y	Y	N	Y
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	POWER PLANT		TURBINE, COMBINED CYCLE, DUCT BURNER	15.21	20100201	NATURAL GAS	175	MW	Y	Y	N	Y

FACILITY	NARRATIVE	NOTES	PROCESS	PROC TYPE	SCC	FUEL	THRUPUT	THRUPUT UNIT	COMP VERIFY	STACK TEST	INSPECTION	CALCULATED
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	POWER PLANT		TURBINE, COMBINED CYCLE, NO DUCT BURNER	15.21	20100201	NATURAL GAS	175	MW	Y	Y	N	Y
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	POWER PLANT		TURBINE, SIMPLE CYCLE, (12)	15.11	20100201	NATURAL GAS	450	MW	N	N	N	N
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	POWER PLANT		TURBINE, SIMPLE CYCLE, (12)	15.11	20100201	NATURAL GAS	450	MW	N	N	N	N
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	POWER PLANT		TURBINE, SIMPLE CYCLE, (12)	15.11	20100201	NATURAL GAS	450	MW	N	N	N	N
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	POWER PLANT		TURBINE, SIMPLE CYCLE, (12)	15.11	20100201	NATURAL GAS	450	MW	N	N	N	N
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	POWER PLANT		TURBINE, COMBINED CYCLE	15.21	20100201	NATURAL GAS	290	MW	Y	Y	Y	N
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	POWER PLANT		TURBINE, COMBINED CYCLE	15.21	20100201	NATURAL GAS	290	MW	Y	Y	Y	N
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	POWER PLANT		TURBINE, COMBINED CYCLE	15.21	20100201	NATURAL GAS	290	MW	Y	Y	Y	N
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	POWER PLANT		TURBINE, COMBINED CYCLE	15.21	20100201	NATURAL GAS	290	MW	Y	Y	Y	N
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	POWER PLANT		TURBINE, COMB'D CYCLE WITH DUCT BURNERS	15.21	20100201	NATURAL GAS	290	MW	Y	Y	Y	N

FACILITY	OTHER TEST	OTHER METHD	PRNOTES	POLLUTANT	CAS	CONTROLCOD	CTRLDESC	RANK OPTS	RANK SEL	EMIS LIMIT1	EMIS LIMIT1 UNIT	EMISLIMIT1 CONDITION	BASIS
APS WEST PHOENIX	N			PM10	PM	P	USE OF NATURAL GAS AND GOOD COMBUSTION PRACTICES	4	3	0.0055	LB/MMBTU		LAER
APS WEST PHOENIX	N			VOC	VOC	A	OXIDATION CATALYST			0.0016	LB/MMBTU		LAER
APS WEST PHOENIX	N			CO	630-08-0	A	OXIDATION CATALYST			6	PPM @ 15% O2		LAER
APS WEST PHOENIX	N			PM10	PM	P	USE OF NATURAL GAS AND GOOD COMBUSTION	4	3	0.0051	LB/MMBTU	3 h avg	LAER
APS WEST PHOENIX	N			VOC	VOC	A	OXIDATION CATALYST	3	3	0.0025	LB/MMBTU	3 h avg	BACT-OTHER
APS WEST PHOENIX	N			CO	630-08-0	A	OXIDATION CATALYST			6	PPM @ 15% O2		LAER
DUKE ENERGY ARLINGTON VALLEY	N			NOX	10102	A	SCR	4	3	2.5	PPM @ 15% O2	3 hr avg	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY	N			CO	630-08-0	N				20	PPM @ 15% O2	3 hr avg	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY	N			PM10	PM	N				27	LB/H		BACT-PSD
DUKE ENERGY ARLINGTON VALLEY	N			VOC	VOC	N				1.4	PPM @ 15% O2	3 hr avg	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	N			NOX	10102	A	SCR			2	PPM @ 15% O2	1 hr avg	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	N			CO	630-08-0	A	CATALYTIC OXIDIZER			3	PPM @ 15% O2	3 hr avg	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	N			PM10	PM	N				25	LB/H		BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	N			VOC	VOC	N				4	PPM	3 hr avg	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	N		This process entry provides emission limits for the combined cycl turbine without the duct burner.	NOX	10102	A	SCR			2	PPM @ 15% O2	1 hr avg	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	N		This process entry provides emission limits for the combined cycl turbine without the duct burner.	CO	630-08-0	A	CATALYTIC OXIDIZER			2	PPM @ 15% O2	3 hr avg	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	N		This process entry provides emission limits for the combined cycl turbine without the duct burner.	PM10	PM	N				18	LB/H		BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	N		This process entry provides emission limits for the combined cycl turbine without the duct burner.	VOC	VOC	N				1	PPM	3 hr avg	BACT-PSD
GILA BEND POWER GENERATING STATION	N			NOX	10102	B	SCR AND LOW NOX COMBUSTORS	3		2	PPM @ 15% O2	1-hr avg	BACT-PSD
GILA BEND POWER GENERATING STATION	N			CO	630-08-0	A	OXIDATION CATALYST	3	2	4	PPM @ 15% O2	3 h avg	BACT-PSD
GILA BEND POWER GENERATING STATION	N			VOC	VOC	B	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICE	2	1	1.4	PPM @ 15% O2		BACT-PSD
GILA BEND POWER GENERATING STATION	N			PM10	PM	N				0.014	LB/MMBTU	3 h avg	BACT-PSD
HARQUAHALA GENERATING PROJECT	N		THERE ARE 3 NATURAL GAS FIRED TURBINES (240 MW EACH) AND THREE STEAM TURBINES (121 MW EACH). THERE IS NO SUPPLEMENTARY DUCT FIRING. THROUGHPUT LISTED IS PER TURBINE.	NOX	10102	A	SCR. EMISSIONS IN THE LB/H ARE FOR EACH COMBINED CYCLE UNIT.			2.5	PPM		BACT-OTHER
HARQUAHALA GENERATING PROJECT	N		THERE ARE 3 NATURAL GAS FIRED TURBINES (240 MW EACH) AND THREE STEAM TURBINES (121 MW EACH). THERE IS NO SUPPLEMENTARY DUCT FIRING. THROUGHPUT LISTED IS PER TURBINE.	SO2	9/5/7446	P	USE OF PIPELINE QUALITY NATURAL GAS ONLY. EMISSIONS IN THE LB/H ARE FOR EACH COMBINED CYCLE UNIT . PPM FOR SO2 NOT AVAILABLE.			5.8	LB/H		BACT-OTHER
HARQUAHALA GENERATING PROJECT	N		THERE ARE 3 NATURAL GAS FIRED TURBINES (240 MW EACH) AND THREE STEAM TURBINES (121 MW EACH). THERE IS NO SUPPLEMENTARY DUCT FIRING. THROUGHPUT LISTED IS PER TURBINE.	PM10	PM	P	GOOD COMBUSTION CONTROL. EMISSIONS IN THE LB/H ARE FOR EACH COMBINED CYCLE UNIT.			24	LB/H		BACT-OTHER
HARQUAHALA GENERATING PROJECT	N		THERE ARE 3 NATURAL GAS FIRED TURBINES (240 MW EACH) AND THREE STEAM TURBINES (121 MW EACH). THERE IS NO SUPPLEMENTARY DUCT FIRING. THROUGHPUT LISTED IS PER TURBINE.	CO	630-08-0	A	OXIDATION CATALYST. EMISSIONS IN THE LB/H ARE FOR EACH COMBINED CYCLE UNIT .			37	LB/H		BACT-OTHER
HARQUAHALA GENERATING PROJECT	N		THERE ARE 3 NATURAL GAS FIRED TURBINES (240 MW EACH) AND THREE STEAM TURBINES (121 MW EACH). THERE IS NO SUPPLEMENTARY DUCT FIRING. THROUGHPUT LISTED IS PER TURBINE.	VOC	VOC	P	COMBUSTION CONTROL AND USE OF NATURAL GAS. EMISSIONS IN THE LB/H ARE FOR EACH COMBINED CYCLE UNIT.			2.8	PPM		BACT-OTHER
INTEL CORPORATION	F			NOX	10102	P	LOW NOX BURNERS	0	0	0			BACT
INTEL CORPORATION	F			SOX/PM10	7446	P	FUEL SPEC: NATURAL GAS PRIMARY, .055 WT % S FUEL OIL BACKUP ONLY	0	0	0			BACT
INTEL CORPORATION	F			VOC	VOC	A	AFTERBURNERS	0	0	0			BACT
INTEL CORPORATION	F			NOX/PM10	10102	A	CYANURIC ACID INJECTION TAILPIPE CONTROL	0	0	0			BACT
INTEL CORPORATION	F			SOX	7446	P	FUEL SPEC: .055 WT % S FUEL OIL	0	0	0			BACT
INTEL CORPORATION	F			VOC	VOC	A	CARBON ADSORPTION KREHA CONTINUOUSLY DESORBED WITH CHILLER	0	0	40	TPY		BACT-OTHER
INTEL CORPORATION	F			SOX	7446	P	FUEL SPEC: 0.055 WT% S OIL	0	0	5	TPY		BACT-OTHER
INTEL CORPORATION	F			NOX	10102	P	LOW NOX BURNERS < 50 PPM NOX	0	0	49	TPY		BACT-OTHER

FACILITY	OTHER TEST	OTHER METHD	PRNOTES	POLLUTANT	CAS	CONTROLCOD	CTRLDESC	RANK OPTS	RANK SEL	EMIS LIMIT1	EMIS LIMIT1 UNIT	EMISLIMIT1 CONDITION	BASIS
KYRENE GENERATING STATION, SALT RIVER PROJECT	N			NOX	10102	A	SCR			2.5	PPM @ 15% O2	3 H avg	LAER
KYRENE GENERATING STATION, SALT RIVER PROJECT	N			CO	630-08-0	A	OXIDATION CATALYST			3.9	PPM @ 15% O2	3 H avg	LAER
KYRENE GENERATING STATION, SALT RIVER PROJECT	N			PM10	PM	N				0.0072	LB/MMBTU		LAER
MESQUITE GENERATING STATION	N		FOUR GE 7FA TURBINES - COMBINED CYCLE 180 MW (WITH POWER AUGMENTATION) TWO 290 MW STEAM TURBINES. THROUGHPUT LISTED PER TURBINE.	VOC	VOC	A	OXIDATION CATALYST. EMISSIONS IN LB/H ARE COMBINED FOR EACH COMBINED CYCLE UNIT (TURBINE AND DUCT BURNER)			16.6	LB/H		BACT-PSD
MESQUITE GENERATING STATION	N		FOUR GE 7FA TURBINES - COMBINED CYCLE 180 MW (WITH POWER AUGMENTATION) TWO 290 MW STEAM TURBINES. THROUGHPUT LISTED PER TURBINE.	SO2	9/5/7446	P	PIPELINE QUALITY NATURAL GAS. EMISSIONS IN LB/H ARE COMBINED FOR EACH COMBINED CYCLE UNIT (TURBINE AND DUCT BURNER). PPM FOR SO2 NOT AVAILABLE.			2.1	LB/H		BACT-OTHER
MESQUITE GENERATING STATION	N		FOUR GE 7FA TURBINES - COMBINED CYCLE 180 MW (WITH POWER AUGMENTATION) TWO 290 MW STEAM TURBINES. THROUGHPUT LISTED PER TURBINE.	PM10	PM	N	EMISSIONS IN LB/H ARE COMBINED FOR EACH COMBINED CYCLE UNIT (TURBINE AND DUCT BURNER)			30.4	LB/H		BACT-PSD
MESQUITE GENERATING STATION	N		FOUR GE 7FA TURBINES - COMBINED CYCLE 180 MW (WITH POWER AUGMENTATION) TWO 290 MW STEAM TURBINES. THROUGHPUT LISTED PER TURBINE.	NOX	10102	A	SCR. EMISSIONS IN LB/H ARE COMBINED FOR EACH COMBINED CYCLE UNIT (TURBINE AND DUCT BURNER)			2.5	PPM @ 15% O2		BACT-PSD
MESQUITE GENERATING STATION	N		FOUR GE 7FA TURBINES - COMBINED CYCLE 180 MW (WITH POWER AUGMENTATION) TWO 290 MW STEAM TURBINES. THROUGHPUT LISTED PER TURBINE.	CO	630-08-0	A	OXIDATION CATALYST. EMISSIONS IN LB/H ARE COMBINED FOR EACH COMBINED CYCLE UNIT (TURBINE AND DUCT BURNER)			4	PPM @ 15% O2		BACT-PSD
MINNESOTA METHANE	F			NOX	10102	P	AIR/FUEL CONTROLLER ADJUSTED TO OBTAIN LOW NOX	0	0	99	TPY		BACT
MINNESOTA METHANE	F			CO	630-08-0	P	AIR/FUEL CONTROLLER	0	0	99.9	TPY		BACT
NORTHWEST REGIONAL LANDFILL	N			NOX	10102	N				0.041	LB/MMBTU		BACT-OTHER
NORTHWEST REGIONAL LANDFILL	N			CO	630-08-0	N				0.13	LB/MMBTU		BACT-OTHER
NORTHWEST REGIONAL LANDFILL	N			NOX	10102	N				0.6	G/B-HP-H		BACT-OTHER
NORTHWEST REGIONAL LANDFILL	N			CO	630-08-0	N				2.5	G/B-HP-H		BACT-OTHER
PANDA GILA RIVER	N			NOX	10102	A	SCR			3	PPM @ 15% O2	3 hr avg	BACT-PSD
PANDA GILA RIVER	N			CO	630-08-0	A	OXIDATION CATALYST			2.8	PPM @ 15% O2	24 hr avg	BACT-PSD
PANDA GILA RIVER	N			PM10	PM	N				0.0056	LB/MMBTU	3 hr avg	BACT-PSD
PANDA GILA RIVER	N			VOC	VOC	N				2.8	PPM @ 15% O2	3 hr avg	BACT-PSD
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	N			NOX	10102	B	SCR AND LOW-NOX BURNERS	4		2.5	PPM @ 15% O2		BACT-PSD
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	N			CO	630-08-0	P	GOOD COMBUSTION	2	2	23	PPM @ 15% O2		BACT-PSD
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	N			VOC	VOC	P	GOOD COMBUSTION	2	2	0.0036	LB/MMBTU		BACT-PSD
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	N			PM10	PM	N				0.0101	LB/MMBTU		BACT-PSD

FACILITY	OTHER TEST	OTHER METHD	PRNOTES	POLLUTANT	CAS	CONTROLCOD	CTRLDESC	RANK OPTS	RANK SEL	EMIS LIMIT1	EMIS LIMIT1 UNIT	EMISLIMIT1 CONDITION	BASIS
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY	N		All limits the same as those for power generation with duct burner, except for limits for CO.	CO	630-08-0	P	GOOD COMBUSTION	2	2	14	PPM @ 15% O2		BACT-PSD
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	N		twelve 45 MW simple cycle natural gas fired turbines, with a nominal generating capacity of 540 MW, combined.	NOX	10102	A	SCR			5	PPM @ 15% O2	3-h avg	BACT-PSD
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	N		twelve 45 MW simple cycle natural gas fired turbines, with a nominal generating capacity of 540 MW, combined.	CO	630-08-0	A	OXIDATION CATALYST			7.5	PPM @ 15% O2	>59 degrees F, 3-h avg	BACT-PSD
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	N		twelve 45 MW simple cycle natural gas fired turbines, with a nominal generating capacity of 540 MW, combined.	PM10	PM	P	GOOD COMBUSTION PRACTICE			7	LB/H		BACT-PSD
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	N		twelve 45 MW simple cycle natural gas fired turbines, with a nominal generating capacity of 540 MW, combined.	VOC	VOC	A	CATALYTIC OXIDIZER			4.5	LB/H		BACT-PSD
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	N			NOX	10102	A	SCR			3	PPM @ 15% O2	3-h avg	BACT-PSD
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	N			CO	630-08-0	P	GOOD COMBUSTION PRACTICE			15.3	PPM @ 15% O2	3-h avg	BACT-PSD
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	N			PM10	PM	P	GOOD COMBUSTION PRACTICE			15.3	LB/H	3-h avg	BACT-PSD
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	N			VOC	VOC	P	GOOD COMBUSTION PRACTICE			8.2	LB/H	3-h avg	BACT-PSD
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC	N			NOX	10102	A	SCR			3	PPM @ 15% O2		BACT-PSD

FACILITY	PCTEFFIC	EMIS LIMIT2	EMISLIMIT2 UNIT	EMISLIMIT2 CONDITION	STDEMISS	STDUNIT	STOTHER CONDITIONS	EMISSTYPE	CAPCOST	ANNUALCOST	OMCOST	COSTEFFECT	COSTVERIFY	DOLLARYEAR	POLNOTES
APS WEST PHOENIX								P					N		
APS WEST PHOENIX								P					N		
APS WEST PHOENIX					6	PPM @ 15% O2		P					N		
APS WEST PHOENIX								P					N		
APS WEST PHOENIX								P					N		
APS WEST PHOENIX					6	PPM @ 15% O2		P					N		
DUKE ENERGY ARLINGTON VALLEY					2.5	PPM @ 15% O2		P					N		
DUKE ENERGY ARLINGTON VALLEY					20	PPM @ 15% O2		P					N		
DUKE ENERGY ARLINGTON VALLEY								P					N		
DUKE ENERGY ARLINGTON VALLEY		3	LB/H					P					N		
DUKE ENERGY ARLINGTON VALLEY (AVEFII)					2	PPM @ 15% O2		P					N		Limit achieved after 2 yr demonstratior period
DUKE ENERGY ARLINGTON VALLEY (AVEFII)					3	PPM @ 15% O2		P					N		
DUKE ENERGY ARLINGTON VALLEY (AVEFII)								P					N		
DUKE ENERGY ARLINGTON VALLEY (AVEFII)								P					N		
DUKE ENERGY ARLINGTON VALLEY (AVEFII)					2	PPM @ 15% O2		P					N		Limit achieved after 2 yr demonstratior period
DUKE ENERGY ARLINGTON VALLEY (AVEFII)					2	PPM @ 15% O2		P					N		
DUKE ENERGY ARLINGTON VALLEY (AVEFII)								P					N		
DUKE ENERGY ARLINGTON VALLEY (AVEFII)								P					N		
GILA BEND POWER GENERATING STATION	78				2	PPM @ 15% O2		P				148288	N		
GILA BEND POWER GENERATING STATION	67				4	PPM @ 15% O2		P				9638	N		
GILA BEND POWER GENERATING STATION	50							P				142238	N		
GILA BEND POWER GENERATING STATION		26.02	LB/H	3 h avg				P					N		
HARQUAHALA GENERATING PROJECT		25	LB/H		2.5	PPM @ 15% O2		P					N		
HARQUAHALA GENERATING PROJECT								P					N		
HARQUAHALA GENERATING PROJECT								P					N		
HARQUAHALA GENERATING PROJECT		10	PPM		10	PPM @ 15% O2		P					N		
HARQUAHALA GENERATING PROJECT		7.8	LB/H		2.8	PPM @ 15% O2		P					N		
INTEL CORPORATION	0	0			0			P	0	0	0		N		
INTEL CORPORATION	0	0			0			P	0	0	0		N		
INTEL CORPORATION	90	0			0			P	0	0	0		N		
INTEL CORPORATION	80	0			0			P	0	0	0		N		
INTEL CORPORATION	0	0			0			P	0	0	0		N		
INTEL CORPORATION	90	0			0			P	0	0	0		N		
INTEL CORPORATION	0	0			0			P	0	0	0		N		
INTEL CORPORATION	0	0			0			P	0	0	0		N		

FACILITY	PCTEFFIC	EMIS LIMIT2	EMISLIMIT2 UNIT	EMISLIMIT2 CONDITION	STDEMISS	STDUNIT	STOTHER CONDITIONS	EMISSTYPE	CAPCOST	ANNUALCOST	OMCOST	COSTEFFECT	COSTVERIFY	DOLLARYEAR	POLNOTES
KYRENE GENERATING STATION, SALT RIVER PROJECT					2.5	PPM @ 15% O2	3 H avg	P					N		
KYRENE GENERATING STATION, SALT RIVER PROJECT					3.9	PPM @ 15% O2	3 H avg	P					N		
KYRENE GENERATING STATION, SALT RIVER PROJECT								P					N		
MESQUITE GENERATING STATION		5.2	PPM @ 15% O2		5.2	PPM @ 15% O2		P					N		
MESQUITE GENERATING STATION								P					N		
MESQUITE GENERATING STATION		0.0128	LB/MMBTU					P					N		
MESQUITE GENERATING STATION		22.2	LB/H		2.5	PPM @ 15% O2		P					N		
MESQUITE GENERATING STATION		21.6	LB/H		4	PPM @ 15% O2		P					N		
MINNESOTA METHANE	0	0			0			P	0	0	0		N		
MINNESOTA METHANE	0	0			0			P	0	0	0		N		
NORTHWEST REGIONAL LANDFILL					0.041	LB/MMBTU		P					N		
NORTHWEST REGIONAL LANDFILL					0.13	LB/MMBTU		P					N		
NORTHWEST REGIONAL LANDFILL		4500	PPM		0.6	G/B-HP-H		P					N		
NORTHWEST REGIONAL LANDFILL		280	PPM		2.5	G/B-HP-H		P					N		
PANDA GILA RIVER					3	PPM @ 15% O2		P					N		
PANDA GILA RIVER					2.8	PPM @ 15% O2		P					N		
PANDA GILA RIVER		12.5	LB/H					P					N		
PANDA GILA RIVER								P					N		
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY					2.5	PPM @ 15% O2		P					N		
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY					23	PPM @ 15% O2		P					N		
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY								P					N		
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY		22.2	LB/H					P					N		

FACILITY	PCTEFFIC	EMIS LIMIT2	EMISLIMIT2 UNIT	EMISLIMIT2 CONDITION	STDEMISS	STDUNIT	STOTHER CONDITIONS	EMISSTYPE	CAPCOST	ANNUALCOST	OMCOST	COSTEFFECT	COSTVERIFY	DOLLARYEAR	POLNOTES
PINNACLE WEST ENERGY CORP./REDHAWK GEN. FACILITY					14	PPM @ 15% O2		P					N		
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY					5	PPM @ 15% O2		P					N		
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY		15	PPM @ 15% O2	<59 degrees F, 3-h avg	7.5	PPM @ 15% O2		P					N		
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY								P					N		
PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY								P					N		
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC					3	PPM @ 15% O2		P					N		
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC					15.3	PPM @ 15% O2		P					N		
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC								P					N		
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC								P					N		
SALT RIVER PROJECT/ DESERT BASIN GENERATING PROJEC					3	PPM @ 15% O2		P					N		

RBLCID	ORIS_CODE	FACILITY_NAME
	50805	ABITIBI CONSOLIDATED SNOWFLAKE DIVISION
	141	Agua Fria Generating Station
	160	Apache Station
	118	APS Saguaro Power Plant
	54594	BIOSPHERE 2 CENTER INC
	55780	Bowie Power Station
	112	CHILDS
	113	Cholla
	6177	Coronado Generating Station
	143	Crosscut
	152	DAVIS
	124	De Moss Petrie Generating Station
AZ-0044	55129	Desert Basin Generating Station
	114	DOUGLAS
AZ-0035	55282	Duke Energy Arlington Valley
	923	Gila Bend
AZ-0038	55507	Gila Bend Power Generation Station
AZ-0037	55306	Gila River Power Station
	153	GLEN CANYON
	54838	GOULD ELECTRONICS FOIL DIVISION
	55124	Griffith Energy LLC
AZ-0034	55372	Harquahala Generating Project
	8902	HOOVER
	145	HORSE MESA
	55257	INA ROAD WATER POLLUTION CONTROL FACILITY
	10564	INTERMOUNTAIN REFINING COMPANY, INC
	115	IRVING
	126	Irvington Generating Station
AZ-0041	147	Kyrene Generating Station
	55711	La Paz Generating Facility
AZ-0033	55481	Mesquite Generating Station
	148	MORMON FLAT
	4941	Navajo Generating Station
	54245	NELSON PLANT GENERATORS
	50738	NEW CORNELIA BRANCH POWER PLANT
	54949	NORDIC POWER OF SOUTH POINT I

RBLCID	ORIS_CODE	FACILITY_NAME
	6088	NORTH LOOP
	116	Ocotillo Power Plant
	6008	PALO VERDE
AZ-0045	55522	PPL Sundance Energy, LLC
AZ-0036	55455	Redhawk Generating Facility
	149	ROOSEVELT
AZ-0039	8068	Santan
	55692	Signal Peak Generating Facility
	100	SOUTH CONSOLIDATED
	55177	South Point Energy Center, LLC
	8223	Springerville Generating Station
	50238	STARWOOD HOTELS RESORTS
	150	STEWART MTN
	6515	VALENCIA
AZ-0040	117	West Phoenix Power Plant
	120	Yuma Axis
	54694	YUMA COGENERATION ASSOCIATES
	464	Alamosa
	10755	AMERICAN ATLAS 1 COGENERATION PLANT
	54630	AMERICAN GYPSUM COGENERATION
	6207	AMES
	465	Arapahoe
CO-0049	55200	Arapahoe Combustion Turbine
	54680	BETASSO HYDROELECTRIC PLANT
	515	BIG THOMPSON
	512	BLUE MESA
	55645	Blue Spruce Energy Center
	466	BOULDER
	10682	Brush 3
	55209	Brush 4
CO-0027 & C(	10683	BRUSH COGEN PROJECT PHASE 2 BCP
	6619	BURLINGTON
	467	CABIN CREEK
	468	Cameo
	469	Cherokee
	54679	CITY OF BOULDER - LAKEWOOD HYDROELECTRIC PLT

RBLCID	ORIS_CODE	FACILITY_NAME
	470	Comanche (470)
	6021	Craig
	6159	CRYSTAL
	496	DELTA
	10421	DILLON HYDRO PLANT
	54671	DRAGON TRAIL GAS PROCESSING PLANT
	513	ESTES
	54973	FAA AIR ROUTE TRAFFIC CONTROL CENTER
	518	FLATIRON
	10070	FOOTHILLS HYDRO PLANT
	8067	FORT LUPTON
CO-0024 & C(	6112	Fort St. Vrain
	55453	Fountain Valley Combustion Turbine
	55505	Frank Knutson Station
CO-0042	55283	Front Range Power Plant
	471	FRUITA
	493	George Birdsall
	472	GEORGETOWN
	54413	GLENWOOD SPRINGS SALT PROJECT
	6708	GR JUNCTION
	516	GREEN MOUNTAIN
	10424	GROSS HYDRO PLANT
	525	Hayden
	54142	HILLCREST POWERPLANT
	502	Holly
	50205	IGNACIO GASOLINE PLANT
	54596	JOHNSTOWN COGENERATION
	55191	KQ1
	506	LA JUNTA
	508	Lamar
	507	LAS ANIMAS
CO-0050	55504	Limon Generating Station
	509	LONGMONT
	520	LOWER MOLINA
CO-0039	55127	Manchief Station
	494	MANITOU

RBLCID	ORIS_CODE	FACILITY_NAME
	492	Martin Drake
	517	MARYS LAKE
	7372	MCPHEE
	10180	METRO WASTEWATER RECLAMATION DISTRICT
	50899	MONTROSE PARTNERS
	514	MORROW POINT
	6208	MOUNT ELBERT
	10423	NORTH FORK HYDRO PLANT
	527	Nucla
	473	PALISADE
	6248	Pawnee
	55650	Plains End Generating Station
	519	POLE HILL
	460	Pueblo
	7995	Pueblo Airport Industrial Park
CO-0053	6761	Rawhide Energy Station
CO-0025 & CO	8219	Ray D Nixon
	50267	REDLANDS WATER & POWER CO
	6516	Rocky Ford
CO-0052	55835	Rocky Mountain Energy Center
	495	RUXTON
	474	SALIDA 1
	475	SALIDA 2
	476	SHOSHONE
	55621	SOUTH BEAR CREEK
	10081	STRONTIA SPRINGS HYDRO PLANT
	50435	SUGARLOAF HYDRO PLANT
	6206	TACOMA
	54729	TAYLOR DRAW HYDROELECTRIC FACILITY
	50707	TCP 122
	50708	TCP 150
	7233	TESLA
	50709	THERMO GREELEY INC
	50676	THERMO POWER ELECTRIC INC
	7373	TOWAOC
	10003	TRIGEN COLORADO ENERGY CORP

USGS for 2002

NONFUEL RAW MINERAL PRODUCTION IN SW REGION

(Thousand metric tons unless otherwise specified)

Mineral		AZ	CO	WY	TX	NV	KS	OK	UT	NM
Beryllium concentrates									2,500	
Cement:										
Masonry					290		30			
Portland					10,700		2,310			
Clays:									W	
Bentonite				3,400		34	647		454	
Common		42	295	41	2,240			735		30
Fuller's earth					29	--				
Kaolin					40					
Copper[3]		760								113
Gemstones		NA	NA	NA	NA				NA	NA
Gold[3]	kilograms	129	W			242,000				
Gypsum, crude					W			2,570		
Helium, crude	n cubic meters				8		32			
Grade-A	n cubic meters						86			
Iodine, crude	metric tons							1,700		
Lime			32		1,560				2,590	
Salt					9,390		3,060			
Sand and gravel:									30,300	
Construction		49,200	40,700	8,300	78,700	33,200	9,600	10,700		10,900
Industrial			W		1,770	608		1,360		
Silver[3]	metric tons	W	W			449				
Stone:									7,800	
Crushed		8,200	16,000	5,400	128,000	9,700	22,000	40,700		5,900
Dimension			10,200		88,100		12,600	16,500		26,100
Talc, crude	metric tons				233,000					
Tripoli	metric tons							11,700		

[e]Estimated. [p]Preliminary. [r]Revised. NA Not available. W Withheld to avoid disclosing company proprietary data; values included with "Combined values" data. XX Not applicable.

[1]Production as measured by mine shipments, sales, or marketable production (including consumption by producers).

[2]Data are rounded to no more than three significant digits; may not add to totals shown.

[3]Recoverable content of ores, etc.

[4]Withheld to avoid disclosing company proprietary data.

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for
eGRID2002yr00_plant.xls, Version 2.01
Year 2000 eGRID Plant, Boiler, and Generator Data Files

eGRID2002 Version 2.01 Plant File (Year 2000 Data)

SEQPLT00 eGRID2002 2000 file plant sequence number	SEQPLT99 eGRID2002 1999 file plant sequence number	PSTATABB State abbreviation	PNAME Plant name	ORISPL DOE/EIA ORIS plant or facility code	PLTYPE Plant type	PREVUTIL Previously a utility plant flag	CHANGE Change? – If Y, go to EGRDPLCH file	OPRNAME Plant operator name
248	243	AZ	ABITIBI CONSOLIDATED SNOWFLA	50805.0	NU	0	N	Abitibi Consolidated
249	244	AZ	AGUA FRIA	141.0	UT	0	N	Salt River Proj Ag I & P Dist
250	245	AZ	APACHE STATION	160.0	UT	0	N	Arizona Electric Pwr Coop Inc
251	246	AZ	BIOSPHERE 2 CENTER INC	54594.0	NU	0	N	Biosphere 2 Center Inc
252	247	AZ	CHILDS	112.0	UT	0	N	Arizona Public Service Co
253	248	AZ	CHOLLA	113.0	UT	0	N	Arizona Public Service Co
254	249	AZ	CORONADO	6177.0	UT	0	N	Salt River Proj Ag I & P Dist
255	250	AZ	CROSSCUT	143.0	UT	0	N	Salt River Proj Ag I & P Dist
256	251	AZ	DAVIS	152.0	UT	0	N	USBR-Lower Colorado Region
257	252	AZ	DOUGLAS	114.0	UT	0	N	Arizona Public Service Co
258	253	AZ	GLEN CANYON	153.0	UT	0	N	USBR-Upper Colorado Region
259	254	AZ	GOULD ELECTRONICS FOIL DIVISI(	54838.0	NU	0	N	Japan Energy Corp Ltd
260	255	AZ	HOOVER	8902.0	UT	0	N	USBR-Lower Colorado Region
261	256	AZ	HORSE MESA	145.0	UT	0	N	Salt River Proj Ag I & P Dist
262	257	AZ	INA ROAD WATER POLLUTION COI	55257.0	NU	0	N	PIMA County Wastewater Manage
263	258	AZ	IRVING	115.0	UT	0	N	Arizona Public Service Co
264	259	AZ	IRVINGTON	126.0	UT	0	N	Tucson Electric Power Co
265	260	AZ	KYRENE	147.0	UT	0	N	Salt River Proj Ag I & P Dist
266	261	AZ	MORMON FLAT	148.0	UT	0	N	Salt River Proj Ag I & P Dist
267	262	AZ	NAVAJO	4941.0	UT	0	N	Salt River Proj Ag I & P Dist
268	263	AZ	NELSON PLANT GENERATORS	54245.0	NU	0	N	Chemical Lime Co
269	N/A	AZ	NEW CORNELIA BRANCH POWER I	50738.0	NU	0	N	Phelps Dodge Corp
270	264	AZ	NORTH LOOP	6088.0	UT	0	N	Tucson Electric Power Co
271	265	AZ	OCOTILLO	116.0	UT	0	N	Arizona Public Service Co
272	266	AZ	PALO VERDE	6008.0	UT	0	N	Arizona Public Service Co
273	267	AZ	ROOSEVELT	149.0	UT	0	N	Salt River Proj Ag I & P Dist
274	268	AZ	SAGUARO	118.0	UT	0	N	Arizona Public Service Co
275	269	AZ	SANTAN	8068.0	UT	0	N	Salt River Proj Ag I & P Dist
276	270	AZ	SOUTH CONSOLIDATED	100.0	UT	0	N	Salt River Proj Ag I & P Dist
277	271	AZ	SPRINGERVILLE	8223.0	UT	0	N	Tucson Electric Power Co

)00 Data)

PNAME Plant name	OPRCODE Plant operator ID	UTLSRVNM Nonutility's service area name	UTLSRVID Nonutility's service area ID	OPPRNUM Location (operator)-based parent company ID	OPPRNAME Location (operator)-based parent company name
ABITIBI CONSOLIDATED SNOWFLA	-1245.0	Arizona Public Service Co	803.0	0.0	
AGUA FRIA	16572.0		0.0	0.0	
APACHE STATION	796.0		0.0	0.0	
BIOSPHERE 2 CENTER INC	-2018.0	USBIA-San Carlos Project	19604.0	0.0	
CHILDS	803.0		0.0	-7042.0	Pinnacle West Capital Corporation
CHOLLA	803.0		0.0	-7042.0	Pinnacle West Capital Corporation
CORONADO	16572.0		0.0	0.0	
CROSSCUT	16572.0		0.0	0.0	
DAVIS	19580.0		0.0	-7061.0	US Bureau Of Reclamation
DOUGLAS	803.0		0.0	-7042.0	Pinnacle West Capital Corporation
GLEN CANYON	25472.0		0.0	-7061.0	US Bureau Of Reclamation
GOULD ELECTRONICS FOIL DIVISI(	9669.0	Salt River Proj Ag I & P Dist	16572.0	0.0	
HOOVER	19580.0		0.0	-7061.0	US Bureau Of Reclamation
HORSE MESA	16572.0		0.0	0.0	
INA ROAD WATER POLLUTION COI	15090.0	Tucson Electric Power Co	24211.0	0.0	
IRVING	803.0		0.0	-7042.0	Pinnacle West Capital Corporation
IRVINGTON	24211.0		0.0	-7058.0	UniSource Energy Corporation
KYRENE	16572.0		0.0	0.0	
MORMON FLAT	16572.0		0.0	0.0	
NAVAJO	16572.0		0.0	0.0	
NELSON PLANT GENERATORS	3468.0	Mohave Electric Coop Inc	21538.0	0.0	
NEW CORNELIA BRANCH POWER I	-1118.0	Ajo Improvement Co	176.0	0.0	
NORTH LOOP	24211.0		0.0	-7058.0	UniSource Energy Corporation
OCOTILLO	803.0		0.0	-7042.0	Pinnacle West Capital Corporation
PALO VERDE	803.0		0.0	-7042.0	Pinnacle West Capital Corporation
ROOSEVELT	16572.0		0.0	0.0	
SAGUARO	803.0		0.0	-7042.0	Pinnacle West Capital Corporation
SANTAN	16572.0		0.0	0.0	
SOUTH CONSOLIDATED	16572.0		0.0	0.0	
SPRINGERVILLE	24211.0		0.0	-7058.0	UniSource Energy Corporation

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PNAME Plant name	PCANAME Location (operator)-based power control area name	PCAID Location (operator)-based power control area ID	NERC Location (operator)-based NERC region acronym	NERCNUM NERC number associated with NERC region	SUBRGN eGRID subregion acronym
ABITIBI CONSOLIDATED SNOWFLA	Arizona Public Service Co/PCA	803.0	WECC	9	WSSW
AGUA FRIA	Salt River Proj Ag I & P Dist/PCA	16572.0	WECC	9	WSSW
APACHE STATION	WAPA - Phoenix (LC)/PCA	19610.0	WECC	9	WSSW
BIOSPHERE 2 CENTER INC	WAPA - Phoenix (LC)/PCA	19610.0	WECC	9	WSSW
CHILDS	Arizona Public Service Co/PCA	803.0	WECC	9	WSSW
CHOLLA	Arizona Public Service Co/PCA	803.0	WECC	9	WSSW
CORONADO	Salt River Proj Ag I & P Dist/PCA	16572.0	WECC	9	WSSW
CROSSCUT	Salt River Proj Ag I & P Dist/PCA	16572.0	WECC	9	WSSW
DAVIS	WAPA - Phoenix (LC)/PCA	19610.0	WECC	9	WSSW
DOUGLAS	Arizona Public Service Co/PCA	803.0	WECC	9	WSSW
GLEN CANYON	WAPA - Rocky Mountains/PCA	28503.0	WECC	9	ROCK
GOULD ELECTRONICS FOIL DIVISI(	Salt River Proj Ag I & P Dist/PCA	16572.0	WECC	9	WSSW
HOOVER	WAPA - Phoenix (LC)/PCA	19610.0	WECC	9	WSSW
HORSE MESA	Salt River Proj Ag I & P Dist/PCA	16572.0	WECC	9	WSSW
INA ROAD WATER POLLUTION COI	Tucson Electric Power Co/PCA	24211.0	WECC	9	WSSW
IRVING	Arizona Public Service Co/PCA	803.0	WECC	9	WSSW
IRVINGTON	Tucson Electric Power Co/PCA	24211.0	WECC	9	WSSW
KYRENE	Salt River Proj Ag I & P Dist/PCA	16572.0	WECC	9	WSSW
MORMON FLAT	Salt River Proj Ag I & P Dist/PCA	16572.0	WECC	9	WSSW
NAVAJO	Salt River Proj Ag I & P Dist/PCA	16572.0	WECC	9	WSSW
NELSON PLANT GENERATORS	WAPA - Phoenix (LC)/PCA	19610.0	WECC	9	WSSW
NEW CORNELIA BRANCH POWER I	Arizona Public Service Co/PCA	803.0	WECC	9	WSSW
NORTH LOOP	Tucson Electric Power Co/PCA	24211.0	WECC	9	WSSW
OCOTILLO	Arizona Public Service Co/PCA	803.0	WECC	9	WSSW
PALO VERDE	Arizona Public Service Co/PCA	803.0	WECC	9	WSSW
ROOSEVELT	Salt River Proj Ag I & P Dist/PCA	16572.0	WECC	9	WSSW
SAGUARO	Arizona Public Service Co/PCA	803.0	WECC	9	WSSW
SANTAN	Salt River Proj Ag I & P Dist/PCA	16572.0	WECC	9	WSSW
SOUTH CONSOLIDATED	Salt River Proj Ag I & P Dist/PCA	16572.0	WECC	9	WSSW
SPRINGERVILLE	Tucson Electric Power Co/PCA	24211.0	WECC	9	WSSW

)00 Data)

PNAME Plant name	SRNAME eGRID subregion name	FIPST Plant FIPS State code	FIPSCNY Plant FIPS county code	CNTYNAME Plant county name	LAT Plant latitude	LON Plant longitude	NUMBLR Number of utility boilers
ABITIBI CONSOLIDATED SNOWFLA	WECC Southwest	4	17	NAVAJO	35.2863	110.2885	N/A
AGUA FRIA	WECC Southwest	4	13	MARICOPA	33.5569	112.2175	3
APACHE STATION	WECC Southwest	4	3	COCHISE	32.0556	109.8861	3
BIOSPHERE 2 CENTER INC	WECC Southwest	4	21	PINAL	32.9836	111.3255	N/A
CHILDS	WECC Southwest	4	25	YAVAPAI	34.7053	112.4042	N/A
CHOLLA	WECC Southwest	4	17	NAVAJO	34.9414	110.3003	4
CORONADO	WECC Southwest	4	1	APACHE	34.5778	109.2717	2
CROSSCUT	WECC Southwest	4	13	MARICOPA	33.3500	112.4900	N/A
DAVIS	WECC Southwest	4	15	MOHAVE	35.6134	113.6474	N/A
DOUGLAS	WECC Southwest	4	3	COCHISE	31.8799	109.7540	N/A
GLEN CANYON	WECC Rockies	4	5	COCONINO	35.6337	112.0444	N/A
GOULD ELECTRONICS FOIL DIVISI(	WECC Southwest	4	13	MARICOPA	33.3500	112.4900	N/A
HOOVER	WECC Southwest	4	15	MOHAVE	35.6134	113.6474	N/A
HORSE MESA	WECC Southwest	4	13	MARICOPA	33.3500	112.4900	N/A
INA ROAD WATER POLLUTION CON	WECC Southwest	4	19	PIMA	31.9699	111.8899	N/A
IRVING	WECC Southwest	4	25	YAVAPAI	34.7053	112.4042	N/A
IRVINGTON	WECC Southwest	4	19	PIMA	32.1600	110.9044	4
KYRENE	WECC Southwest	4	13	MARICOPA	33.3547	111.9364	2
MORMON FLAT	WECC Southwest	4	13	MARICOPA	33.3500	112.4900	N/A
NAVAJO	WECC Southwest	4	5	COCONINO	36.9125	111.3917	3
NELSON PLANT GENERATORS	WECC Southwest	4	15	MOHAVE	35.6134	113.6474	N/A
NEW CORNELIA BRANCH POWER I	WECC Southwest	4	19	PIMA	31.9699	111.8899	N/A
NORTH LOOP	WECC Southwest	4	19	PIMA	31.9699	111.8899	N/A
OCOTILLO	WECC Southwest	4	13	MARICOPA	33.4467	111.9417	2
PALO VERDE	WECC Southwest	4	13	MARICOPA	33.3500	112.4900	N/A
ROOSEVELT	WECC Southwest	4	13	MARICOPA	33.3500	112.4900	N/A
SAGUARO	WECC Southwest	4	21	PINAL	32.5522	111.2992	2
SANTAN	WECC Southwest	4	13	MARICOPA	33.3500	112.4900	N/A
SOUTH CONSOLIDATED	WECC Southwest	4	13	MARICOPA	33.3500	112.4900	N/A
SPRINGERVILLE	WECC Southwest	4	1	APACHE	34.3186	109.1636	2

)00 Data)

PNAME Plant name	NUMGEN Number of generators	SOURCEM Plant emissions source(s)	PLPRIMFL Plant primary fuel	PLFFLCTG Plant fossil fuel category	CAPFAC Plant capacity factor	BOILCAP Utility plant boiler capacity (MMBtu/hr)	NAMEPCAP Plant generator capacity (MW)	CHPFLAG Combined heat and power (CHP) (cogenerator) 2000 plant flag	USETHRMO CHP plant 2000 useful thermal output (MMBtu)
ABITIBI CONSOLIDATED SNOWFLA	2	E	SUB	C	0.5541	N/A	70.55	U	3155479
AGUA FRIA	6	T,E	GAS	G	0.3803	3672.00	613.42		0
APACHE STATION	6	T	COL	C	0.7062	4515.20	559.14		0
BIOSPHERE 2 CENTER INC	2	E	NG	G	0.0932	N/A	3.05	U	2590
CHILDS	1	Z	WT		0.4414	N/A	5.40		0
CHOLLA	4	T	COL	C	0.7017	10506.00	1105.44		0
CORONADO	2	T	COL	C	0.8717	7471.84	821.88		0
CROSSCUT	5	Z	WT		0.0181	N/A	33.00		0
DAVIS	1	Z	WT		0.5911	N/A	240.00		0
DOUGLAS	1	E	OIL	O	0.0196	N/A	21.40		0
GLEN CANYON	1	Z	WT		0.3642	N/A	1296.00		0
GOULD ELECTRONICS FOIL DIVISI(	2	E	NG	G	0.0599	N/A	1.05	U	818
HOOVER	1	Z	WT		0.3148	N/A	1039.40		0
HORSE MESA	2	Z	WT		0.1957	N/A	129.58		0
INA ROAD WATER POLLUTION CON	7	E	NG	G	0.4703	N/A	4.54	U	70733
IRVING	1	Z	WT		0.8549	N/A	1.60		0
IRVINGTON	6	T,E	COL	C	0.3352	3633.92	558.50		0
KYRENE	6	T,E	GAS	G	0.1345	1349.12	334.85		0
MORMON FLAT	2	Z	WT		0.1598	N/A	57.85		0
NAVAJO	3	T	COL	C	0.8574	22072.80	2409.48		0
NELSON PLANT GENERATORS	1	E	DFO	O	0.0237	N/A	2.27		0
NEW CORNELIA BRANCH POWER I	2	E	NG	G	0.0350	N/A	10.50		0
NORTH LOOP	3	E	GAS	G	0.0700	N/A	81.00		0
OCOTILLO	5	T,E	GAS	G	0.2561	2176.00	333.90		0
PALO VERDE	1	Z	UR		0.8239	N/A	4209.57		0
ROOSEVELT	1	Z	WT		0.1130	N/A	36.02		0
SAGUARO	4	T,E	GAS	G	0.2126	2448.00	356.25		0
SANTAN	4	E	GAS	G	0.4091	N/A	414.00		0
SOUTH CONSOLIDATED	1	Z	WT		0.0882	N/A	1.40		0
SPRINGERVILLE	2	T	COL	C	0.7896	7656.80	849.60		0

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PNAME Plant name	PWRTOHT CHP plant 2000 power to heat ratio	ELCALLOC CHP plant 2000 electric allocation factor	PLNUCONN Nonutility plant connected to grid flag	PSFLG Plant pumped storage flag	ARDBNU ARD nonutility flag	LMSWFLG Nonutility plant landfill methane or solid waste flag	PLNUCMBS Plant nonutility combustion flag	PLNUCOAL Plant nonutility coal flag	UTNOWNU Now nonutility flag
ABITIBI CONSOLIDATED SNOWFLA	0.3703	0.4255	Y	0	N/A	N/A	N/A	N/A	N/A
AGUA FRIA	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
APACHE STATION	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
BIOSPHERE 2 CENTER INC	3.2787	0.8677	Y	0	N/A	N/A	N/A	N/A	N/A
CHILDS	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
CHOLLA	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
CORONADO	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
CROSSCUT	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
DAVIS	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
DOUGLAS	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
GLEN CANYON	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
GOULD ELECTRONICS FOIL DIVISI(	2.2967	0.8212	Y	0	N/A	N/A	N/A	N/A	N/A
HOOVER	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
HORSE MESA	N/A	N/A		1	N/A	N/A	N/A	N/A	N/A
INA ROAD WATER POLLUTION COI	0.9022	0.6434	Y	0	N/A	N/A	N/A	N/A	N/A
IRVING	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
IRVINGTON	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
KYRENE	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
MORMON FLAT	N/A	N/A		1	N/A	N/A	N/A	N/A	N/A
NAVAJO	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
NELSON PLANT GENERATORS	N/A	N/A	Y	0	N/A	N/A	N/A	N/A	N/A
NEW CORNELIA BRANCH POWER I	N/A	N/A	Y	0	N/A	N/A	N/A	N/A	N/A
NORTH LOOP	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
OCOTILLO	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
PALO VERDE	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
ROOSEVELT	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
SAGUARO	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
SANTAN	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
SOUTH CONSOLIDATED	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A
SPRINGERVILLE	N/A	N/A		0	N/A	N/A	N/A	N/A	N/A

)00 Data)

PNAME Plant name	GENERVAL Generation value source	EMISVAL Emission value source	RESMXVAL Resource mix value source	PLHTIAN Plant 2000 annual heat input (MMBtu)	PLHTIOZ Plant 2000 ozone season heat input (MMBtu)	PLGGENAN Plant 2000 annual gross generation (MWh)	PLNGENAN Plant 2000 annual net generation (MWh)	PLNGENOZ Plant 2000 ozone season net generation (MWh)	PLNOXAN Plant 2000 annual NOx emissions (tons)
ABITIBI CONSOLIDATED SNOWFLA	N/A	N/A	N/A	3086048.8	1285853.7	N/A	342452.4	142688.5	722.74
AGUA FRIA	N/A	N/A	N/A	22470746.6	11170252.9	N/A	2043449.0	1131526.0	6103.47
APACHE STATION	N/A	N/A	N/A	37032772.0	16502992.0	N/A	3459141.0	1570982.0	7781.45
BIOSPHERE 2 CENTER INC	N/A	N/A	N/A	27022.7	11259.5	N/A	2488.8	1037.0	2.50
CHILDS	N/A	N/A	N/A	0.0	0.0	N/A	20879.0	8833.0	0.00
CHOLLA	N/A	N/A	N/A	82362288.0	35757011.0	N/A	6795289.0	2920529.0	13780.99
CORONADO	N/A	N/A	N/A	69344438.0	29514079.0	N/A	6276187.0	2691266.0	14271.79
CROSSCUT	N/A	N/A	N/A	0.0	0.0	N/A	5236.0	5053.0	0.00
DAVIS	N/A	N/A	N/A	0.0	0.0	N/A	1242714.0	573382.0	0.00
DOUGLAS	N/A	N/A	N/A	72745.9	30310.8	N/A	3672.0	1431.0	32.10
GLEN CANYON	N/A	N/A	N/A	0.0	0.0	N/A	4134622.0	1589468.0	0.00
GOULD ELECTRONICS FOIL DIVISI(	N/A	N/A	N/A	6668.3	2778.5	N/A	550.6	229.4	0.63
HOOVER	N/A	N/A	N/A	0.0	0.0	N/A	2865991.0	1213516.0	0.00
HORSE MESA	N/A	N/A	N/A	0.0	0.0	N/A	222126.0	130262.0	0.00
INA ROAD WATER POLLUTION COI	N/A	N/A	N/A	167667.2	69861.3	N/A	18702.9	7792.9	16.20
IRVING	N/A	N/A	N/A	0.0	0.0	N/A	11982.0	5114.0	0.00
IRVINGTON	N/A	N/A	N/A	18316851.6	9628483.4	N/A	1639965.0	876354.0	2884.34
KYRENE	N/A	N/A	N/A	7916713.6	5002054.6	N/A	394424.0	251668.0	2762.78
MORMON FLAT	N/A	N/A	N/A	0.0	0.0	N/A	80958.0	50221.0	0.00
NAVAJO	N/A	N/A	N/A	196273976.0	84036483.0	N/A	18096243.0	7623743.0	37267.01
NELSON PLANT GENERATORS	N/A	N/A	N/A	3822.0	1592.5	N/A	471.2	196.3	0.35
NEW CORNELIA BRANCH POWER I	N/A	N/A	N/A	38141.9	15892.5	N/A	3221.2	1342.2	3.79
NORTH LOOP	N/A	N/A	N/A	831481.6	346450.7	N/A	49686.0	34023.0	133.59
OCOTILLO	N/A	N/A	N/A	8435320.4	4236604.5	N/A	749070.0	414904.0	701.54
PALO VERDE	N/A	N/A	N/A	0.0	0.0	N/A	30380571.0	13435250.0	0.00
ROOSEVELT	N/A	N/A	N/A	0.0	0.0	N/A	35643.0	29375.0	0.00
SAGUARO	N/A	N/A	N/A	8191494.3	4013723.5	N/A	663616.0	346773.0	678.92
SANTAN	N/A	N/A	N/A	13056927.2	5440386.3	N/A	1483808.0	773607.0	2151.86
SOUTH CONSOLIDATED	N/A	N/A	N/A	0.0	0.0	N/A	1082.0	861.0	0.00
SPRINGERVILLE	N/A	N/A	N/A	60872540.0	25745307.0	N/A	5876943.0	2559848.0	11715.30

)00 Data)

PNAME Plant name	PLNOXOZ Plant 2000 ozone season NOx emissions (tons)	PLSO2AN Plant 2000 annual SO2 emissions (tons)	PLCO2AN Plant 2000 annual CO2 emissions (tons)	PLHGAN Plant 2000 annual mercury emissions (lbs)	PLNOXRTA Plant 2000 annual NOx output emission rate (lbs/MWh)	PLNOXRTO Plant 2000 ozone season NOx output emission rate (lbs/MWh)	PLSO2RTA Plant 2000 annual SO2 output emission rate (lbs/MWh)	PLCO2RTA Plant 2000 annual CO2 output emission rate (lbs/MWh)	PLHGRTA Plant 2000 annual mercury output emission rate (lbs/GWh)
ABITIBI CONSOLIDATED SNOWFLA	301.14	733.44	313283.88	N/A	4.221	4.221	4.283	1829.649	N/A
AGUA FRIA	3024.54	82.02	1333531.54	N/A	5.974	5.346	0.080	1305.177	N/A
APACHE STATION	3540.10	6568.90	3597609.90	130.09	4.499	4.507	3.798	2080.060	0.0376
BIOSPHERE 2 CENTER INC	1.04	0.02	1596.87	N/A	2.006	2.006	0.020	1283.242	N/A
CHILDS	0.00	0.00	0.00	N/A	0.000	0.000	0.000	0.000	N/A
CHOLLA	6071.50	17896.80	8441969.40	351.41	4.056	4.158	5.267	2484.654	0.0517
CORONADO	5932.80	19459.90	7113186.50	298.99	4.548	4.409	6.201	2266.722	0.0476
CROSSCUT	0.00	0.00	0.00	N/A	0.000	0.000	0.000	0.000	N/A
DAVIS	0.00	0.00	0.00	N/A	0.000	0.000	0.000	0.000	N/A
DOUGLAS	13.37	2.78	5807.08	N/A	17.483	18.692	1.513	3162.898	N/A
GLEN CANYON	0.00	0.00	0.00	N/A	0.000	0.000	0.000	0.000	N/A
GOULD ELECTRONICS FOIL DIVISI(	0.26	0.00	386.09	N/A	2.301	2.301	0.004	1402.402	N/A
HOOVER	0.00	0.00	0.00	N/A	0.000	0.000	0.000	0.000	N/A
HORSE MESA	0.00	0.00	0.00	N/A	0.000	0.000	0.000	0.000	N/A
INA ROAD WATER POLLUTION CON	6.75	0.25	5532.85	N/A	1.732	1.732	0.027	591.657	N/A
IRVING	0.00	0.00	0.00	N/A	0.000	0.000	0.000	0.000	N/A
IRVINGTON	1413.40	3419.00	1455423.61	3.14	3.518	3.226	4.170	1774.945	0.0019
KYRENE	2053.45	95.32	472553.85	N/A	14.009	16.319	0.483	2396.172	N/A
MORMON FLAT	0.00	0.00	0.00	N/A	0.000	0.000	0.000	0.000	N/A
NAVAJO	16184.00	4837.10	20137720.90	321.36	4.119	4.246	0.535	2225.625	0.0178
NELSON PLANT GENERATORS	0.15	0.50	305.10	N/A	1.498	1.498	2.135	1295.067	N/A
NEW CORNELIA BRANCH POWER I	1.58	0.10	2219.04	N/A	2.354	2.354	0.064	1377.749	N/A
NORTH LOOP	55.66	1.44	48392.20	N/A	5.377	3.272	0.058	1947.921	N/A
OCOTILLO	343.99	7.66	504972.50	N/A	1.873	1.658	0.020	1348.265	N/A
PALO VERDE	0.00	0.00	0.00	N/A	0.000	0.000	0.000	0.000	N/A
ROOSEVELT	0.00	0.00	0.00	N/A	0.000	0.000	0.000	0.000	N/A
SAGUARO	306.85	154.00	495723.06	N/A	2.046	1.770	0.464	1494.006	N/A
SANTAN	896.61	30.43	764564.40	N/A	2.900	2.318	0.041	1030.544	N/A
SOUTH CONSOLIDATED	0.00	0.00	0.00	N/A	0.000	0.000	0.000	0.000	N/A
SPRINGERVILLE	4891.10	19048.40	6245526.40	326.68	3.987	3.821	6.482	2125.434	0.0556

)00 Data)

PNAME Plant name	PLNOXRA Plant 2000 annual NOx input emission rate (lbs/MMBtu)	PLNOXRO Plant 2000 ozone season NOx input emission rate (lbs/MMBtu)	PLSO2RA Plant 2000 annual SO2 input emission rate (lbs/MMBtu)	PLCO2RA Plant 2000 annual CO2 input emission rate (lbs/MMBtu)	PLHGRA Plant 2000 annual mercury input emission rate (lbs/BBtu)	PLHTRT Plant 2000 nominal heat rate (Btu/kWh)	PLGENACL Plant 2000 annual coal net generation (MWh)	PLGENAOL Plant 2000 annual oil net generation (MWh)
ABITIBI CONSOLIDATED SNOWFLA	0.468	0.468	0.475	203.032	N/A	9011.614	330502.4	278.6
AGUA FRIA	0.543	0.542	0.007	118.690	N/A	10996.480	0.0	32226.0
APACHE STATION	0.420	0.429	0.355	194.293	0.0035	10705.771	2862418.0	0.0
BIOSPHERE 2 CENTER INC	0.185	0.185	0.002	118.187	N/A	10857.703	0.0	135.5
CHILDS	0.000	0.000	0.000	0.000	N/A	0.000	0.0	0.0
CHOLLA	0.335	0.340	0.435	204.996	0.0043	12120.498	6787337.0	6576.0
CORONADO	0.412	0.402	0.561	205.155	0.0043	11048.816	6272316.0	3871.0
CROSSCUT	0.000	0.000	0.000	0.000	N/A	0.000	0.0	0.0
DAVIS	0.000	0.000	0.000	0.000	N/A	0.000	0.0	0.0
DOUGLAS	0.882	0.882	0.076	159.654	N/A	19810.974	0.0	3672.0
GLEN CANYON	0.000	0.000	0.000	0.000	N/A	0.000	0.0	0.0
GOULD ELECTRONICS FOIL DIVISI	0.190	0.190	0.000	115.799	N/A	12110.654	0.0	0.0
HOOVER	0.000	0.000	0.000	0.000	N/A	0.000	0.0	0.0
HORSE MESA	0.000	0.000	0.000	0.000	N/A	0.000	0.0	0.0
INA ROAD WATER POLLUTION CO	0.193	0.193	0.003	65.998	N/A	8964.768	0.0	0.0
IRVING	0.000	0.000	0.000	0.000	N/A	0.000	0.0	0.0
IRVINGTON	0.315	0.294	0.373	158.916	0.0002	11169.050	789923.0	320.0
KYRENE	0.698	0.821	0.024	119.381	N/A	20071.582	0.0	15357.0
MORMON FLAT	0.000	0.000	0.000	0.000	N/A	0.000	0.0	0.0
NAVAJO	0.380	0.385	0.049	205.200	0.0016	10846.117	18076057.0	20186.0
NELSON PLANT GENERATORS	0.185	0.185	0.263	159.654	N/A	8111.717	0.0	471.2
NEW CORNELIA BRANCH POWER	0.199	0.199	0.005	116.357	N/A	11840.724	0.0	41.0
NORTH LOOP	0.321	0.321	0.003	116.400	N/A	16734.726	0.0	25.0
OCOTILLO	0.166	0.162	0.002	119.728	N/A	11261.058	0.0	0.0
PALO VERDE	0.000	0.000	0.000	0.000	N/A	0.000	0.0	0.0
ROOSEVELT	0.000	0.000	0.000	0.000	N/A	0.000	0.0	0.0
SAGUARO	0.166	0.153	0.038	121.034	N/A	12343.726	0.0	30784.0
SANTAN	0.330	0.330	0.005	117.112	N/A	8799.607	0.0	25262.0
SOUTH CONSOLIDATED	0.000	0.000	0.000	0.000	N/A	0.000	0.0	0.0
SPRINGERVILLE	0.385	0.380	0.626	205.200	0.0054	10357.858	5874576.0	2367.0

)00 Data)

PNAME Plant name	PLGENAGS Plant 2000 annual gas net generation (MWh)	PLGENANC Plant 2000 annual nuclear net generation (MWh)	PLGENAHY Plant 2000 annual hydro net generation (MWh)	PLGENABM Plant 2000 annual biomass/ wood net generation (MWh)	PLGENAWI Plant 2000 annual wind net generation (MWh)	PLGENASO Plant 2000 annual solar net generation (MWh)	PLGENAGT Plant 2000 annual geothermal net generation (MWh)	PLGENAOF Plant 2000 annual other fossil (tires, batteries, chemicals, etc.) net generation (MWh)	PLGENASW Plant 2000 annual solid waste net generation (MWh)
ABITIBI CONSOLIDATED SNOWFLA	11671.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AGUA FRIA	2011223.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
APACHE STATION	596723.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BIOSPHERE 2 CENTER INC	2353.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CHILDS	0.0	0.0	20879.0	0.0	0.0	0.0	0.0	0.0	0.0
CHOLLA	1376.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CORONADO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CROSSCUT	0.0	0.0	5236.0	0.0	0.0	0.0	0.0	0.0	0.0
DAVIS	0.0	0.0	1242714.0	0.0	0.0	0.0	0.0	0.0	0.0
DOUGLAS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GLEN CANYON	0.0	0.0	4134622.0	0.0	0.0	0.0	0.0	0.0	0.0
GOULD ELECTRONICS FOIL DIVISI(	550.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HOOVER	0.0	0.0	2865991.0	0.0	0.0	0.0	0.0	0.0	0.0
HORSE MESA	0.0	0.0	222126.0	0.0	0.0	0.0	0.0	0.0	0.0
INA ROAD WATER POLLUTION COI	14119.6	0.0	0.0	4583.3	0.0	0.0	0.0	0.0	0.0
IRVING	0.0	0.0	11982.0	0.0	0.0	0.0	0.0	0.0	0.0
IRVINGTON	849722.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
KYRENE	379067.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MORMON FLAT	0.0	0.0	80958.0	0.0	0.0	0.0	0.0	0.0	0.0
NAVAJO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NELSON PLANT GENERATORS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NEW CORNELIA BRANCH POWER I	3180.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NORTH LOOP	49661.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OCOTILLO	749070.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PALO VERDE	0.0	30380571.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ROOSEVELT	0.0	0.0	35643.0	0.0	0.0	0.0	0.0	0.0	0.0
SAGUARO	632832.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SANTAN	1458546.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTH CONSOLIDATED	0.0	0.0	1082.0	0.0	0.0	0.0	0.0	0.0	0.0
SPRINGERVILLE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

)00 Data)

PNAME Plant name	PLGENATN Plant 2000 annual total nonrenewables net generation (MWh)	PLGENATR Plant 2000 annual total renewables net generation (MWh)	PLGENATH Plant 2000 annual total nonhydro renewables net generation (MWh)	PLCLPR Plant 2000 coal generation percent (resource mix)	PLOLPR Plant 2000 oil generation percent (resource mix)	PLGSPR Plant 2000 gas generation percent (resource mix)	PLNCPR Plant 2000 nuclear generation percent (resource mix)	PLHYPR Plant 2000 hydro generation percent (resource mix)	PLBMPR Plant 2000 biomass/ wood generation percent (resource mix)
ABITIBI CONSOLIDATED SNOWFLA	342452.4	0.0	0.0	96.5105	0.0813	3.4082	0.0000	0.0000	0.0000
AGUA FRIA	2043449.0	0.0	0.0	0.0000	1.5770	98.4230	0.0000	0.0000	0.0000
APACHE STATION	3459141.0	0.0	0.0	82.7494	0.0000	17.2506	0.0000	0.0000	0.0000
BIOSPHERE 2 CENTER INC	2488.8	0.0	0.0	0.0000	5.4457	94.5543	0.0000	0.0000	0.0000
CHILDS	0.0	20879.0	0.0	0.0000	0.0000	0.0000	0.0000	100.0000	0.0000
CHOLLA	6795289.0	0.0	0.0	99.8830	0.0968	0.0202	0.0000	0.0000	0.0000
CORONADO	6276187.0	0.0	0.0	99.9383	0.0617	0.0000	0.0000	0.0000	0.0000
CROSSCUT	0.0	5236.0	0.0	0.0000	0.0000	0.0000	0.0000	100.0000	0.0000
DAVIS	0.0	1242714.0	0.0	0.0000	0.0000	0.0000	0.0000	100.0000	0.0000
DOUGLAS	3672.0	0.0	0.0	0.0000	100.0000	0.0000	0.0000	0.0000	0.0000
GLEN CANYON	0.0	4134622.0	0.0	0.0000	0.0000	0.0000	0.0000	100.0000	0.0000
GOULD ELECTRONICS FOIL DIVISI(	550.6	0.0	0.0	0.0000	0.0000	100.0000	0.0000	0.0000	0.0000
HOOVER	0.0	2865991.0	0.0	0.0000	0.0000	0.0000	0.0000	100.0000	0.0000
HORSE MESA	0.0	222126.0	0.0	0.0000	0.0000	0.0000	0.0000	100.0000	0.0000
INA ROAD WATER POLLUTION COI	14119.6	4583.3	4583.3	0.0000	0.0000	75.4941	0.0000	0.0000	24.5059
IRVING	0.0	11982.0	0.0	0.0000	0.0000	0.0000	0.0000	100.0000	0.0000
IRVINGTON	1639965.0	0.0	0.0	48.1671	0.0195	51.8134	0.0000	0.0000	0.0000
KYRENE	394424.0	0.0	0.0	0.0000	3.8935	96.1065	0.0000	0.0000	0.0000
MORMON FLAT	0.0	80958.0	0.0	0.0000	0.0000	0.0000	0.0000	100.0000	0.0000
NAVAJO	18096243.0	0.0	0.0	99.8885	0.1115	0.0000	0.0000	0.0000	0.0000
NELSON PLANT GENERATORS	471.2	0.0	0.0	0.0000	100.0000	0.0000	0.0000	0.0000	0.0000
NEW CORNELIA BRANCH POWER I	3221.2	0.0	0.0	0.0000	1.2718	98.7282	0.0000	0.0000	0.0000
NORTH LOOP	49686.0	0.0	0.0	0.0000	0.0503	99.9497	0.0000	0.0000	0.0000
OCOTILLO	749070.0	0.0	0.0	0.0000	0.0000	100.0000	0.0000	0.0000	0.0000
PALO VERDE	30380571.0	0.0	0.0	0.0000	0.0000	0.0000	100.0000	0.0000	0.0000
ROOSEVELT	0.0	35643.0	0.0	0.0000	0.0000	0.0000	0.0000	100.0000	0.0000
SAGUARO	663616.0	0.0	0.0	0.0000	4.6388	95.3612	0.0000	0.0000	0.0000
SANTAN	1483808.0	0.0	0.0	0.0000	1.7025	98.2975	0.0000	0.0000	0.0000
SOUTH CONSOLIDATED	0.0	1082.0	0.0	0.0000	0.0000	0.0000	0.0000	100.0000	0.0000
SPRINGERVILLE	5876943.0	0.0	0.0	99.9597	0.0403	0.0000	0.0000	0.0000	0.0000

)00 Data)

PNAME Plant name	PLWIPR Plant 2000 wind generation percent (resource mix)	PLSOPR Plant 2000 solar generation percent (resource mix)	PLGTPR Plant 2000 geothermal generation percent (resource mix)	PLOFPR Plant 2000 other fossil (tires, batteries, chemicals, etc.) generation percent (resource mix)	PLSWPR Plant 2000 solid waste generation percent (resource mix)	PLTNPR Plant 2000 total nonrenewables generation percent (resource mix)	PLTRPR Plant 2000 total renewables generation percent (resource mix)	PLTHPR Plant 2000 total nonhydro renewables generation percent (resource mix)
ABITIBI CONSOLIDATED SNOWFLA	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
AGUA FRIA	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
APACHE STATION	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
BIOSPHERE 2 CENTER INC	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
CHILDS	0.0000	0.0000	0.0000	0.0000	N/A	0.0000	100.0000	0.0000
CHOLLA	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
CORONADO	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
CROSSCUT	0.0000	0.0000	0.0000	0.0000	N/A	0.0000	100.0000	0.0000
DAVIS	0.0000	0.0000	0.0000	0.0000	N/A	0.0000	100.0000	0.0000
DOUGLAS	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
GLEN CANYON	0.0000	0.0000	0.0000	0.0000	N/A	0.0000	100.0000	0.0000
GOULD ELECTRONICS FOIL DIVISI(	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
HOOVER	0.0000	0.0000	0.0000	0.0000	N/A	0.0000	100.0000	0.0000
HORSE MESA	0.0000	0.0000	0.0000	0.0000	N/A	0.0000	100.0000	0.0000
INA ROAD WATER POLLUTION CON	0.0000	0.0000	0.0000	0.0000	N/A	75.4941	24.5059	24.5059
IRVING	0.0000	0.0000	0.0000	0.0000	N/A	0.0000	100.0000	0.0000
IRVINGTON	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
KYRENE	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
MORMON FLAT	0.0000	0.0000	0.0000	0.0000	N/A	0.0000	100.0000	0.0000
NAVAJO	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
NELSON PLANT GENERATORS	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
NEW CORNELIA BRANCH POWER I	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
NORTH LOOP	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
OCOTILLO	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
PALO VERDE	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
ROOSEVELT	0.0000	0.0000	0.0000	0.0000	N/A	0.0000	100.0000	0.0000
SAGUARO	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
SANTAN	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000
SOUTH CONSOLIDATED	0.0000	0.0000	0.0000	0.0000	N/A	0.0000	100.0000	0.0000
SPRINGERVILLE	0.0000	0.0000	0.0000	0.0000	N/A	100.0000	0.0000	0.0000

)00 Data)

PNAME Plant name	OWNRNM01 Plant 2000 owner name (first)	OWNRUC01 Plant 2000 owner code (first)	OWNRPR01 Plant 2000 owner percent (first)	OWNRTY01 Plant 2000 owner type (first)	OWNRNM02 Plant 2000 owner name (second)
ABITIBI CONSOLIDATED SNOWFLA	Abitibi Consolidated	-1245.0	100.0000	NU	
AGUA FRIA	Salt River Proj Ag I & P Dist	16572.0	100.0000	UT	
APACHE STATION	Arizona Electric Pwr Coop Inc	796.0	100.0000	UT	
BIOSPHERE 2 CENTER INC	Decisions Investments Corp	4831.0	100.0000	NU	
CHILDS	Arizona Public Service Co	803.0	100.0000	UT	
CHOLLA	Arizona Public Service Co	803.0	62.5487	UT	PacifiCorp-East
CORONADO	Salt River Proj Ag I & P Dist	16572.0	100.0000	UT	
CROSSCUT	Salt River Proj Ag I & P Dist	16572.0	100.0000	UT	
DAVIS	USBR-Lower Colorado Region	19580.0	100.0000	UT	
DOUGLAS	Arizona Public Service Co	803.0	100.0000	UT	
GLEN CANYON	USBR-Upper Colorado Region	25472.0	100.0000	UT	
GOULD ELECTRONICS FOIL DIVISI(	Japan Energy Corp Ltd	9669.0	100.0000	NU	
HOOVER	USBR-Lower Colorado Region	19580.0	100.0000	UT	
HORSE MESA	Salt River Proj Ag I & P Dist	16572.0	100.0000	UT	
INA ROAD WATER POLLUTION COI	PIMA County Wastewater Manage	15090.0	100.0000	NU	
IRVING	Arizona Public Service Co	803.0	100.0000	UT	
IRVINGTON	Tucson Electric Power Co	24211.0	100.0000	UT	
KYRENE	Salt River Proj Ag I & P Dist	16572.0	100.0000	UT	
MORMON FLAT	Salt River Proj Ag I & P Dist	16572.0	100.0000	UT	
NAVAJO	USBR-Upper Colorado Region	25472.0	24.3000	UT	Salt River Proj Ag I & P Dist
NELSON PLANT GENERATORS	Chemical Lime Co	3468.0	100.0000	NU	
NEW CORNELIA BRANCH POWER I	Phelps Dodge Corp	-1118.0	100.0000	NU	
NORTH LOOP	Tucson Electric Power Co	24211.0	100.0000	UT	
OCOTILLO	Arizona Public Service Co	803.0	100.0000	UT	
PALO VERDE	Arizona Public Service Co	803.0	29.1000	UT	Salt River Proj Ag I & P Dist
ROOSEVELT	Salt River Proj Ag I & P Dist	16572.0	100.0000	UT	
SAGUARO	Arizona Public Service Co	803.0	100.0000	UT	
SANTAN	Salt River Proj Ag I & P Dist	16572.0	100.0000	UT	
SOUTH CONSOLIDATED	Salt River Proj Ag I & P Dist	16572.0	100.0000	UT	
SPRINGERVILLE	Tucson Electric Power Co	24211.0	100.0000	UT	

)00 Data)

PNAME Plant name	OWNRUC02 Plant 2000 owner code (second)	OWNRPR02 Plant 2000 owner percent (second)	OWNRTY02 Plant 2000 owner type (second)	OWNRNM03 Plant 2000 owner name (third)	OWNRUC03 Plant 2000 owner code (third)	OWNRPR03 Plant 2000 owner percent (third)	OWNRTY03 Plant 2000 owner type (third)
ABITIBI CONSOLIDATED SNOWFLA	0.0	0.0000			0.0	0.0000	
AGUA FRIA	0.0	0.0000			0.0	0.0000	
APACHE STATION	0.0	0.0000			0.0	0.0000	
BIOSPHERE 2 CENTER INC	0.0	0.0000			0.0	0.0000	
CHILDS	0.0	0.0000			0.0	0.0000	
CHOLLA	14354.1	37.4513	UT		0.0	0.0000	
CORONADO	0.0	0.0000			0.0	0.0000	
CROSSCUT	0.0	0.0000			0.0	0.0000	
DAVIS	0.0	0.0000			0.0	0.0000	
DOUGLAS	0.0	0.0000			0.0	0.0000	
GLEN CANYON	0.0	0.0000			0.0	0.0000	
GOULD ELECTRONICS FOIL DIVISI(	0.0	0.0000			0.0	0.0000	
HOOVER	0.0	0.0000			0.0	0.0000	
HORSE MESA	0.0	0.0000			0.0	0.0000	
INA ROAD WATER POLLUTION COI	0.0	0.0000			0.0	0.0000	
IRVING	0.0	0.0000			0.0	0.0000	
IRVINGTON	0.0	0.0000			0.0	0.0000	
KYRENE	0.0	0.0000			0.0	0.0000	
MORMON FLAT	0.0	0.0000			0.0	0.0000	
NAVAJO	16572.0	21.7000	UT	Los Angeles City of	11208.0	21.2000	UT
NELSON PLANT GENERATORS	0.0	0.0000			0.0	0.0000	
NEW CORNELIA BRANCH POWER I	0.0	0.0000			0.0	0.0000	
NORTH LOOP	0.0	0.0000			0.0	0.0000	
OCOTILLO	0.0	0.0000			0.0	0.0000	
PALO VERDE	16572.0	17.4900	UT	El Paso Electric Co	5701.0	15.8000	UT
ROOSEVELT	0.0	0.0000			0.0	0.0000	
SAGUARO	0.0	0.0000			0.0	0.0000	
SANTAN	0.0	0.0000			0.0	0.0000	
SOUTH CONSOLIDATED	0.0	0.0000			0.0	0.0000	
SPRINGERVILLE	0.0	0.0000			0.0	0.0000	

)00 Data)

PNAME Plant name	OWNRNM04 Plant 2000 owner name (fourth)	OWNRUC04 Plant 2000 owner code (fourth)	OWNRPR04 Plant 2000 owner percent (fourth)	OWNRTY04 Plant 2000 owner type (fourth)	OWNRNM05 Plant 2000 owner name (fifth)	OWNRUC05 Plant 2000 owner code (fifth)
ABITIBI CONSOLIDATED SNOWFLA		0.0	0.0000			0.0
AGUA FRIA		0.0	0.0000			0.0
APACHE STATION		0.0	0.0000			0.0
BIOSPHERE 2 CENTER INC		0.0	0.0000			0.0
CHILDS		0.0	0.0000			0.0
CHOLLA		0.0	0.0000			0.0
CORONADO		0.0	0.0000			0.0
CROSSCUT		0.0	0.0000			0.0
DAVIS		0.0	0.0000			0.0
DOUGLAS		0.0	0.0000			0.0
GLEN CANYON		0.0	0.0000			0.0
GOULD ELECTRONICS FOIL DIVISI(		0.0	0.0000			0.0
HOOVER		0.0	0.0000			0.0
HORSE MESA		0.0	0.0000			0.0
INA ROAD WATER POLLUTION COI		0.0	0.0000			0.0
IRVING		0.0	0.0000			0.0
IRVINGTON		0.0	0.0000			0.0
KYRENE		0.0	0.0000			0.0
MORMON FLAT		0.0	0.0000			0.0
NAVAJO	Arizona Public Service Co	803.0	14.0000	UT	Nevada Power Co	13407.0
NELSON PLANT GENERATORS		0.0	0.0000			0.0
NEW CORNELIA BRANCH POWER I		0.0	0.0000			0.0
NORTH LOOP		0.0	0.0000			0.0
OCOTILLO		0.0	0.0000			0.0
PALO VERDE	Southern California Edison Co	17609.0	15.8000	UT	Public Service Co of NM	15473.0
ROOSEVELT		0.0	0.0000			0.0
SAGUARO		0.0	0.0000			0.0
SANTAN		0.0	0.0000			0.0
SOUTH CONSOLIDATED		0.0	0.0000			0.0
SPRINGERVILLE		0.0	0.0000			0.0

)00 Data)

PNAME Plant name	OWNRPR05 Plant 2000 owner percent (fifth)	OWNRTY05 Plant 2000 owner type (fifth)	OWNRNM06 Plant 2000 owner name (sixth)	OWNRUC06 Plant 2000 owner code (sixth)	OWNRPR06 Plant 2000 owner percent (sixth)	OWNRTY06 Plant 2000 owner type (sixth)	OWNRNM07 Plant 2000 owner name (seventh)
ABITIBI CONSOLIDATED SNOWFLA	0.0000			0.0	0.0000		
AGUA FRIA	0.0000			0.0	0.0000		
APACHE STATION	0.0000			0.0	0.0000		
BIOSPHERE 2 CENTER INC	0.0000			0.0	0.0000		
CHILDS	0.0000			0.0	0.0000		
CHOLLA	0.0000			0.0	0.0000		
CORONADO	0.0000			0.0	0.0000		
CROSSCUT	0.0000			0.0	0.0000		
DAVIS	0.0000			0.0	0.0000		
DOUGLAS	0.0000			0.0	0.0000		
GLEN CANYON	0.0000			0.0	0.0000		
GOULD ELECTRONICS FOIL DIVISI	0.0000			0.0	0.0000		
HOOVER	0.0000			0.0	0.0000		
HORSE MESA	0.0000			0.0	0.0000		
INA ROAD WATER POLLUTION COI	0.0000			0.0	0.0000		
IRVING	0.0000			0.0	0.0000		
IRVINGTON	0.0000			0.0	0.0000		
KYRENE	0.0000			0.0	0.0000		
MORMON FLAT	0.0000			0.0	0.0000		
NAVAJO	11.3000	UT	Tucson Electric Power Co	24211.0	7.5000	UT	
NELSON PLANT GENERATORS	0.0000			0.0	0.0000		
NEW CORNELIA BRANCH POWER I	0.0000			0.0	0.0000		
NORTH LOOP	0.0000			0.0	0.0000		
OCOTILLO	0.0000			0.0	0.0000		
PALO VERDE	10.2000	UT	Southern California P P A	17513.0	5.9100	UT	Los Angeles City of
ROOSEVELT	0.0000			0.0	0.0000		
SAGUARO	0.0000			0.0	0.0000		
SANTAN	0.0000			0.0	0.0000		
SOUTH CONSOLIDATED	0.0000			0.0	0.0000		
SPRINGERVILLE	0.0000			0.0	0.0000		

)00 Data)

PNAME Plant name	OWNRUC07 Plant 2000 owner code (seventh)	OWNRPR07 Plant 2000 owner percent (seventh)	OWNRTY07 Plant 2000 owner type (seventh)	OWNRNM08 Plant 2000 owner name (eighth)	OWNRUC08 Plant 2000 owner code (eighth)	OWNRPR08 Plant 2000 owner percent (eighth)	OWNRTY08 Plant 2000 owner type (eighth)
ABITIBI CONSOLIDATED SNOWFLA	0.0	0.0000			0.0	0.0000	
AGUA FRIA	0.0	0.0000			0.0	0.0000	
APACHE STATION	0.0	0.0000			0.0	0.0000	
BIOSPHERE 2 CENTER INC	0.0	0.0000			0.0	0.0000	
CHILDS	0.0	0.0000			0.0	0.0000	
CHOLLA	0.0	0.0000			0.0	0.0000	
CORONADO	0.0	0.0000			0.0	0.0000	
CROSSCUT	0.0	0.0000			0.0	0.0000	
DAVIS	0.0	0.0000			0.0	0.0000	
DOUGLAS	0.0	0.0000			0.0	0.0000	
GLEN CANYON	0.0	0.0000			0.0	0.0000	
GOULD ELECTRONICS FOIL DIVISI(	0.0	0.0000			0.0	0.0000	
HOOVER	0.0	0.0000			0.0	0.0000	
HORSE MESA	0.0	0.0000			0.0	0.0000	
INA ROAD WATER POLLUTION COI	0.0	0.0000			0.0	0.0000	
IRVING	0.0	0.0000			0.0	0.0000	
IRVINGTON	0.0	0.0000			0.0	0.0000	
KYRENE	0.0	0.0000			0.0	0.0000	
MORMON FLAT	0.0	0.0000			0.0	0.0000	
NAVAJO	0.0	0.0000			0.0	0.0000	
NELSON PLANT GENERATORS	0.0	0.0000			0.0	0.0000	
NEW CORNELIA BRANCH POWER I	0.0	0.0000			0.0	0.0000	
NORTH LOOP	0.0	0.0000			0.0	0.0000	
OCOTILLO	0.0	0.0000			0.0	0.0000	
PALO VERDE	11208.0	5.7000	UT		0.0	0.0000	
ROOSEVELT	0.0	0.0000			0.0	0.0000	
SAGUARO	0.0	0.0000			0.0	0.0000	
SANTAN	0.0	0.0000			0.0	0.0000	
SOUTH CONSOLIDATED	0.0	0.0000			0.0	0.0000	
SPRINGERVILLE	0.0	0.0000			0.0	0.0000	

)00 Data)

PNAME Plant name	OWNRNM09 Plant 2000 owner name (ninth)	OWNRUC09 Plant 2000 owner code (ninth)	OWNRPR09 Plant 2000 owner percent (ninth)	OWNRTY09 Plant 2000 owner type (ninth)	OWNRNM10 Plant 2000 owner name (tenth)	OWNRUC10 Plant 2000 owner code (tenth)
ABITIBI CONSOLIDATED SNOWFLA		0.0	0.0000			0.0
AGUA FRIA		0.0	0.0000			0.0
APACHE STATION		0.0	0.0000			0.0
BIOSPHERE 2 CENTER INC		0.0	0.0000			0.0
CHILDS		0.0	0.0000			0.0
CHOLLA		0.0	0.0000			0.0
CORONADO		0.0	0.0000			0.0
CROSSCUT		0.0	0.0000			0.0
DAVIS		0.0	0.0000			0.0
DOUGLAS		0.0	0.0000			0.0
GLEN CANYON		0.0	0.0000			0.0
GOULD ELECTRONICS FOIL DIVISI		0.0	0.0000			0.0
HOOVER		0.0	0.0000			0.0
HORSE MESA		0.0	0.0000			0.0
INA ROAD WATER POLLUTION CON		0.0	0.0000			0.0
IRVING		0.0	0.0000			0.0
IRVINGTON		0.0	0.0000			0.0
KYRENE		0.0	0.0000			0.0
MORMON FLAT		0.0	0.0000			0.0
NAVAJO		0.0	0.0000			0.0
NELSON PLANT GENERATORS		0.0	0.0000			0.0
NEW CORNELIA BRANCH POWER F		0.0	0.0000			0.0
NORTH LOOP		0.0	0.0000			0.0
OCOTILLO		0.0	0.0000			0.0
PALO VERDE		0.0	0.0000			0.0
ROOSEVELT		0.0	0.0000			0.0
SAGUARO		0.0	0.0000			0.0
SANTAN		0.0	0.0000			0.0
SOUTH CONSOLIDATED		0.0	0.0000			0.0
SPRINGERVILLE		0.0	0.0000			0.0

PNAME Plant name	OWNRPR10 Plant 2000 owner percent (tenth)	OWNRTY10 Plant 2000 owner type (tenth)	OWNRNM11 Plant 2000 owner name (eleventh)	OWNRUC11 Plant 2000 owner code (eleventh)	OWNRPR11 Plant 2000 owner percent (eleventh)
ABITIBI CONSOLIDATED SNOWFLA	0.0000			0.0	0.0000
AGUA FRIA	0.0000			0.0	0.0000
APACHE STATION	0.0000			0.0	0.0000
BIOSPHERE 2 CENTER INC	0.0000			0.0	0.0000
CHILDS	0.0000			0.0	0.0000
CHOLLA	0.0000			0.0	0.0000
CORONADO	0.0000			0.0	0.0000
CROSSCUT	0.0000			0.0	0.0000
DAVIS	0.0000			0.0	0.0000
DOUGLAS	0.0000			0.0	0.0000
GLEN CANYON	0.0000			0.0	0.0000
GOULD ELECTRONICS FOIL DIVISI(	0.0000			0.0	0.0000
HOOVER	0.0000			0.0	0.0000
HORSE MESA	0.0000			0.0	0.0000
INA ROAD WATER POLLUTION COI	0.0000			0.0	0.0000
IRVING	0.0000			0.0	0.0000
IRVINGTON	0.0000			0.0	0.0000
KYRENE	0.0000			0.0	0.0000
MORMON FLAT	0.0000			0.0	0.0000
NAVAJO	0.0000			0.0	0.0000
NELSON PLANT GENERATORS	0.0000			0.0	0.0000
NEW CORNELIA BRANCH POWER I	0.0000			0.0	0.0000
NORTH LOOP	0.0000			0.0	0.0000
OCOTILLO	0.0000			0.0	0.0000
PALO VERDE	0.0000			0.0	0.0000
ROOSEVELT	0.0000			0.0	0.0000
SAGUARO	0.0000			0.0	0.0000
SANTAN	0.0000			0.0	0.0000
SOUTH CONSOLIDATED	0.0000			0.0	0.0000
SPRINGERVILLE	0.0000			0.0	0.0000

)00 Data)

PNAME Plant name	OWNRTY11 Plant 2000 owner type (eleventh)	OWNRNM12 Plant 2000 owner name (twelfth)	OWNRUC12 Plant 2000 owner code (twelfth)	OWNRPR12 Plant 2000 owner percent (twelfth)	OWNRTY12 Plant 2000 owner type (twelfth)
ABITIBI CONSOLIDATED SNOWFLA			0.0	0.0000	
AGUA FRIA			0.0	0.0000	
APACHE STATION			0.0	0.0000	
BIOSPHERE 2 CENTER INC			0.0	0.0000	
CHILDS			0.0	0.0000	
CHOLLA			0.0	0.0000	
CORONADO			0.0	0.0000	
CROSSCUT			0.0	0.0000	
DAVIS			0.0	0.0000	
DOUGLAS			0.0	0.0000	
GLEN CANYON			0.0	0.0000	
GOULD ELECTRONICS FOIL DIVISI(			0.0	0.0000	
HOOVER			0.0	0.0000	
HORSE MESA			0.0	0.0000	
INA ROAD WATER POLLUTION COI			0.0	0.0000	
IRVING			0.0	0.0000	
IRVINGTON			0.0	0.0000	
KYRENE			0.0	0.0000	
MORMON FLAT			0.0	0.0000	
NAVAJO			0.0	0.0000	
NELSON PLANT GENERATORS			0.0	0.0000	
NEW CORNELIA BRANCH POWER I			0.0	0.0000	
NORTH LOOP			0.0	0.0000	
OCOTILLO			0.0	0.0000	
PALO VERDE			0.0	0.0000	
ROOSEVELT			0.0	0.0000	
SAGUARO			0.0	0.0000	
SANTAN			0.0	0.0000	
SOUTH CONSOLIDATED			0.0	0.0000	
SPRINGERVILLE			0.0	0.0000	

)00 Data)

PNAME Plant name	OWNRNM13 Plant 2000 owner name (thirteenth)	OWNRUC13 Plant 2000 owner code (thirteenth)	OWNRPR13 Plant 2000 owner percent (thirteenth)	OWNRTY13 Plant 2000 owner type (thirteenth)	OWNRNM14 Plant 2000 owner name (fourteenth)
ABITIBI CONSOLIDATED SNOWFLA		0.0	0.0000		
AGUA FRIA		0.0	0.0000		
APACHE STATION		0.0	0.0000		
BIOSPHERE 2 CENTER INC		0.0	0.0000		
CHILDS		0.0	0.0000		
CHOLLA		0.0	0.0000		
CORONADO		0.0	0.0000		
CROSSCUT		0.0	0.0000		
DAVIS		0.0	0.0000		
DOUGLAS		0.0	0.0000		
GLEN CANYON		0.0	0.0000		
GOULD ELECTRONICS FOIL DIVISI(		0.0	0.0000		
HOOVER		0.0	0.0000		
HORSE MESA		0.0	0.0000		
INA ROAD WATER POLLUTION COI		0.0	0.0000		
IRVING		0.0	0.0000		
IRVINGTON		0.0	0.0000		
KYRENE		0.0	0.0000		
MORMON FLAT		0.0	0.0000		
NAVAJO		0.0	0.0000		
NELSON PLANT GENERATORS		0.0	0.0000		
NEW CORNELIA BRANCH POWER I		0.0	0.0000		
NORTH LOOP		0.0	0.0000		
OCOTILLO		0.0	0.0000		
PALO VERDE		0.0	0.0000		
ROOSEVELT		0.0	0.0000		
SAGUARO		0.0	0.0000		
SANTAN		0.0	0.0000		
SOUTH CONSOLIDATED		0.0	0.0000		
SPRINGERVILLE		0.0	0.0000		

)00 Data)

PNAME Plant name	OWNRUC14 Plant 2000 owner code (fourteenth)	OWNRPR14 Plant 2000 owner percent (fourteenth)	OWNRTY14 Plant 2000 owner type (fourteenth)	SEQPLT eGRID96 1996 file plant sequence number	SEQPLT97 eGRID97 1997 file plant sequence number	SEQPLT98 eGRID2000 1998 file plant sequence number
ABITIBI CONSOLIDATED SNOWFLA	0.0	0.0000		281	280	244
AGUA FRIA	0.0	0.0000		249	248	245
APACHE STATION	0.0	0.0000		250	249	246
BIOSPHERE 2 CENTER INC	0.0	0.0000		251	250	247
CHILDS	0.0	0.0000		252	251	248
CHOLLA	0.0	0.0000		253	252	249
CORONADO	0.0	0.0000		254	253	250
CROSSCUT	0.0	0.0000		255	254	251
DAVIS	0.0	0.0000		256	255	252
DOUGLAS	0.0	0.0000		258	257	254
GLEN CANYON	0.0	0.0000		259	258	255
GOULD ELECTRONICS FOIL DIVISI	0.0	0.0000		260	259	256
HOOVER	0.0	0.0000		261	260	257
HORSE MESA	0.0	0.0000		262	261	258
INA ROAD WATER POLLUTION COI	0.0	0.0000		N/A	N/A	N/A
IRVING	0.0	0.0000		264	263	259
IRVINGTON	0.0	0.0000		265	264	260
KYRENE	0.0	0.0000		266	265	261
MORMON FLAT	0.0	0.0000		267	266	262
NAVAJO	0.0	0.0000		268	267	263
NELSON PLANT GENERATORS	0.0	0.0000		269	268	264
NEW CORNELIA BRANCH POWER I	0.0	0.0000		270	269	N/A
NORTH LOOP	0.0	0.0000		272	271	265
OCOTILLO	0.0	0.0000		273	272	266
PALO VERDE	0.0	0.0000		274	273	267
ROOSEVELT	0.0	0.0000		275	274	268
SAGUARO	0.0	0.0000		276	275	269
SANTAN	0.0	0.0000		277	276	270
SOUTH CONSOLIDATED	0.0	0.0000		278	277	271
SPRINGERVILLE	0.0	0.0000		279	278	272

eGRID2002 Version 2.01 Boiler File (Year 2000 Data)

SEQBLR00 eGRID2002 2000 file boiler sequence number	SEQBLR99 eGRID2002 1999 file boiler sequence number	PSTATABB State abbreviation	PNAME Plant name	ORISPL DOE/EIA ORIS plant or facility code	BLRID Boiler ID	AFFECTED Affected flag	BOTFIRTY Boiler bottom and firing types	BOILCAP Boiler capacity (MMBtu/hr)
82	78	AZ	AGUA FRIA	141.0	1	Y	DBFF	1020.00
83	79	AZ	AGUA FRIA	141.0	2	Y	DBFF	1020.00
84	80	AZ	AGUA FRIA	141.0	3	Y	DBOT	1632.00
85	81	AZ	APACHE STATION	160.0	1	Y	DBFF	829.60
86	82	AZ	APACHE STATION	160.0	2	Y	DBOF	1842.80
87	83	AZ	APACHE STATION	160.0	3	Y	DBOF	1842.80
88	84	AZ	CHOLLA	113.0	1	Y	DBTF	1176.40
89	85	AZ	CHOLLA	113.0	2	Y	DBTF	2740.40
90	86	AZ	CHOLLA	113.0	3	Y	DBTF	2740.40
91	87	AZ	CHOLLA	113.0	4	Y	DBTF	3848.80
92	88	AZ	CORONADO	6177.0	U1B	Y	DBOF	3735.92
93	89	AZ	CORONADO	6177.0	U2B	Y	DBOF	3735.92
94	90	AZ	IRVINGTON	126.0	1	Y	DBTF	782.00
95	91	AZ	IRVINGTON	126.0	2	Y	DBTF	782.00
96	92	AZ	IRVINGTON	126.0	3	Y	DBTF	1088.00
97	93	AZ	IRVINGTON	126.0	4	Y	DBFF	981.92
98	94	AZ	KYRENE	147.0	K-1	Y	DBFF	476.00
99	95	AZ	KYRENE	147.0	K-2	Y	DBFF	873.12
100	96	AZ	NAVAJO	4941.0	1	Y	DBTF	7357.60
101	97	AZ	NAVAJO	4941.0	2	Y	DBTF	7357.60
102	98	AZ	NAVAJO	4941.0	3	Y	DBTF	7357.60
103	99	AZ	OCOTILLO	116.0	1	Y	DBTF	1088.00
104	100	AZ	OCOTILLO	116.0	2	Y	DBTF	1088.00
105	101	AZ	SAGUARO	118.0	1	Y	DBTF	1224.00
106	102	AZ	SAGUARO	118.0	2	Y	DBTF	1224.00

SEQBLR00 eGRID2002 2000 file boiler sequence number	SEQBLR99 eGRID2002 1999 file boiler sequence number	PSTATABB State abbreviation	PNAME Plant name	ORISPL DOE/EIA ORIS plant or facility code	BLRID Boiler ID	AFFECTED Affected flag	BOTFIRTY Boiler bottom and firing types	BOILCAP Boiler capacity (MMBtu/hr)
107	103	AZ	SPRINGERVILLE	8223.0	1	Y	DBTF	3828.40
108	104	AZ	SPRINGERVILLE	8223.0	2	Y	DBTF	3828.40
109	105	AZ	YUCCA	120.0	1	Y	DBFF	N/A
212	207	CO	ARAPAHOE	465.0	1	Y	DBVF	612.00
213	208	CO	ARAPAHOE	465.0	2	Y	DBVF	612.00
214	209	CO	ARAPAHOE	465.0	3	Y	DBVF	612.00
215	210	CO	ARAPAHOE	465.0	4	Y	DBVF	1264.80
216	N/A	CO	ARAPAHOE COMBUSTION TURBINI	55200.0	CT5	Y		N/A
217	N/A	CO	ARAPAHOE COMBUSTION TURBINI	55200.0	CT6	Y		N/A
218	211	CO	CAMEO	468.0	1	N	DBFF	N/A
219	212	CO	CAMEO	468.0	2	Y	DBFF	N/A
220	213	CO	CHEROKEE	469.0	1	Y	DBVF	1158.72
221	214	CO	CHEROKEE	469.0	2	Y	DBVF	1158.72
222	215	CO	CHEROKEE	469.0	3	Y	DBFF	1550.40
223	216	CO	CHEROKEE	469.0	4	Y	DBTF	3518.32
224	217	CO	COMANCHE	470.0	1	Y	DBTF	3446.24
225	218	CO	COMANCHE	470.0	2	Y	DBOF	3446.24
226	219	CO	CRAIG	6021.0	C1	Y	DBOF	4127.60
227	220	CO	CRAIG	6021.0	C2	Y	DBOF	4127.60
228	221	CO	CRAIG	6021.0	C3	Y	DBOF	4148.00
229	222	CO	FORT ST VRAIN	6112.0	2	Y	DBOT	938.40
230	223	CO	FORT ST VRAIN	6112.0	3	Y	DBOT	938.40
231	224	CO	GEORGE BIRDSALL	493.0	1	N	DBFF	N/A
232	225	CO	GEORGE BIRDSALL	493.0	2	N	DBFF	N/A
233	226	CO	GEORGE BIRDSALL	493.0	3	N	DBFF	N/A
234	227	CO	HAYDEN	525.0	H1	Y	DBFF	1632.00

:000 Data)

PNAME Plant name	NUMGEN Number of associated generators	FUELB1 Primary boiler fuel	LOADHRS Hours connected to load	HTIEAN Boiler 2000 annual ETS/CEM heat input (MMBtu)	HTIEOZ Boiler 2000 ozone season ETS/CEM heat input (MMBtu)	HTIFAN Boiler 2000 annual total EIA-based calculated heat input (MMBtu)	HTIFOZ Boiler 2000 ozone season EIA-based calculated heat input (MMBtu)	HTICL Boiler 2000 annual EIA-based calculated coal heat input (MMBtu)
AGUA FRIA	1	G	4884	4749733.0	2545490.0	4666025.3	2497259.1	0.0
AGUA FRIA	1	G	4705	4426448.0	2044063.0	4665896.0	2428561.3	0.0
AGUA FRIA	1	G	5452	9071394.0	4821045.0	8809257.3	4609684.9	0.0
APACHE STATION	1	G	7331	4595848.0	2352325.0	3579906.5	1767378.6	0.0
APACHE STATION	1	C	8646	17151222.0	7112977.0	15599086.3	6510969.4	15563247.2
APACHE STATION	1	C	8186	15285702.0	7037690.0	14421579.3	6317091.5	14386302.8
CHOLLA	1	C	8292	9431578.0	4265475.0	8585833.5	3807466.3	8568126.0
CHOLLA	1	C	8494	25087567.0	10331574.0	21499508.0	8700190.1	21491864.6
CHOLLA	1	C	7216	20767690.0	10165881.0	18756802.0	9247592.2	18740326.8
CHOLLA	1	C	7336	27075453.0	10994081.0	24735618.8	9580740.3	24687948.8
CORONADO	1	C	8351	34681360.0	15448886.0	31563327.2	13639171.5	31532469.2
CORONADO	1	C	8687	34663078.0	14065193.0	32993429.2	14166480.9	32982379.2
IRVINGTON	1	G	4168	2549079.0	1555852.0	2707141.2	1656153.9	0.0
IRVINGTON	1	G	4260	2820425.0	1666890.0	2944894.2	1762968.1	0.0
IRVINGTON	1	G	3452	3547241.0	2334671.0	3397082.0	2255132.6	0.0
IRVINGTON	1	C	8351	8902912.0	3863906.0	8086117.9	3495936.0	7955107.8
KYRENE	1	G	2061	1064408.0	603597.0	818637.4	493877.8	0.0
KYRENE	1	G	3181	4758957.0	3526229.0	2304917.0	1354391.5	0.0
NAVAJO	1	C	8541	63503234.0	26651681.0	62104129.2	25690198.8	62057402.0
NAVAJO	1	C	7963	62748887.0	27265272.0	58957274.7	25718230.8	58859674.8
NAVAJO	1	C	8375	70021855.0	30119530.0	62322743.4	26627291.2	62233405.4
OCOTILLO	1	G	6131	3798195.0	1919839.0	3619867.5	1923963.4	0.0
OCOTILLO	1	G	5953	3493553.0	1840277.0	3627184.0	1878352.2	0.0
SAGUARO	1	G	4554	3211899.0	1558964.0	3187992.1	1554678.3	0.0
SAGUARO	1	G	4856	3122995.0	1681176.0	3168324.8	1677794.3	0.0

PNAME Plant name	NUMGEN Number of associated generators	FUELB1 Primary boiler fuel	LOADHRS Hours connected to load	HTIEAN Boiler 2000 annual ETS/CEM heat input (MMBtu)	HTIEOZ Boiler 2000 ozone season ETS/CEM heat input (MMBtu)	HTIFAN Boiler 2000 annual total EIA-based calculated heat input (MMBtu)	HTIFOZ Boiler 2000 ozone season EIA-based calculated heat input (MMBtu)	HTICL Boiler 2000 annual EIA-based calculated coal heat input (MMBtu)
SPRINGERVILLE	1	C	7451	28736736.0	12548228.0	27428007.0	12040965.2	27404487.0
SPRINGERVILLE	1	C	8709	32135804.0	13197079.0	30190504.2	12560976.6	30186388.2
YUCCA	1	G	6534	3038057.0	1822943.0	3023164.6	1774895.4	0.0
ARAPAHOE	1	C	7947	3593472.4	1625399.0	3451132.5	1528190.2	3412723.2
ARAPAHOE	1	C	5791	2463698.6	1340916.0	2338451.4	1418460.7	1601877.4
ARAPAHOE	1	C	8118	4336365.0	1759674.0	3401858.6	1372743.6	3373144.0
ARAPAHOE	1	C	8273	8668123.0	3588212.0	8190205.0	3460017.3	7501643.4
ARAPAHOE COMBUSTION TURBINI	N/A	G	N/A	172848.0	56247.0	0.0	0.0	0.0
ARAPAHOE COMBUSTION TURBINI	N/A	G	N/A	151942.0	55564.0	0.0	0.0	0.0
CAMEO	1	C	7881	0.0	0.0	2374993.3	1084577.4	2359738.6
CAMEO	1	C	8519	4434395.0	1970557.0	4775522.5	2177962.5	4766264.0
CHEROKEE	1	C	7974	8984969.0	3950360.0	7879886.8	3448464.5	7477869.6
CHEROKEE	1	C	8356	11608612.0	4632458.0	8615533.0	3664283.4	8311229.0
CHEROKEE	1	C	8369	11824012.0	5235036.0	11334163.8	4925383.8	10995773.8
CHEROKEE	1	C	7016	20736114.0	11465305.0	20792247.2	11163717.8	20531810.4
COMANCHE	1	C	6625	20074913.0	8611915.0	20050163.1	8703756.3	20001485.8
COMANCHE	1	C	8316	27676003.0	11392694.0	24595224.5	9826419.8	24553236.2
CRAIG	1	C	8482	34304580.0	13938281.0	33983748.4	14420713.9	33929637.2
CRAIG	1	C	8506	34111517.0	13227958.0	34471387.3	13468357.0	34435179.6
CRAIG	1	C	8710	33928905.0	14236458.0	33110757.4	13908835.4	33074265.6
FORT ST VRAIN	1	G	7589	11286681.0	5625851.0	1025436.3	678571.8	0.0
FORT ST VRAIN	1	G	7809	11694948.0	5588743.0	1067526.2	653758.0	0.0
GEORGE BIRDSALL	1	G	4452	0.0	0.0	555822.1	361222.8	0.0
GEORGE BIRDSALL	1	G	4249	0.0	0.0	524738.4	296814.3	0.0
GEORGE BIRDSALL	1	G	3648	0.0	0.0	509291.9	336397.7	0.0
HAYDEN	1	C	5456	12131871.0	2444139.0	10093234.0	2009653.0	10067686.4

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PNAME Plant name	HTIOL Boiler 2000 annual EIA-based calculated oil heat input (MMBtu)	HTIGS Boiler 2000 annual EIA-based calculated gas heat input (MMBtu)	HTIBM Boiler 2000 annual EIA-based calculated biomass/ wood heat input (MMBtu)	HTISW Boiler 2000 annual EIA-based calculated solid waste heat input (MMBtu)	HTIOT Boiler 2000 annual EIA-based calculated other fuel heat input (MMBtu)	HTIBAN Boiler 2000 annual best heat input (MMBtu)	HTIBOZ Boiler 2000 ozone season best heat input (MMBtu)	NOXEAN Boiler 2000 annual ETS/CEM NOx emissions (tons)
AGUA FRIA	75703.2	4590322.1	0.0	N/A	0.0	4749733.0	2545490.0	772.39
AGUA FRIA	81017.0	4584879.0	0.0	N/A	0.0	4426448.0	2044063.0	835.93
AGUA FRIA	158931.8	8650325.5	0.0	N/A	0.0	9071394.0	4821045.0	3805.52
APACHE STATION	0.0	3579906.5	0.0	N/A	0.0	4595848.0	2352325.0	355.39
APACHE STATION	0.0	35839.1	0.0	N/A	0.0	17151222.0	7112977.0	4142.17
APACHE STATION	0.0	35276.5	0.0	N/A	0.0	15285702.0	7037690.0	3283.89
CHOLLA	0.0	17707.5	0.0	N/A	0.0	9431578.0	4265475.0	1890.46
CHOLLA	7643.4	0.0	0.0	N/A	0.0	25087567.0	10331574.0	4611.64
CHOLLA	16475.2	0.0	0.0	N/A	0.0	20767690.0	10165881.0	3410.27
CHOLLA	47670.0	0.0	0.0	N/A	0.0	27075453.0	10994081.0	3868.62
CORONADO	30858.0	0.0	0.0	N/A	0.0	34681360.0	15448886.0	7300.18
CORONADO	11050.0	0.0	0.0	N/A	0.0	34663078.0	14065193.0	6971.61
IRVINGTON	0.0	2707141.2	0.0	N/A	0.0	2549079.0	1555852.0	246.62
IRVINGTON	0.0	2944894.2	0.0	N/A	0.0	2820425.0	1666890.0	340.11
IRVINGTON	0.0	3397082.0	0.0	N/A	0.0	3547241.0	2334671.0	307.02
IRVINGTON	0.0	131010.1	0.0	N/A	0.0	8902912.0	3863906.0	1909.47
KYRENE	53298.9	765338.5	0.0	N/A	0.0	1064408.0	603597.0	280.99
KYRENE	122907.0	2182010.0	0.0	N/A	0.0	4758957.0	3526229.0	2144.71
NAVAJO	46727.2	0.0	0.0	N/A	0.0	63503234.0	26651681.0	13004.99
NAVAJO	97599.9	0.0	0.0	N/A	0.0	62748887.0	27265272.0	11090.36
NAVAJO	89338.0	0.0	0.0	N/A	0.0	70021855.0	30119530.0	13171.65
OCOTILLO	0.0	3619867.5	0.0	N/A	0.0	3798195.0	1919839.0	291.06
OCOTILLO	0.0	3627184.0	0.0	N/A	0.0	3493553.0	1840277.0	227.62
SAGUARO	346921.0	2841071.1	0.0	N/A	0.0	3211899.0	1558964.0	191.84
SAGUARO	0.0	3168324.8	0.0	N/A	0.0	3122995.0	1681176.0	148.80

PNAME Plant name	HTIOL Boiler 2000 annual EIA-based calculated oil heat input (MMBtu)	HTIGS Boiler 2000 annual EIA-based calculated gas heat input (MMBtu)	HTIBM Boiler 2000 annual EIA-based calculated biomass/ wood heat input (MMBtu)	HTISW Boiler 2000 annual EIA-based calculated solid waste heat input (MMBtu)	HTIOT Boiler 2000 annual EIA-based calculated other fuel heat input (MMBtu)	HTIBAN Boiler 2000 annual best heat input (MMBtu)	HTIBOZ Boiler 2000 ozone season best heat input (MMBtu)	NOXEAN Boiler 2000 annual ETS/CEM NOx emissions (tons)
SPRINGERVILLE	23520.0	0.0	0.0	N/A	0.0	28736736.0	12548228.0	5556.92
SPRINGERVILLE	4116.0	0.0	0.0	N/A	0.0	32135804.0	13197079.0	6158.39
YUCCA	0.0	3023164.6	0.0	N/A	0.0	3038057.0	1822943.0	178.77
ARAPAHOE	0.0	38409.3	0.0	N/A	0.0	3593472.4	1625399.0	1307.43
ARAPAHOE	0.0	736574.0	0.0	N/A	0.0	2463698.6	1340916.0	896.38
ARAPAHOE	0.0	28714.6	0.0	N/A	0.0	4336365.0	1759674.0	1439.66
ARAPAHOE	0.0	688561.6	0.0	N/A	0.0	8668123.0	3588212.0	1086.34
ARAPAHOE COMBUSTION TURBINI	0.0	0.0	0.0	N/A	0.0	172848.0	56247.0	7.76
ARAPAHOE COMBUSTION TURBINI	0.0	0.0	0.0	N/A	0.0	151942.0	55564.0	6.98
CAMEO	0.0	15254.7	0.0	N/A	0.0	2374993.3	1084577.4	0.00
CAMEO	0.0	9258.5	0.0	N/A	0.0	4434395.0	1970557.0	905.59
CHEROKEE	0.0	402017.2	0.0	N/A	0.0	8984969.0	3950360.0	1538.83
CHEROKEE	0.0	304304.0	0.0	N/A	0.0	11608612.0	4632458.0	4658.23
CHEROKEE	0.0	338390.0	0.0	N/A	0.0	11824012.0	5235036.0	2270.56
CHEROKEE	0.0	260436.8	0.0	N/A	0.0	20736114.0	11465305.0	3493.38
COMANCHE	0.0	48677.3	0.0	N/A	0.0	20074913.0	8611915.0	2520.42
COMANCHE	0.0	41988.3	0.0	N/A	0.0	27676003.0	11392694.0	4457.93
CRAIG	5139.1	48972.1	0.0	N/A	0.0	34304580.0	13938281.0	6196.02
CRAIG	4111.3	32096.4	0.0	N/A	0.0	34111517.0	13227958.0	7303.56
CRAIG	6680.9	29810.9	0.0	N/A	0.0	33928905.0	14236458.0	6064.50
FORT ST VRAIN	0.0	1025436.3	0.0	N/A	0.0	11286681.0	5625851.0	216.32
FORT ST VRAIN	0.0	1067526.2	0.0	N/A	0.0	11694948.0	5588743.0	188.70
GEORGE BIRDSALL	34055.9	521766.2	0.0	N/A	0.0	555822.1	361222.8	0.00
GEORGE BIRDSALL	577.0	524161.4	0.0	N/A	0.0	524738.4	296814.3	0.00
GEORGE BIRDSALL	569.3	508722.6	0.0	N/A	0.0	509291.9	336397.7	0.00
HAYDEN	556.9	24990.7	0.0	N/A	0.0	12131871.0	2444139.0	2450.99

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PNAME Plant name	NOXEOZ Boiler 2000 ozone season ETS/CEM NOx emissions (tons)	NOXFAN Boiler 2000 annual EIA-based calculated NOx emissions (tons)	NOXFOZ Boiler 2000 ozone season EIA-based calculated NOx emissions (tons)	SO2EAN Boiler 2000 annual ETS/CEM SO2 emissions (tons)	SO2FAN Boiler 2000 annual EIA-based calculated SO2 emissions (tons)	CO2EAN Boiler 2000 annual ETS/CEM CO2 emissions (tons)	CO2FAN Boiler 2000 annual EIA-based calculated CO2 emissions (tons)	SRCBEST Source of "best" 2000 heat input, NOx, SO2, and CO2 data
AGUA FRIA	395.90	650.73	347.70	18.10	17.02	282523.80	273629.39	E
AGUA FRIA	376.50	650.90	338.11	21.70	17.53	264212.60	273769.58	E
AGUA FRIA	1964.80	1229.01	641.64	33.20	33.10	540620.60	517045.62	E
APACHE STATION	165.20	489.54	241.68	1.30	6.12	273126.40	208321.71	E
APACHE STATION	1796.80	5459.68	2279.98	3410.70	1117.50	1757801.40	1606263.37	E
APACHE STATION	1578.10	5047.55	2212.95	3156.90	1043.16	1566682.10	1484917.38	E
CHOLLA	866.40	1931.81	857.42	859.10	844.63	967513.20	884187.88	E
CHOLLA	1839.20	4837.39	1957.47	1389.40	1210.37	2572425.90	2215878.72	E
CHOLLA	1704.30	4220.28	2081.50	8378.20	7337.35	2128413.50	1932969.67	E
CHOLLA	1661.60	5565.51	2153.36	7270.10	11188.66	2773616.80	2548509.51	E
CORONADO	3100.50	9696.27	4191.11	10051.40	2239.81	3557628.20	3252664.68	E
CORONADO	2832.30	10340.16	4439.80	9408.50	2422.90	3555558.30	3400532.59	E
IRVINGTON	147.20	224.99	137.64	0.70	4.63	151487.80	157533.80	E
IRVINGTON	205.90	244.74	146.52	1.30	5.04	167733.30	171369.11	E
IRVINGTON	203.20	282.06	187.25	1.10	5.81	210801.60	197682.80	E
IRVINGTON	823.30	2830.14	1220.46	3414.90	3273.43	896387.20	827594.48	E
KYRENE	149.90	113.34	67.40	45.30	10.01	64862.50	49119.65	E
KYRENE	1763.10	318.07	185.63	45.90	31.03	285549.50	137544.05	E
NAVAJO	5597.10	13973.43	5780.21	1206.00	1134.81	6515438.70	6400281.30	E
NAVAJO	4874.30	13265.39	5784.91	1687.40	1075.85	6438039.70	6074737.38	E
NAVAJO	5712.60	14022.62	5991.77	1943.70	1139.72	7184242.50	6421824.29	E
OCOTILLO	145.30	301.54	160.27	4.60	6.21	230763.90	210647.12	E
OCOTILLO	122.50	301.84	156.31	1.10	6.21	207661.90	211072.88	E
SAGUARO	85.00	273.85	132.49	144.40	149.88	198772.20	195158.83	E
SAGUARO	80.90	262.89	139.21	0.90	5.41	185634.50	184370.97	E

PNAME Plant name	NOXEOZ Boiler 2000 ozone season ETS/CEM NOx emissions (tons)	NOXFAN Boiler 2000 annual EIA-based calculated NOx emissions (tons)	NOXFOZ Boiler 2000 ozone season EIA-based calculated NOx emissions (tons)	SO2EAN Boiler 2000 annual ETS/CEM SO2 emissions (tons)	SO2FAN Boiler 2000 annual EIA-based calculated SO2 emissions (tons)	CO2EAN Boiler 2000 annual ETS/CEM CO2 emissions (tons)	CO2FAN Boiler 2000 annual EIA-based calculated CO2 emissions (tons)	SRCBEST Source of "best" 2000 heat input, NOx, SO2, and CO2 data
SPRINGERVILLE	2448.50	9558.66	4196.21	9035.50	7637.88	2948392.80	2826588.18	E
SPRINGERVILLE	2442.60	10521.39	4377.00	10012.90	8422.16	3297133.60	3111782.99	E
YUCCA	117.60	418.00	245.41	12.30	5.23	181134.60	175923.82	E
ARAPAHOE	589.40	1154.45	510.16	844.27	839.67	368716.93	354000.70	E
ARAPAHOE	507.90	638.30	389.65	578.83	390.38	252793.77	207975.78	E
ARAPAHOE	565.10	1140.46	458.02	1078.80	830.67	444909.80	349356.93	E
ARAPAHOE	470.30	2623.73	1066.23	1664.80	1433.38	888367.50	813298.76	E
ARAPAHOE COMBUSTION TURBINI	2.40	0.00	0.00	0.00	0.00	10272.70	0.00	E
ARAPAHOE COMBUSTION TURBINI	2.30	0.00	0.00	0.00	0.00	9029.60	0.00	E
CAMEO	0.00	1189.03	543.99	0.00	1030.53	0.00	244117.17	F
CAMEO	368.80	2401.49	1095.13	2288.40	2083.04	454741.90	491820.24	E
CHEROKEE	676.40	3151.96	1368.03	2622.40	2319.48	915938.40	794173.70	E
CHEROKEE	1788.80	3446.21	1448.33	4560.50	3315.64	1185501.50	874385.89	E
CHEROKEE	1046.90	2833.54	1224.64	5012.80	4377.23	1205689.80	1153078.21	E
CHEROKEE	1875.10	4678.26	2519.45	6949.00	6684.53	2117548.70	2131466.55	E
COMANCHE	1054.00	4511.29	1958.39	5956.30	6216.79	2055774.30	2064480.78	E
COMANCHE	2048.80	6148.81	2456.44	8404.80	7689.08	2836431.90	2533262.07	E
CRAIG	2414.70	8495.94	3605.67	4203.80	3653.07	3511949.20	3500548.90	E
CRAIG	2788.40	8617.85	3366.00	4059.20	3590.13	3478470.10	3551593.48	E
CRAIG	2491.70	8277.69	3477.77	1802.30	1550.60	3476245.80	3411389.73	E
FORT ST VRAIN	111.60	0.73	0.48	3.40	1.74	670752.30	59672.13	E
FORT ST VRAIN	94.10	0.76	0.47	3.50	1.81	695004.90	62121.42	E
GEORGE BIRDSALL	0.00	96.10	62.50	0.00	11.56	0.00	33291.02	F
GEORGE BIRDSALL	0.00	90.74	51.32	0.00	1.32	0.00	30551.58	F
GEORGE BIRDSALL	0.00	88.13	58.21	0.00	1.24	0.00	29652.51	F
HAYDEN	501.50	2321.44	461.11	694.60	502.31	1240852.20	1039222.98	E

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PNAME Plant name	NOXBAN Boiler 2000 annual best NOx emissions (tons)	NOXBOZ Boiler 2000 ozone season best NOx emissions (tons)	SO2BAN Boiler 2000 annual best SO2 emissions (tons)	CO2BAN Boiler 2000 annual best CO2 emissions (tons)	SO2CTLDV 2000 SO2 (scrubber) control device for utilities	NOXCTLDV 2000 NOx control device for utilities	T4A00 Year 2000 Title IV SO2 1998 reallocation plus repowering allowance (tons)	T4A10 Year 2010 Title IV SO2 1998 reallocation plus repowering allowance (tons)
AGUA FRIA	772.39	395.90	18.10	282523.80		NA	54	34
AGUA FRIA	835.93	376.50	21.70	264212.60		NA	65	39
AGUA FRIA	3805.52	1964.80	33.20	540620.60		NA	77	67
APACHE STATION	355.39	165.20	1.30	273126.40		NA	331	332
APACHE STATION	4142.17	1796.80	3410.70	1757801.40	PA	OV	1609	1420
APACHE STATION	3283.89	1578.10	3156.90	1566682.10	PA	OV	3011	2836
CHOLLA	1890.46	866.40	859.10	967513.20	VE	NA	2223	2034
CHOLLA	4611.64	1839.20	1389.40	2572425.90	VE	OV	5443	5067
CHOLLA	3410.27	1704.30	8378.20	2128413.50		OV	5147	4858
CHOLLA	3868.62	1661.60	7270.10	2773616.80	PA	OV	8334	7784
CORONADO	7300.18	3100.50	10051.40	3557628.20	SP	OV	5733	5199
CORONADO	6971.61	2832.30	9408.50	3555558.30	SP	OV	5903	5465
IRVINGTON	246.62	147.20	0.70	151487.80		NA	16	14
IRVINGTON	340.11	205.90	1.30	167733.30		NA	28	40
IRVINGTON	307.02	203.20	1.10	210801.60		NA	0	2
IRVINGTON	1909.47	823.30	3414.90	896387.20		LN	2854	2805
KYRENE	280.99	149.90	45.30	64862.50		NA	7	7
KYRENE	2144.71	1763.10	45.90	285549.50		NA	18	16
NAVAJO	13004.99	5597.10	1206.00	6515438.70	SP	OT	26220	24949
NAVAJO	11090.36	4874.30	1687.40	6438039.70	SP	OT	24262	23354
NAVAJO	13171.65	5712.60	1943.70	7184242.50	SP	OT	25042	23693
OCOTILLO	291.06	145.30	4.60	230763.90		NA	56	40
OCOTILLO	227.62	122.50	1.10	207661.90		NA	132	129
SAGUARO	191.84	85.00	144.40	198772.20		NA	204	189
SAGUARO	148.80	80.90	0.90	185634.50		NA	25	22

PNAME Plant name	NOXBAN Boiler 2000 annual best NOx emissions (tons)	NOXBOZ Boiler 2000 ozone season best NOx emissions (tons)	SO2BAN Boiler 2000 annual best SO2 emissions (tons)	CO2BAN Boiler 2000 annual best CO2 emissions (tons)	SO2CTLDV 2000 SO2 (scrubber) control device for utilities	NOXCTLDV 2000 NOx control device for utilities	T4A00 Year 2000 Title IV SO2 1998 reallocation plus repowering allowance (tons)	T4A10 Year 2010 Title IV SO2 1998 reallocation plus repowering allowance (tons)
SPRINGERVILLE	5556.92	2448.50	9035.50	2948392.80	SD	LN	6566	6099
SPRINGERVILLE	6158.39	2442.60	10012.90	3297133.60	SD	LN	5756	5765
YUCCA	178.77	117.60	12.30	181134.60			42	40
ARAPAHOE	1307.43	589.40	844.27	368716.93		NA	221	208
ARAPAHOE	896.38	507.90	578.83	252793.77		NA	247	229
ARAPAHOE	1439.66	565.10	1078.80	444909.80		NA	181	172
ARAPAHOE	1086.34	470.30	1664.80	888367.50	OT	LN	1927	1829
ARAPAHOE COMBUSTION TURBINI	7.76	2.40	0.00	10272.70			0	0
ARAPAHOE COMBUSTION TURBINI	6.98	2.30	0.00	9029.60			0	0
CAMEO	1189.03	543.99	1030.53	244117.17			0	0
CAMEO	905.59	368.80	2288.40	454741.90			904	852
CHEROKEE	1538.83	676.40	2622.40	915938.40	OT	LN	2138	2035
CHEROKEE	4658.23	1788.80	4560.50	1185501.50		OV	2838	2722
CHEROKEE	2270.56	1046.90	5012.80	1205689.80		LN	3761	3562
CHEROKEE	3493.38	1875.10	6949.00	2117548.70	SD	LN	7535	7132
COMANCHE	2520.42	1054.00	5956.30	2055774.30		NA	7698	7363
COMANCHE	4457.93	2048.80	8404.80	2836431.90		OV	6914	6450
CRAIG	6196.02	2414.70	4203.80	3511949.20	SP	LN	8218	7678
CRAIG	7303.56	2788.40	4059.20	3478470.10	SP	LN	7845	7352
CRAIG	6064.50	2491.70	1802.30	3476245.80	SD	LN	2602	2149
FORT ST VRAIN	216.32	111.60	3.40	670752.30		LN	0	0
FORT ST VRAIN	188.70	94.10	3.50	695004.90		LN	0	0
GEORGE BIRDSALL	96.10	62.50	11.56	33291.02			0	0
GEORGE BIRDSALL	90.74	51.32	1.32	30551.58			0	0
GEORGE BIRDSALL	88.13	58.21	1.24	29652.51			0	0
HAYDEN	2450.99	501.50	694.60	1240852.20	SD	LN	6063	5776

:000 Data)

PNAME Plant name	BLRYRONL Boiler year on-line	BLRSEQ Unique boiler identifier originating in NADB, and continuing in ARDB and IMDB data files	SEQBLR eGRID96 1996 file boiler sequence number	SEQBLR97 eGRID97 1997 file boiler sequence number	SEQBLR98 eGRID2000 1998 file boiler sequence number
AGUA FRIA	1958	52	81	71	71
AGUA FRIA	1957	53	82	72	72
AGUA FRIA	1961	54	83	73	73
APACHE STATION	1964	55	84	74	74
APACHE STATION	1979	56	85	75	75
APACHE STATION	1979	57	86	76	76
CHOLLA	1962	58	87	77	77
CHOLLA	1978	59	88	78	78
CHOLLA	1980	60	89	79	79
CHOLLA	1981	61	90	80	80
CORONADO	1979	63	91	81	81
CORONADO	1980	64	92	82	82
IRVINGTON	1958	79	102	83	83
IRVINGTON	1960	80	103	84	84
IRVINGTON	1962	81	104	85	85
IRVINGTON	1967	82	105	86	86
KYRENE	1952	83	106	87	87
KYRENE	1954	84	107	88	88
NAVAJO	1974	85	108	89	89
NAVAJO	1975	86	109	90	90
NAVAJO	1976	87	110	91	91
OCOTILLO	1960	88	111	92	92
OCOTILLO	1960	89	112	93	93
SAGUARO	1954	90	113	94	94
SAGUARO	1955	91	114	95	95

PNAME Plant name	BLRYRONL Boiler year on-line	BLRSEQ Unique boiler identifier originating in NADB, and continuing in ARDB and IMDB data files	SEQBLR eGRID96 1996 file boiler sequence number	SEQBLR97 eGRID97 1997 file boiler sequence number	SEQBLR98 eGRID2000 1998 file boiler sequence number
SPRINGERVILLE	1985	92	115	96	96
SPRINGERVILLE	1990	93	116	97	97
YUCCA	N/A	98	120	98	98
ARAPAHOE	1950	276	256	194	187
ARAPAHOE	1951	277	257	195	188
ARAPAHOE	1951	278	258	196	189
ARAPAHOE	1955	279	259	197	190
ARAPAHOE COMBUSTION TURBINI	N/A	4188	N/A	N/A	N/A
ARAPAHOE COMBUSTION TURBINI	N/A	4189	N/A	N/A	N/A
CAMEO	N/A	280	260	198	191
CAMEO	N/A	281	261	199	192
CHEROKEE	1957	282	262	200	193
CHEROKEE	1959	283	263	201	194
CHEROKEE	1962	284	264	202	195
CHEROKEE	1968	285	265	203	196
COMANCHE	1973	286	266	204	197
COMANCHE	1975	287	267	205	198
CRAIG	1980	288	268	206	199
CRAIG	1979	289	269	207	200
CRAIG	1984	290	270	208	201
FORT ST VRAIN	1998	3187	271	209	202
FORT ST VRAIN	1999	3469	N/A	N/A	N/A
GEORGE BIRDSALL	N/A	291	272	210	203
GEORGE BIRDSALL	N/A	292	273	211	204
GEORGE BIRDSALL	N/A	293	274	212	205
HAYDEN	1965	294	275	213	206

eGRID2002 Version 2.01 Generator File (Year 2000 Data)

SEQGEN00 eGRID2002 2000 file generator sequence number	SEQGEN99 eGRID2002 1999 file generator sequence number	PSTATABB State abbreviation	PNAME Plant name	ORISPL DOE/EIA ORIS plant or facility code	GENID Generator ID or grouped identifier	GENTYPE Generator type	NUMBLR Number of associated boilers	GENSTAT Generator 2000 status
764	766	AZ	ABITIBI CONSOLIDATED SNOWFLA	50805.0	GEN1	NU	N/A	OP
765	767	AZ	ABITIBI CONSOLIDATED SNOWFLA	50805.0	GEN2	NU	N/A	OP
766	768	AZ	AGUA FRIA	141.0	AF1	UT	1	OP
767	769	AZ	AGUA FRIA	141.0	AF2	UT	1	OP
768	770	AZ	AGUA FRIA	141.0	AF3	UT	1	OP
769	771	AZ	AGUA FRIA	141.0	AF4	UT	N/A	OP
770	772	AZ	AGUA FRIA	141.0	AF5	UT	N/A	OP
771	773	AZ	AGUA FRIA	141.0	AF6	UT	N/A	OP
772	774	AZ	APACHE STATION	160.0	GT1	UT	N/A	OP
773	775	AZ	APACHE STATION	160.0	GT2	UT	N/A	OP
774	776	AZ	APACHE STATION	160.0	GT3	UT	N/A	OP
775	777	AZ	APACHE STATION	160.0	ST1	UT	1	OP
776	778	AZ	APACHE STATION	160.0	ST2	UT	1	OP
777	779	AZ	APACHE STATION	160.0	ST3	UT	1	OP
778	780	AZ	BIOSPHERE 2 CENTER INC	54594.0	G-1	NU	N/A	CS
779	N/A	AZ	BIOSPHERE 2 CENTER INC	54594.0	G-4	NU	N/A	SB
780	782	AZ	CHILDS	112.0	HY#	UT	N/A	OP
781	783	AZ	CHOLLA	113.0	1	UT	1	OP
782	784	AZ	CHOLLA	113.0	2	UT	1	OP
783	785	AZ	CHOLLA	113.0	3	UT	1	OP
784	786	AZ	CHOLLA	113.0	4	UT	1	OP
785	787	AZ	CORONADO	6177.0	CO1	UT	1	OP
786	788	AZ	CORONADO	6177.0	CO2	UT	1	OP
787	789	AZ	CROSSCUT	143.0	CC1	UT	1	SB
788	790	AZ	CROSSCUT	143.0	CC2	UT	1	SB
789	791	AZ	CROSSCUT	143.0	CC3	UT	1	SB
790	792	AZ	CROSSCUT	143.0	CC4	UT	3	SB
791	793	AZ	CROSSCUT	143.0	HY#	UT	N/A	OP
792	794	AZ	DAVIS	152.0	HY#	UT	N/A	OP

SEQGEN00 eGRID2002 2000 file generator sequence number	SEQGEN99 eGRID2002 1999 file generator sequence number	PSTATABB State abbreviation	PNAME Plant name	ORISPL DOE/EIA ORIS plant or facility code	GENID Generator ID or grouped identifier	GENTYPE Generator type	NUMBLR Number of associated boilers	GENSTAT Generator 2000 status
793	795	AZ	DOUGLAS	114.0	1	UT	N/A	OP
794	796	AZ	GLEN CANYON	153.0	HY#	UT	N/A	OP
795	797	AZ	GOULD ELECTRONICS FOIL DIVISI	54838.0	G1	NU	N/A	CS
796	798	AZ	GOULD ELECTRONICS FOIL DIVISI	54838.0	G2	NU	N/A	CS
797	799	AZ	HOOVER	8902.0	HY#	UT	N/A	OP
798	800	AZ	HORSE MESA	145.0	HY#	UT	N/A	OP
799	801	AZ	HORSE MESA	145.0	PS#	UT	N/A	OP
800	802	AZ	INA ROAD WATER POLLUTION CON	55257.0	1	NU	N/A	OP
801	803	AZ	INA ROAD WATER POLLUTION CON	55257.0	2	NU	N/A	OP
802	804	AZ	INA ROAD WATER POLLUTION CON	55257.0	3	NU	N/A	SB
803	805	AZ	INA ROAD WATER POLLUTION CON	55257.0	4	NU	N/A	OP
804	806	AZ	INA ROAD WATER POLLUTION CON	55257.0	5	NU	N/A	OP
805	807	AZ	INA ROAD WATER POLLUTION CON	55257.0	6	NU	N/A	OP
806	808	AZ	INA ROAD WATER POLLUTION CON	55257.0	7	NU	N/A	OP
807	809	AZ	IRVING	115.0	HY#	UT	N/A	OP
808	810	AZ	IRVINGTON	126.0	4	UT	1	OP
809	811	AZ	IRVINGTON	126.0	GT1	UT	N/A	OP
810	812	AZ	IRVINGTON	126.0	GT2	UT	N/A	OP
811	813	AZ	IRVINGTON	126.0	ST1	UT	1	OP
812	814	AZ	IRVINGTON	126.0	ST2	UT	1	OP
813	815	AZ	IRVINGTON	126.0	ST3	UT	1	OP
814	816	AZ	KYRENE	147.0	KY1	UT	1	OP
815	817	AZ	KYRENE	147.0	KY2	UT	1	OP
816	818	AZ	KYRENE	147.0	KY3	UT	N/A	SD
817	819	AZ	KYRENE	147.0	KY4	UT	N/A	OP
818	820	AZ	KYRENE	147.0	KY5	UT	N/A	OP
819	821	AZ	KYRENE	147.0	KY6	UT	N/A	OP
820	822	AZ	MORMON FLAT	148.0	HY#	UT	N/A	OP
821	823	AZ	MORMON FLAT	148.0	PS#	UT	N/A	OP
822	824	AZ	NAVAJO	4941.0	NAV1	UT	1	OP

'ear 2000 Data)

PNAME Plant name	PRMVR Prime mover type	FUELG1 Primary generator fuel	NAMEPCAP Generator nameplate capacity (MW)	CFACT Generator 2000 capacity factor	GENNTAN Generator 2000 annual net generation (MWh)	GENNTOZ Generator 2000 ozone season net generation (MWh)	GENYRONL Generator year on-line	SEQGEN eGRID96 1996 file generator sequence number
ABITIBI CONSOLIDATED SNOWFLA	ST	SUB	27.20	0.5319	126747.0	52811.3	1961	N/A
ABITIBI CONSOLIDATED SNOWFLA	ST	SUB	43.35	0.5680	215705.4	89877.2	1974	N/A
AGUA FRIA	ST	NG	113.64	0.4391	437140.0	182141.7	1958	303
AGUA FRIA	ST	NG	113.64	0.4347	432757.0	180315.4	1957	304
AGUA FRIA	ST	NG	163.20	0.5848	836014.0	348339.2	1961	305
AGUA FRIA	GT	NG	80.55	N/A	N/A	N/A	1975	N/A
AGUA FRIA	GT	NG	71.20	N/A	N/A	N/A	1974	N/A
AGUA FRIA	GT	NG	71.20	N/A	N/A	N/A	1974	N/A
APACHE STATION	CT	NG	10.05	N/A	N/A	N/A	1965	307
APACHE STATION	GT	DFO	19.80	N/A	N/A	N/A	1972	N/A
APACHE STATION	GT	DFO	64.89	N/A	N/A	N/A	1974	N/A
APACHE STATION	CA	RFO	75.00	0.5651	371281.0	154700.4	1965	309
APACHE STATION	ST	SUB	194.70	0.8680	1480476.7	616865.3	1979	310
APACHE STATION	ST	SUB	194.70	0.8140	1388425.1	578510.5	1979	311
BIOSPHERE 2 CENTER INC	IC	DFO	1.47	0.0143	183.8	76.6	1990	N/A
BIOSPHERE 2 CENTER INC	IC	NG	1.58	0.1666	2305.0	960.4	2000	N/A
CHILDS	HY	WAT	5.40	N/A	N/A	N/A	N/A	312
CHOLLA	ST	SUB	113.64	0.7997	796037.9	331682.5	1962	313
CHOLLA	ST	SUB	288.90	0.7671	1941407.5	808919.8	1978	314
CHOLLA	ST	SUB	288.90	0.6857	1735247.1	723019.6	1980	315
CHOLLA	ST	SUB	414.00	0.6404	2322439.5	967683.1	1981	316
CORONADO	ST	SUB	410.94	0.8527	3069595.0	1278997.9	1979	318
CORONADO	ST	SUB	410.94	0.8908	3206765.0	1336152.1	1980	319
CROSSCUT	ST	NG	7.50	N/A	N/A	N/A	1942	320
CROSSCUT	ST	NG	7.50	N/A	N/A	N/A	1942	321
CROSSCUT	ST	NG	7.50	N/A	N/A	N/A	1942	322
CROSSCUT	ST	NG	7.50	N/A	N/A	N/A	1949	323
CROSSCUT	HY	WAT	3.00	N/A	N/A	N/A	N/A	324
DAVIS	HY	WAT	240.00	N/A	N/A	N/A	N/A	325

PNAME Plant name	PRMVR Prime mover type	FUELG1 Primary generator fuel	NAMEPCAP Generator nameplate capacity (MW)	CFACT Generator 2000 capacity factor	GENNTAN Generator 2000 annual net generation (MWh)	GENNTOZ Generator 2000 ozone season net generation (MWh)	GENYRONL Generator year on-line	SEQGEN eGRID96 1996 file generator sequence number
DOUGLAS	GT	DFO	21.40	N/A	N/A	N/A	1972	N/A
GLEN CANYON	HY	WAT	1296.00	N/A	N/A	N/A	N/A	328
GOULD ELECTRONICS FOIL DIVISI(	IC	NG	0.53	0.0621	285.4	118.9	1994	N/A
GOULD ELECTRONICS FOIL DIVISI(	IC	NG	0.53	0.0577	265.2	110.5	1994	N/A
HOOVER	HY	WAT	1039.40	N/A	N/A	N/A	N/A	330
HORSE MESA	HY	WAT	29.70	N/A	N/A	N/A	N/A	331
HORSE MESA	PS	WAT	99.88	N/A	N/A	N/A	N/A	332
INA ROAD WATER POLLUTION COI	IC	NG	0.65	0.3707	2110.9	879.6	1977	N/A
INA ROAD WATER POLLUTION COI	IC	NG	0.65	0.6190	3524.5	1468.5	1977	N/A
INA ROAD WATER POLLUTION COI	IC	NG	0.65	0.1480	842.6	351.1	1977	N/A
INA ROAD WATER POLLUTION COI	IC	NG	0.65	0.5767	3283.9	1368.3	1977	N/A
INA ROAD WATER POLLUTION COI	IC	NG	0.65	0.6187	3522.8	1467.8	1977	N/A
INA ROAD WATER POLLUTION COI	IC	NG	0.64	0.4104	2300.8	958.7	1977	N/A
INA ROAD WATER POLLUTION COI	IC	NG	0.65	0.5475	3117.4	1298.9	1977	N/A
IRVING	HY	WAT	1.60	N/A	N/A	N/A	N/A	333
IRVINGTON	ST	SUB	173.30	0.5224	792994.0	330414.2	1967	338
IRVINGTON	GT	NG	27.00	N/A	N/A	N/A	1972	N/A
IRVINGTON	GT	NG	27.00	N/A	N/A	N/A	1972	N/A
IRVINGTON	ST	NG	108.80	0.2439	232422.3	96842.6	1958	335
IRVINGTON	ST	NG	108.80	0.2773	264337.6	110140.7	1960	336
IRVINGTON	ST	NG	113.60	0.3123	310780.8	129492.0	1962	337
KYRENE	ST	NG	34.50	0.1888	57069.0	23778.8	1952	340
KYRENE	ST	NG	73.50	0.2921	188043.0	78351.3	1954	341
KYRENE	GT	NG	53.13	N/A	N/A	N/A	1972	N/A
KYRENE	GT	NG	53.13	N/A	N/A	N/A	1971	N/A
KYRENE	GT	NG	60.30	N/A	N/A	N/A	1973	N/A
KYRENE	GT	NG	60.30	N/A	N/A	N/A	1973	N/A
MORMON FLAT	HY	WAT	9.20	N/A	N/A	N/A	N/A	342
MORMON FLAT	PS	WAT	48.65	N/A	N/A	N/A	N/A	343
NAVAJO	ST	SUB	803.16	0.8849	6225990.0	2594162.5	1974	344

'ear 2000 Data)

PNAME Plant name	SEQGEN97 eGRID97 1997 file generator sequence number	SEQGEN98 eGRID2000 1998 file generator sequence number
ABITIBI CONSOLIDATED SNOWFLA	N/A	524
ABITIBI CONSOLIDATED SNOWFLA	N/A	525
AGUA FRIA	248	526
AGUA FRIA	249	527
AGUA FRIA	250	528
AGUA FRIA	N/A	N/A
AGUA FRIA	N/A	N/A
AGUA FRIA	N/A	N/A
APACHE STATION	252	531
APACHE STATION	N/A	N/A
APACHE STATION	N/A	N/A
APACHE STATION	254	532
APACHE STATION	255	533
APACHE STATION	256	534
BIOSPHERE 2 CENTER INC	N/A	535
BIOSPHERE 2 CENTER INC	N/A	N/A
CHILDS	257	537
CHOLLA	258	538
CHOLLA	259	539
CHOLLA	260	540
CHOLLA	261	541
CORONADO	262	543
CORONADO	263	544
CROSSCUT	264	545
CROSSCUT	265	546
CROSSCUT	266	547
CROSSCUT	267	548
CROSSCUT	268	549
DAVIS	269	550

PNAME Plant name	SEQGEN97 eGRID97 1997 file generator sequence number	SEQGEN98 eGRID2000 1998 file generator sequence number
DOUGLAS	N/A	N/A
GLEN CANYON	272	554
GOULD ELECTRONICS FOIL DIVISI(	N/A	556
GOULD ELECTRONICS FOIL DIVISI(	N/A	557
HOOVER	273	559
HORSE MESA	274	560
HORSE MESA	275	561
INA ROAD WATER POLLUTION COI	N/A	N/A
INA ROAD WATER POLLUTION COI	N/A	N/A
INA ROAD WATER POLLUTION COI	N/A	N/A
INA ROAD WATER POLLUTION COI	N/A	N/A
INA ROAD WATER POLLUTION COI	N/A	N/A
INA ROAD WATER POLLUTION COI	N/A	N/A
INA ROAD WATER POLLUTION COI	N/A	N/A
IRVING	276	562
IRVINGTON	281	563
IRVINGTON	N/A	N/A
IRVINGTON	N/A	N/A
IRVINGTON	278	565
IRVINGTON	279	566
IRVINGTON	280	567
KYRENE	283	569
KYRENE	284	570
KYRENE	N/A	N/A
KYRENE	N/A	N/A
KYRENE	N/A	N/A
KYRENE	N/A	N/A
MORMON FLAT	285	571
MORMON FLAT	286	572
NAVAJO	287	573

eGRID2002 Version 2.01 Plant Note File

SEQPLCH eGRID2002 plant change sequence number	SEQPLT00 eGRID2002 2000 file plant sequence number	SEQPLT98 eGRID2002 1998 file plant sequence number	PNAME Plant name	ORISPL DOE/EIA ORIS plant or facility code	CHTYPE Type of note	CHDATE Change date (yymm)
1	3909	3866	Abilene	3517.0	OPR	0201
2	3909	3866	Abilene	3517.0	OWN	0201
3	288	284	Alamitos	315.0	OPR	9805
4	288	284	Alamitos	315.0	OWN	9805
5	3112	3067	Albany	2539.0	OPR	0005
6	3112	3067	Albany	2539.0	OWN	0005
7	3116	3070	Allens Falls	2540.0	OPR	9907
8	3116	3070	Allens Falls	2540.0	OWN	9907
9	3703	3578	Allentown	3139.0	OPR	0007
10	3703	3578	Allentown	3139.0	OWN	0007
11	0	2124	Androscog Mill Lower	7047.0	OPR	99xx
12	0	2124	Androscog Mill Lower	7047.0	OWN	99xx
13	2151	2126	Androscoggin 3	1480.0	OPR	99xx
14	2151	2126	Androscoggin 3	1480.0	OWN	99xx
15	3622	3581	Armstrong	3178.0	OPR	0001
16	3622	3581	Armstrong	3178.0	OWN	0001
17	2154	0	Aroostook Valley	7513.0	OPR	9904
18	2154	0	Aroostook Valley	7513.0	OWN	9904
19	4489	4435	Arpin Dam	3995.0	OPR	0104
20	4489	4435	Arpin Dam	3995.0	OWN	0104
21	3119	3073	Arthur Kill	2490.0	OPR	9906
22	3119	3073	Arthur Kill	2490.0	OWN	9906
23	3122	3075	Astoria	8906.0	SPL	9908
24	3121	3076	Astoria (GT)	55243.0	OPR	9906
25	3121	3076	Astoria (GT)	55243.0	OWN	9906
26	3122	3075	Astoria (ST)	8906.0	OPR	9908
27	3122	3075	Astoria (ST)	8906.0	OWN	9908
28	3416	3383	Avon Lake	2836.0	OPR	0004
29	3416	3383	Avon Lake	2836.0	OWN	0004
30	1583	1578	Baldwin	889.0	OPR	9910

SEQPLCH eGRID2002 plant change sequence number	SEQPLT00 eGRID2002 2000 file plant sequence number	SEQPLT98 eGRID2002 1998 file plant sequence number	PNAME Plant name	ORISPL DOE/EIA ORIS plant or facility code	CHTYPE Type of note	CHDATE Change date (yymm)
31	1583	1578	Baldwin	889.0	OWN	9910
32	0	3078	Baldwinsville	2542.0	OPR	9907
33	0	3078	Baldwinsville	2542.0	OWN	9907
34	1044	1041	Bantam	6457.0	OPR	0003
35	1044	1041	Bantam	6457.0	OWN	0003
36	2157	2132	Bar Mills	1481.0	OPR	9904
37	2157	2132	Bar Mills	1481.0	OWN	9904
38	3914	3872	Barney M Davis	4939.0	OPR	0201
39	3914	3872	Barney M Davis	4939.0	OWN	0201
40	0	0	Bates Mill Lower	7045.0	OPR	9904
41	0	0	Bates Mill Lower	7045.0	OWN	9904
42	2160	2135	Bates Mill Upper	7044.0	OPR	9904
43	2160	2135	Bates Mill Upper	7044.0	OWN	9904
44	2961	2921	Bayonne	2397.0	OPR	0008
45	2961	2921	Bayonne	2397.0	OWN	0008
46	4233	4174	Bayview	3782.0	OPR	0007
47	4233	4174	Bayview	3782.0	OWN	0007
48	2011	1986	Bear Swamp	8005.0	OPR	9809
49	2011	1986	Bear Swamp	8005.0	OWN	9809
50	3126	3080	Beardslee	2543.0	OPR	9907
51	3126	3080	Beardslee	2543.0	OWN	9907
52	3130	3083	Beebee Island	10531.0	OPR	9907
53	3130	3083	Beebee Island	10531.0	OWN	9907
54	3131	3084	Belfort	2544.0	OPR	9907
55	3131	3084	Belfort	2544.0	OWN	9907
56	4325	4265	Bellows Falls	3745.0	OPR	9809
57	4325	4265	Bellows Falls	3745.0	OWN	9809
58	3132	3085	Bennetts Bridge	2545.0	OPR	9907
59	3132	3085	Bennetts Bridge	2545.0	OWN	9907
60	1094	1093	Benning	603.0	OPR	0012
61	1094	1093	Benning	603.0	OWN	0012

PNAME	OLDNAME	OLDID
Plant name	Old name	Old ID
Abilene	West Texas Utilities Co	20404.0
Abilene	West Texas Utilities Co	20404.0
Alamitos	Southern California Edison Co	17609.0
Alamitos	Southern California Edison Co	17609.0
Albany	Niagara Mohawk Power Corp	13573.0
Albany	Niagara Mohawk Power Corp	13573.0
Allens Falls	Niagara Mohawk Power Corp	13573.0
Allens Falls	Niagara Mohawk Power Corp	13573.0
Allentown	PPL Utilities	14715.0
Allentown	PPL Utilities	14715.0
Androscog Mill Lower	Central Maine Power Co	3266.0
Androscog Mill Lower	Central Maine Power Co	3266.0
Androscoggin 3	Central Maine Power Co	3266.0
Androscoggin 3	Central Maine Power Co	3266.0
Armstrong	West Penn Power Co	20387.0
Armstrong	West Penn Power Co	20387.0
Aroostook Valley	Central Maine Power Co	3266.0
Aroostook Valley	Central Maine Power Co	3266.0
Arpin Dam	North Central Power Co Inc	13697.0
Arpin Dam	North Central Power Co Inc	13697.0
Arthur Kill	Consolidated Edison Co-NY Inc	4226.0
Arthur Kill	Consolidated Edison Co-NY Inc	4226.0
Astoria		0.0
Astoria (GT)	Consolidated Edison Co-NY Inc	4226.0
Astoria (GT)	Consolidated Edison Co-NY Inc	4226.0
Astoria (ST)	Consolidated Edison Co-NY Inc	4226.0
Astoria (ST)	Consolidated Edison Co-NY Inc	4226.0
Avon Lake	Duquesne Light Co	5487.0
Avon Lake	Duquesne Light Co	5487.0
Baldwin	Illinois Power Co	9208.0

PNAME	OLDNAME	OLDID
Plant name	**Old name**	**Old ID**
Baldwin	Illinois Power Co	9208.0
Baldwinsville	Niagara Mohawk Power Corp	13573.0
Baldwinsville	Niagara Mohawk Power Corp	13573.0
Bantam	Connecticut Light & Power Co	4176.0
Bantam	Connecticut Light & Power Co	4176.0
Bar Mills	Central Maine Power Co	3266.0
Bar Mills	Central Maine Power Co	3266.0
Barney M Davis	Central Power & Light Co	3278.0
Barney M Davis	Central Power & Light Co	3278.0
Bates Mill Lower	Central Maine Power Co	3266.0
Bates Mill Lower	Central Maine Power Co	3266.0
Bates Mill Upper	Central Maine Power Co	3266.0
Bates Mill Upper	Central Maine Power Co	3266.0
Bayonne	Public Service Electric&Gas Co	15477.0
Bayonne	Public Service Electric&Gas Co	15477.0
Bayview	Delmarva Power & Light Co	5027.0
Bayview	Delmarva Power & Light Co	5027.0
Bear Swamp	New England Power Co	13433.0
Bear Swamp	New England Power Co	13433.0
Beardslee	Niagara Mohawk Power Corp	13573.0
Beardslee	Niagara Mohawk Power Corp	13573.0
Beebee Island	Niagara Mohawk Power Corp	13573.0
Beebee Island	Niagara Mohawk Power Corp	13573.0
Belfort	Niagara Mohawk Power Corp	13573.0
Belfort	Niagara Mohawk Power Corp	13573.0
Bellows Falls	New England Power Co	13433.0
Bellows Falls	New England Power Co	13433.0
Bennetts Bridge	Niagara Mohawk Power Corp	13573.0
Bennetts Bridge	Niagara Mohawk Power Corp	13573.0
Benning	Pepco	15270.0
Benning	Pepco	15270.0

PNAME Plant name	NEWNAME New name	NEWID New ID	PRVOWNTY Previous owner type, if CHTYPE= OWN or OPR	OLDPERC Old percent, if CHTYPE= OWN	NEWPERC New percent, if CHTYPE= OWN
Abilene	AEP NUGs	-206.0	U	0.0000	0.0000
Abilene	AEP NUGs	-206.0	U	100.0000	100.0000
Alamitos	AES NUGs	-1001.0	U	0.0000	0.0000
Alamitos	AES NUGs	-1001.0	U	100.0000	100.0000
Albany	PSEG Fossil LLC	15147.0	U	0.0000	0.0000
Albany	PSEG Fossil LLC	15147.0	U	100.0000	100.0000
Allens Falls	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	0.0000	0.0000
Allens Falls	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	100.0000	100.0000
Allentown	PPL Generation LLC	-1227.0	U	0.0000	0.0000
Allentown	PPL Generation LLC	-1227.0	U	100.0000	100.0000
Androscog Mill Lower	FPL Energy	-1064.0	U	0.0000	0.0000
Androscog Mill Lower	FPL Energy	-1064.0	U	100.0000	100.0000
Androscoggin 3	FPL Energy	-1064.0	U	0.0000	0.0000
Androscoggin 3	FPL Energy	-1064.0	U	100.0000	100.0000
Armstrong	Allegheny Energy Supply Co	-1172.0	U	0.0000	0.0000
Armstrong	Allegheny Energy Supply Co	-1172.0	U	100.0000	100.0000
Aroostook Valley	FPL Energy	-1064.0	U	0.0000	0.0000
Aroostook Valley	FPL Energy	-1064.0	U	100.0000	100.0000
Arpin Dam	Flambeau Hydro LLC	6338.0	U	0.0000	0.0000
Arpin Dam	Flambeau Hydro LLC	6338.0	U	100.0000	100.0000
Arthur Kill	NRG Energy	-1105.0	U	0.0000	0.0000
Arthur Kill	NRG Energy	-1105.0	U	100.0000	100.0000
Astoria		0.0		0.0000	0.0000
Astoria (GT)	NRG Energy	-1105.0	U	0.0000	0.0000
Astoria (GT)	NRG Energy	-1105.0	U	100.0000	100.0000
Astoria (ST)	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	0.0000	0.0000
Astoria (ST)	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	100.0000	100.0000
Avon Lake	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	0.0000	0.0000
Avon Lake	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	100.0000	100.0000
Baldwin	Dynegy Marketing & Trade	-1054.0	U	0.0000	0.0000

PNAME	NEWNAME	NEWID	PRVOWNTY	OLDPERC	NEWPERC
Plant name	New name	New ID	Previous owner type, if CHTYPE= OWN or OPR	Old percent, if CHTYPE= OWN	New percent, if CHTYPE= OWN
Baldwin	Dynegy Marketing & Trade	-1054.0	U	100.0000	100.0000
Baldwinsville	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	0.0000	0.0000
Baldwinsville	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	100.0000	100.0000
Bantam	Northeast Generation Services	-180.0	U	0.0000	0.0000
Bantam	Northeast Generation Company	27972.0	U	100.0000	100.0000
Bar Mills	FPL Energy	-1064.0	U	0.0000	0.0000
Bar Mills	FPL Energy	-1064.0	U	100.0000	100.0000
Barney M Davis	AEP NUGs	-206.0	U	0.0000	0.0000
Barney M Davis	AEP NUGs	-206.0	U	100.0000	100.0000
Bates Mill Lower	FPL Energy	-1064.0	U	0.0000	0.0000
Bates Mill Lower	FPL Energy	-1064.0	U	100.0000	100.0000
Bates Mill Upper	FPL Energy	-1064.0	U	0.0000	0.0000
Bates Mill Upper	FPL Energy	-1064.0	U	100.0000	100.0000
Bayonne	PSEG Fossil LLC	15147.0	U	0.0000	0.0000
Bayonne	PSEG Fossil LLC	15147.0	U	100.0000	100.0000
Bayview	Conectiv Energy Supply Inc	-1188.0	U	0.0000	0.0000
Bayview	Conectiv Energy Supply Inc	-1188.0	U	100.0000	100.0000
Bear Swamp	PG&E National Energy Group	-1178.0	U	0.0000	0.0000
Bear Swamp	PG&E National Energy Group	-1178.0	U	100.0000	100.0000
Beardslee	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	0.0000	0.0000
Beardslee	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	100.0000	100.0000
Beebee Island	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	0.0000	0.0000
Beebee Island	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	100.0000	100.0000
Belfort	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	0.0000	0.0000
Belfort	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	100.0000	100.0000
Bellows Falls	PG&E National Energy Group	-1178.0	U	0.0000	0.0000
Bellows Falls	PG&E National Energy Group	-1178.0	U	100.0000	100.0000
Bennetts Bridge	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	0.0000	0.0000
Bennetts Bridge	Reliant Resources (formerly Orion Power Holdings Inc)	-1124.0	U	100.0000	100.0000
Benning	Mirant Corp (formerly Southern Energy Inc)	-1138.0	U	0.0000	0.0000
Benning	Potomac Power Resources	15274.0	U	100.0000	100.0000

eGRID2002 Version 2.01 Electric Generating Company Note File

SEQEGCH eGRID2002 EGC change sequence number	SEQEGO00 eGRID2002 2000 file owner-based EGC sequence number	SEQEGP00 eGRID2002 2000 file location (operator)-based EGC sequence number	SEQEGO98 eGRID2002 1998 file owner-based EGC sequence number	SEQEGP98 eGRID2002 1998 file location (operator)-based EGC sequence number	EGCNAME EGC name	EGCID EGC ID	CHTYPE Type of note	CHDATE Change year
1	27	27	27	25	Albany City of	228.0	NN	1998
2	27	27	27	25	Albany City of	228.0	RC	2001
3	0	0	42	38	Alliant Energy/Interstate Power Co	9392.0	M	2002
4	0	0	42	38	Alliant Energy/Interstate Power Co	9392.0	NN	2000
5	0	0	42	38	Alliant Energy/Interstate Power Co	9392.0	NP	1998
6	0	0	42	38	Alliant Energy/Interstate Power Co	9392.0	R	2000
7	0	0	42	38	Alliant Energy/Interstate Power Co	9392.0	RC	1998
8	0	0	43	39	Alliant Energy/IES Utilities Inc	9162.0	M	2002
9	0	0	43	39	Alliant Energy/IES Utilities Inc	9162.0	NN	1998
10	0	0	43	39	Alliant Energy/IES Utilities Inc	9162.0	NP	1998
11	0	0	43	39	Alliant Energy/IES Utilities Inc	9162.0	R	2000
12	0	0	43	39	Alliant Energy/IES Utilities Inc	9162.0	RC	1998
13	38	38	44	40	Alliant Energy/Wisc Power & Light	20856.0	NP	1998
14	38	38	44	40	Alliant Energy/Wisc Power & Light	20856.0	R	2000
15	48	49	54	50	AmerenCIPS	3253.0	R	1997
16	48	49	54	50	AmerenCIPS	3253.0	RC	1998
17	49	50	55	51	AmerenUE	19436.0	R	1997
18	57	58	63	59	Ames City of	554.0	NC	1998
19	59	59	64	61	Anaheim City of	590.0	RC	1999
20	70	68	0	0	Aquila Networks-Colorado	-230.1	M	2002
21	71	69	0	0	Aquila Networks-Kansas	-230.2	M	2002
22	72	70	0	0	Aquila Networks-Missouri	-230.3	M	2002
23	78	77	80	75	Arkansas Electric Coop Corp	807.0	NN	1998
24	87	85	89	82	Associated Electric Coop Inc	924.0	NN	1998
25	92	89	93	85	Atlantic City Electric Co	963.0	NP	1998
26	92	89	93	85	Atlantic City Electric Co	963.0	NP	2002
27	103	99	103	94	Avista Utilities	20169.0	R	1999
28	107	0	106	0	Azusa City of	1050.0	RC	1999

SEQEGCH eGRID2002 EGC change sequence number	SEQEGO00 eGRID2002 2000 file owner-based EGC sequence number	SEQEGP00 eGRID2002 2000 file location (operator)-based EGC sequence number	SEQEGO98 eGRID2002 1998 file owner-based EGC sequence number	SEQEGP98 eGRID2002 1998 file location (operator)-based EGC sequence number	EGCNAME EGC name	EGCID EGC ID	CHTYPE Type of note	CHDATE Change year
29	112	0	32	0	AGC Division of APG Inc	261.0	R	2000
30	0	0	0	0	Baltimore Gas & Electric Co	1167.0	NP	1999
31	0	0	118	105	Bangor Hydro-Electric Co	1179.0	NP	2001
32	144	128	147	127	Bellevue City of	1515.0	NN	1998
33	144	128	147	127	Bellevue City of	1515.0	RC	1998
34	163	143	165	140	Black Hills Corp	19545.0	NP	0
35	0	0	0	0	Blackstone Valley Electric Co	1796.0	NP	2000
36	0	0	0	0	Blackstone Valley Electric Co	1796.0	NP	2002
37	169	147	172	144	Bloomfield City of	1869.0	NN	1998
38	0	0	0	0	Boston Edison Co	1998.0	NP	1999
39	203	175	205	173	Brooklyn City of	2287.0	NN	1998
40	203	175	205	173	Brooklyn City of	2287.0	RC	1998
41	211	182	212	178	Bryan City of	2439.0	RC	1998
42	225	192	226	188	Bushnell City of	2634.0	RC	1998
43	0	0	0	0	Cajun Electric Power Coop Inc	2777.0	NN	1998
44	240	203	240	202	California Dept-Wtr Resources	3255.0	RC	1999
45	247	209	247	207	Cambridge Electric Light Co	2886.0	NP	1999
46	0	0	250	0	Canal Electric Co	2951.0	NP	1999
47	256	215	258	216	Carmi City of	3040.0	RC	1998
48	257	216	259	217	Carolina Power & Light Co	3046.0	NP	2000
49	264	221	266	221	Cascade Municipal Utilities	3137.0	NN	1998
50	264	221	266	221	Cascade Municipal Utilities	3137.0	RC	1998
51	0	0	1446	1247	CenterPoint Energy	8901.0	NP	2002
52	0	0	1446	1247	CenterPoint Energy	8901.0	R	2002
53	276	231	277	232	Central Electric Power Coop	3242.0	NN	1998
54	278	232	279	233	Central Hudson Gas & Elec Corp	3249.0	NP	2000
55	279	233	280	234	Central Illinois Light Company	3252.0	NP	1999
56	279	233	280	234	Central Illinois Light Company	3252.0	P	0
57	280	234	281	235	Central Iowa Power Coop	3258.0	NN	1998

EGCNAME	CHDESC
EGC name	Note text
Albany City of	City of Albany moved from SPP to MAPP in 1998.
Albany City of	City of Albany's PCA reconfigured from St Joseph Light & Power Co/PCA to Missouri Public Service Co/PCA in 2001.
Alliant Energy/Interstate Power Co	Alliant Energy/IES Utilities Inc and Alliant Energy/Interstate Power Co merged to form Interstate Power and Light Company in 20
Alliant Energy/Interstate Power Co	Alliant Energy/Interstate Power Co moved from MAPP to MAIN in 1998.
Alliant Energy/Interstate Power Co	Alliant Energy/Interstate Power Co became a subsidiary of Alliant Energy Corp in 1998.
Alliant Energy/Interstate Power Co	Interstate Power Co was renamed Alliant Energy/Interstate Power Co in 2000.
Alliant Energy/Interstate Power Co	Alliant Energy/Interstate Power Co's PCA reconfigured from Interstate Power Co/PCA to Alliant West/PCA in 1998.
Alliant Energy/IES Utilities Inc	Alliant Energy/IES Utilities Inc and Alliant Energy/Interstate Power Co merged to form Interstate Power and Light Company in 20
Alliant Energy/IES Utilities Inc	Alliant Energy/IES Utilities Inc moved from MAPP to MAIN in 1998.
Alliant Energy/IES Utilities Inc	Alliant Energy/IES Utilities Inc became a subsidiary of Alliant Energy Corp in 1998.
Alliant Energy/IES Utilities Inc	IES Utilities Inc was renamed Alliant Energy/IES Utililties Inc in 2000.
Alliant Energy/IES Utilities Inc	Alliant Energy/IES Utilities Inc's PCA reconfigured from IES Utilities Inc/PCA to Alliant West/PCA in 1998.
Alliant Energy/Wisc Power & Light	Alliant Energy/Wisc Power & Light became a subsidiary of Alliant Energy Corp in 1998.
Alliant Energy/Wisc Power & Light	Wisconsin Power & Light Co was renamed Alliant Energy/Wisc Power & Light in 2000.
AmerenCIPS	Central Illinois Pub Serv Co was renamed AmerenCIPS in 1997.
AmerenCIPS	AmerenCIPS's PCA reconfigured from Central Illinois Pub Serv Co/PCA to Ameren Corp/PCA in 1998.
AmerenUE	Union Electric Co was renamed AmerenUE in 1997.
Ames City of	City of Ames moved from IES Utilities Inc/PCA to MidAmerican Energy Company/PCA in 1998.
Anaheim City of	City of Anaheim's PCA reconfigured from Southern California Edison Co/PCA to California ISO/PCA in 1999.
Aquila Networks-Colorado	West Plains Energy-CO, West Plains Energy-KS, and Missouri Public Service Co merged to form Aquila Networks in 2002; for E-
Aquila Networks-Kansas	West Plains Energy-CO, West Plains Energy-KS, and Missouri Public Service Co merged to form Aquila Networks in 2002; for E-
Aquila Networks-Missouri	West Plains Energy-CO, West Plains Energy-KS, and Missouri Public Service Co merged to form Aquila Networks in 2002; for E-
Arkansas Electric Coop Corp	Arkansas Electric Coop Corp moved from SPP to SERC in 1998.
Associated Electric Coop Inc	Associated Electric Coop Inc moved from SPP to SERC in 1998.
Atlantic City Electric Co	Atlantic City Electric Co became a subsidiary of Conectiv in 1998.
Atlantic City Electric Co	Atlantic City Electric Co became a subsidiary Pepco Holdings, Inc in 2002.
Avista Utilities	Washington Water Power Co was renamed Avista Utilities in 1999.
Azusa City of	City of Azusa's PCA reconfigured from Southern California Edison Co/PCA to California ISO/PCA in 1999.

EGCNAME	CHDESC
EGC name	**Note text**
AGC Division of APG Inc	Alcoa Generating Company was renamed AGC Division of APG Inc in 2000.
Baltimore Gas & Electric Co	Baltimore Gas & Electric Co became a subsidiary of Constellation Energy Group, Inc in 1999.
Bangor Hydro-Electric Co	Bangor Hydro-Electric Co became a subsidiary of Emera Inc in 2001.
Bellevue City of	City of Bellevue moved from MAPP to MAIN in 1998.
Bellevue City of	City of Bellevue's PCA reconfigured from Interstate Power Co/PCA to Alliant West/PCA in 1998.
Black Hills Corp	Black Hills Corp became a subsidiary of Black Hills Corp.
Blackstone Valley Electric Co	Blackstone Valley Electric Co became a subsidiary of National Grid Group PLC (UK) in 2000.
Blackstone Valley Electric Co	Blackstone Valley Electric Co became a subsidiary of National Grid Transco (UK) in 2002.
Bloomfield City of	City of Bloomfield moved from SPP to SERC in 1998.
Boston Edison Co	Boston Edison Co became a subsidiary of NSTAR in 1999.
Brooklyn City of	City of Brooklyn moved from MAPP to MAIN in 1998.
Brooklyn City of	City of Brooklyn's PCA reconfigured from IES Utilities Inc/PCA to Alliant West/PCA in 1998.
Bryan City of	City of Bryan's PCA reconfigured from Toledo Edison Co/PCA to FirstEnergy Corp/PCA in 1998.
Bushnell City of	City of Bushnell's PCA reconfigured from Central Illinois Pub Serv Co/PCA to Ameren Corp/PCA in 1998.
Cajun Electric Power Coop Inc	Cajun Electric Power Coop Inc moved from SPP to SERC in 1998.
California Dept-Wtr Resources	California Dept-Wtr Resources's PCA reconfigured from Pacific Gas & Electric Co/PCA to California ISO/PCA in 1999.
Cambridge Electric Light Co	Cambridge Electric Light Co became a subsidiary of NSTAR in 1999.
Canal Electric Co	Canal Electric Co became a subsidiary of NSTAR in 1999.
Carmi City of	City of Carmi's PCA reconfigured from Central Illinois Pub Serv Co/PCA to Ameren Corp/PCA in 1998.
Carolina Power & Light Co	Carolina Power & Light Co became a subsidiary of Progress Energy in 2000.
Cascade Municipal Utilities	Cascade Municipal Utilities moved from MAPP to MAIN in 1998.
Cascade Municipal Utilities	Cascade Municipal Utilities's PCA reconfigured from IES Utilities Inc/PCA to Alliant West/PCA in 1998.
CenterPoint Energy	CenterPoint Energy became a subsidiary of CenterPoint Energy in 2002.
CenterPoint Energy	Reliant Energy HL&P was renamed CenterPoint Energy in 2002.
Central Electric Power Coop	Central Electric Power Coop moved from SPP to SERC in 1998.
Central Hudson Gas & Elec Corp	Central Hudson Gas & Elec Corp became a subsidiary of CH Energy Group, Inc in 2000.
Central Illinois Light Company	Central Illinois Light Company became a subsidiary of AES Corp in 1999.
Central Illinois Light Company	Central Illinois Light Company's change to a subsidiary of Ameren Corp is pending
Central Iowa Power Coop	Central Iowa Power Coop moved from MAPP to MAIN in 1998.

EGCNAME	OLDNAME	OLDID	NEWNAME	NEWID
EGC name	**Old name**	**Old ID**	**New name**	**New ID**
Albany City of	SPP	8.0	MAPP	5.0
Albany City of	St Joseph Light & Power Co/PCA	17881.0	Missouri Public Service Co/PCA	12699.0
Alliant Energy/Interstate Power Co	Alliant Energy/Interstate Power Co	9392.0	Interstate Power and Light Company	-207.0
Alliant Energy/Interstate Power Co	MAPP	5.0	MAIN	4.0
Alliant Energy/Interstate Power Co		0.0	Alliant Energy Corp	-7004.0
Alliant Energy/Interstate Power Co	Interstate Power Co	9392.0	Alliant Energy/Interstate Power Co	9392.0
Alliant Energy/Interstate Power Co	Interstate Power Co/PCA	9392.0	Alliant West/PCA	193.0
Alliant Energy/IES Utilities Inc	Alliant Energy/IES Utilities Inc	9162.0	Interstate Power and Light Company	-207.0
Alliant Energy/IES Utilities Inc	MAPP	5.0	MAIN	4.0
Alliant Energy/IES Utilities Inc		0.0	Alliant Energy Corp	-7004.0
Alliant Energy/IES Utilities Inc	IES Utililties Inc	9162.0	Alliant Energy/IES Utilities Inc	9162.0
Alliant Energy/IES Utilities Inc	IES Utililties Inc/PCA	9162.0	Alliant West/PCA	193.0
Alliant Energy/Wisc Power & Light		0.0	Alliant Energy Corp	-7004.0
Alliant Energy/Wisc Power & Light	Wisconsin Power & Light Co	20856.0	Alliant Energy/Wisc Power & Light	20856.0
AmerenCIPS	Central Illinois Pub Serv Co	3253.0	AmerenCIPS	3253.0
AmerenCIPS	Central Illinois Pub Serv Co/PCA	3253.0	Ameren Corp/PCA	19436.0
AmerenUE	Union Electric Co	19436.0	AmerenUE	19436.0
Ames City of	IES Utililties Inc/PCA	9162.0	MidAmerican Energy Company/PCA	12341.0
Anaheim City of	Southern California Edison Co/PCA	17609.0	California ISO/PCA	-4.0
Aquila Networks-Colorado		0.0	Aquila Networks-Colorado	-230.1
Aquila Networks-Kansas		0.0	Aquila Networks-Kansas	-230.2
Aquila Networks-Missouri		0.0	Aquila Networks-Missouri	-230.3
Arkansas Electric Coop Corp	SPP	8.0	SERC	7.0
Associated Electric Coop Inc	SPP	8.0	SERC	7.0
Atlantic City Electric Co		0.0	Conectiv	-7013.0
Atlantic City Electric Co		0.0	Pepco Holdings, Inc	-7112.0
Avista Utilities	Washington Water Power Co	20169.0	Avista Utilities	20169.0
Azusa City of	Southern California Edison Co/PCA	17609.0	California ISO/PCA	-4.0

EGCNAME	OLDNAME	OLDID	NEWNAME	NEWID
EGC name	Old name	Old ID	New name	New ID
AGC Division of APG Inc	Alcoa Generating Company	261.0	AGC Division of APG Inc	261.0
Baltimore Gas & Electric Co		0.0	Constellation Energy Group, Inc	-7015.0
Bangor Hydro-Electric Co		0.0	Emera Inc	-7106.0
Bellevue City of	MAPP	5.0	MAIN	4.0
Bellevue City of	Interstate Power Co/PCA	9392.0	Alliant West/PCA	193.0
Black Hills Corp		0.0	Black Hills Corp	-7008.0
Blackstone Valley Electric Co		0.0	National Grid Group PLC (UK)	-7035.0
Blackstone Valley Electric Co		0.0	National Grid Transco (UK)	-7109.0
Bloomfield City of	SPP	8.0	SERC	7.0
Boston Edison Co		0.0	NSTAR	-7038.0
Brooklyn City of	MAPP	5.0	MAIN	4.0
Brooklyn City of	IES Utililties Inc/PCA	9162.0	Alliant West/PCA	193.0
Bryan City of	Toledo Edison Co/PCA	18997.0	FirstEnergy Corp/PCA	-5.0
Bushnell City of	Central Illinois Pub Serv Co/PCA	3253.0	Ameren Corp/PCA	19436.0
Cajun Electric Power Coop Inc	SPP	8.0	SERC	7.0
California Dept-Wtr Resources	Pacific Gas & Electric Co/PCA	14328.0	California ISO/PCA	-4.0
Cambridge Electric Light Co		0.0	NSTAR	-7038.0
Canal Electric Co		0.0	NSTAR	-7038.0
Carmi City of	Central Illinois Pub Serv Co/PCA	3253.0	Ameren Corp/PCA	19436.0
Carolina Power & Light Co		0.0	Progress Energy	-7069.0
Cascade Municipal Utilities	MAPP	5.0	MAIN	4.0
Cascade Municipal Utilities	IES Utililties Inc/PCA	9162.0	Alliant West/PCA	193.0
CenterPoint Energy		0.0	CenterPoint Energy	-7117.0
CenterPoint Energy	Reliant Energy HL&P	8901.0	CenterPoint Energy	8901.0
Central Electric Power Coop	SPP	8.0	SERC	7.0
Central Hudson Gas & Elec Corp		0.0	CH Energy Group, Inc	-7010.0
Central Illinois Light Company		0.0	AES Corp	-7001.0
Central Illinois Light Company	AES Corp	-7001.0	Ameren Corp	-7005.0
Central Iowa Power Coop	MAPP	5.0	MAIN	4.0

eGRID2002 Version 2.01 Parent Note File

SEQPRCH eGRID2002 parent company change sequence number	SEQPRO00 eGRID2002 2000 file owner-based parent company sequence number	SEQPRP00 eGRID2002 2000 file location (operator)-based parent company sequence number	SEQPRO98 eGRID2002 1998 file owner-based parent company sequence number	SEQPRP98 eGRID2002 1998 file location (operator)-based parent company sequence number	PRNAME Parent company name	PRNUM Parent company ID	CHTYPE Type of note	CHDATE Change year
1	3	3	2	2	Allegheny Energy Inc	550.0	R	1997
2	4	4	3	3	Alliant Energy Corp	-7004.0	M, NP	1998
3	5	5	4	4	Ameren Corp	-7005.0	P	2002
4	6	6	5	5	American Electric Power Co Inc	829.0	A	2000
5	6	6	5	5	American Electric Power Co Inc (east)	829.0	NP	2000
6	6	6	5	5	American Electric Power Co Inc (west	829.0	NP	2000
7	0	0	0	0	American States Water Company	-7006.0	NP	1999
8	9	9	68	64	Aquila Inc	-7062.0	R	2002
9	0	0	0	0	Atlantic City Energy Co	963.0	M	1998
10	11	11	8	8	AES Corp	-7001.0	A	1999
11	11	11	8	8	AES Corp	-7001.0	A	2001
12	11	11	8	8	AES Corp	-7001.0	AS	2001
13	12	12	9	9	ALLETE	-7003.0	NP	2000
14	0	0	11	0	BayCorp Holdings Ltd	-7007.0	NP	0
15	15	15	12	11	Black Hills Corp	-7008.0	NP	0
16	16	16	0	0	CenterPoint Energy	-7117.0	FP	2002
17	16	16	0	0	CenterPoint Energy	-7117.0	NP	2002
18	19	19	14	13	Citizens Communications	3611.0	R	2000
19	0	0	15	14	Conectiv	-7013.0	M	2002
20	0	0	15	14	Conectiv	-7013.0	M, NP	1998
21	20	20	16	15	Consolidated Edison Inc	-7014.0	NP	1999
22	21	21	17	16	Constellation Energy Group Inc	-7015.0	NP	1999
23	0	0	0	0	Cooperative Power Assoc.	4322.0	M	1999
24	22	22	18	17	CH Energy Group	-7010.0	NP	2000
25	23	23	19	18	CLECO Corporation	-7011.0	NP	1999
26	0	0	0	0	Delmarva Power & Lgt	5027.0	M	1998

PRNAME	CHDESC
Parent company name	**Note text**
Allegheny Energy Inc	Allegheny Power System Inc was renamed Allegheny Energy Inc in 1997.
Alliant Energy Corp	Alliant Energy Corp was formed by the merger of IES Utilities Inc, Interstate Power Co, and WPL Holdings Inc in 1998.
Ameren Corp	Ameren Corp's absorption of Central Illinois Light Company is pending.
American Electric Power Co Inc	Central & Southwest Corporation was absorbed by American Electric Power Inc in 2000.
American Electric Power Co Inc (east)	American Electric Power Co (east) is a "dummy" parent company consisting of the original AEP before its merger with Central &
American Electric Power Co Inc (west	American Electric Power Co (west) is a "dummy" parent company consisting of the original Central & Southwest Corp before its a
American States Water Company	American States Water Company became a parent company for Southern California Water Company in 1999.
Aquila Inc	Utilicorp United Inc was renamed Aquila Inc in 2002.
Atlantic City Energy Co	Conectiv was formed by the merger of Atlantic City Energy Co and Delmarva Power & Light Co in 1998.
AES Corp	CILCORP Inc was absorbed by AES Corp in 1999.
AES Corp	Ipalco Enterprises, Inc was absorbed by AES Corp in 2001.
AES Corp	Indianapolis Power & Light Co became a subsidiary of AES Corp in 2001.
ALLETE	ALLETE became a parent company for Minnesota Power and Superior Water Light&Power Co in 2000.
BayCorp Holdings Ltd	BayCorp Holdings Ltd became a parent company for Great Bay Power Corp and Little Bay Power Corp.
Black Hills Corp	Black Hills Corp became a parent company for Black Hills Power & Light, Black Hills Capital, and Adirondack Hydro Develop Cor
CenterPoint Energy	CenterPoint Energy was formerly the parent company of Reliant Resources until 2002.
CenterPoint Energy	CenterPoint Energy was formed from Reliant Energy Inc in 2002.
Citizens Communications	Citizens Utilities was renamed Citizens Communications in 2000.
Conectiv	Pepco Holdings, Inc was formed by the merger of Pepco and Conectiv in 2002.
Conectiv	Conectiv was formed by the merger of Atlantic City Energy Co and Delmarva Power & Light Co in 1998.
Consolidated Edison Inc	Consolidated Edison Inc became a parent company for Consolidated Edison of NY Inc in 1999.
Constellation Energy Group Inc	Constellation Energy Group Inc became a parent company for Baltimore Gas & Electric Co in 1999.
Cooperative Power Assoc.	Great River Energy was formed by the merger of Cooperative Power Association and United Power Association in 1999.
CH Energy Group	CH Energy Group became a parent company for Central Hudson Gas & Electric Co in 2000.
CLECO Corporation	CLECO Corporation became a parent company for CLECO Corporation and CLECO Utility Group, Inc in 1999.
Delmarva Power & Lgt	Conectiv was formed by the merger of Atlantic City Energy Co and Delmarva Power & Light Co in 1998.

PRNAME	OLDNAME	OLDID	NEWNAME	NEWID
Parent company name	**Old name**	**Old ID**	**New name**	**New ID**
Allegheny Energy Inc	Allegheny Power System Inc	12796.0	Allegheny Energy Inc	550.0
Alliant Energy Corp		0.0	Alliant Energy Corp	-7004.0
Ameren Corp	Central Illinois Light Company	3252.0	Ameren Corp	-7005.0
American Electric Power Co Inc	Central & Southwest Corporation	40023.0	American Electric Power Co Inc	829.0
American Electric Power Co Inc (east)	American Electric Power Co Inc	829.0	American Electric Power Co Inc (eas	829.0
American Electric Power Co Inc (west	Central & Southwest Corporation	40023.0	American Electric Power Co Inc (wes	829.0
American States Water Company		0.0	American States Water Company	-7006.0
Aquila Inc	Utilicorp United Inc	-7062.0	Aquila Inc	-7062.0
Atlantic City Energy Co	Atlantic City Energy Co	963.0	Conectiv	-7013.0
AES Corp	CILCORP Inc	-7078.0	AES Corp	-7001.0
AES Corp	Ipalco Enterprises, Inc	-7031.0	AES Corp	-7001.0
AES Corp		0.0	AES Corp	-7001.0
ALLETE		0.0	ALLETE	-7003.0
BayCorp Holdings Ltd		0.0	BayCorp Holdings Ltd	-7007.0
Black Hills Corp		0.0	Black Hills Corp	-7008.0
CenterPoint Energy	Reliant Resources	-1124.0		0.0
CenterPoint Energy		0.0	CenterPoint Energy	-7117.0
Citizens Communications	Citizens Utilities	3611.0	Citizens Communications	3611.0
Conectiv	Conectiv	-7013.0	Pepco Holdings, Inc	-7112.0
Conectiv		0.0	Conectiv	-7013.0
Consolidated Edison Inc		0.0	Consolidated Edison Inc	-7014.0
Constellation Energy Group Inc		0.0	Constellation Energy Group Inc	-7015.0
Cooperative Power Assoc.	Cooperative Power Assoc.	4322.0	Great River Energy	-7028.0
CH Energy Group		0.0	CH Energy Group	-7010.0
CLECO Corporation		0.0	CLECO Corporation	-7011.0
Delmarva Power & Lgt	Delmarva Power & Lgt	5027.0	Conectiv	-7013.0

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SEQPCCH eGRID2002 PCA change sequence number	SEQPCO00 eGRID2002 2000 file owner-based PCA sequence number	SEQPCP00 eGRID2002 2000 file location (operator)-based PCA sequence number	SEQPCO98 eGRID2002 1998 file owner-based PCA sequence number	SEQPCP98 eGRID2002 1998 file location (operator)-based PCA sequence number	PCANAME PCA name	PCAID PCA ID	CHTYPE Type of note	CHDATE Change year
1	4	4	4	4	Alliant East/PCA	186.0	R	
2	5	5	5	5	Alliant West/PCA	193.0	M	1998
3	5	5	5	5	Alliant West/PCA	193.0	NN	2000
4	6	6	6	6	Ameren Corp/PCA	19436.0	M	1997
5	0	0	8	8	American Electric Power - West (ERC	3280.0	M	
6	0	0	8	8	American Electric Power - West (ERC	3280.0	M	2001
7	7	7	9	9	American Electric Power - West (SPP)	3283.0	M	
8	7	7	9	9	American Electric Power - West (SPP)	3283.0	NT	
9	11	11	125	126	Aquila Networks - Kansas/PCA	20391.0	R	
10	10	10	68	69	Aquila Networks - Missouri/PCA	12699.0	R	
11	13	13	12	12	Associated Electric Coop/PCA	924.0	NN	1998
12	0	0	13	13	Austin Energy/PCA	1015.0	M	2001
13	0	0	13	13	Austin Energy/PCA	1015.0	R	
14	14	14	14	14	Avista Corp/PCA	20169.0	R	
15	0	0	17	17	Brownsville Public Utils Board/PCA	2409.0	M	2001
16	17	17	18	18	California ISO/PCA	-4.0	M	2000
17	17	17	18	18	California ISO/PCA	-4.0	RC	2002
18	0	0	0	0	Central Illinois Public Service/PCA	3253.0	M	1997
19	0	0	0	0	Central Power & Light Co/PCA	3278.0	M	
20	0	0	0	0	Cincinnati Gas & Electric/PCA	3542.0	M	
21	21	21	22	22	Cinergy Corporation/PCA	3260.0	M	
22	0	0	0	0	City of Pasadena/PCA	14534.0	M	2000
23	0	0	0	0	Cleveland Electric Illuminating Co/PCA	3755.0	M	1997
24	24	24	25	25	CLECO Corporation/PCA	3265.0	R	
25	27	27	123	124	Dominion Virginia Power/PCA	19876.0	R	
26	28	28	28	28	Duke Power Co/PCA	5416.0	RC	
27	33	33	33	34	Entergy Electric System/PCA	12506.0	NN	1998
28	35	35	34	35	FirstEnergy/PCA	-5.0	M	1997

SEQPCCH eGRID2002 PCA change sequence number	SEQPCO00 eGRID2002 2000 file owner-based PCA sequence number	SEQPCP00 eGRID2002 2000 file location (operator)-based PCA sequence number	SEQPCO98 eGRID2002 1998 file owner-based PCA sequence number	SEQPCP98 eGRID2002 1998 file location (operator)-based PCA sequence number	PCANAME PCA name	PCAID PCA ID	CHTYPE Type of note	CHDATE Change year
29	36	36	35	36	Florida Municipal Power Pool/PCA	14610.0	A	2002
30	36	36	35	36	Florida Municipal Power Pool/PCA	14610.0	M	
31	0	0	0	0	Fort Pierce Utilities Auth/PCA	6616.0	M	
32	40	40	39	40	Golden Valley Electric Association/PC	7353.0	A	1999
33	42	42	41	42	Great River Energy/PCA	7570.0	R	
34	50	50	49	50	Independence City Of/PCA	9231.0	NT	
35	0	0	0	0	Interstate Power/PCA	9392.0	M	1998
36	0	0	0	0	IES Utilities Inc/PCA	9162.0	M	1998
37	52	52	51	52	JEA (City of Jacksonville)/PCA	9617.0	R	
38	0	0	0	0	Key West City of/PCA	10226.0	M	
39	0	0	0	0	Kissimmee Utility Authority/PCA	10376.0	M	
40	0	0	54	55	KGE, A Western Resources Co/PCA	10005.0	M	
41	113	113	55	56	KPL, a Western Resources Co/PCA	22500.0	A	
42	113	113	55	56	KPL, a Western Resources Co/PCA	22500.0	M	
43	55	55	56	57	Lafayette (LA) Utilities System/PCA	9096.0	R	
44	59	59	61	62	Louisiana Generating LLC/PCA	2777.0	NN	1998
45	59	59	61	62	Louisiana Generating LLC/PCA	2777.0	R	
46	0	0	62	63	Lower Colorado River Authority/PCA	11269.0	M	2001
47	60	60	63	64	LG&E Energy/PCA	11249.0	A	
48	62	62	65	66	Michigan Electric Power Coordination	12427.0	R	
49	10	10	68	69	Missouri Public Service Co/PCA	12699.0	A	2001
50	69	69	73	74	New England ISO/PCA	13434.0	R	
51	71	71	75	76	New York ISO/PCA	13501.0	R	
52	0	0	0	0	Ohio Edison Co/PCA	13998.0	M	1997
53	0	0	0	0	Pacific Gas & Electric/PCA	14328.0	M	2000
54	0	0	0	0	Public Service Co of Oklahoma/PCA	15474.0	M	
55	87	87	91	92	Puget Sound Energy Transmission/PC	15500.0	R	
56	0	0	0	0	PSI Energy Inc/PCA	15470.0	M	
57	0	0	94	95	Reliant Energy HL&P/PCA	8901.0	M	2001

SEQPCCH eGRID2002 PCA change sequence number	SEQPCO00 eGRID2002 2000 file owner-based PCA sequence number	SEQPCP00 eGRID2002 2000 file location (operator)-based PCA sequence number	SEQPCO98 eGRID2002 1998 file owner-based PCA sequence number	SEQPCP98 eGRID2002 1998 file location (operator)-based PCA sequence number	PCANAME PCA name	PCAID PCA ID	CHTYPE Type of note	CHDATE Change year
58	0	0	94	95	Reliant Energy HL&P/PCA	8901.0	R	
59	90	90	0	0	Sacramento Municipal Utility District/P	-7.0	NC	2002
60	0	0	96	97	San Antonio Public Service Bd/PCA	16604.0	M	2001
61	0	0	0	0	San Diego Gas & Electric/PCA	16609.0	M	2000
62	0	0	103	104	South Texas Electric Coop Inc/PCA	17583.0	M	2001
63	98	98	104	105	Southeastern Power Administration/P(	-6.0	M	2000
64	0	0	0	0	Southern California Edison/PCA	17609.0	M	2000
65	0	0	0	0	Southwestern Electric Power/PCA	17698.0	M	
66	105	105	111	112	Springfield (IL) Water Light & Power/P	17828.0	NT	
67	105	105	111	112	Springfield (IL) Water Light & Power/P	17828.0	R	
68	0	0	112	113	St Joseph Light & Power/PCA	17881.0	A	2001
69	0	0	112	113	St Joseph Light & Power/PCA	17881.0	NN	1998
70	0	0	0	0	Starke City of/PCA	18004.0	M	
71	107	107	114	115	Tacoma City Dept Of Public Utilities/P	18429.0	NT	
72	0	0	118	119	Texas Municipal Power Pool/PCA	18664.0	M	2001
73	0	0	119	120	Texas-New Mexico Power Co/PCA	40051.0	M	2001
74	0	0	0	0	Toledo Edison Co/PCA	18997.0	M	1997
75	0	0	121	122	TXU Electric/PCA	44372.0	M	2001
76	0	0	121	122	TXU Electric/PCA	44372.0	R	
77	6	6	6	6	Union Electric/PCA	19436.0	M	1997
78	0	0	0	0	Vero Beach City of/PCA	19804.0	M	
79	0	0	0	0	West Texas Utilities/PCA	20404.0	M	
80	113	113	55	56	Westar Energy/PCA	22500.0	NT	
81	113	113	55	56	Westar Energy/PCA	22500.0	R	
82	113	113	55	56	Western Resources Inc/PCA	22500.0	M	
83	115	115	126	127	Wisconsin Energy Corporation/PCA	20847.0	R	
84	117	117	128	129	WAPA - Phoenix (LC)/PCA	19610.0	NT	
85	117	117	128	129	WAPA - Phoenix (LC)/PCA	19610.0	R	
86	118	118	129	130	WAPA - Rocky Mountains/PCA	28503.0	NT	

PCANAME	CHDESC
PCA name	**Note text**
Alliant East/PCA	Wisconsin Power & Light/PCA was renamed Alliant East/PCA.
Alliant West/PCA	Alliant West/PCA was formed by the merger of IES Utilities Inc/PCA and Interstate Power/PCA in 1998.
Alliant West/PCA	Alliant West/PCA moved from MAPP to MAIN in 2000.
Ameren Corp/PCA	Ameren Corp/PCA was formed by the merger of Central Illinois Public Service/PCA and Union Electric/PCA in 1997.
American Electric Power - West (ERC	American Electric Power - West (ERCOT)/PCA was formed by the merger of Central Power & Light Co/PCA, West Texas Utilities
American Electric Power - West (ERC	ERCOT ISO/PCA was formed by the merger of 10 PCAs: Austin Energy,Brownsville Public Utils Bd,AEP West-ERCOT,Reliant E
American Electric Power - West (SPP)	American Electric Power - West (SPP)/PCA was formed by the merger of Public Service Co of Oklahoma/PCA and Southwestern
American Electric Power - West (SPP)	American Electric Power - West (SPP)/PCA is called Central and Southwest by NERC.
Aquila Networks - Kansas/PCA	Westplains Energy/PCA was renamed Aquila Networks - Kansas/PCA.
Aquila Networks - Missouri/PCA	Missouri Public Service Co/PCA was renamed Aquila Networks - Missouri/PCA.
Associated Electric Coop/PCA	Associated Electric Coop/PCA moved from SPP to SERC in 1998.
Austin Energy/PCA	ERCOT ISO/PCA was formed by the merger of 10 PCAs: Austin Energy,Brownsville Public Utils Bd,AEP West-ERCOT,Reliant E
Austin Energy/PCA	City of Austin/PCA was renamed Austin Energy/PCA.
Avista Corp/PCA	Washington Water Power Co/PCA was renamed Avista Corp/PCA.
Brownsville Public Utils Board/PCA	ERCOT ISO/PCA was formed by the merger of 10 PCAs: Austin Energy,Brownsville Public Utils Bd,AEP West-ERCOT,Reliant E
California ISO/PCA	California ISO/PCA was formed by the merger of Pacific Gas & Electric/PCA, San Diego Gas & Electric/PCA, and Southern Calif
California ISO/PCA	Sacramento Municipal Utility District/PCA was formerly part of California ISO/PCA.
Central Illinois Public Service/PCA	Ameren Corp/PCA was formed by the merger of Central Illinois Public Service/PCA and Union Electric/PCA in 1997.
Central Power & Light Co/PCA	American Electric Power - West (ERCOT)/PCA was formed by the merger of Central Power & Light Co/PCA, West Texas Utilities
Cincinnati Gas & Electric/PCA	Cinergy Corporation/PCA was formed by the merger of Cincinnati Gas & Electric/PCA and PSI Energy Inc/PCA.
Cinergy Corporation/PCA	Cinergy Corporation/PCA was formed by the merger of Cincinnati Gas & Electric/PCA and PSI Energy Inc/PCA.
City of Pasadena/PCA	California ISO/PCA was formed by the merger of Pacific Gas & Electric/PCA, San Diego Gas & Electric/PCA, and Southern Calif
Cleveland Electric Illuminating Co/PCA	FirstEnergy/PCA was formed by the merger of Cleveland Electric Illuminating Co/PCA, Ohio Edison Co/PCA and Toledo Edison
CLECO Corporation/PCA	Central Louisiana Electric Co/PCA was renamed CLECO Corporation/PCA.
Dominion Virginia Power/PCA	Virginia Electric & Power Co/PCA was renamed Dominion Virginia Power/PCA.
Duke Power Co/PCA	Yadkin Inc/PCA was formerly part of Duke Power Co/PCA.
Entergy Electric System/PCA	Entergy Electric System/PCA moved from SPP to SERC in 1998.
FirstEnergy/PCA	FirstEnergy/PCA was formed by the merger of Cleveland Electric Illuminating Co/PCA, Ohio Edison Co/PCA and Toledo Edison

PCANAME	CHDESC
PCA name	**Note text**
Florida Municipal Power Pool/PCA	Lake Worth Utilities/PCA was absorbed by Florida Municipal Power Pool/PCA in 2002.
Florida Municipal Power Pool/PCA	FL Mun Pwr Pool/PCA was formed by the merger of Ft Pierce Ut Ath,Key W City of,W Ut Bd,Kissimmee Ut Ath,Starke City of,&V
Fort Pierce Utilities Auth/PCA	FL Mun Pwr Pool/PCA was formed by the merger of Ft Pierce Ut Ath,Key W City of,W Ut Bd,Kissimmee Ut Ath,Starke City of,&V
Golden Valley Electric Association/PC	City of Fairbanks/PCA was absorbed by Golden Valley Electric Association/PCA in 1999.
Great River Energy/PCA	United Power Association/PCA was renamed Great River Energy/PCA.
Independence City Of/PCA	Independence City Of/PCA is called City of Independence P&L Dept. by NERC.
Interstate Power/PCA	Alliant West/PCA was formed by the merger of IES Utilities Inc/PCA and Interstate Power/PCA in 1998.
IES Utilities Inc/PCA	Alliant West/PCA was formed by the merger of IES Utilities Inc/PCA and Interstate Power/PCA in 1998.
JEA (City of Jacksonville)/PCA	Jacksonville Electric Authority/PCA was renamed JEA (City of Jacksonville)/PCA.
Key West City of/PCA	FL Mun Pwr Pool/PCA was formed by the merger of Ft Pierce Ut Ath,Key W City of,W Ut Bd,Kissimmee Ut Ath,Starke City of,&V
Kissimmee Utility Authority/PCA	FL Mun Pwr Pool/PCA was formed by the merger of Ft Pierce Ut Ath,Key W City of,W Ut Bd,Kissimmee Ut Ath,Starke City of,&V
KGE, A Western Resources Co/PCA	Western Resources Inc/PCA was formed by the merger of KPL, a Western Resources Co/PCA and KGE, A Western Resources
KPL, a Western Resources Co/PCA	Midwest Energy/PCA was absorbed by KPL, a Western Resources Co/PCA.
KPL, a Western Resources Co/PCA	Western Resources Inc/PCA was formed by the merger of KPL, a Western Resources Co/PCA and KGE, A Western Resources
Lafayette (LA) Utilities System/PCA	City of Lafayette/PCA was renamed Lafayette (LA) Utilities System/PCA.
Louisiana Generating LLC/PCA	Louisiana Generating LLC/PCA moved from SPP to SERC in 1998.
Louisiana Generating LLC/PCA	Cajun Electric Power Coop/PCA was renamed Louisiana Generating LLC/PCA.
Lower Colorado River Authority/PCA	ERCOT ISO/PCA was formed by the merger of 10 PCAs: Austin Energy,Brownsville Public Utils Bd,AEP West-ERCOT,Reliant E
LG&E Energy/PCA	Kentucky Utilities/PCA was absorbed by LG&E Energy/PCA.
Michigan Electric Power Coordination	Michigan Power Pool/PCA was renamed Michigan Electric Power Coordination Center/PCA.
Missouri Public Service Co/PCA	St Joseph Light & Power/PCA was absorbed by Missouri Public Service Co/PCA in 2001.
New England ISO/PCA	New England Power Exchange/PCA was renamed New England ISO/PCA.
New York ISO/PCA	New York Power Pool/PCA was renamed New York ISO/PCA.
Ohio Edison Co/PCA	FirstEnergy/PCA was formed by the merger of Cleveland Electric Illuminating Co/PCA, Ohio Edison Co/PCA and Toledo Edison (
Pacific Gas & Electric/PCA	California ISO/PCA was formed by the merger of Pacific Gas & Electric/PCA, San Diego Gas & Electric/PCA, and Southern Calif
Public Service Co of Oklahoma/PCA	American Electric Power - West (SPP)/PCA was formed by the merger of Public Service Co of Oklahoma/PCA and Southwestern
Puget Sound Energy Transmission/PC	Puget Sound Power & Light Co/PCA was renamed Puget Sound Energy Transmission/PCA.
PSI Energy Inc/PCA	Cinergy Corporation/PCA was formed by the merger of Cincinnati Gas & Electric/PCA and PSI Energy Inc/PCA.
Reliant Energy HL&P/PCA	ERCOT ISO/PCA was formed by the merger of 10 PCAs: Austin Energy,Brownsville Public Utils Bd,AEP West-ERCOT,Reliant E

PCANAME	CHDESC
PCA name	**Note text**
Reliant Energy HL&P/PCA	Houston Lighting & Power Co/PCA was renamed Reliant Energy HL&P/PCA.
Sacramento Municipal Utility District/P	Sacramento Municipal Utility Dist EGC, previously part of California ISO/PCA, formed a new PCA, Sacramento Municipal Utility D
San Antonio Public Service Bd/PCA	ERCOT ISO/PCA was formed by the merger of 10 PCAs: Austin Energy,Brownsville Public Utils Bd,AEP West-ERCOT,Reliant E
San Diego Gas & Electric/PCA	California ISO/PCA was formed by the merger of Pacific Gas & Electric/PCA, San Diego Gas & Electric/PCA, and Southern Calif
South Texas Electric Coop Inc/PCA	ERCOT ISO/PCA was formed by the merger of 10 PCAs: Austin Energy,Brownsville Public Utils Bd,AEP West-ERCOT,Reliant E
Southeastern Power Administration/P(	Southeastern Power Administration/PCA was formed by the merger of SEPA Hartwell/PCA, SEPA Thurmond/PCA, and SEPA R
Southern California Edison/PCA	California ISO/PCA was formed by the merger of Pacific Gas & Electric/PCA, San Diego Gas & Electric/PCA, and Southern Calif
Southwestern Electric Power/PCA	American Electric Power - West (SPP)/PCA was formed by the merger of Public Service Co of Oklahoma/PCA and Southwestern
Springfield (IL) Water Light & Power/P	Springfield (IL) Water Light & Power/PCA is called City Water Light & Power by NERC.
Springfield (IL) Water Light & Power/P	City of Springfield/PCA was renamed Springfield (IL) Water Light & Power/PCA.
St Joseph Light & Power/PCA	St Joseph Light & Power/PCA was absorbed by Missouri Public Service Co/PCA in 2001.
St Joseph Light & Power/PCA	St Joseph Light & Power/PCA moved from SPP to MAPP in 1998.
Starke City of/PCA	FL Mun Pwr Pool/PCA was formed by the merger of Ft Pierce Ut Ath,Key W City of,W Ut Bd,Kissimmee Ut Ath,Starke City of,&V
Tacoma City Dept Of Public Utilities/P	Tacoma City Dept Of Public Utilities/PCA is called Tacoma Power by NERC.
Texas Municipal Power Pool/PCA	ERCOT ISO/PCA was formed by the merger of 10 PCAs: Austin Energy,Brownsville Public Utils Bd,AEP West-ERCOT,Reliant E
Texas-New Mexico Power Co/PCA	ERCOT ISO/PCA was formed by the merger of 10 PCAs: Austin Energy,Brownsville Public Utils Bd,AEP West-ERCOT,Reliant E
Toledo Edison Co/PCA	FirstEnergy/PCA was formed by the merger of Cleveland Electric Illuminating Co/PCA, Ohio Edison Co/PCA and Toledo Edison (
TXU Electric/PCA	ERCOT ISO/PCA was formed by the merger of 10 PCAs: Austin Energy,Brownsville Public Utils Bd,AEP West-ERCOT,Reliant E
TXU Electric/PCA	Texas Utilities Electric Co/PCA was renamed TXU Electric/PCA.
Union Electric/PCA	Ameren Corp/PCA was formed by the merger of Central Illinois Public Service/PCA and Union Electric/PCA in 1997.
Vero Beach City of/PCA	FL Mun Pwr Pool/PCA was formed by the merger of Ft Pierce Ut Ath,Key W City of,W Ut Bd,Kissimmee Ut Ath,Starke City of,&V
West Texas Utilities/PCA	American Electric Power - West (ERCOT)/PCA was formed by the merger of Central Power & Light Co/PCA, West Texas Utilities
Westar Energy/PCA	Westar Energy/PCA is called Western Resources dba Western Energy by NERC.
Westar Energy/PCA	Western Resources Inc/PCA was renamed Westar Energy/PCA.
Western Resources Inc/PCA	Western Resources Inc/PCA was formed by the merger of KPL, a Western Resources Co/PCA and KGE, A Western Resources
Wisconsin Energy Corporation/PCA	Wisconsin Electric Power Co/PCA was renamed Wisconsin Energy Corporation/PCA.
WAPA - Phoenix (LC)/PCA	WAPA - Phoenix (LC)/PCA is called Western Area Power Administration - DSW by NERC.
WAPA - Phoenix (LC)/PCA	WAPA-Lower Colorado/PCA was renamed WAPA - Phoenix (LC)/PCA.
WAPA - Rocky Mountains/PCA	WAPA - Rocky Mountains/PCA is called Western Area Power Administration - CM by NERC.

PCANAME	OLDNAME	OLDID
PCA name	Old name	Old ID
Alliant East/PCA	Wisconsin Power & Light/PCA	20856.0
Alliant West/PCA		0.0
Alliant West/PCA	MAPP	5.0
Ameren Corp/PCA		0.0
American Electric Power - West (ERC		0.0
American Electric Power - West (ERC	American Electric Power - West (ERCOT)/PCA	3280.0
American Electric Power - West (SPP)		0.0
American Electric Power - West (SPP)		0.0
Aquila Networks - Kansas/PCA	Westplains Energy/PCA	20391.0
Aquila Networks - Missouri/PCA	Missouri Public Service Co/PCA	12699.0
Associated Electric Coop/PCA	SPP	8.0
Austin Energy/PCA	Austin Energy/PCA	1015.0
Austin Energy/PCA	Austin City of/PCA	1015.0
Avista Corp/PCA	Washington Water Power Co/PCA	20169.0
Brownsville Public Utils Board/PCA	Brownsville Public Utils Board/PCA	2409.0
California ISO/PCA		0.0
California ISO/PCA	California ISO/PCA	-4.0
Central Illinois Public Service/PCA	Central Illinois Public Service/PCA	3253.0
Central Power & Light Co/PCA	Central Power & Light CO/PCA	3278.0
Cincinnati Gas & Electric/PCA	Cincinnati Gas & Electric/PCA	3542.0
Cinergy Corporation/PCA		0.0
City of Pasadena/PCA	City of Pasadena/PCA	14534.0
Cleveland Electric Illuminating Co/PCA	Cleveland Electric Illuminating Co/PCA	3755.0
CLECO Corporation/PCA	Central Louisiana Electric Co/PCA	3265.0
Dominion Virginia Power/PCA	Virginia Electric & Power Co/PCA	19876.0
Duke Power Co/PCA	Duke Power Co/PCA	5416.0
Entergy Electric System/PCA	SPP	8.0
FirstEnergy/PCA		0.0

PCANAME	OLDNAME	OLDID
PCA name	Old name	Old ID
Florida Municipal Power Pool/PCA	Lake Worth Utilities/PCA	10620.0
Florida Municipal Power Pool/PCA		0.0
Fort Pierce Utilities Auth/PCA	Fort Pierce Utilities Auth/PCA	6616.0
Golden Valley Electric Association/PC	Fairbanks City of/PCA	6129.0
Great River Energy/PCA	United Power Association/PCA	19514.0
Independence City Of/PCA		0.0
Interstate Power/PCA	Interstate Power/PCA	9392.0
IES Utilities Inc/PCA	IES Utilities Inc/PCA	9162.0
JEA (City of Jacksonville)/PCA	Jacksonville Electric Authority/PCA	9617.0
Key West City of/PCA	Key West City of/PCA	10226.0
Kissimmee Utility Authority/PCA	Kissimmee Utility Authority/PCA	10376.0
KGE, A Western Resources Co/PCA	KGE, A Western Resources Co/PCA	10005.0
KPL, a Western Resources Co/PCA	Midwest Energy Inc/PCA	12524.0
KPL, a Western Resources Co/PCA	KPL, a Western Resources Co/PCA	22500.0
Lafayette (LA) Utilities System/PCA	Lafayette City of/PCA	9096.0
Louisiana Generating LLC/PCA	SPP	8.0
Louisiana Generating LLC/PCA	Cajun Electric Power Coop/PCA	2777.0
Lower Colorado River Authority/PCA	Lower Colorado River Authority/PCA	11269.0
LG&E Energy/PCA	Kentucky Utilities Co/PCA	10171.0
Michigan Electric Power Coordination	Michigan Power Pool/PCA	12427.0
Missouri Public Service Co/PCA	St Joseph Light & Power/PCA	17881.0
New England ISO/PCA	New England Power Exchange/PCA	13434.0
New York ISO/PCA	New York Power Pool/PCA	13501.0
Ohio Edison Co/PCA	Ohio Edison Co/PCA	13998.0
Pacific Gas & Electric/PCA	Pacific Gas & Electric/PCA	14328.0
Public Service Co of Oklahoma/PCA	Public Service Co of Oklahoma/PCA	15474.0
Puget Sound Energy Transmission/PC	Puget Sound Power & Light Co/PCA	15500.0
PSI Energy Inc/PCA	PSI Energy Inc/PCA	15470.0
Reliant Energy HL&P/PCA	Reliant Energy HL&P/PCA	8901.0

PCANAME	OLDNAME	OLDID
PCA name	Old name	Old ID
Reliant Energy HL&P/PCA	Houston Lighting & Power Co/PCA	8901.0
Sacramento Municipal Utility District/P		0.0
San Antonio Public Service Bd/PCA	San Antonio Public Service Bd/PCA	16604.0
San Diego Gas & Electric/PCA	San Diego Gas & Electric/PCA	16609.0
South Texas Electric Coop Inc/PCA	South Texas Electric Coop Inc/PCA	17583.0
Southeastern Power Administration/P(		0.0
Southern California Edison/PCA	Southern California Edison/PCA	17609.0
Southwestern Electric Power/PCA	Southwestern Electric Power/PCA	17698.0
Springfield (IL) Water Light & Power/P		0.0
Springfield (IL) Water Light & Power/P	Springfield City of/PCA	17828.0
St Joseph Light & Power/PCA	St Joseph Light & Power/PCA	17881.0
St Joseph Light & Power/PCA	SPP	8.0
Starke City of/PCA	Starke City of/PCA	18004.0
Tacoma City Dept Of Public Utilities/P		0.0
Texas Municipal Power Pool/PCA	Texas Municipal Power Pool/PCA	18664.0
Texas-New Mexico Power Co/PCA	Texas-New Mexico Power Co/PCA	40051.0
Toledo Edison Co/PCA	Toledo Edison Co/PCA	18997.0
TXU Electric/PCA	TXU Electric/PCA	44372.0
TXU Electric/PCA	Texas Utilities Electric Co/PCA	44372.0
Union Electric/PCA	Union Electric/PCA	19436.0
Vero Beach City of/PCA	Vero Beach City of/PCA	19804.0
West Texas Utilities/PCA	West Texas Utilities/PCA	20404.0
Westar Energy/PCA		0.0
Westar Energy/PCA	Western Resources Inc/PCA	22500.0
Western Resources Inc/PCA		0.0
Wisconsin Energy Corporation/PCA	Wisconsin Electric Power Co/PCA	20847.0
WAPA - Phoenix (LC)/PCA		0.0
WAPA - Phoenix (LC)/PCA	WAPA - Lower Colorado/PCA	19610.0
WAPA - Rocky Mountains/PCA		0.0

PCANAME	NEWNAME	NEWID
PCA name	**New name**	**New ID**
Alliant East/PCA	Alliant East/PCA	186.0
Alliant West/PCA	Alliant West/PCA	193.0
Alliant West/PCA	MAIN	4.0
Ameren Corp/PCA	Ameren Corp/PCA	19436.0
American Electric Power - West (ERC	American Electric Power - West (ERCOT)/PCA	3280.0
American Electric Power - West (ERC	ERCOT ISO/PCA	-8.0
American Electric Power - West (SPP)	American Electric Power - West (SPP)/PCA	3283.0
American Electric Power - West (SPP)		0.0
Aquila Networks - Kansas/PCA	Aquila Networks - Kansas/PCA	20391.0
Aquila Networks - Missouri/PCA	Aquila Networks - Missouri/PCA	12699.0
Associated Electric Coop/PCA	SERC	7.0
Austin Energy/PCA	ERCOT ISO/PCA	-8.0
Austin Energy/PCA	Austin Energy/PCA	1015.0
Avista Corp/PCA	Avista Corp/PCA	20169.0
Brownsville Public Utils Board/PCA	ERCOT ISO/PCA	-8.0
California ISO/PCA	California ISO/PCA	-4.0
California ISO/PCA	California ISO/PCA	-4.0
Central Illinois Public Service/PCA	Ameren Corp/PCA	19436.0
Central Power & Light Co/PCA	American Electric Power - West (ERCOT)/PCA	3280.0
Cincinnati Gas & Electric/PCA	Cinergy Corporation/PCA	3260.0
Cinergy Corporation/PCA	Cinergy Corporation/PCA	3260.0
City of Pasadena/PCA	California ISO/PCA	-4.0
Cleveland Electric Illuminating Co/PCA	FirstEnergy/PCA	-5.0
CLECO Corporation/PCA	CLECO Corporation/PCA	3265.0
Dominion Virginia Power/PCA	Dominion Virginia Power/PCA	19876.0
Duke Power Co/PCA	Duke Power Co/PCA	5416.0
Entergy Electric System/PCA	SERC	7.0
FirstEnergy/PCA	FirstEnergy/PCA	-5.0

PCANAME	NEWNAME	NEWID
PCA name	New name	New ID
Florida Municipal Power Pool/PCA	Florida Municipal Power Pool/PCA	14610.0
Florida Municipal Power Pool/PCA	Florida Municipal Power Pool/PCA	14610.0
Fort Pierce Utilities Auth/PCA	Florida Municipal Power Pool/PCA	14610.0
Golden Valley Electric Association/PC	Golden Valley Electric Association/PCA	7353.0
Great River Energy/PCA	Great River Energy/PCA	7570.0
Independence City Of/PCA		0.0
Interstate Power/PCA	Alliant West/PCA	193.0
IES Utilities Inc/PCA	Alliant West/PCA	193.0
JEA (City of Jacksonville)/PCA	JEA (City of Jacksonville)/PCA	9617.0
Key West City of/PCA	Florida Municipal Power Pool/PCA	14610.0
Kissimmee Utility Authority/PCA	Florida Municipal Power Pool/PCA	14610.0
KGE, A Western Resources Co/PCA	Western Resources Inc/PCA	22500.0
KPL, a Western Resources Co/PCA	KPL, a Western Resources Co/PCA	22500.0
KPL, a Western Resources Co/PCA	Western Resources Inc/PCA	22500.0
Lafayette (LA) Utilities System/PCA	Lafayette (LA) Utilities System/PCA	9096.0
Louisiana Generating LLC/PCA	SERC	7.0
Louisiana Generating LLC/PCA	Louisiana Generating LLC/PCA	2777.0
Lower Colorado River Authority/PCA	ERCOT ISO/PCA	-8.0
LG&E Energy/PCA	LG&E Energy/PCA	11249.0
Michigan Electric Power Coordination	Michigan Electric Power Coordination Center/PCA	12427.0
Missouri Public Service Co/PCA	Missouri Public Service Co/PCA	12699.0
New England ISO/PCA	New England ISO/PCA	13434.0
New York ISO/PCA	New York ISO/PCA	13501.0
Ohio Edison Co/PCA	FirstEnergy/PCA	-5.0
Pacific Gas & Electric/PCA	California ISO/PCA	-4.0
Public Service Co of Oklahoma/PCA	American Electric Power - West (SPP)/PCA	3283.0
Puget Sound Energy Transmission/PC	Puget Sound Energy Transmission/PCA	15500.0
PSI Energy Inc/PCA	Cinergy Corporation/PCA	3260.0
Reliant Energy HL&P/PCA	ERCOT ISO/PCA	-8.0

PCANAME	NEWNAME	NEWID
PCA name	New name	New ID
Reliant Energy HL&P/PCA	Reliant Energy HL&P/PCA	8901.0
Sacramento Municipal Utility District/P	Sacramento Municipal Utility District/PCA	-7.0
San Antonio Public Service Bd/PCA	ERCOT ISO/PCA	-8.0
San Diego Gas & Electric/PCA	California ISO/PCA	-4.0
South Texas Electric Coop Inc/PCA	ERCOT ISO/PCA	-8.0
Southeastern Power Administration/P(	Southeastern Power Administration/PCA	-6.0
Southern California Edison/PCA	California ISO/PCA	-4.0
Southwestern Electric Power/PCA	American Electric Power - West (SPP)/PCA	3283.0
Springfield (IL) Water Light & Power/P		0.0
Springfield (IL) Water Light & Power/P	Springfield (IL) Water Light & Power/PCA	17828.0
St Joseph Light & Power/PCA	Missouri Public Service Co/PCA	12699.0
St Joseph Light & Power/PCA	MAPP	5.0
Starke City of/PCA	Florida Municipal Power Pool/PCA	14610.0
Tacoma City Dept Of Public Utilities/P		0.0
Texas Municipal Power Pool/PCA	ERCOT ISO/PCA	-8.0
Texas-New Mexico Power Co/PCA	ERCOT ISO/PCA	-8.0
Toledo Edison Co/PCA	FirstEnergy/PCA	-5.0
TXU Electric/PCA	ERCOT ISO/PCA	-8.0
TXU Electric/PCA	TXU Electric/PCA	44372.0
Union Electric/PCA	Ameren Corp/PCA	19436.0
Vero Beach City of/PCA	Florida Municipal Power Pool/PCA	14610.0
West Texas Utilities/PCA	American Electric Power - West (ERCOT)/PCA	3280.0
Westar Energy/PCA		0.0
Westar Energy/PCA	Westar Energy/PCA	22500.0
Western Resources Inc/PCA	Western Resources Inc/PCA	22500.0
Wisconsin Energy Corporation/PCA	Wisconsin Energy Corporation/PCA	20847.0
WAPA - Phoenix (LC)/PCA		0.0
WAPA - Phoenix (LC)/PCA	WAPA - Phoenix (LC)/PCA	19610.0
WAPA - Rocky Mountains/PCA		0.0

U.S. FUEL ETHANOL PRODUCTION CAPACITY
million gallons per year (mmgy)

http://www.ethanolrfa.org/eth_prod_fac.html

COMPANY	LOCATION	STATE	FEEDSTOCK	Current Capacity (mmgy)	Under Construction/ Expansion (mmgy)
Golden Cheese Company of California*	Corona, CA	CA	Cheese whey	5	
Parallel Products	R. Cucamonga, CA	CA		4	
Merrick/Coors	Golden, CO	CO	Waste beer	1.5	
Amaizing Energy, LLC*^	Denison, IA	IA	Corn		40
Archer Daniels Midland	Cedar Rapids, IA	IA	Corn		
Archer Daniels Midland	Clinton, IA	IA	Corn		
Big River Resources, LLC*	West Burlington, IA	IA	Corn	40	
Cargill, Inc.	Eddyville, IA	IA	Corn	35	
Central Iowa Renewable Energy, LLC*^	Goldfield, IA	IA	Corn		50
Golden Grain Energy, LLC*^	Mason City, IA	IA	Corn		40
Grain Processing Corp.	Muscatine, IA	IA	Corn	10	
Iowa Ethanol, LLC*	Hanlontown, IA	IA	Corn	45	
Little Sioux Corn Processors, LP*	Marcus, IA	IA	Corn	46	
Midwest Grain Processors*	Lakota, IA	IA	Corn	45	
Midwest Renewables^	Iowa Falls, IA	IA	Corn		40
Otter Creek Ethanol, LLC*	Ashton, IA	IA	Corn	45	
Permeate Refining	Hopkinton, IA	IA	Sugars & starches	1.5	
Pine Lake Corn Processors, LLC*^	Steamboat Rock, IA	IA	Corn		20
Quad-County Corn Processors*	Galva, IA	IA	Corn	23	
Siouxland Energy & Livestock Coop*	Sioux Center, IA	IA	Corn	18	
Tall Corn Ethanol, LLC*	Coon Rapids, IA	IA	Corn	45	
VeraSun Fort Dodge, LLC^	Ft. Dodge, IA	IA	Corn		110
Voyager Ethanol, LLC*^	Emmetsburg, IA	IA	Corn		50
J.R. Simplot	Caldwell, ID	ID	Potato waste	4	
Adkins Energy, LLC*	Lena, IL	IL	Corn	40	
Archer Daniels Midland	Decatur, IL	IL	Corn	1070	
Archer Daniels Midland	Peoria, IL	IL	Corn		
Aventine Renewable Energy, Inc.	Pekin, IL	IL	Corn	100	
Lincolnland Agri-Energy, LLC*	Palestine, IL	IL	Corn	40	
MGP Ingredients, Inc.	Pekin, IL	IL	Corn/wheat starch	78	
New Energy Corp.	South Bend, IN	IN	Corn	95	
Abengoa Bioenergy Corp.	Colwich, KS	KS		20	
East Kansas Agri-Energy, LLC*^	Garnett, KS	KS	Corn		35
ESE Alcohol Inc.	Leoti, KS	KS	Seed corn	1.5	

COMPANY	LOCATION	STATE	FEEDSTOCK	Current Capacity (mmgy)	Under Construction/ Expansion (mmgy)
MGP Ingredients, Inc.	Atchison, KS	KS			
Reeve Agri-Energy	Garden City, KS	KS	Corn/milo	12	
U.S. Energy Partners, LLC	Russell, KS	KS	Milo/wheat starch	40	
Western Plains Energy, LLC*	Campus, KS	KS	Corn	30	
Commonwealth Agri-Energy, LLC*	Hopkinsville, KY	KY	Corn	20	
Parallel Products	Louisville, KY	KY	Beverage waste	4	
Michigan Ethanol, LLC	Caro, MI	MI	Corn	45	
Agra Resources Coop. d.b.a. EXOL*	Albert Lea, MN	MN	Corn	38	
Agri-Energy, LLC*	Luverne, MN	MN	Corn	21	
Al-Corn Clean Fuel*	Claremont, MN	MN	Corn	30	
Archer Daniels Midland	Marshall, MN	MN	Corn		
Central MN Ethanol Coop*	Little Falls, MN	MN	Corn	20	
Chippewa Valley Ethanol Co.*	Benson, MN	MN	Corn	42	
Corn Plus, LLP*	Winnebago, MN	MN	Corn	44	
DENCO, LLC*	Morris, MN	MN	Corn	21.5	
Ethanol2000, LLP*	Bingham Lake, MN	MN	Corn	30	
Gopher State Ethanol	St. Paul, MN	MN	Corn/Beverage Waste	15	
Granite Falls Energy, LLC^	Granite Falls, MN	MN	Corn		45
Heartland Corn Products*	Winthrop, MN	MN	Corn	36	
Land O' Lakes*	Melrose, MN	MN	Cheese whey	2.6	
Minnesota Energy*	Buffalo Lake, MN	MN	Corn	18	
Northstar Ethanol, LLC^	Lake Crystal, MN	MN	Corn		50
Pro-Corn, LLC*	Preston, MN	MN	Corn	40	
Golden Triangle Energy, LLC*	Craig, MO	MO	Corn	20	
Mid-Missouri Energy, Inc.*^	Malta Bend, MO	MO	Corn		40
Northeast Missouri Grain, LLC*	Macon, MO	MO	Corn	40	
Alchem Ltd. LLLP	Grafton, ND	ND	Corn	10.5	
Archer Daniels Midland	Wallhalla, ND	ND	Corn/barley		
Abengoa Bioenergy Corp.	York, NE	NE	Corn/milo	50	
AGP*	Hastings, NE	NE	Corn	52	
Archer Daniels Midland	Columbus, NE	NE	Corn		
Aventine Renewable Energy, Inc.	Aurora, NE	NE	Corn	40	
Cargill, Inc.	Blair, NE	NE	Corn	83	
Chief Ethanol	Hastings, NE	NE	Corn	62	
Husker Ag, LLC*	Plainview, NE	NE	Corn	23	
KAAPA Ethanol, LLC*	Minden, NE	NE	Corn	40	

COMPANY	LOCATION	STATE	FEEDSTOCK	Current Capacity (mmgy)	Under Construction/ Expansion (mmgy)
Platte Valley Fuel Ethanol, LLC	Central City, NE	NE	Corn	40	
Trenton Agri Products, LLC	Trenton, NE	NE	Corn	30	
Abengoa Bioenergy Corp.	Portales, NM	NM		15	
Liquid Resources of Ohio^	Medina, OH	OH	Waste Beverage		4
Broin Enterprises, Inc.	Scotland, SD	SD	Corn	9	
Dakota Ethanol, LLC*	Wentworth, SD	SD	Corn	48	
Glacial Lakes Energy, LLC*	Watertown, SD	SD	Corn	48	
Great Plains Ethanol, LLC*	Chancellor, SD	SD	Corn	42	
Heartland Grain Fuels, LP*	Aberdeen, SD	SD	Corn	8	
Heartland Grain Fuels, LP*	Huron, SD	SD	Corn	14	
James Valley Ethanol, LLC	Groton, SD	SD	Corn	45	
Northern Lights Ethanol, LLC*	Big Stone City, SD	SD	Corn	45	
Sioux River Ethanol, LLC*	Hudson, SD	SD	Corn	45	
Tri-State Ethanol Co., LLC*	Rosholt, SD	SD	Corn	18	
VeraSun Energy Corporation	Aurora, SD	SD	Corn	100	
Tate & Lyle	Loudon, TN	TN	Corn	65	
Miller Brewing Co.	Olympia, WA	WA	Brewery waste	0.7	
ACE Ethanol, LLC	Stanley, WI	WI	Corn	30	
Badger State Ethanol, LLC*	Monroe, WI	WI	Corn	48	
Central Wisconsin Alcohol	Plover, WI	WI	Seed corn	4	
United WI Grain Producers, LLC*^	Friesland, WI	WI	Corn		40
Utica Energy, LLC	Oshkosh, WI	WI	Corn	24	26
Western Wisconsin Renewable Energy, LLC*^	Boyceville, WI	WI	Corn		40
Wyoming Ethanol	Torrington, WY	WY	Corn	5	
Total Existing Capacity				**3425.8**	
Total Under Construction/Expansions					**630**
Total Capacity				**4055.8**	

* farmer-owned

^ under construction
Last Updated: October 2004

One Massachusetts Ave., Suite 820, Washington DC 20001
Phone (202)289-3835, Fax (202)289-7519
e-mail info@ethanolrfa.org

http://www.ethanol.org/productionlist.htm

Ethanol Plants Currently Operating	City	State	MGY
Golden Cheese Company	Corona	CA	4.5
U.S. Liquids	Rancho Cucamonga	CA	4
Merrick/Coors	Golden	CO	1.5
Archer Daniels Midland	Cedar Rapids	IA	1030
Archer Daniels Midland	Clinton	IA	
Big River Resources, LLC	West Burlington	IA	40
Cargill	Eddyville	IA	35
Grain Processing Corp.	Muscatine	IA	60
Iowa Ethanol, LLC	Hanlontown	IA	45
Little Sioux Corn Processors	Marcus	IA	40
Midwest Grain Processors	Lakota	IA	45
Otter Creek Ethanol, LLC	Ashton	IA	45
Permeate Refining	Hopkinton	IA	2
Quad County Corn Processors	Galva	IA	20
Siouxland Energy & Livestock	Sioux Center	IA	15
Tall Corn Ethanol	Coon Rapids	IA	40
J.R. Simplot	Caldwell	ID	4
Adkins Energy, LLC	Lena	IL	43
Archer Daniels Midland	Decatur	IL	
Archer Daniels Midland	Peoria	IL	
Aventine Renewable Energy, Inc.	Pekin	IL	100
LincolnLand Agri-Energy	Robinson	IL	40
MGP Ingredients, Inc.	Pekin	IL	65
New Energy Corp.	South Bend	IN	95
Abengoa Bioenergy Corp.	Colwich	KS	20
ESE Alcohol,Inc.	Leoti	KS	1.5
MGP Ingredients, Inc.	Atchison	KS	30
Reeve Agri-Energy	Garden City	KS	12
U.S. Energy Partners, LLC	Russell	KS	40
Western Plains Energy, LLC	Campus	KS	30
Commonwealth Agri-Energy, LLC	Hopkinsville	KY	20
U.S. Liquids	Louisville	KY	4
Michigan Ethanol, LLC	Caro	MI	40
Agra Resources d.b.a. EXOL	Albert Lea	MN	37

Ethanol Plants Currently Operating	City	State	MGY
Agri-Energy, LLC	Luverne	MN	21
Al-Corn Clean Fuels	Claremont	MN	30
Archer Daniels Midland	Marshall	MN	
Central Minnesota Ethanol	Little Falls	MN	21
Chippewa Valley Ethanol	Benson	MN	45
Corn Plus, LLP	Winnebago	MN	44
Diversified Energy Co. (DENCO)	Morris	MN	21.5
Ethanol2000, LLP	Bingham Lake	MN	27
Gopher State Ethanol	St. Paul	MN	20
Heartland Corn Products	Winthrop	MN	35
Land O'Lakes	Melrose	MN	3
Minnesota Energy	Buffalo Lake	MN	18
Pro-Corn, LLC	Preston	MN	40
Golden Triangle Energy	Craig	MO	20
Northeast Missouri Grain	Macon	MO	45
Alchem, Ltd.	Grafton	ND	10.5
Archer Daniels Midland	Walhalla	ND	
Abengoa Bioenergy Corp.	York	NE	50
Ag Processing, Inc.	Hastings	NE	52
Archer Daniels Midland	Columbus	NE	
Cargill	Blair	NE	83
Chief Ethanol, Inc.	Hastings	NE	62
Husker Ag Processing, LLC	Plainview	NE	20
KAAPA Ethanol, LLC	Minden	NE	40
Nebraska Energy	Aurora	NE	35
Platte Valley Fuel Ethanol, LLC	Central City	NE	40
Trenton Agri-Products	Trenton	NE	30
Abengoa Bioenergy Corp.	Portales	NM	15
Broin Enterprises, Inc.	Scotland	SD	8.5
Dakota Ethanol, LLC	Wentworth	SD	40
Glacial Lakes Energy	Watertown	SD	45
Great Plains Ethanol, LLC	Chancellor	SD	40
Heartland Grain Fuels	Aberdeen	SD	8.9
Heartland Grain Fuels	Huron	SD	12
James Valley Ethanol, LLC	Groton	SD	45
Northern Lights Ethanol, LLC	Big Stone City	SD	40

Ethanol Plants Currently Operating	City	State	MGY
Sioux River Ethanol, LLC	Hudson	SD	45
VeraSun Energy	Aurora	SD	100
A.E. Staley	Loudon	TN	60
Miller Brewing Co.	Tumwater	WA	0.7
ACE Ethanol, LLC	Stanley	WI	15
Badger State Ethanol, LLC	Monroe	WI	48
Central Wisconsin Alcohol	Plover	WI	4
Utica Energy, LLC	Oshkosh	WI	20
Wyoming Ethanol	Torrington	WY	5
	Total: (million gallons per year)		**3334**

Ethanol Plants Under Construction	City	State	MGY
Amaizing Energy	Denison	IA	40
Central Illinois Energy Cooperative	Canton	IL	33
Cornhusker Energy Lexington, LLC	Lexington	NE	42
East Kansas Agri-Energy	Garnett	KS	20
Ethyl Alternative Fuels	Baton Rouge	LA	50
Golden Grain Energy LLC	Mason City	IA	40
Mid-Missouri Energy	Malta Bend	MO	40
Midwest Renewables	Alden	IA	40
Northstar Ethanol LLC	Lake Crystal	MN	49.5
Pine Lake Corn Processors, LLC	Steamboat Rock	IA	20
Tri-State Ethanol Company	Rosholt	SD	20
United Wisconsin Grain Producers	Friesland	WI	40
VeraSun Ft. Dodge	Ft. Dodge	IA	110
Voyager Ethanol, LLC	Emmetsburg	IA	50
	Total: (million gallons per year)		**594.5**

U.S. FUEL ETHANOL PRODUCTION CAPACITY
million gallons per year (mmgy)

COMPANY	LOCATION	STATE	FEEDSTOCK	Current Capacity (mmgy)	Under Construction/ Expansions (mmgy)	Address	City/State/Zip
Merrick/Coors	Golden, CO	CO	Waste beer	1.5		13th and Ford St	Golden, CO 80401
Abengoa Bioenergy Corp.	Colwich, KS	KS		20		523 East Union /	Colwich, KS 67030 USA
East Kansas Agri-Energy, LLC*^	Garnett, KS	KS	Corn		35		
ESE Alcohol Inc.	Leoti, KS	KS	Seed corn	1.5		PO Box 813	Leoti, KS 67861
MGP Ingredients, Inc.	Atchison, KS	KS				1300 Main Stree	Atchison, KS 66002
Reeve Agri-Energy	Garden City, KS	KS	Corn/milo	12		PO Box 1036	Garden City, KS 67849
U.S. Energy Partners, LLC	Russell, KS	KS	Milo/wheat starch	40		1224 E. 15th	Russell, Kansas 67665
Western Plains Energy, LLC*	Campus, KS	KS	Corn	30		3022 County Roa	Oakley, Kansas 67748
Abengoa Bioenergy Corp.	Portales, NM	NM		15		1827 Industrial D	Portales, NM 88130 USA
Wyoming Ethanol	Torrington, WY	WY	Corn	5		307.532.2449	
Total Existing Capacity				**125**			
Total Under Construction/Expansions					**35**		
Total Capacity				**160**			

* farmer-owned
^ under construction
Last Updated: October 2004

One Massachusetts Ave., Suite 820, Washington DC 20001
Phone (202)289-3835, Fax (202)289-7519
e-mail info@ethanolrfa.org

Appendix H: Risk Factors - Assessment and Evaluation

A critical aspect of the SWP Phase 1 program was to gather information necessary to evaluate under what conditions will sequestration technologies be safe and have minimal and controllable impact on the environment. We concluded that specific validation and/or deployment sites will require a systematic evaluation of uncertainty and risks associated with CO2 storage to develop a quantitative assessment of potential impacts from any unintended CO2 release. Furthermore, analysis by the SWP during its Phase I program suggests that for any and all validation and deployment phases of sequestration, risk potential may best be approached with a combined program of risk assessment and risk mitigation; we view assessment and mitigation as different components that must be employed in tandem.

Risk assessment and risk management methods developed by the nuclear power industry and other industries are an extremely valuable resource. Specifically, the SWP drew on industry resources to develop a screening methodology for evaluating potential environmental and safety risks of geologic CO_2 storage projects. The methodology is based on the "FEPs" approach developed previously by others, including Quintessa (2004; see http://www.quintessa.org/about/news04.html). FEPs are the features, events, and processes that make up the physical and chemical behavior of CO2 in the system being assessed – physical and chemical Features of the system, relevant Processes that may influence the evolution of the system, and specific Events that may impact sequestration and take place over timescales coincident with sequestration.

For any specific validation (e.g., Phase 2) or deployment programs, risk factors in the form of FEPs specific to the site(s) must be quantitatively described and catalogued in a database, including and especially uncertainties. We recommend that pre-pilot geologic characterization and associated modeling results be used to establish this basic database. During the course of each pilot test, the databases will continue to be populated and expanded with additional data, observations, model results, and specialized analysis. This approach is designed to integrate fundamental observations with results of detailed analysis and interpretation, and will facilitate an objective and quantitative assessment of potential risks for each site and provide outreach to stakeholders.

For future geologic sequestration validation (e.g., Phase 2) and deployment programs, we recommend that fundamental risk assessment should continue throughout injection operations. Reservoir and seal performance, using all MMV data and quantitative description of specific FEPs, will be analyzed continuously, and reservoir simulation models and their forecasts should be updated periodically (~ monthly). Additionally, uncertainty and risk assessment data will also be updated continuously. This evolving risk assessment framework could in turn be used to guide subsequent MMV and data collection activities, as well as pilot test engineering design (injection, etc.). In sum, combined MMV and risk assessment data could be used in tandem to guide engineering operations and vice-versa, in the form of a continuous, iterative feedback loop.

The most general risk criteria associated with geologic sequestration include

- Leakage through poor quality or aging injection well completions
- Leakage up abandoned wells
- Leakage due to inadequate caprock characterization
- Inconsistent or inadequate monitoring

Even a basic FEPs database for a given site will provide a mechanism for communicating risk potential, which affects regulatory permitting, identification of regulatory gaps, MMV design, and outreach and education of stakeholders.

We suggest that the most basic, but also most important, FEPs – risk factors are those that address CO2 trapping mechanisms. Perhaps future geologic sequestration validation (e.g. Phase 2) and deployment operations could begin with FEPs (risk factors) associated with trapping mechanisms and their failure modes, and then proceed with other FEPs of the system under consideration. For sake of example, and for the purpose of outlining what we suggest as the most essential FEPs to consider, the next section describes fundamental CO2 trapping mechanisms, basic failure modes of each, and an approach we recommend for quantifying uncertainty of these FEPs through development of appropriate probability distribution functions.

CO_2 Trapping Mechanisms and Associated Failure Modes

In this report we consider four primary trapping mechanisms, including hydrostratigraphic, residual gas, solubility, and mineral trapping. Failure modes of each trapping mechanism are outlined, including discussion of how to define uncertainty of these failure modes.

Hydrostratigraphic trapping: hydrostratigraphic trapping refers to trapping of CO_2 by low permeability sealing layers. This type of trapping is often distinguished by whether the CO_2 is contained by stratigraphic and structural traps, e.g., similar to oil and gas reservoirs, called <u>static accumulations</u>, or whether it is trapped as a migrating plume in large-scale flow systems, called <u>hydrodynamic trapping</u>. Major failure modes for hydrostratigraphic trapping include:

(1) unintended migration by pre-existing but unidentified faults, fractures, or other fast-flow paths,
(2) unintended migration by stress-induced or reactivated fractures or faults,
(3) unintended migration by reaction-induced breaching of a seal layer
(4) unintended lateral flow to unintended areas,
(5) catastrophic events (e.g., unexpected earthquakes, etc.),
(6) wellbore failure events.

One approach to mitigating several of these failure modes is to select a storage site with multiple alternating seals and reservoirs above the primary (intended) reservoir, sometimes described as stacked reservoirs. However, even when stacked reservoirs are present, other measures must be taken to minimize risk of failure.

Residual gas trapping: At the interface between two different liquid phases (such as CO_2 and water), the cohesive forces acting on the molecules in either phase are unbalanced. This imbalance exerts tension on the interface, causing the interface to contract to as small an area as possible. The importance of this interfacial tension in multiphase flow is paramount; the multiphase CO_2-brine-oil-gas flow equations are more sensitive to interfacial tension than many other fluid properties. Interfacial tension may trap CO_2 in pores, if fluid saturations are low. The threshold at which this occurs is called the “irreducible saturation” of CO_2, and is a key concept for defining “residual gas trapping.” The magnitude of residual CO_2 saturation within rock, and thus the amount of CO_2 that can be trapped by this mechanism, is a function of the rock's pore network geometry as well as fluid properties. Geologic conditions that impact the amount of CO_2 trapped as a residual phase include petrophysics, burial effects, temperature and pressure gradients, CO_2 properties (density) under different P-T conditions, and on engineering parameters such as injection pressure, induced flow rates, and/or well orientation.

The primary failure mode for residual gas trapping is loss of capillary forces (surface tension) of the pore matrix. Such loss would be due to any process that changes the pore geometry or size or changes the interfacial tension, including compaction, dissolution or precipitation of cements in or around pores, or changing fluid composition.

Solubility trapping: Perhaps the most fundamental type of trapping is dissolution, or "solubility trapping." First, CO_2 dissolves to an aqueous species followed by rapid dissociation of carbonic acid producing bicarbonate and carbonate ions while lowering pH. The primary failure mode for solubility trapping is exsolution, which would only occur under significant (large) changes in pressure or temperature.

Mineral trapping: "Mineral trapping" refers to the process of CO_2 reacting with divalent cations to form mineral precipitates in the subsurface. The reactions, especially reaction rates and associated processes that affect rates (e.g., complexation, pH buffering, etc.) are complicated and make estimates of CO_2 storage capacity difficult. The primary failure mode for mineral trapping is dissolution of the carbonate minerals that trapped CO_2.

An Approach for Quantifying Uncertainty of Trapping Mechanisms and Failure Modes

Quantitative assessment of geologic uncertainty has been of great interest in the last few years (Caumon, et al., 2004), and that interest is growing with the advent of new carbon sequestration testing programs. In the oil industry, several different approaches have been used to obtain probability distribution functions (PDFs) of desired parameters, such as hydrocarbons in place, recovery factors, etc. In CO_2 sequestration one might want to determine critical fault properties that could lead to hydrostratigraphic trapping failure or to thickness variations of the seal that could lead to seal breach. The two most prominent methods for developing effective PDFs are:

- Experimental design based methods
- Bayesian probabilistic formalism

We suggest employing both methods for defining PDFs of critical parameters for each trapping mechanism failure mode.

In general, experimental design methods are based on generating simpler response surfaces using selected rigorous simulations (for example, reservoir models with appropriate fully coupled thermal-hydrologic-chemical-mechanical processes) followed by Monte Carlo simulations to identify the parameters that are most critical in affecting the targeted outcome. Initial rigorous models should be simulated to honor observed data. Such history matching is critical to the success of this method.

Sufficient data to validate models of trapping mechanisms and associated failure modes FEPs may not be available from previous field tests. For example, very few new wells that could provide calibration data, including log and seismic data, will be drilled in most ongoing or planned field demonstrations. It is possible that data available from these wells may be limited to logs and seismic data. In these situations where information is sparse, the Bayesian framework suggested by Caumon et al. (2004) will be used to obtain probability distributions of critical parameters. In this approach several conceptual geologic models are constructed based on all available data. Each scenario is then depicted using a spatial variability model. At that stage, several choices of spatial variability models (variograms, for example) are available. The global estimate of a given target variable is constructed using the interpretation of the quantitative data under a given geologic scenario. Once the uncertainty in a given parameter is quantified, specific experimental design tools can be identified and used to collect additional data (such as well-bore seismic, logs etc.) to reduce uncertainty.

In summary, we recommend identifying FEPs for a given system, followed by a quantitative evaluation of relevant FEPs, e.g. for trapping mechanism failure modes, in the form of developing appropriate PDFs for each critical parameter employing either experimental design-based methods or Bayesian probabilistic formalisms. As injection proceeds and MMV data are collected, these PDFs describing the FEPs and associated risk can be updated and refined. This framework can be used to identify and catalog potential longer-term impacts to the system. Figure 1 summarizes the general approach in schematic fashion.

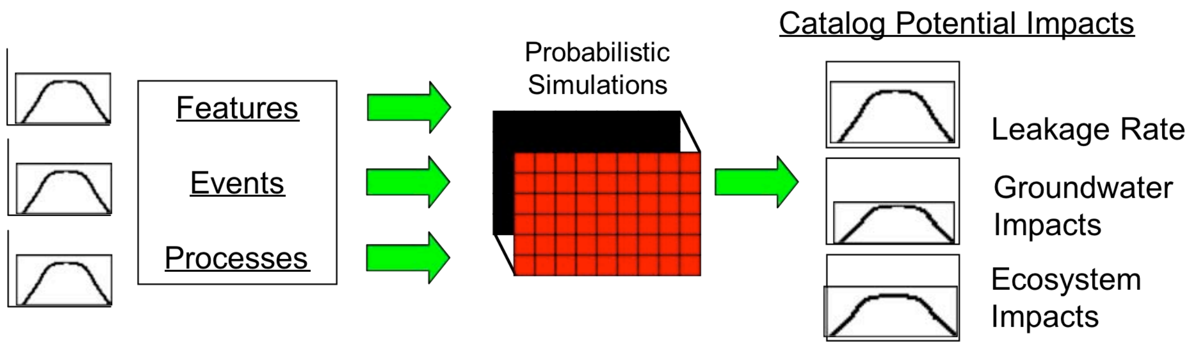

Figure 1. Schematic of general risk and uncertainty analysis, left-to-right: FEPs identified, then PDFs evaluated through probabilistic simulations, leading to a cataloging of potential longer-term impacts on the system. Adapted from Benson, S.M., 2004, written communication.

Reference

Caumon, et al., 2004, Assessment of Global Uncertainty in the early Assessment of Hydrocarbon Fields, SPE 89943, Society of Petroleum Engineers, Dallas, Texas.

Appendix I: Monitoring Protocols and Gaps in Coverage

MMV is at the heart of all SWP activities. MMV deployment and associated modeling will be the primary vehicles for determining how well the southwest region may meet or exceed performance targets of the Carbon Sequestration Roadmap, including prediction of storage capacity to +/- 30% accuracy, verification of indirect sequestration and associated costs, and verification of MMV technology efficacy. MMV is also central to our risk assessment and risk mitigation approaches. It is possible that MMV deployment of the Southwest and other partnerships' pilot tests will influence how regulation and permitting evolves and how regulatory gaps are filled. All MMV protocols are designed to meet the performance goals of the DOE Roadmap and the DOE EIA 1605B "Voluntary Guidelines for Greenhouse Gas Reporting," where possible, to meet the needs of evolving voluntary carbon markets in the U.S.

Results of the SWP Phase I program suggests recommendation of extensive MMV protocols, including direct and indirect approaches. MMV plans for the region should be designed to track the movement and fate of CO_2 injected into deep saline aquifers and coal beds, and oil and gas reservoirs. Additional MMV goals are to monitor CO_2 well injectivity, verify abandoned well veracity, and to assist with risk assessment and mitigation. Baseline MMV activities will elucidate geologic, hydrogeochemical, isotopic and other physical conditions prior to injection. During pilot tests and possible long-term sequestration operations, baseline data will be compared to results of repeat and continuous MMV surveys conducted after injection to forecast ultimate fate of CO_2 in the subsurface for different conditions.

The SWP conducted extensive analysis of sequestration options in the region, and ranked the top 5 sites/options in the region for comprehensive pilot-testing. Our MMV programs proposed for each of the ranked sites are tailored for the unique setting of each site and for maximizing comparisons to approaches deployed at the other sites.

In the following sections we summarize recommended MMV technologies.

Direct MMV Technologies Recommended for the Southwest Region

<u>INJECTION WELL MONITORING:</u> At the injection well, continuous measurements of injection rate, pressure and temperature will be monitored. Periodic shut-in tests will provide permeability changes in near- and far-well regions. Pressure transient tests prior to injection are proposed for all sites.

<u>IN SITU FIBER OPTIC P/T SENSORS</u>: In-situ borehole monitoring faces two major technical challenges: 1) the high-temperature and high-pressure, harsh environment of boreholes has excluded many conventional chemical sensors (e.g. electronic sensors), and 2) the long-distance from depth to the surface presents a challenge for high fidelity data transmission. Recently, optical fiber based in-situ physical sensors have been demonstrated successfully in field trials for downhole oil recovery and geothermal applications (Xiao et al., 2005a; Wang et al., 2001; May et al., 1999). Zeolite-coated optical fiber chemical sensors have also shown great potential for applications under hostile conditions found in typical borehole environment (Xiao et al., 2005b). For MMV at all sites, optical fiber based pressure and temperature sensors will be deployed in the injection wells for in-situ monitoring of CO_2 injectivity. These sensors, less than 1 mm in size, operate on the remote interrogation using Faby-Perot interferometer (EFPI). Test data show that the sensor is capable of measuring temperature up to 600°C and hydraulic pressure up to 8000 psi at temperatures up to 220°C.

<u>SPINNER FLOWMETER SURVEYS:</u> At an injection well, spinner surveys will be performed

to determine vertical injection conformance.
PRODUCTION WELL IN-SITU LI-COR©: In addition to continuous monitoring of gas and water production rates and pressures, continuous monitoring of produced gas CO_2 content will be made using LI-COR© IRGA devices at selected production wells.
ABANDONED WELL LI-COR©: At selected abandoned wells nearby, LI-COR© IRGA devices will also be installed in situ, to monitor potential flow of CO_2 from units below (e.g., degraded well-casings).
GAS PIEZOMETERS USING LI-COR©: We propose drilling five shallow wells of less than 800 ft depth for the purposes of cross-well seismic, ASTLI, and/or VSP, described below. These wells will be outfitted with in situ LI-COR© IRGA devices with dataloggers and wireless data transmission, for constant monitoring. In concept, these are like water-well piezometers, but instead of measuring hydraulic head, they will record CO_2 flux from depth.
ISOTOPIC AND COMPOSITION MEASUREMENTS: Periodic gas sampling and measurements of produced CO_2 isotopic signatures will also be made to distinguish between naturally produced CO_2 (CO_2 content of the produced gas is currently –25 ‰ to –27 ‰ range for $\delta^{13}C$) and the $\delta^{13}C$ of the injected CO_2 (either –1 ‰ to –2 ‰ from magmatic sources of CO_2 or –38 ‰ to –43 ‰ from industrial sources of CO_2) (~monthly). Periodic gas and water samples will also be collected for compositional analysis (~monthly), and pressure transient tests performed to monitor any changes in coal permeability (~every six months). Baseline measurements of gas CO_2 content and isotopic signature, as well as gas/water compositional analyses, and water chemistry will be obtained prior to injection of CO_2.
TILTMETERS [For the SJB ECBM pilot only] Potential coal swelling will likely cause a significant geodetic response. Specifically, actual laboratory strain measurements on San Juan basin coal, when methane is replaced with CO_2 at pressures of around 100 psi, show a volumetric strain on the order of 0.5–1.0% occurs due to coal swelling. Furthermore, computations of potential larger-scale response were made by Sandia National Lab (Warpinski, written communication, 2005), showing that such coal-swelling by injection at the depths and conditions at the San Juan basin ECBM site may result in a l° tilt at the surface. Thus, this is a promising method for tracking CO_2 movement in coal seams.

Indirect MMV Technologies Recommended for the Southwest Region

2-D and 3-D SEISMIC SURVEYS: 2-D or 3-D seismic surveys, coupled with borehole seismic data, will be used to monitor the injection process at the pilot sites. At Aneth and SJB ECBM, repeated 2-D seismic surveys will be conducted. At SACROC-Claytonville, 3-D seismic surveys will be conducted. For both 2-D and 3-D surveys, surface seismic data will be collected before, during, and after injection to allow us to assess changes in seismic response of the reservoir caused by the CO_2 injection.
VERTICAL SEISMIC PROFILES (VSP) AND CROSSWELL SEISMIC: Boreholes will be used to collect VSP data, which will have significantly higher frequencies than surface data and hence be more sensitive to small-scale changes in reservoir properties. By drilling multiple boreholes at each site, we will be able to collect data in both surface-downhole geometry and downhole-downhole (crosswell) geometry to allow interrogation of the reservoir on different scales and over different region sizes. VSP and crosswell data will be interpreted to infer changes in reflection character due to the presence of CO_2. We will also employ Active-Source Time-Lapse Intercomparison, or ASTLI: small changes in the phases of the individual wave packets measured before, during, and after the injection can be measured using an interferometric

approach to determine very small changes in seismic velocity within the reservoir. Borehole sensors will record seismic data when the 2D surface seismic surveys are being conducted, allowing us to compare surface and downhole data in addition to giving us more source location coverage than would be available if a conventional VSP survey alone was conducted. For analysis of crosswell data, we will use a combination of crosswell tomography and seismic migration, which is a fairly new application to crosswell data been shown to yield high-resolution information about the interwell region.

PASSIVE SEISMIC**:** Passive seismic monitoring using instruments placed in boreholes will be used to detect induced seismicity caused by the CO_2 injection. It has been shown that there is considerable information in the pattern of locations of induced seismic events about the interaction of the injected fluid with the fracture system and regional stress field (see Fehler et al., 2001).

SEISMIC MODELING: Appropriate modeling will determine the optimum data acquisition geometry for both surface and borehole, and active/passive seismic data.

HIGH RESOLUTION RESISTIVITY METHOD FOR BOREHOLE INTEGRITY: We are pleased to add an international partner, the National Institute for Advanced Industrial Science and Technology (AIST) of Japan, who will deploy and field test an advanced electrical method at two field sites (see attached support letter). The proposed technology is based on electro-kinetic changes and will be deployed to perform continuous monitoring. At Aneth, the method will be used to monitor for possible CO_2 leakage near the surface in the vicinities of well bores. At Claytonville, the method will be used to monitor CO_2 plume migration. AIST will conduct all fieldwork and facilitate interpretation.

DATA TRANSMISSION: IRGA devices and dataloggers will be connected to each operator's wireless data transmission system such that pattern performance can be monitored continuously and remotely.

MMV Options for the Top-Ranked Sequestration Sites/Options: Aneth Field, Utah – Deep Saline Sequestration and EOR with Sequestration

For future testing at Aneth, the primary contrast with other recommended pilot sites is the application and testing of 2-D seismic lines. Additionally, passive seismic monitoring promises to be particularly effective at the Aneth site, because a brine injection facility (Allis, Utah GS, personal communication) near the Colorado–Utah border provides an abundance of passive seismic energy.

MMV Options for the Top-Ranked Sequestration Sites/Options: San Juan Basin, New Mexico – ECBM with Sequestration and Riparian Restoration for Terrestrial Sequestration

For future San Juan basin pilot-tests, the primary contrast with other potential test sites concerns coal and CH_4. Specifically, we recommend testing techniques to help track the movement of CO_2 within the coalbeds, a potentially difficult task given that the coals are already saturated with CH_4. Thus, we recommend several special MMV applications. As CO_2 is injected, swelling of the coals will occur, permeability will reduce, and fluid pressures will increase dramatically. Swelling may be significant and detectable by tiltmeters. For example, a patternedgrid array of 30 or more surface tiltmeters could be deployed throughout an area, calibrated by fixed GPS stations, and could serve as one of the primary monitoring methods of CO_2 movement in coals. In any interwell areas, continuous monitoring of tiltmeter arrays may effectively monitor surface deformation related to coal swelling with CO_2 injection. In the event the CO_2 plume extends beyond the pattern, interferometric synthetic aperture radar (In SAR) data may be obtained periodically (~monthly) to monitor surface deformation over a larger area. Additionally, spinner surveys near injection wells may be used to determine vertical injection conformance among the individual coal seams that exist at specific sites.

Finally, we recommend focusing on both 2-D and 1-D seismic methods, to evaluate CO_2 movement out of the top and bottom of the coal beds. If coals are already saturated with CH4, MMV plans must account for seismic properties of CH4 and CO_2 being nearly identical, and thus resolving the CO_2 front (laterally) will likely be impossible, and 3-D surveys may be excessive (e.g., "overkill"). Thus, the SWP recommends focusing on evaluating the vertical change in seismic reflectors as a means of tracking the CO_2 front; 1-D and 2-D seismic methods (single source reflection; borehole methods such as VSP, etc.) will likely be effective for resolving changes in vertical reflectors at the coal boundaries. Combining and co-interpreting seismic and borehole geophysical methods with tiltmeters is a promising "coupled" approach for monitoring CO_2 and its effects on injectivity, methane production, and efficacy of CO_2 storage in the coals.

MMV Options for the Top-Ranked Sequestration Sites/Options: Permian Basin, Texas EOR with Sequestration

The SWP recommends EOR-related sequestration pilot tests for the Permian basin, site of decades of CO2 injection for EOR purposes. For future Texas pilot tests, we recommend application and testing of 3-D seismic lines. We will also recommend comparison of efficacy and approaches for these 4-D surveys to planned repeat 2-D surveys in other potential pilot test sites in the region.

Establishing and communicating the consequences and tradeoffs between alternate sequestration sites and strategies to store GHG is the necessary first step in formulating an effective and publicly acceptable sequestration program, and in addressing the 2007 and 2012 metrics for success of the DOE Carbon Sequestration Technology Roadmap. In the field pilot operations, MMV protocols and associated modeling are the primary vehicles for determining how well the SWP meets or exceeds performance targets of the CST Roadmap, including prediction of storage capacity to +/- 30% accuracy, verification of indirect sequestration and associated costs, and verification of MMV technology efficacy.

Monitoring Methods Coverage and General Gap Analysis

We evaluated the spatial (areal) and depth coverage of MMV (monitoring) technologies appropriate for the region, and from this analysis interpreted potential gaps in coverage that should receive extra attention as validation (e.g., Phase 2) and deployment programs are undertaken. Figure I-1 is a crude schematic diagram that depicts which types of monitoring technologies apply at the range of spatial (areal) scales to consider for geologic sequestration. Point measurements of surface or subsurface gas fluxes ("gas piezometer" via wells) and groundwater chemistry apply at small spatial scales, although if the point measurements are distributed over larger areas and tracked over time, larger areas may be monitored effectively for movement of CO2 at the surface, within the target reservoir, and within any geologic units that well-screens penetrate. Unfortunately, wells typically only penetrate oil or freshwater reservoirs, because of the high cost of drilling and completion.

Figure I-2 is a schematic diagram that depicts the depth-scales covered by the range of monitoring technologies appropriate for the region. Geophysical methods such as seismic technologies, electrical resistivity, microgravity, etc., offer the broadest spatial (areal) coverage (Figure I-1) and the best depth coverage (Figure I-2) independent of available wells. The method with the highest resolution for imaging CO2 migration over large areas (Figure I-1) and depth (Figure I-2) is seismic-reflection surveying, but this is also the most expensive method. Results of the Weyburn project suggest that even the most sophisticated 4-D seismic approaches have limited efficacy for CO_2 sequestration monitoring; seismic methods are very effective for detecting the “front” of a CO_2 plume, but are not very effective for determining volumes or amounts of CO_2 behind the plume front. Thus, we recommend investigation of how to optimize 2-D seismic lines for detection and monitoring purposes, because 2-D lines are two to four times less expensive than 3-D. We recommend optimization of 2-D seismic efficacy by combining surveys with crosswell, VSP, and ASTLI. We also recommend comparison of the efficacy and approaches for 2-D surveys to planned 3-D surveys at other sites in the region.

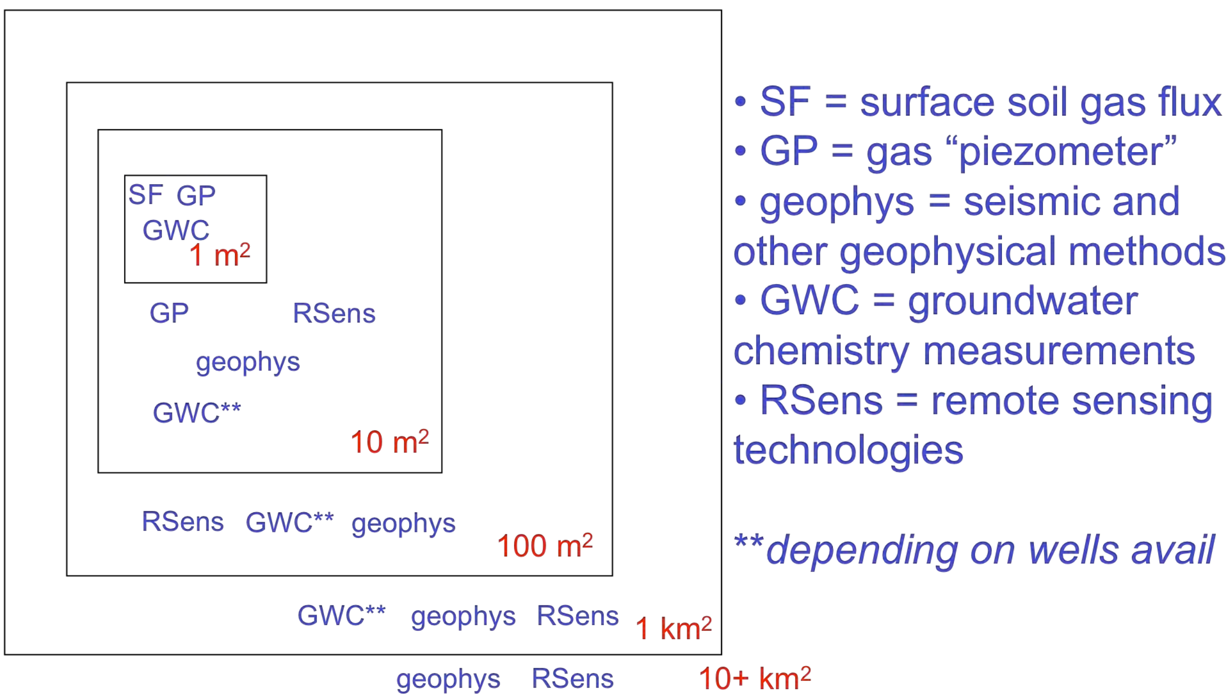

Figure I-1. Applicable spatial scales of different monitoring types/categories.

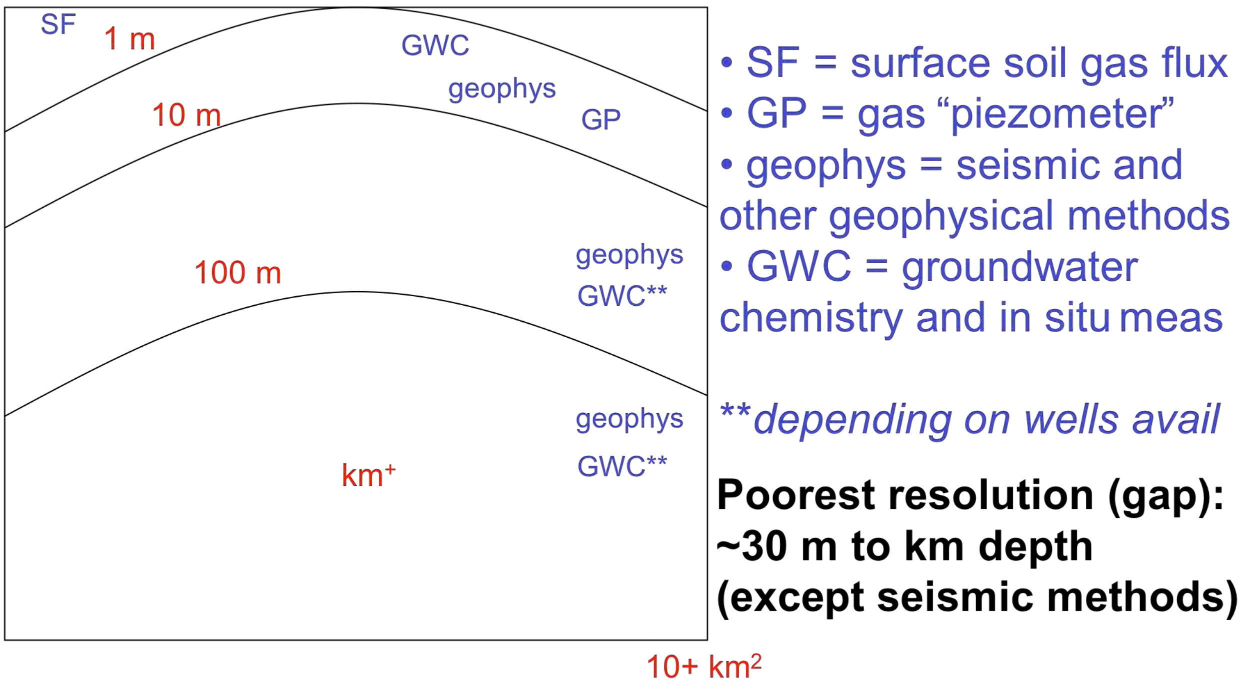

Figure I-2. Applicable depth scales of different monitoring types.

Figure I-2 illustrates that, in general, the most significant gap in monitoring coverage is what we call the "Intermediate Zone" (IZ), which is the depth interval between approximately 30 m depth to the geologic unit just above the target reservoir's seal/caprock formation. The extent of the IZ can be minimized and resolution maximized with more wells that penetrate units within the IZ or with high resolution geophysical methods (e.g., seismic imaging). However, both of these monitoring options are extremely expensive. For future validation (e.g., Phase 2) and deployment operations, we recommend extreme attention be paid to development of monitoring technologies that will increase resolution of CO2 detection in the IZ.

Regarding temporal coverage of monitoring technologies, cost is the only limiting factor; larger budgets translate to smaller temporal gaps in coverage. Remote sensing (for example, direct observations of surface vegetation albedo from satellite measurements) is probably the least expensive monitoring method, but necessarily only a surface monitor. Point measurements of gas fluxes and water chemistry are labor-intensive but perhaps the next least expensive among monitoring methods, and thus offer the most frequent observations. However, such point measurements are limited to available well coverage (Figure I-2). Seismic imaging methods offer the highest resolution over depth and area, including the IZ, but the high expense prohibits frequent surveys.

In sum, at this time, spatial and temporal gaps in monitoring are significant, and our ability to minimize these gaps are a direct function of available budget. We recommend focus on improving ability to monitor the IZ; optimization of 2-D seismic imaging methods (rather than more expensive 3-D methods) offers a great deal of promise for improving IZ-monitoring. Efficacy of microgravity and other novel geophysical methods also need to be evaluated in greater detail.

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Appendix J: Western Governors' Association Activities for the SWP

A. Objectives

Provided support to the U.S. Department of Energy, Office of Fossil Energy, to advance the concepts and promote the infrastructure for carbon sequestration in the Western United States. Working in collaboration with the Western Interstate Energy Board, an affiliate organization, WGA provided services and completed tasks as described below to meet that objective.

B. Scope of Work

(1)Provide information and promote technology transfer for carbon sequestration concepts in the Western United States; and (2) promote infrastructure development for possible wide-scale deployment of Greenhouse Gas Mitigation strategies in the Western United States.

C. Tasks to be Performed and Accomplishments

Task 1: Provide Information and Promote Technology Transfer for Carbon Sequestration Concepts in the Western United States

Accomplishments:

a) Established a Web site page on the four Western Carbon Sequestration Partnerships. The Western Interstate Energy Board was tasked with keeping the site up to date and maintaining links to each of the four partnerships' Web pages.
b) Organized efforts of the four Western partnerships to participate in a poster session during the Western Governors' Association's North American Energy Summit, held April 14 – 16, 2004 in Albuquerque. The summit attracted nearly 700 participants as well as members of the general public and the media. Participants included the private sector; non-profit groups; and state, provincial, tribal and federal officials from the U.S., Canada and Mexico.
c) During November and December of 2005, a representative of WIEB attended the meetings of three of the Western carbon sequestration partnerships, during which they wrapped-up Phase 1 and kicked-off Phase II. Reports on each of these meetings was prepared and sent to the appropriate staff for WGA's lead Governors for Carbon Sequestration, Govs. Mike Rounds (S.D.) and Bill Richardson (N.M.).
d) Participated in the 2004 and 2005 National Conference on Carbon Capture and Sequestration. Representatives from WGA and WIEB participated in breakout sessions and discussions on outreach activities
e) Representatives from WGA and WIEB participated on monthly calls of the Outreach and Education Working Group to stay informed of

education and outreach developments and to share information with governors' offices as needed.

f) Governors and WGA's Staff Council were kept informed of the work of the partnerships through a quarterly management status report and Annual Report in both 2004 and 2005.

g) In late fall of 2003, a representative of WGA/WIEB attended the Phase I kick-off meetings of the Plains CO2 Reduction Partnership, the Southwest Regional Partnership on Carbon Sequestration, and the West Coast Regional Carbon Sequestration Partnership. In addition, a representative attended: one of the SW partnership's public outreach meetings; the Plains Second Advisory Board meeting in October 2004; and the West Coast advisory committee meeting in May 2005. WGA/WIEB also helped the West Coast partnership identify state employees and others who could be helpful when holding its October 27, 2004 forum in Portland, Oregon.

h) The Western Interstate Energy Board (WIEB) invited the partnerships to its April 13, 2004 meeting to explain the work of the partnerships to the energy advisors for Western Governors and Premiers.

Task 2: Promote Infrastructure Development for Possible Wide Scale Deployment of Greenhouse Gas Mitigation Strategies in the Western United States

Accomplishments:

a) As part of this task, WGA held a stakeholder meeting. During WGA's Annual Meeting on June 20, 2004 in Santa Fe, N.M., Gov. Mike Rounds of South Dakota moderated a Q & A session on the work of the four western partnerships. The partnerships' representatives briefly described the technologies and infrastructures they are evaluating to determine which ones have the best potential to sequester or reuse CO2, thereby reducing greenhouse gas emissions. Materials on the partnerships were available to all the 300-plus participants at the Annual Meeting, including representatives from government, the private sector, non-profit groups and the media.

b) The potential role of carbon sequestration in increasing clean and diversified energy throughout the West was discussed extensively at meetings of WGA's Clean and Diversified Energy Advisory Committee and its Advanced Coal Task Force. The report was open to public comment and was made available on WGA's Web site. It includes several recommendations states can take to encourage the development of four to five 500 MW advanced coal plants with at least 60 percent carbon sequestration. Western Governors will consider the recommendations at their Annual Meeting in June 2006.

c) Communications materials were prepared and distributed on the work for the four Western Partnerships at the North American Energy Summit in April 2004 in Albuquerque.

d) Designed a standardized web-based GIS database for the Western carbon sequestration partnerships. With input from partnerships, created GIS dataset. Data was added to the central database as received from the western partnerships and normalized as needed to allow for query and display. After the database was designed and the dataset created, we developed and hosted the necessary Web-based interactive maps that utilize GIS datasets for map display, query, and organization/integration of partnership carbon sequestration data.

D. Deliverables

As noted in Task 1 and 2 above, the WGA and WIEB completed the following deliverables:

- Internet site and other appropriate communication media
- Regional GIS map server of partnership carbon sequestration data
- Formation of WGA oversight subcommittee (Lead Govs. Rounds and Richardson)
- At least two meetings engaging stakeholders
- Final report summarizing the activities undertaken throughout the budget period.

Appendix K: Proposed SWP Phase 2 Action Plan

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1. TECHNOLOGY MERIT AND IMPLEMENTATION PLAN

Overview of Most Promising Sequestration Technologies: First Options for Sequestration

The Southwest Regional Partnership on Carbon Sequestration (SWP) proposes to conduct a series of validation tests of the most promising sequestration technologies for the region, including three major geologic pilot tests and two terrestrial pilot test programs. A possible theme of the SWP is “First Options for Carbon Sequestration.” The Regional Partnerships are collectively evaluating sequestration options and will begin testing options soon. If carbon sequestration becomes a practical carbon management approach, the “first options” of sequestration will likely be those that fall along existing CO_2 transportation infrastructure. The Southwest region possesses an extensive CO_2 pipeline network that transports over 30 Mt of naturally-sourced CO_2 per year from the central Rockies to the Permian basin (Figure 1). In our Phase I project, we concluded that the “lowest-hanging fruit” for sequestration would be to supplant the natural CO_2 in those pipelines with anthropogenic CO_2 (e.g., power-plant sourced). With such an approach the region would meet, at the least, minimum GHG intensity reduction targets for the region. We maintain this idea and suggest that “first options” for the nation will lie along existing pipelines. If deliberate CO_2 sequestration becomes necessary, pipeline infrastructure may expand and increase the number of practical and cost-effective sequestration opportunities. Our Phase I ranking of sequestration opportunities factored proximity to sources and/or pipeline infrastructure in addition to economic, safety, risk mitigation potential, and other factors. The result of the Phase I ranking process resulted in this proposal of three geologic pilot tests that are located on the CO_2 pipeline infrastructure, illustrated in Figure 1.

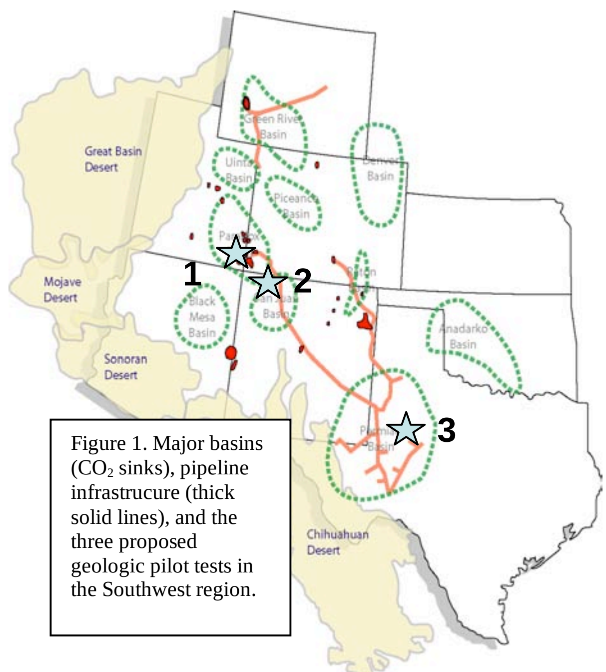


Figure 1. Major basins (CO_2 sinks), pipeline infrastrucure (thick solid lines), and the three proposed geologic pilot tests in the Southwest region.

The SWP proposes a truly regional approach for its technology validation program, including geologic pilot tests located in Utah, New Mexico, Texas, and a region-wide terrestrial analysis. Each geologic sequestration test will include injection of a minimum of ~75,000 tons/year to ~150,000 tons/year, with a minimum injection duration of one year. Our SWP proposed pilots are summarized in Table 1.

Table 1: Pilot Test Portfolio

Pilot Test Location	Type of Pilot(s)	Amount/Duration of CO_2 Injection	Key Industry / Govt. Partner(s)
Aneth Field, Paradox basin, near Bluff, UT	Deep Saline Aquifer and EOR with Sequestration	Up to 150,000 tons per year for 3.5 years	Navajo Nation Oil and Gas Co. Resolute Natural Resources Co.
San Juan basin Coal Fairway, near Navajo City, NM	ECBM and Sequestration, with Produced Water Desalination, and Terrestrial Riparian Restoration Sequestration	Est. 75,000 tons per year for 1 year	Burlington Resources, BLM, USDA
SACROC-Claytonville Fields, Permian basin, near Snyder, TX	EOR with Sequestration	Over 150,000 tons per year for 2 years	Kinder Morgan CO_2 Company, L.P. (KinderMorgan)
Entire Southwest Region	Regional Terrestrial Analysis	N/A	USDA

Aneth Background: The Aneth oil field, discovered in 1956, is one of the largest in the nation. Because the field is Navajo Nation land, mineral royalties go to the Navajo Nation and are utilized in many ways, including a scholarship fund. Aneth is located on the CO_2 pipeline system, and the sheer size of the field makes it a possible target for larger-scale sequestration operations. Petroleum production interests were recently purchased from ChevronTexaco, and now these interests are jointly owned by Resolute Natural Resources Company (Resolute) and the Navajo Nation Oil and Gas Company. Both companies operate the field together, and the SWP is pleased to partner with Resolute and the Navajo Nation OGC in a combined deep saline aquifer – EOR – sequestration pilot test.

San Juan Enhanced Coalbed Methane (ECBM) Background: The San Juan basin (SJB) is one of the top ranked basins in the world for CO_2 coalbed sequestration because it has: 1) advantageous geology and high methane content; 2) abundant anthropogenic CO_2 from nearby power plants, 3) low capital and operating costs; 4) well developed natural gas and CO_2 pipeline systems; and 4) local companies, e.g., Burlington Resources, with CBM and ECBM expertise. Burlington has agreed to operate a project in collaboration with the SWP, specifically to examine ECBM efficacy with CO_2 sequestration. Because of its enormous coal resource, the SJB offers a tremendous sequestration opportunity with value-added natural gas production. An extensive CO_2 infrastructure is already in place, making the area ready for future operations. In addition to the ECBM pilot test, a terrestrial pilot test will be conducted. ECBM operations are notorious for producing huge volumes of water. We propose to desalinate produced water from our ECBM pilot and use this water for irrigating a riparian restoration project, forming a combined ECBM – terrestrial sequestration project. The BLM and Burlington are both interested in making beneficial and environmentally-friendly use of the produced water.

SACROC-Claytonville Background*:* The SACROC Unit in the Permian Basin of Texas is the oldest CO_2-EOR operation in the United States, with CO_2 injection dating from 1972—only one CO_2-EOR project in Hungary is older, dating from ~1969. SACROC continues to be flooded by the current owner/operator, Kinder Morgan CO_2 Company, L.P. (KinderMorgan). Current operations inject ~13.5 $MtCO_2$/yr and withdraw/recycle ~7 $MtCO_2$/yr, for a net storage of ~6.5 $MtCO_2$/yr. In total, the site has accumulated more than 55 $MtCO_2$.

Our first effort at the SACROC unit will be an intensive post-audit modeling analysis to understand the fate of the CO_2 injected over 30 years time. KinderMorgan maintains a vast database of CO_2 injection/production data to facilitate an effective analysis. We will also conduct extensive MMV studies at SACROC during its ongoing injection operations. Results of these analyses will then be used to define a better working model of the Claytonville field, a nearby field with similar geology recently acquired by KinderMorgan that has never been subjected to CO_2 injection. The combined SACROC-Claytonville pilot represents an unprecedented opportunity for CO_2 storage history-matching in tandem with large-scale MMV operations. Finally and most importantly, the SACROC-Claytonville pilot will be an initial high resolution analysis of the potential for CO_2 storage in the broader carbonate “Horseshoe Atoll” system, a huge (area and volume) system with potentially enormous CO_2 capacity (Figure 2). Given that most of the western side of the atoll is below the oil-water contact, it is particularly appealing for large-scale sequestration, as suggested by our Phase 1 analysis of the region.

In sum, the SWP proposes a regional portfolio of sequestration technology validation tests in a broad variety of carbon sink targets, with demonstration of multiple value-added benefits, including testing of deep saline sequestration, enhanced oil recovery and sequestration, enhanced coalbed methane production and sequestration combined with a local terrestrial (riparian restoration) sequestration pilot, and a regional terrestrial sequestration pilot program focusing on improved terrestrial MMV methods and reporting approaches specific for the Southwest region. All of our proposed pilots represent “first opportunities” because of their proximity to CO_2 pipeline infrastructure. And, all proposed pilots represent medium-scale tests of possible larger-scale sequestration operations in the future. The SWP’s portfolio of proposed pilots seek to maximize specific performance, economic, and environmental goals of the DOE Carbon Sequestration Roadmap.

Overview of Proposed Geologic Pilot Tests

Regulatory, Permitting, and NEPA Approach for all Geologic Pilots

Regulatory efforts for Phase 2 activities have two complementary objectives: (1) to ascertain and monitor the permitting requirements for each State in the SWP as a resource for future carbon sequestration projects, and (2) to outline a specific action plan to secure permits for proposed test projects.

Manual of Best Practices: The SWP began developing regulatory and permitting action plans during Phase I, and will continue that effort in Phase 2. Action plans will be produced in the form of a “Manual of Best Practices,” and will outline and satisfy project permitting requirements to conduct sequestration projects (including but not limited to capture, transportation, storage, monitoring, and risk assessment and mitigation). The permitting guidelines will specify steps for satisfying the federal National Environmental Policy Act (NEPA) requirements for Environmental Assessments (EA) and developing required Environmental Impact Statements (EIS) for each of the Southwest pilot tests.

The Regulatory and Permitting Manual of Best Practices will be useful both to SWP members and

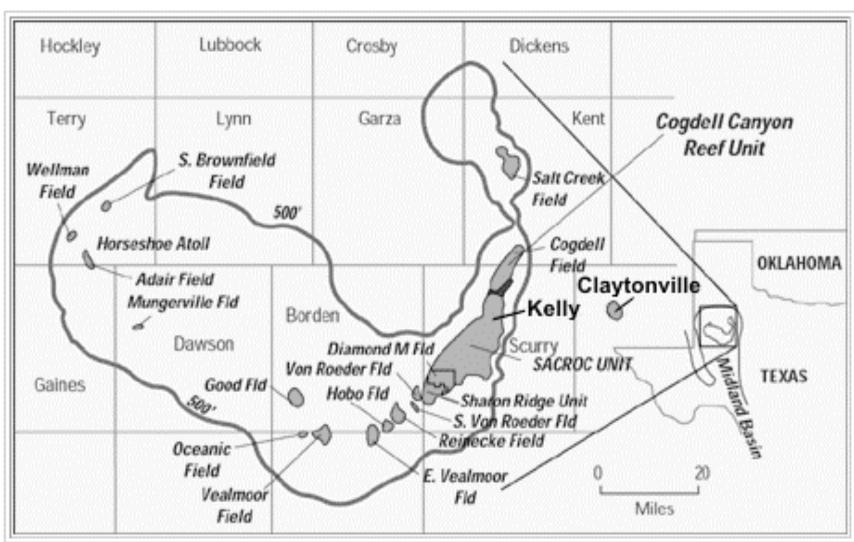


Figure 2. Schematic of the “Horseshoe Atoll” that represents an extremely large CO_2 sink and sequestration opportunity (dark line). Also indicated are the locations of Kelly (SACROC) and Claytonville Pilot tests. Figure adapted from WorldOil.com.

to others considering future carbon sequestration projects. It will provide a “roadmap” for permitting sequestration projects anywhere in the region, and will detail existing regulatory gaps, uncertainties and an explanation of potential barriers for technology deployment. A significant start has been made by the Interstate Oil and Gas Compact Commission (IOGCC) Geological Sequestration Task Force, who already assembled a regulatory framework for carbon capture and geological storage at the request of the Department of Energy (IOGCC, written communication, 2005). Its report summarizes the current regulatory regime for CO_2 on a state-by-state basis. It is possible that current regulations may change in response to the test phase projects or other external factors during Phase 2. The manual will capture these changes at the federal and state levels. The manual of best practices will be designed as a permitting roadmap for the partnership and others engaging in carbon sequestration activities.

Permitting Test Case Projects: The geologic pilots will require the strictest permitting requirements, and fortunately, Utah, Texas, and New Mexico already have some existing regulatory regimes for CO_2 injection in EOR projects, as a start. The development of MMV protocols for carbon sequestration projects is an evolutionary process, and therefore the designs implemented for the test cases could become permitting requirements. Our intention is to work closely with the appropriate regulators to identify and implement appropriate MMV procedures. In addition to state-specific permitting, any permitting required from the Bureau of Land Management (BLM), inclusive of environmental assessments or environmental impact statements, will be conducted in a manner that satisfies requirements of the NEPA.

Risk Assessment and Evaluation

The SWP will address risk potential with a combined program of risk assessment and risk mitigation; we view assessment and mitigation as different components that must be employed in tandem. Regarding risk assessment and evaluation, during Phase I, the SWP developed a screening methodology for evaluating potential environmental and safety risks of geologic CO_2 storage projects. Similar to our Phase I approach, pre-pilot geologic characterization and associated modeling results will be used to establish a basic database of risk factors or criteria for each pilot site. During the course of each pilot test, the databases will continue to be populated and expanded with additional data, observations, model results, and specialized analysis. This approach is designed to integrate fundamental observations with results of detailed analysis and interpretation, and will facilitate an objective and quantitative assessment of potential risks for each site and provide outreach to stakeholders. General risk criteria associated with geologic sequestration include (1) integrity of immediate seals and therefore CO_2 containment potential of the primary sequestration target unit; (2) secondary and tertiary CO_2 containment potential if immediate seals or borehole casings fail; (3) potential to mitigate effects of CO_2 migration to surface and associated time constants, in the unlikely event that CO_2 is not contained. This database and risk analysis framework is basic, but it provides a mechanism for communicating risk potential, which affects regulatory permitting, identification of regulatory gaps, MMV design, and outreach and education of stakeholders. A new partner, the Det Norske Veritas (DNV) research organization of Norway, offers expertise in both risk assessment and mitigation. DNV will use its own funding for the project (see attached letter).

Risk Mitigation Approach: Continuous Iterative Risk Assessment and Adaptive Pilot Design

Risk assessment will continue throughout the duration of each SWP pilot. As described in subsequent sections of this proposal, our MMV activities will produce large amounts of time series data. These data will provide the basis of an adaptive risk mitigation approach. Specifically, pilot test performance, using all MMV data, will be analyzed continuously, and reservoir simulation models and their forecasts will be updated periodically (~ monthly). The risk assessment frameworks will also be updated continuously throughout the duration of the pilots. This adaptive risk assessment framework will then in turn be used to guide subsequent MMV and data collection activities, as well as pilot test engineering design (injection, etc.). In sum, combined MMV and risk assessment data will be used in tandem to guide engineering operations and vice-versa, in the form of a continuous feedback loop. For example, methane recovery and concomitant CO_2 migration and storage efficacy will be monitored in the SJB ECBM pilot, and appropriate engineering responses will be made by the operator, Burlington, and in turn the risk assessment framework and MMV design updated, etc. This approach will be taken with all pilots.

Injection/production performance, abandoned wells, and all other MMV data will be continuously evaluated, and these data along with associated reservoir simulations will be used to update risk criteria, including any new, unanticipated impacts and processes. In addition, models will be used to evaluate how the system may evolve after the pilot concludes. Following the example of previous risk assessment studies (e.g. Wilson and Monea, 2005), we will evaluate an extensive range of model scenarios to assess future possible risks such as those associated with specific geologic features – faults, fracture zones, seal degradability, etc. In addition to deterministic models, we will also carry out probabilistic analyses; the DNV brings state-of-the-art probabilistic modeling and analysis approaches to the SWP projects.

Summary and Overview of MMV Protocols Planned for the Southwest Geologic Pilots

MMV is at the heart of all SWP activities. MMV deployment and associated modeling are the primary vehicles for determining how well the SWP meets or exceeds performance targets of the Carbon Sequestration Roadmap, including prediction of storage capacity to +/- 30% accuracy, verification of indirect sequestration and associated costs, and verification of MMV technology efficacy. MMV is also central to our risk assessment and risk mitigation approaches. It is possible that MMV deployment of the Southwest and other partnerships' pilot tests will influence how regulation and permitting evolves and how regulatory gaps are filled. All MMV protocols are designed to meet the performance goals of the DOE Roadmap and the DOE EIA 1605B "Voluntary Guidelines for Greenhouse Gas Reporting," where possible, to meet the needs of evolving voluntary carbon markets in the U.S.

We propose extensive MMV protocols, including direct and indirect approaches. Our MMV plans for each field pilot are designed to track the movement and fate of CO_2 injected into deep saline aquifers and coal beds, and oil and gas reservoirs. Additional MMV goals are to monitor CO_2 well injectivity, verify abandoned well veracity, and to assist with risk assessment and mitigation. Baseline MMV activities will elucidate the geologic, hydrogeochemical, isotopic and other physical conditions prior to injection. These baseline data will be compared to results of repeat and continuous MMV surveys conducted after injection to forecast ultimate fate of CO_2 in the subsurface for different conditions.

In the following sections we will first summarize all components of our MMV program. Subsequent site-specific pilot-test descriptions will tabulate the specific MMV approaches to be deployed at each site.

The specific MMV technologies proposed for each pilot-test site were selected based on the unique geologic setting of the site and to maximize our ability to test MMV technology efficacy.

Direct MMV Technologies Proposed

INJECTION WELL MONITORING: At the injection well, continuous measurements of injection rate, pressure and temperature will be monitored. Periodic shut-in tests will provide permeability changes in near- and far-well regions. Pressure transient tests prior to injection are proposed for all sites.

IN SITU FIBER OPTIC P/T SENSORS: In-situ borehole monitoring faces two major technical challenges: 1) the high-temperature and high-pressure, harsh environment of boreholes has excluded many conventional chemical sensors (e.g. electronic sensors), and 2) the long-distance from depth to the surface presents a challenge for high fidelity data transmission. Recently, optical fiber based in-situ physical sensors have been demonstrated successfully in field trials for downhole oil recovery and geothermal applications (Xiao et al., 2005a; Wang et al., 2001; May et al., 1999). Zeolite-coated optical fiber chemical sensors have also shown great potential for applications under hostile conditions found in typical borehole environment (Xiao et al., 2005b). For MMV at all sites, optical fiber based pressure and temperature sensors will be deployed in the injection wells for in-situ monitoring of CO_2 injectivity. These sensors, less than 1 mm in size, operate on the remote interrogation using Faby-Perot interferometer (EFPI). Test data show that the sensor is capable of measuring temperature up to 600°C and hydraulic pressure up to 8000 psi at temperatures up to 220°C.

SPINNER FLOWMETER SURVEYS: At an injection well, spinner surveys will be performed to determine vertical injection conformance.

PRODUCTION WELL IN-SITU LI-COR©: In addition to continuous monitoring of gas and water production rates and pressures, continuous monitoring of produced gas CO_2 content will be made using LI-COR© IRGA devices at selected production wells.

ABANDONED WELL LI-COR©: At selected abandoned wells nearby, LI-COR© IRGA devices will also be installed in situ, to monitor potential flow of CO_2 from units below (e.g., degraded well-casings).

GAS PIEZOMETERS USING LI-COR©: We propose drilling five shallow wells of less than 800 ft depth for the purposes of cross-well seismic, ASTLI, and/or VSP, described below. These wells will be outfitted with in situ LI-COR© IRGA devices with dataloggers and wireless data transmission, for constant monitoring. In concept, these are like water-well piezometers, but instead of measuring hydraulic head, they will record CO_2 flux from depth.

ISOTOPIC AND COMPOSITION MEASUREMENTS: Periodic gas sampling and measurements of produced CO_2 isotopic signatures will also be made to distinguish between naturally produced CO_2 (CO_2 content of the produced gas is currently –25 ‰ to –27 ‰ range for $\delta^{13}C$) and the $\delta^{13}C$ of the injected CO_2 (either –1 ‰ to –2 ‰ from magmatic sources of CO_2 or –38 ‰ to –43 ‰ from industrial sources of CO_2) (~monthly). Periodic gas and water samples will also be collected for compositional analysis (~monthly), and pressure transient tests performed to monitor any changes in coal permeability (~every six months). Baseline measurements of gas CO_2 content and isotopic signature, as well as gas/water compositional analyses, and water chemistry will be obtained prior to injection of CO_2.

TILTMETERS [For the SJB ECBM pilot only] Potential coal swelling will likely cause a significant geodetic response. Specifically, actual laboratory strain measurements on San Juan basin coal, when methane is replaced with CO_2 at pressures of around 100 psi, show a volumetric strain on the order of 0.5–1.0% occurs due to coal swelling. Furthermore, computations of potential larger-scale response were made by Sandia National Lab (Warpinski, written communication, 2005), showing that such coal-swelling by injection at the depths and conditions at the San Juan basin ECBM site may result in a l° tilt at the surface. Thus, this is a promising method for tracking CO_2 movement in coal seams.

Indirect MMV Technologies Proposed (Seismic)

2-D and 3-D SEISMIC SURVEYS: 2-D or 3-D seismic surveys, coupled with borehole seismic data, will be used to monitor the injection process at the pilot sites. At Aneth and SJB ECBM, repeated 2-D seismic surveys will be conducted. At SACROC-Claytonville, 3-D seismic surveys will be conducted. For both 2-D and 3-D surveys, surface seismic data will be collected before, during, and after injection to allow us to assess changes in seismic response of the reservoir caused by the CO_2 injection.

VERTICAL SEISMIC PROFILES (VSP) AND CROSSWELL SEISMIC: Boreholes will be used to collect VSP data, which will have significantly higher frequencies than surface data and hence be more sensitive to small-scale changes in reservoir properties. By drilling multiple boreholes at each site, we will be able to collect data in both surface-downhole geometry and downhole-downhole (crosswell) geometry to allow interrogation of the reservoir on different scales and over different region sizes. VSP and crosswell data will be interpreted to infer changes in reflection character due to the presence of CO_2. We will also employ Active-Source Time-Lapse Intercomparison, or ASTLI: small changes in the phases of the individual wave packets measured before, during, and after the injection can be measured using an interferometric approach to determine very small changes in seismic velocity within the reservoir. Borehole sensors will record seismic data when the 2D surface seismic surveys are being conducted, allowing us to compare surface and downhole data in addition to giving us more source location coverage than would be available if a conventional VSP survey alone was conducted. For analysis of crosswell data, we will use a combination of crosswell tomography and seismic migration, which is a fairly new application to crosswell data been shown to yield high-resolution information about the interwell region.

PASSIVE SEISMIC**:** Passive seismic monitoring using instruments placed in boreholes will be used to detect induced seismicity caused by the CO_2 injection. It has been shown that there is considerable information in the pattern of locations of induced seismic events about the interaction of the injected fluid with the fracture system and regional stress field (see Fehler et al., 2001).

SEISMIC MODELING: Appropriate modeling will determine the optimum data acquisition geometry for both surface and borehole, and active/passive seismic data.

HIGH RESOLUTION RESISTIVITY METHOD FOR BOREHOLE INTEGRITY: We are pleased to add an international partner, the National Institute for Advanced Industrial Science and Technology (AIST) of Japan, who will deploy and field test an advanced electrical method at two field sites (see attached support letter). The proposed technology is based on electro-kinetic changes and will be deployed to perform continuous monitoring. At Aneth, the method will be used to monitor for possible

CO_2 leakage near the surface in the vicinities of well bores. At Claytonville, the method will be used to monitor CO_2 plume migration. AIST will conduct all fieldwork and facilitate interpretation.

DATA TRANSMISSION: IRGA devices and dataloggers will be connected to each operator's wireless data transmission system such that pattern performance can be monitored continuously and remotely.

CO_2 Sources and Transportation for All Geologic Pilot Tests

CO_2 for Aneth and the SJB ECBM test will be sourced from McElmo dome, and is ~98% pure CO_2, with < 2% nitrogen and methane. At SACROC-Claytonville, CO_2 (~98% purity) will come from natural sources (McElmo, Sheep Mountain, and Bravo Dome), with ~10–15% derived from Val Verde's gas purification facility. All pilots are located on the KinderMorgan pipeline infrastructure in the region (Figure 1), and thus transportation is provided. CO_2 cost details are provided in the budget volume; the SWP is paying ~$8/ton for CO_2 at Aneth, ~$5/ton for CO_2 at SJB ECBM, and CO_2 is provided free of charge by KinderMorgan for SACROC-Claytonville. Amounts to be injected are summarized in Table 1.

Pilot Deployment Plan: Aneth Deep Saline and EOR Pilot Test, Bluff, UT

Suitability, Availability, and Characterization

The Greater Aneth Field is the largest oil field in the Paradox Basin, covering approximately 48,000 acres in San Juan County, extreme southeastern Utah. This field is typical of many petroleum reservoirs in the Rocky Mountains and intermountain west. The petroleum accumulation is a stratigraphic trap formed by the localized deposition of a large carbonate mound, and possesses a great potential for CO_2 storage subsequent to EOR operations. The Texas Company (Texaco) drilled the discovery well (23-T40S-R24E) in 1956 on Navajo Indian Tribal lands, which had an initial production of 568 BOPD and no water from perforations at ~5,800 feet depth. The Aneth Unit is currently producing about 3,100 BOPD from 133 producing wells with a 94% water cut. It has produced 147 MMBO since discovery.

Resolute purchased the Aneth Field from ChevronTexaco in December 2004. Resolute is making its upcoming CO_2 injection for EOR operation available for extensive MMV studies of associated sequestration in this large oil reservoir. Additionally and more importantly, Resolute has agreed to work with the SWP to field-test CO_2 injection in the deep Mississippian Leadville Limestone, a saline aquifer (no oil in place) below the oilfield. Thus, the Aneth pilot offers both deep saline sequestration testing and EOR sequestration testing.

Pilot Site Location and Description

The pilot test site is located within the Aneth mound complex (Figure 3), which formed on a weak structural nose. The present-day structural relief of about 150 feet is largely the result of differential compaction. The primary CO_2 sequestration target is the Pennsylvanian Desert Creek and overlying Ismay members of the Paradox formation, the primary producers in the Greater Aneth Field. These carbonate strata were deposited on the southwestern flank of the Paradox evaporite basin, and are laterally equivalent to the more basinward anhydrites and salts. The “seal” unit above the sequestration target is the low-permeability Gothic Shale, and the underlying seal is an organic-rich mud deposit, the Chimney Rock Shale. Both shales are seals as well as original oil source rocks. Oil generation began during the Cretaceous as these strata were buried to depths greater than 10,000 feet. Later tectonic uplift and gentle structural development had only minor effects on redistribution of the accumulation.

The Aneth Unit was originally developed with vertical wells drilled on 80-acre spacing. The field was

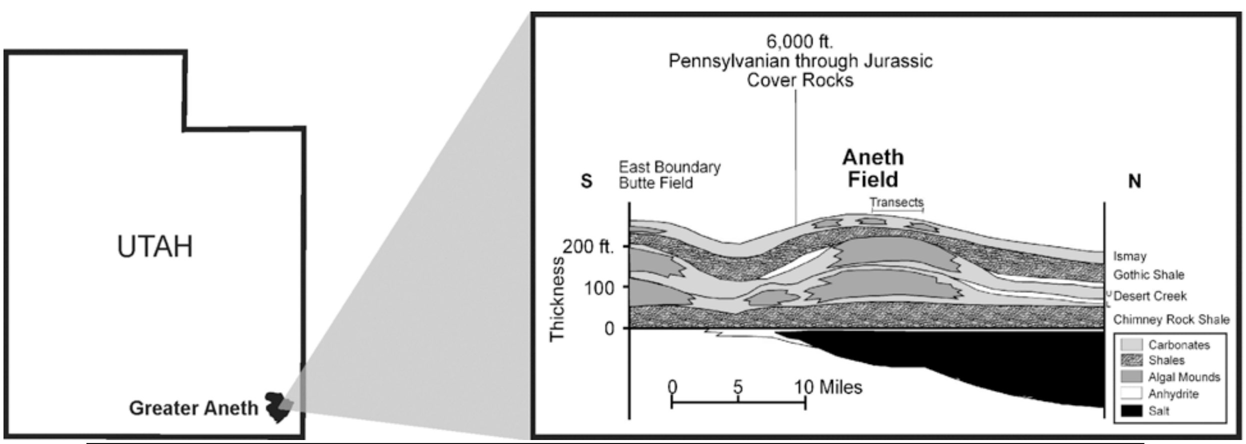


Figure 3. Location map of Aneth field and pilot site (left) and representative cross-section (right). The area indicated by “transects” is the location of a profile of CO_2 flux measurements the Partnership conducted in January 2005.

infill drilled in the 1970s to 40 acre spacing. The field has been managed with water injection that began with unitization in the early 1960s. In 1996 Texaco drilled 43 multi-lateral horizontal wells (23 producers and 20 injectors). In 1998, the injectors in section 14 were converted to a CO_2 WAG project to pilot the possibility of a field wide CO_2 injection program. Thus, monitoring of horizontal CO_2 injection is an added attraction offered by this pilot test site.

Task 1: Site/Reservoir Characterization and Model Development

All information for the site will be collected from Resolute, and a thorough site and reservoir characterization developed. The information collected will include precise well locations, completion and stimulation information, and production and operating histories for each. Historical gas and water production data will also be obtained. From a reservoir characterization perspective, well logs, core data, pressure-transient data, and any other relevant information for the area will be obtained from Resolute. Resolute currently possesses core and pressure transient data for over 80 wells within 10 miles of the demonstration site. Using this information, a detailed numerical reservoir model and operating/production history will be constructed for the demonstration site. In this task, we will also continue working on the initial risk assessment that was begun in Phase 1.

Task 2: Implement Regulatory Permitting Requirements and Risk Mitigation

For the Aneth pilot, we will follow the overall proposed regulatory and permitting plan, including development of a best practices manual, described in a previous section of this proposal. An important regulatory aspect specific to the Aneth pilot is that, in Utah, wells that are used for the enhanced recovery of oil and gas are considered Class II wells under the Underground Injection Control (UIC) program, and normally regulated by the Utah Division of Oil, Gas, and Mining of the State's Department of Natural Resources. However, the regulation of Class II injection on Native American tribal lands is retained by the federal government through the U.S. Environmental Protection Agency, specifically the Region 8 office in Denver, Colorado. The proposed Aneth pilot project is on Navajo Nation land, and therefore falls under EPA jurisdiction. In this second task, we will also begin integration of our reservoir models, risk assessment criteria, regulatory constructs, and the MMV protocols for the systematic risk mitigation approach (described earlier in this proposal). Please refer to Gantt charts (Section 3) for schedules.

Task 3: Construction, Safety and Site Preparation, Baseline MMV

The Aneth Unit has an 800 acre CO_2 pilot program in the eastern side of the field and it has been running since 1998. Resolute intends to expand the program to cover much of the remainder of the field, probably avoiding the portion (eastern side) of the field that has already been drilled up with horizontal wells. As an initial “reconnaissance” of CO_2 flux for baseline MMV information, the SWP sampled a representative transect of 35 flux measurements (location indicated on Figure 3); all measurements suggest ambient fluxes are completely soil/ biogenic.

The extension of the CO_2 area to the west will entail at least three phases of development with each phase accessing approximately 1600 acres of new CO_2 flood area. In each development Resolute will be constructing approximately 50 miles of new flow lines, two new injection well headers, new production well headers at each separating facility and a new parallel production facility at each current production facility location. The new lines will be required to distribute the CO_2 to the western side of the field, replace the existing flow lines from the wells to the tank batteries (to enable CO_2 service) and provide for parallel new produced gas return lines so that produced gas high in CO_2 can be returned for reinjection while the still-uncontaminated gas can be directed to sales. The new injection headers will allow the CO_2 and injected water in the water-alternating-gas system to be diverted to the appropriate injection wells at the appropriate time. New production headers will be necessary so that the wells producing high CO_2 concentrations can be diverted to one production separation facility where the gas will be diverted to re-injection. The new production headers will allow wells still low in CO_2 to be directed to the current facility where these will have their gas diverted to sales.

The first phase of the CO_2 expansion will be up to the western edge of the Navajo Nation land within the unit. The second and third phases will be for 2) BLM land to the west of the Navajo Nation lands (the farthest west portion of the field) and 3) the remainder of the field between the first phase discussed above and the existing pilot and horizontal wells. Each phase will probably have 10 wells dedicated to each injection header and 20 or more producing wells in each production facility.

In this third task, we will conduct baseline measurements of our MMV program; MMV protocols for the Aneth pilot are described under Task 5, below. Gantt chart schedules are provided in Section 3.

Task 4: Injection Operations, MMV and Capacity Analysis

<u>*EOR Testing*</u>: The field has the capacity to take delivery of up to 20 MMCF per day of CO_2 and re-

injection capacity of a similar amount. The CO_2 comes from the McElmo Dome CO_2 source and arrives at a pressure of about 2750 psi, which is sufficient to inject it into the wells without compression.

For our proposed combined EOR/sequestration program, individual well CO_2 injection rates are planned and expected to be about 300 MCF per day per well. The process of displacing approximately 20% of the reservoir pore volume will take about five to eight years. It is proposed to inject CO_2 at the site for a period of several years and to intensely monitor CO_2 movement for 18 to 24 months. Lower-intensity monitoring will be performed for the remaining period of the four-year SWP Phase 2 program. It is assumed CO_2 injection will commence in early 2006. State-of-the-art reservoir modeling will be used to simulate flow and chemical processes and forecast ultimate CO2 storage capacities.

Deep Saline Sequestration Testing: A deeper non-hydrocarbon bearing zone would make a better longer-term carbon dioxide sequestering interval, due to its larger areal extent and volume, and the fact that injection into this type of interval would not be subject to limitations in rate and volume related to using CO_2 for an oil recovery process. Explicitly for this Phase 2 project (i.e., Resolute NRC would not do this if the SWP was not proposing the pilot), Resolute will complete an available well in a deeper porous formation and test the reservoir's permeability and injective capacity by first injecting water into the interval. This testing would consist of a pressure transient test conducted after some period of water injection. Resolute will then connect the well to the CO_2 supply being used for the oil recovery process by installing a temporary surface flow line and inject CO_2 for a brief period (e.g., 1500 to 2000 tons of CO_2 over a period of ~1 week). During the injection of CO_2, Resolute will measure injection pressure and conduct a subsequent pressure transient fall-off test. This information will allow us to determine the relationship between the capacity for the injection of water (single phase – natural occurring conditions) and CO_2 into the same potential carbon dioxide sequestering formation. This information would allow the same formation in other areas to be tested with water injection alone (where CO_2 is not readily available for injection) and to use those results to better predict the capacity of the formation to handle CO_2 injection and sequestration. MMV protocols would be implemented for the deep saline test and continue for the duration of the SWP program.

MMV Operations: All MMV protocols to be deployed by the SWP are summarized earlier in this proposal. The specific MMV methods for the Aneth pilot are tabulated below.

Direct MMV Methods at Aneth		**Indirect MMV Methods at Aneth**	
Injection rate monitoring	Prod. well LI-COR©	2-D seismic surveys	VSP
Abandoned well LI-COR©	H_2O chem. & isotopes	crosswell seismic	ASTLI
Gas piezometers (LI-COR©)	Fluid/gas chemistry and isotope analysis	passive seismic	Integrated seismic model
In situ P/T well monitoring (fiber optic sensors)		Borehole integrity by resistivity monitoring	State-of-the-art reservoir modeling

Our MMV programs proposed for each site are tailored for the unique setting of each site and for maximizing comparisons to approaches deployed at the other two geologic pilots (SJB ECBM and SACROC-Claytonville). For Aneth, the primary contrast with other field project sites is the application and testing of 2-D seismic lines. Results of the Weyburn project suggest that even the most sophisticated 4-D seismic approaches have limited efficacy for CO_2 sequestration monitoring; seismic methods are very effective for detecting the "front" of a CO_2 plume, but are not very effective for determining volumes or amounts of CO_2 behind the plume front. Thus, we plan to investigate how to optimize 2-D seismic lines for detection and monitoring purposes, because 2-D lines are two to four times less expensive than 3-D. We will attempt to maximize 2-D seismic efficacy by combining surveys with crosswell, VSP, and ASTLI. We will also compare efficacy and approaches for 2-D surveys to planned 3-D surveys in our proposed SACROC-Claytonville pilot. Additionally, passive seismic monitoring promises to be particularly effective at the Aneth site, because a brine injection facility (Allis, Utah GS, personal communication) near the Colorado–Utah border provides an abundance of passive seismic energy.

<u>Pilot Plan: San Juan Basin Enhanced Coalbed Methane (ECBM) Pilot Test, Navajo City, NM</u>

Suitability, Availability, and Characterization

The SJB ECBM/CO_2 sequestration field test site is located in San Juan County, New Mexico, in the heart of the San Juan Basin (SJB) coalbed methane (CBM) fairway (Figure 4). This location is uniquely favorable for an ECBM/sequestration demonstration for several reasons. For instance, the SJB has been previously assessed by Advanced Resources International (ARI) under the DOE-sponsored Coal-Seq project as one of the nation's top coal basins for sequestration in terms of potential storage capacity (12 Gt of CO_2, 12% of U.S. total), ECBM potential (16 TCF, 10% of U.S. total), and potential cost of storage (at a predicted net profit of $4-8/ton of CO_2). The results of the demonstration would be directly scalable to a large portion of the SJB for significant, low-cost sequestration.

The SJB is a mature CBM play, and thus much of the infrastructure and services required to implement large-scale sequestration are already in place (e.g., wellbores, gathering and distribution systems, processing facilities, etc.). In addition, a well-established, reasonably-priced service capability to maintain and expand that infrastructure exists. Finally, and perhaps most importantly, the infrastructure to deliver CO_2 to the region exists – the Cortez pipeline that delivers (natural) CO_2 from McElmo Dome to West Texas passes directly through the SJB (Figure 4). If/when that pipeline begins transporting anthropogenic CO_2, the SJB will become a premier national sequestration site. Thus, the SJB represents an important near-term option for CO_2 sequestration.

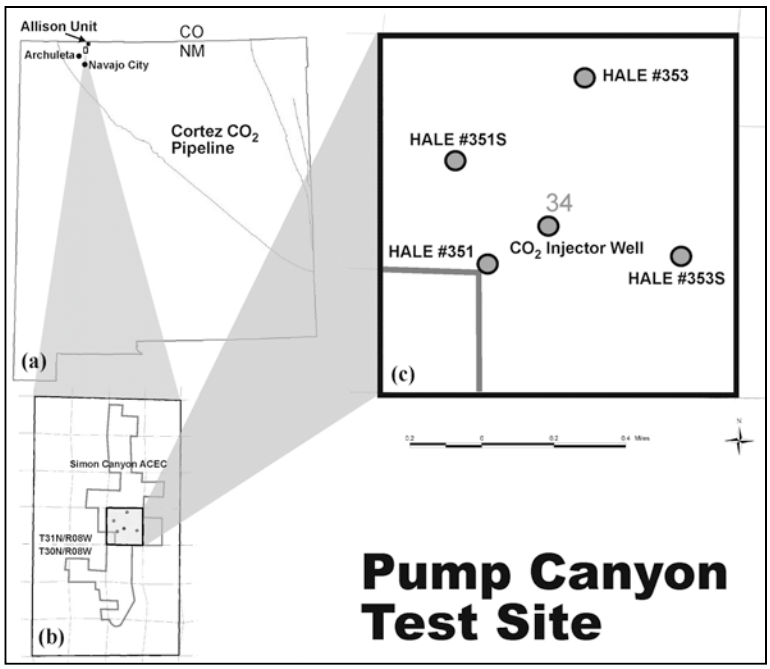


Figure 4: Location of SJB ECBM (Pump Canyon) Demonstration Site in San Juan Basin, NM.

The coals in the SJB fairway area are of exceptionally high permeability—100s of millidarcies. Due to the tendency of coal to swell when in contact with CO_2, high initial coal permeability is required to maintain high CO_2 injection rates over time. Maintaining high injectivity is an important requirement for large-scale, low-cost CO_2 sequestration in coal, and demonstrating this is an important DOE carbon sequestration program goal (as stated in DOE's 2004 Technology Roadmap and Program Plan). This demonstration represents an ideal opportunity to achieve that goal. The SJB ECBM pilot site lies entirely within the BLM's Simon Canyon Area of Critical

Environmental Concern (ACEC) (Figure 4). This 4,000 acre ACEC, which is managed for semi-primitive forms of recreation including fishing, hiking, and backpacking, was established in 1950 and is the oldest ACEC in New Mexico. We will be working closely with the BLM's Farmington Office to ensure that the entire project is done in an environmentally friendly manner and that all federal regulations concerning safety and environment are strictly followed. As part of this local terrestrial sequestration pilot, we are proposing to desalinate produced water so that it can be used in nearby riparian areas within the ACEC.

Site Location and Description

The exact pilot site location is Section 34, T31N, R8W in northeastern San Juan County, New Mexico (Figure 4). The site will consist of four CBM producing wells drilled on 80-acre spacing. The primary gas-producing horizons in this area are coal beds in the Upper Cretaceous Fruitland Formation. The coals, which occur at depths of approximately 3,000 feet, are about 75 feet thick split among three seams over a 175-foot gross interval. This area of the fairway has undergone significant CBM production, and reservoir pressures at the test site are less than100 psi. Coal matrix shrinkage is significant at these low pressures, contributing to the high coal permeabilities that exist there. In addition, CO_2 injection pressures will be low, eliminating any potential CO_2 compression needs for the pilot project. The site is operated by Burlington, San Juan Division, operator of more than 1,200 CBM wells in the SJB (more than any other company), and a pioneer in CO_2-ECBM technology. Burlington was the operator of the Allison Unit CO_2-ECBM pilot located in San Juan County, NM, just north of the proposed test site (Figure 4). To date, the Allison Pilot is the largest and longest-running CO_2 injection project in coal for the purposes of ECBM. That project, analyzed by ARI as part of the DOE's Coal-Seq project, has provided most of industry's experience and technical foundation regarding CO_2-ECBM. Burlington remains the single most experienced and knowledgeable operator in the world regarding CO_2 injection in coal.

Task 1: Site/Reservoir Characterization and Model Development

In this task all of the information for the site will be collected from Burlington, and a thorough site and reservoir characterization and numerical model will be developed. The information collected will include precise well locations, completion and stimulation information, and production and operating histories for each well. Historical gas and water compositional data will also be obtained. From a reservoir characterization perspective, well logs, core data, pressure-transient data, and any other relevant information for the area will be obtained. Burlington currently possesses core and pressure transient data for several wells within 10 miles of the demonstration site. Using this information, a detailed geologic model and operating/production history will be constructed for the demonstration (Figure 4). The area's CBM performance history will then be matched via reservoir simulation to calibrate unknown reservoir properties (e.g., relative permeability), which will be the primary basis for understanding subsequent pattern performance under CO_2 injection. Initial forecasting of pattern performance under CO_2 injection will be performed to aid in operational planning for the demonstration (i.e., fine-tune injection rates, estimate injection pressures, etc.). In this first task, we will also continue working on the initial risk assessment that was begun in Phase 1.

Task 2: Implement Regulatory Permitting Requirements and Risk Mitigation

For the San Juan ECBM pilot, we will follow the overall proposed regulatory and permitting plan, including development of a best practices manual, described in a previous section of this proposal. An important regulatory aspect specific to the ECBM pilot is that New Mexico already has an existing regulatory construct for CO_2 injection—New Mexico classifies EOR and EGR injection activity as Class II under UIC. The State has also adopted specific rules and regulations governing long-term CO_2 storage through the Oil Conservation Division. Thus, the enhanced coalbed methane project in the San Juan Basin will be permitted under rules and regulations developed and administered by the New Mexico Oil Conservation Division (IOGCC, 2005), and the San Juan basin terrestrial project (riparian restoration, described below) will be conducted by the U.S. Forest Service and permitted in accordance with USDA regulations. In this second task, we will also begin integration of our reservoir models, risk assessment criteria, regulatory constructs, and the MMV protocols for the systematic risk mitigation approach (described earlier in this proposal). Please refer to Gantt charts (Section 3) for schedules.

Task 3: Construction, Safety and Site Preparation, Baseline MMV

The next task will be to prepare the site for the demonstration. This will firstly involve the drilling of the CO_2 injection well. The proposed well location is in the center of four CBM production wells (Figure 4). The well will be drilled vertically to a depth of ~ 3200 ft, completed open-hole to minimize formation damage, and stimulated using hydra-jetting or a similar method. (Burlington's experience with the open-hole, cavitation technique in low reservoir pressure environments has been mixed at best, and thus an alternative stimulation approach is proposed). Stimulation will provide the greatest opportunity for sustaining high CO_2 injection rates throughout the demonstration. One of the key findings from the Allison Pilot, where the injection wells were not stimulated, was that well stimulation (in addition to high coal permeability) will probably be necessary for successful CO_2-ECBM sequestration.

Coal cuttings will be collected when drilling though each of the three main coal seams, and methane and CO_2 isotherms measured at in-situ reservoir temperature. Other coal characterization tests will also be performed, such as vitrinite reflectance, maceral composition, and proximate analysis.

The well will be equipped with carbon-steel casing, fiberglass-coated tubing, and a stainless-steel injection packer. A permanent, surface-readout, downhole pressure gauge will also be installed to monitor injection pressures continuously throughout the demonstration. The surface equipment will consist of a heater to heat the CO_2 to reservoir temperature prior to injection, and flow rate and pressure monitoring devices. Appropriate safety and emergency shut-off devices will also be installed.

To transport the CO_2 approximately two miles from the existing pipeline to the well, a 2-in. pipeline along the access road right-of-way will be installed. Burlington's 4-in. pipeline off Kinder-Morgan's Cortez pipeline (which operates at approximately 2,000 psi in this area), is currently unused and filled with nitrogen for corrosion prevention. It will be returned to CO_2 service (Figure 4). A pressure reduction manifold will be installed at the tap between the 4-in. and 2-in. lines. In this third task, we will conduct baseline measurements of our MMV program – MMV protocols for the SJB ECBM pilot are described under Task 5, below. Gantt chart schedules are provided in Section 3.

Task 4: Injection Operations, MMV and Capacity Analysis

We propose injecting CO_2 at the site for a period of 12 months and monitoring CO_2 movement intensely over a period of 24 months, which includes an additional 12 months after injection (assuming

CO_2 injection will commence around January, 2008). The volume of CO_2 to be injected was computed by first estimating the methane storage capacity of the coal in the pattern area (160 acres) at 35 psi (Burlington's expected abandonment pressure). Assuming a CO_2:CH4 replacement ratio of 2:1 (based on isotherm measurements from the Allison Unit), and a volumetric sweep efficiency of 75%, the CO_2 volume required to sweep the inter-well area of methane is approximately 1.2 BCF. Over 12 months, this translates to an average CO_2 injection rate of about 3.5 MMCFD. This approach to volume estimation minimizes the potential for injected CO_2 to breakthrough prematurely to producing wells and contaminate the gas production in the pattern. Volumes will be estimated by coal/reservoir modeling, also.

Injection will be controlled using a constant surface injection pressure, and the injection rate will be allowed to vary as downhole conditions change, similar to successful operations at Allison. The actual injection pressures will be estimated based upon initial reservoir modeling, and thereafter supplemented with field experience and continued modeling. It is anticipated that the CO_2 will be heated to reservoir temperature prior to injection to minimize tubing expansion/contraction during shut-down periods, and also to reduce CO_2 adsorptive capacity in the near-well region (to reduce coal swelling). However, some experimentation with unheated CO_2 injection will be performed to investigate whether thermal contraction of the coal at lower temperatures improves or worsens CO_2 injectivity.

MMV Operations: All MMV protocols to be deployed by the SWP are summarized earlier in this proposal. The specific MMV methods for the San Juan ECBM pilot are tabulated below.

Direct MMV Methods at San Juan ECBM		**Indirect MMV Methods at San Juan**	
Injection Rate Monitoring	Prod. Well LI-COR©	2-D Seismic Surveys	VSP
Abandoned Well LI-COR©	H_2O Chem & Isotopes.	Crosswell Seismic	ASTLI
Gas Piezometers (LI-COR©)	Fluid/gas Chemistry and Isotope Analysis	Passive Seismic	Integrated seismic model
In situ P/T well monitoring (fiber optic sensors)		Borehole integrity by resistivity monitoring	State-of-the-art reservoir models
Tiltmeter Arrays	Spinner Surveys		

Our MMV programs proposed for each site are tailored for the unique setting of each site and for maximizing comparisons to approaches deployed at the other two geologic pilots (Aneth and SACROC-Claytonville). For the SJB ECBM pilot, the primary contrast with other field project sites concerns coal and CH_4. Specifically, we must apply techniques to help track the movement of CO_2 within the coalbeds, a potentially difficult task given that the coals are already saturated with CH_4. Thus, we plan for several special MMV applications. As CO_2 is injected, swelling of the coals will occur, permeability will reduce, and fluid pressures will increase dramatically. Swelling will be significant and detectable by tiltmeters, as discussed in the MMV section of the proposal. An array of 30 surface tiltmeters will be deployed throughout the pattern area, calibrated by three fixed GPS stations, as one of the primary monitoring methods of CO_2 movement in the coal. In the interwell area, continuous monitoring of the tiltmeter array will be performed to monitor surface deformation related to coal swelling with CO_2 injection. In the event the CO_2 plume extends beyond the pattern, interferometric synthetic aperture radar (In SAR) data will be obtained periodically (~monthly) to monitor surface deformation over a larger area. Additionally, spinner surveys will be performed in the injection well to determine vertical injection conformance among the individual coal seams that exist at the site (~every six months).

Finally, we will employ and focus on both 2-D and 1-D seismic methods, to evaluate CO_2 movement out of the top and bottom of the coal beds. Because the coals are already saturated with CH4 and the seismic properties of CH4 and CO_2 are nearly identical, resolving the CO_2 front (laterally) will likely be impossible, and 3-D surveys may be excessive (e.g., “overkill”). Thus, we will focus on evaluating the vertical change in seismic reflectors as a means of tracking the CO_2 front; 1-D and 2-D seismic methods (single source reflection; borehole methods such as VSP, etc.) will likely be effective for resolving changes in vertical reflectors at the coal boundaries. Combining and co-interpreting seismic and borehole geophysical methods with tiltmeters is a promising “coupled” approach for monitoring CO_2 and its effects on injectivity, methane production, and efficacy of CO_2 storage in the coals.

Task 5: Post-Injection Monitoring and Analysis

Following the injection period, the monitoring program described for previous tasks will continue for an additional period of approximately 12 months. Following that initial 12-month post-injection period, the site will be monitored on a less-frequent and lower intensity basis for the balance of the project (approximately 18 mos). While the specifics of the scale-down will be decided at the time, when a better understanding of what data are providing the most useful information, and how frequently it should be collected, it is envisioned at this point that the tiltmeter array will be demobilized, and continuation and/or frequency of other periodic measurements evaluated. As with during injection, post-injection reservoir simulation models will be periodically updated (approximately three months). Long-term predictions of CO_2 movement/storage will be made by interpretation and modeling, as well as ECBM performance.

San Juan Basin Terrestrial Sequestration Pilot

Rangelands in the San Juan Basin of New Mexico are a potentially large reservoir for carbon, in addition to their value as recreational lands. The challenges to achieving their potential lie primarily in the limited growing conditions (erratic precipitation) and reduced capacity for recovery (ongoing disturbance and poorly developed soils). Optimizing carbon storage in soils and vegetation while increasing the value of other ecosystem services requires a two-pronged strategy: enhancing existing and reintroducing woody plant species along riparian areas and reestablishing native grasses and shrubs in upland areas. The limiting factor in both cases is water, both quality and quantity. A reliable source of water of sufficient quality for agricultural irrigation could provide the necessary base for the reestablishment of native vegetation with a host of environmental benefits in addition to carbon sequestration. The water produced during ECBM production should provide that source.

Work Plan: Regulatory and permitting requirements will be addressed first. The terrestrial sequestration activities in this project will all take place on land administered by the BLM, who has an established permitting process for such activities. As a strategy of retrieving maximized CBM clean water for beneficial use and minimized wastewater for disposal, we developed and demonstrated a new method using zeolite RO membrane for produced water purification. The zeolite RO has advantages of organic solvent resistance and can separate salt and organics from produced water simultaneously (Li et al., 2004a). The molecular sieve MFI-type zeolite membrane can separate ion and organics from water with a high separation efficiency based on size exclusion mechanism because the hydrated ions and organics have effective sizes (0.8~1.0 nm) much larger than the uniform zeolite pore size (0.56 nm) while the dynamic size of water molecules (~0.29 nm) is much smaller than the zeolite pore size and therefore can transport freely (Lin et al., 2001; Li et al., 2004b, 2004c). Recently, an overall 83.5% ion rejection was achieved for a real CBM produced water containing TDS of ~1.86×10^4 mg/l on a MFI zeolite membrane.

Desalinated produced water will be applied to 5 linear km of second order or higher stream where riparian vegetation is currently degraded. Frequency of applications of water will be determined by the amount of water available, but will not be less than bank-full, for one week, monthly, April-November; and bank-full for one week every other month December through March. To assess the impact on vegetation, standard indicators of rangeland riparian ecosystems will be measured at the beginning of the project and seasonally thereafter (Winward, 2000). Water will be applied to at least 100 ha of upland soils, reseeded with drought tolerant native grasses at least three times per year to simulate 2.5 cm of natural precipitation. Impacts of the upland reseeding and irrigation will be determined by application of rangeland health monitoring standards (Herrick et al., 2005). *The Big Sky Partnership will collaborate with the Southwest Partnership on this project, specifically on economic modeling and analysis.*

Pilot Deployment Plan: SACROC-Claytonville EOR Pilot Test, Snyder, Texas

Suitability, Availability, and Characterization

The SACROC unit and Claytonville (Canyon lime) reservoir are part of the Horseshoe Atoll and Pennsylvanian Reef/Bank plays (Figure 2). The two plays have produced more than 3.2 billion barrels of oil, a very large pore volume for potential CO_2 sequestration. The pilot sites are in a very sparsely populated portion of Texas. There are no metropolitan areas in the counties that the pilot areas cover; residents are involved in either the oil industry or agriculture. A large oil industry infrastructure exists, including pipelines, supply stores, and oil processing facilities. The infrastructure to deliver CO_2 is part of the largest CO_2 pipeline infrastructure in the world. Land use over the pilot areas consists of tilled farming and animal grazing. Information about the two fields is summarized in Table 2.

Both reservoirs are highly suitable for a CO_2 pilot demonstration project. The reef depositional setting is representative of the larger Permian Basin Pennsylvanian oil plays. The minimum miscibility pressure of CO_2 in oil for both reservoirs is estimated to be 1,500 psi, well below the initial reservoir pressures. Both fields contain low production-rate oil wells, shut-in wells, and plugged and abandoned wells. The high gravity oil in each field also makes them good candidates for CO_2 enhanced oil recovery.

Pilot Site Location and Description

The exact pilot site locations include the center of the SACROC Kelly oilfield (Figure 2), where CO_2 injection is ongoing, and the northeastern portion of the Claytonville field (Figure 2). At both Claytonville and SACROC, the geology of the injection zone is comparable to a large class of potential brine storage reservoirs. Depth of the flooded zones range from ~6300–7100 ft (1900–2200 m) with average reservoir pressures of ~2600 psig. The reservoir fluids in the flooded zones are typical brines. Impermeable shale caps the limestone reservoir, which itself has permeabilities generally <~50 md and porosities in the range of 2–15%. KinderMorgan has a well-developed CO_2 handling infrastructure, with ~1850 wells within the ~50,000 acre site. Roughly 175 of these wells are CO_2 injection wells. The area currently has a gas separation facility capable of handling 635 MMscf/d (~13 MtCO_2/yr). An amine-based process is used for scrubbing/polishing the last 10% of CO_2 from final gas mixtures. Compression facilities are capable of pressurizing comparable volumes of CO_2 to reservoir injection conditions. KinderMorgan has generously agreed to provide all CO_2 for the proposed EOR/sequestration analysis at SACROC and Claytonville. SACROC injection is ongoing, and MMV operations can begin right away. Redevelopment of the Claytonville Canyon Lime reservoir with a CO_2 enhanced oil recovery project will be rapid. A branch pipeline will be laid from SACROC to the Claytonville reservoir in 2006. During this time workovers and new wells will be drilled to obtain the necessary perforated well coverage. Additionally, surface facilities

Table 2.	**SACROC**	**Claytonville**
County	Scurry	Fischer
Discovery year	1948	1952
Play	Horseshoe Atoll	Pennsylvanian Reef/Bank
Trend	NE-SW	N-S
Porosity	8%	5%
Permeability	19 md	10 md
Initial BH Pressure	3122 psi	2335 psi
API Gravity	42	42
Pore Types	Vugs, interparticle, fractures	Vugs, interparticle, fractures
Depositional Setting	Reef	Reef
CO_2 Flooding	1973	1975
Size	170 mi long	3360 acres (5 x 0.75 mi)
Production	1227 mmbo	66 mmbo

and high pressure CO_2 lines will be constructed. The target date for injection to begin will be January 2007; see Gantt charts in section 3 for all schedules.

Research work will aid in the determination of the approach that will be taken for the CO_2 EOR flood. A gravity stable flood is likely because of the steeply dipping reservoir with good vertical communication. This type of flood injects CO_2 at the top of the structure and causes oil to be produced at lower structural positions. This effectively “fills” the structure with CO_2 and could represent an optimal approach to both enhancing oil recovery and increasing the amount of CO_2 sequestered. Initial CO_2 injection is planned to begin in the north-east structural high. Injection quantities and rates are yet to be determined. Any produced CO_2 will likely be reinjected with minimal methane removal. This location will thus focus the MMV work within the project.

Task 1: Site/Reservoir Characterization and Model Development

In this task all of the information for the site will be collected from KinderMorgan, and a thorough site and reservoir characterization developed. The information collected will include, for example, precise well locations, completion and stimulation information, and production and operating histories for each. Historical oil, gas and water compositional data will also be obtained. From a reservoir characterization perspective, well logs, core data, pressure-transient data, and any other relevant information for the area will be obtained from KinderMorgan. KinderMorgan currently possesses, or will acquire in 2005, core and pressure transient data for several wells within or near to the demonstration site.

One of the project collaborators, ARI, is also working on a separate DOE-sponsored project at the SACROC Unit. The primary objective of that effort is to develop a reservoir characterization of the northern platform area, which contains the bulk of the oil for the field, to evaluate the feasibility of gravity-stable CO_2-EOR there. Gravity-stable CO_2-EOR is not only more efficient than pattern flooding, but it has the potential to sequester more CO_2, creating a win-win situation. However, this technique requires specific geologic conditions to be effective, conditions that are believed to exist in the northern platform area. To assess geologic and reservoir conditions, core and cross-well seismic data are being acquired in four wells in the area. A 3-D surface seismic survey already exists over the area.

Through the ARI project, these data will also benefit the SWP's efforts to understand CO_2 movement at SACROC. Another project collaborator, the Texas BEG, also has a detailed characterization implemented in an existing numerical model of the SACROC area, based on seismic stratigraphy and other data. These combined a priori characterizations of SACROC will be leveraged to develop a better model of the SACROC field and also to develop the basis for a sound characterization of Claytonville. Detailed geologic models and operating/production histories will be constructed for both demonstration sites. Production histories will then be matched via reservoir simulation to calibrate unknown reservoir properties (e.g., relative permeability), which will be the primary basis for understanding subsequent performance under CO_2 injection. Initial forecasting of performance under CO_2 injection will be performed to aid in operational planning for the demonstration (i.e., fine-tune injection rates, estimate injection pressures, etc.). As described in the introduction, SACROC provides an unparalleled opportunity for "back-forecasting" or history-matching: over 30 years of CO_2 injection and EOR operations provides a sound database and basis for understanding new operations at Claytonville. In this first task, we will also continue working on the initial risk assessment that was begun in Phase 1.

Task 2: Implement Regulatory Permitting Requirements and Risk Mitigation

For the SACROC-Claytonville pilots, we will follow the overall proposed regulatory and permitting plan, including development of a best practices manual, described in a previous section of this proposal. In Texas, such activity is classified as Class II injection under UIC. Furthermore, the industry partner for this project, KinderMorgan, has extensive experience transporting and injecting CO_2, and is familiar with the permitting requirements. In this second task, we will also begin integration of our reservoir models, risk assessment criteria, regulatory constructs, and the MMV protocols for the systematic risk mitigation approach (described earlier in this proposal). Please refer to Gantt charts (Section 3) for schedules.

Task 3: Construction, Safety and Site Preparation, Baseline MMV

The next task will be to prepare the site for the demonstration, including construction. This includes transportation of CO_2 to the Claytonville field from KinderMorgan's Cortez and Centerline pipelines (which operate at approximately 2,000 psi in this area) and a new 30-mile pipeline to be built from the terminus of the Centerline Pipeline at Snyder, Texas, to the Claytonville field. Other activities will include construction of a CO_2 injection distribution system within the field, a new gathering system to collect all produced CO_2 and hydrocarbon gases, and a gas plant to recover at least some of the hydrocarbons in the produced stream. State-of-the-art reservoir modeling will be used to simulate flow and chemical processes and forecast ultimate CO2 storage capacities. In this third task, we will conduct baseline measurements of our MMV program; MMV protocols for the Texas pilot are described under Task 5, below. As an initial "reconnaissance" of CO_2 flux for baseline MMV information, the SWP sampled a representative transect of 25 flux measurements; all measurements suggest ambient fluxes are completely soil/ biogenic. Gantt chart schedules are provided in Section 3

Task 4: Injection Operations, MMV and Capacity Analysis

Injection at SACROC is ongoing, as it has been for over 30 years. KinderMorgan plans to inject CO_2 at Claytonville for several years, and the SWP proposes to intensely monitor CO_2 movement for the entire period (see Gantt charts in Section 3). Enhanced oil recovery will require injection of CO_2 for several years, possibly using a water-alternating-gas scheme. Lower-intensity monitoring will be performed for the final ~18-months of the project (it is assumed CO_2 injection will commence around January 1, 2007). The daily rate of CO_2 to be injected will be between 5 and 15 MMcf / day. An average well will inject 5 BCF of CO_2 over its life. Injection will be controlled using a constant injection pressure, and the injection rate will be allowed to vary as downhole conditions change. At a later time when CO_2 is produced with hydrocarbon gases, some gas may remain in the recycled CO_2 stream and will be reinjected. It is not anticipated that the hydrocarbon fraction in the reinjected stream will ever exceed 15% by volume.

MMV Operations: All MMV protocols to be deployed by the SWP are summarized earlier in this proposal. The specific MMV methods for the SACROC-Claytonville pilot are tabulated below.

Direct MMV Methods at SACROC-Claytonville		**Indirect MMV Methods at SACROC-Claytonville**	
Injection Rate Monitoring	Prod. Well LI-COR©	4-D Seismic Surveys	VSP
Abandoned Well LI-COR©	H_2O Chem & Isotopes.	Crosswell Seismic	ASTLI
Gas Piezometers (LI-COR©)	Gas Chem & Isotopes.	Passive Seismic	Integrated seismic model
In situ P/T well monitoring (fiber optic sensors)		Borehole integrity by resistivity monitoring	State-of-the-art reservoir models

Our MMV programs for each site are tailored for the unique setting of each site and for maximizing comparisons to approaches deployed at the other two geologic pilots (SJB ECBM and Aneth). For the Texas pilots, the primary contrast with other sites is the application and testing of 3-D seismic lines. We will be testing 2-D seismic comprehensively at Aneth; we propose to use repeat 3-D (i.e., 4-D) surveys at SACROC-Claytonville, and leverage or couple interpretation and modeling of 4-D results with borehole geophysical results (VSP, ASTLI, crosswell) – i.e., we will attempt to maximize 4-D seismic efficacy by combining surveys with crosswell, VSP, and ASTLI results. We will also compare efficacy and approaches for these 4-D surveys to planned repeat 2-D surveys in our proposed Aneth pilot.

Southwest Regional Terrestrial Pilot Test

The analyses conducted in Phase I on carbon sequestration potential for the region clearly showed that there is tremendous potential to increase carbon storage in soils and vegetation through changes in land use and management. Achieving that potential, however, is constrained by three factors: (1) low per ha rates of accumulation due to low rainfall and soil fertility (2) year to year climatic variability that makes local prediction of sequestration difficult (3) lack of cost effective carbon measurement systems.

The greatest influence on carbon stocks in the area, without doubt, is yearly variation in precipitation. However, changes in land use and management also greatly influence soil and vegetation carbon fluxes. Broad, landscape scale analysis showed that much of the region would be predicted to accumulate soil carbon at less than 0.1 t/ha/y unless changes in land use occurred, primarily converting cropland to perennial grasses or trees. Land use conversion can result in accumulation rates of up to 1.0 t/ha/y in a limited portion of the region. Given current economic constraints on the ability of land managers to change land use, the potential for conversion is limited.

The dominant influence on land use and management in the region is government policy. The impact of federal conservation programs on private land management is prevalent throughout the region. Government programs such as the Conservation Reserve Program (CRP) encourage land conversion from cropland to perennial plant cover and other programs such as the Conservation Security Program (CSP), Environmental Quality Incentives Program (EQIP), Wildlife Habitat Incentives Program (WHIP), etc., provide incentives for land managers to adopt conservation practices on cropland, rangeland and forestland. It is through these land use changes and adoption of management practices that the greatest increases in terrestrial carbon storage will occur.

Crediting changes in terrestrial carbon and assigning them to specific management requires a system of monitoring, measurement and verification that can reliably separate changes in climatically driven fluxes from those due to actions taken by land managers. The ability to partition changes in carbon stocks is greatly limited by the climatic and edaphic constraints described above.

To overcome these constraints, we will develop a carbon reporting and monitoring system that functions consistently across hierarchical scales and is compatible with the existing technology underlying the 1605b reporting system. Our major objectives in developing and implementing this system are :(1) Develop improved technologies and systems for direct measurements of soil and vegetation carbon at reference sites selected within SWP region. (2) Develop remote sensing and classification protocols to improve mesocsale (km^2) soil and vegetation carbon estimates. (3) Construct ecological process (State and Transition) models that reflect soil/vegetation changes resulting from current land use and land use associated with implementation of programs to sequester carbon or reduce carbon losses. (4) Develop a regional inventory and decision support tool that integrates information gathered during the course of the Phase I investigation and from Objective 1-3 above.

Task 1: *Develop improved technologies and systems for direct measurements of soil and vegetation carbon at reference sites selected within Southwest Carbon Partnership region:* The purpose of Task 1 is to use advanced instrumentation on the ground to identify and characterize the distribution of, then to relate these distributions to the land use practices implemented at the site. Advanced techniques for measuring soil carbon and other nutrients are needed. We will address three subtasks for Objective 1: (1) Calibrate and test the newly developed Laser-Induced Breakdown Spectroscopy (LIBS) instrument along with portable Near Infrared Spectroscopy (NIRS) for soil carbon measurements. (2) Determine near land surface patterns of soil carbon in a spatially extensive manner. (3) Relate near land surface patterns of soil carbon to associated soil profiles, site inventories, and management practices. (4) Improving estimates of carbon inventories in soils is currently hindered by lack of a rapid analysis method for total soil carbon.

A rapid, accurate, and precise method that could be used in the field would be a significant benefit to researchers investigating carbon sequestration. Recent tests suggest that the LIBS method (Cremers et al., 2001) rapidly and efficiently measures soil carbon with excellent detection limits (~300 mg / kg), precision (4-5%), and accuracy (3-14%). Initial testing shows that LIBS measurements and dry combustion analyses are highly correlated (adjusted $r^2 = 0.96$) for soils of distinct morphology, and that a sample can be analyzed by LIBS in less than one minute. The LIBS method has been adapted to a field-portable instrument, and this attribute—in combination with rapid and accurate sample analysis— suggest that this new method offers promise for improving measurement of total soil carbon.

NIRS technology has recently been used for assessing soil carbon in both crop and rangeland conditions. As part of work conducted under the Consortium for Agricultural Soil Mitigation of Greenhouse Gases (CASMGS) project, we found that NIRS had the potential to be a useful method for rapidly assessing carbon in the field (CASMGS 2003). Although predictions of carbon were not consistently as accurate as conventional laboratory methods, the ability to collect many samples and the reduced cost of sampling make this an attractive method. In conjunction with the calibration of the LIBS instrument, we will work to improve calibration of the field instrument and examine its potential as methodology complimentary to the LIBS system.

Key data need to be collected to link changes in soil carbon to vegetation change related to management practices to sequester soil carbon. To accomplish this, a series of shallow and spatially extensive measurements of soil carbon will be collected to characterize distributions of soil carbon and nutrients at selected sites across the SWP region that were identified during the Phase I analysis. This information will be used for assessing correspondence to remote sensing data (Objective 2) and for development of state and transition models (Objective 3). This data will also be used as part of the regional inventory and decision support system (Objective 4).

Task 2: *Develop remote sensing and classification protocols to improve mesocsale (km^2) soil and vegetation carbon estimates:* The purpose of this objective is to identify and refine existing techniques in remote sensing that can detect and link changes in vegetation and soil properties that reflect soil C at a scale consistent with the output from Objective 1. While remotely sensed imagery has been valuable in natural resource management as a tool for inventory and large-scale production estimation, there has been little, if any, application to site-specific management such as land use and management change related to carbon sequestration. Two subtasks include: (1) Using results of the spatial characterization of carbon at the selected study sites in Objective 1, determine remote sensing technology(ies) capable of providing appropriate scale and frequency of imagery that could be useful in assessing changes in carbon stocks; (2) Integration of remote sensing data identified in Task 1, above, into the state and transition models and a regional inventory and decision support tool (Objective 4).

While the use of LANDSAT imagery is fairly common in agricultural and forestland resource inventories and assessments, the scale associated with this technology is likely to be inappropriate for detecting patterns at <$10m^2$ scale. However, new satellites and aircraft borne instruments, such as multispectral videography, which can generate information down to cell sizes of ~$1m^2$ and can be gathered frequently, offer the most promise in this area (Havstad et al., 2000).

Task 3: *Construct ecological process (State and Transition) models that reflect soil/vegetation changes resulting from current land use and land use associated with implementation of programs to sequester carbon or reduce carbon losses:* The purpose of this objective is to integrate existing qualitative knowledge about soil/vegetation change in response to management and climate variability and quantitative information gained as a result of Objective 1 into State and Transition Models (STMs) appropriate for the regions represented by our study sites, link to objective remotely sensed land attributes (Objective 2) and provide inputs to improve model estimates (Objective 4). Estimates are that approximately 50% of changes in carbon stocks on rangelands are attributable to changes in management practices (Follett et al., 2001). Unfortunately, the application of these types of practices (i.e. changes in grazing intensity) is difficult to detect and highly variable in their effect on soil C. However, vegetation structure has been shown to reflect soil C more accurately when the complex spatial relationships are accounted for and vegetation structure is much easier to detect objectively via remote sensing (Objective

2). STMs can be used to guide land managers and policy makers in selecting which practices can result in changes in soil C. Once the STMs are developed for specific management practices/land uses, they can be distributed to soil mapping units within the region and thereby expand the influence of the study. Currently, the only available model for estimating soil C changes on rangelands (COMET VR; see Objective 4) requires management inputs in terms of practices applied and the uncertainty associated with this approach is unacceptably high (>50%). Thus, associating soil C changes with vegetation state will both improve support of decision making and increase estimation accuracy. Finally, we will alter COMET VR to allow for inputs in terms of ecological state rather than practices, which more accurately reflect soil and vegetation C levels. Subtasks include: (1) Develop State and Transition Models (STMs) for the range of soil/vegetation combinations represented by the carbon management practices and land uses in the selected study areas. (2) Distribute STMs across appropriate soil units within the region. (3) Integrate the STMs into the regional inventory and decision support system.

The development of STMs requires a combination of field inventory and literature review. Although STMs have been proposed for over a decade, their field use is limited as a basis for management, especially in areas where vegetation structure is complex. We will use existing information from long-term studies at the selected study sites to assemble a catalog of vegetation states and transitions associated with past and current land use and with implementation of programs to sequester carbon.

Task 4. *Develop a regional inventory and decision support tool that integrates information gathered during the course of the Phase I investigation and from Objective 1-3 above*: The purpose of this objective is the development of a tool that will allow the integration of the spatial and carbon sequestration potential data developed under Phase I along with the information and data gathered as part of Objectives 1,2, and 3 of this effort into a decision support framework that can be used by landholders, service agencies (NRCS), and policy makers. This tool would allow a spatially explicit analysis of carbon sequestration at local scales and allow aggregation of sequestration response under various conditions to regional scales. Subtasks include: (1) Build a web-based tool, with a GIS framework, that incorporates the soil, climate, and land use data gathered and processed in Phase I along with the soil carbon, state and transition, and remote sensing data gathered in the Phase II efforts. (2) Establish a linkage to the COMET VR tool that will allow the data fields required by COMET VR to be automatically filled based on the latitude/longitude, premise boundary, or region input or selected by the user. (3) Build a state and transition interface that will allow users to examine carbon sequestration under various management practices, government programs, or land uses. (4) Design display tools for mapping, data visualization, and reporting in a spatially coherent manner. (5) Improve the COMET VR tool for assessing carbon sequestration at the individual field and farm scale for arid and semi-arid rangelands and croplands. (6) Develop protocols for updating the system with new data (NASS, NRI) and options for carbon sequestration so that the system will stay current with relevant government programs and incentives. This regional inventory system and decision support tool will be designed for use in estimating carbon change at varying levels of scale using existing models. This system will allow users to examine carbon sequestration alternatives and to track progress of an implemented program. The system will also give policy makers the ability to examine impacts of implementing carbon sequestration programs at local and regional scales, thus improving program and policy decision making.

Collaboration: To improve technology transfer and enhance quality of the science in the project, we will meet annually with scientists of the Big Sky and WESTCARB projects for a one-week workshop. Additionally, Big Sky will collaborate directly with us on the project, on economic modeling and analysis.

Merit of Proposed Projects In Context of GHG Reduction Goals and Economics

In our Phase I proposal, we suggested that a possible first approach to CO_2 sequestration in the Southwest would be to supplant natural CO_2 supplies used for EOR with anthropogenic CO_2 (e.g., power-plant sourced). Our Phase 1 analysis showed that such an approach the region would meet, at the least, minimum GHG intensity reduction targets for the region, and our Phase 2 portfolio of pilot tests are based on this theme. Furthermore, as part of the SWP Phase 1, an integrated economic/GHG model was developed, based on an initial SWP regional “test case” analysis. The economic/GHG model analysis has been used to evaluate all potential Phase 2 pilot tests, and is now being applied to the Southwest region overall. The integrated economic/GHG model analysis, developed in tandem by economists, engineers and scientists in the SWP and lead by Sandia National Lab, is being used to project to 2025 the region's total greenhouse gas (GHG) emissions based on total energy use, by fuel type, and to assess the potential to reduce GHG intensity in the region. Regional economic, energy and GHG data are based on projections developed by the Energy Information Administration. In addition, capacities and costs of capture and sequestration technologies for the region, including the proposed pilot tests (Aneth, SJB ECBM, and SACROC-Claytonville) are factored in the economic/GHG analysis, including delays and costs associated with project permitting and MMV requirements. Establishing and communicating the consequences and tradeoffs between alternate sequestration sites and strategies to store GHG is the necessary first step in formulating an effective and publicly acceptable sequestration program, and in addressing the 2007 and 2012 metrics for success of the DOE Carbon Sequestration Technology Roadmap. In the field pilot operations, MMV protocols and associated modeling are the primary vehicles for determining how well the SWP meets or exceeds performance targets of the CST Roadmap, including prediction of storage capacity to +/- 30% accuracy, verification of indirect sequestration and associated costs, and verification of MMV technology efficacy. Public perceptions and acceptance will be in part addressed by giving interested parties access to the integrated assessment model (see Outreach plans in the next section) to determine if the analysis approach reflects the important sequestration and GHG issues, and to increase understanding of the tradeoffs between different sequestration approaches.

Outreach and Education Plans

We have designed a regional outreach initiative to initiate and then facilitate a public dialogue regarding CO_2 sequestration. Our approach begins with an assessment of public knowledge bases, and then delivers outreach and public education in appropriate formats. Our programs builds on the NIST's (2002) recommendations that effective science communication programs should (a) illustrate both the process and product of science, (b) involve scientists, (c) involve decision makers, (d) use multimedia and interactivity, (e) relate science to everyday life, (f) avoid parochialism, (g) view the topic from the audience's perspective, (h) use face-to-face methods, and (i) provide readily usable information to media.

Dissemination methods, activities, and media are guided by learning theory and basic research on public awareness of science and technology. The concept of Collaborative Learning (Daniels and Walker, 2001) guides our outreach program, allowing for variations according to the socio-political dimensions and demographics of each locale. This approach provides a non-threatening format within which constituent groups with varied values and goals can establish a common understanding. The process encourages integration of individual interests within a broad, systemic view to achieve mutual benefit.

For decision makers, policy leaders, and the “attentive public” (Miller and Pardo, 1999), Mediated Modeling facilitates learning among constituents (van den Belt, 2004). It features a streamlined user interface that representatives can use with various groups to choose between a set of alternatives and build quantitative models of carbon sequestration strategies. The models are intended as educational tools, and results are intended for comparison of the impacts of various sequestration strategies.

We will begin with concentrated information gathering in communities near pilot projects. We will conduct focus groups with opinion leaders and decision-makers in the communities to identify relevant (1) local knowledge and (2) local opinion. We will use transcripts from those focus groups, along with existing NETL materials, to construct a questionnaire for distribution to a random sample of the population in relevant communities. Questionnaires will be administered by telephone. We will use the results of this information gathering to guide information dissemination and community-based activities.

In cooperation with NETL’s national efforts, we will work with local media outlets to develop quarterly press releases, potential radio/television segments. We also will invite local media to attend workshops & community events. We will expand and revise the SWP web site to include interactive capabilities. We will encourage science teachers to use the web site as appropriate to their curriculum. The website will include an education section with supplementary curriculum materials and guides for science teachers. The website also will provide public access to the system model (see below). We will develop and disseminate a library of interactive CO_2 sequestration tutorials on CD. These tutorials include digital field trips, demonstrations of best practices, and self-teaching modules. Field trips allow users to interact with the site; best practice modules are broken down into small tasks with recognized experts demonstrating proper procedure; and self-teaching modules include interactive opportunities for self-evaluation. We will encourage teachers, industry partners, and local community leaders to use this library. We also will make it available to local commercial media.

We will develop print materials for distribution at community events. Both to enhance credibility and to maximize convenience for community members, we will use existing venues, rather than scheduling additional meetings. Distribution methods can range from providing a guest speaker to providing written materials to hand out. Organizations to target include school districts, chambers of commerce, environmental groups, parent-teacher organizations, and county/city governments. We will recruit decision makers, policy leaders, and members of the attentive public for expanded participation in mediated modeling activities. During Phase I we worked with industry to develop and test a preliminary system model. We will continue model development with an expanded group of stakeholders.

Broad inclusion in mediated modeling alternatives will enable us to directly involve interested community residents in determining what factors should be considered, and how those factors relate to each other. It provides opportunities for participants to discover common ground and negotiate mutual benefits. By working within a learning format, participants with varied values, interests, and insights can establish commonalities with diminished fear of practical, political impacts. The workshops deepen participants' understanding of the potential impacts CO_2 sequestration projects may have on the quality of life experienced by residents. The experience has immediate benefits, as community members gain a sense of ownership over the process and resulting decisions. At the conclusion of the project, we will engage in a mirrored set of concentrated information gathering activities. We will again conduct focus groups with opinion leaders and decision-makers, and we will administer questionnaires to the broader public. Analysis of the resulting data will be used to determine

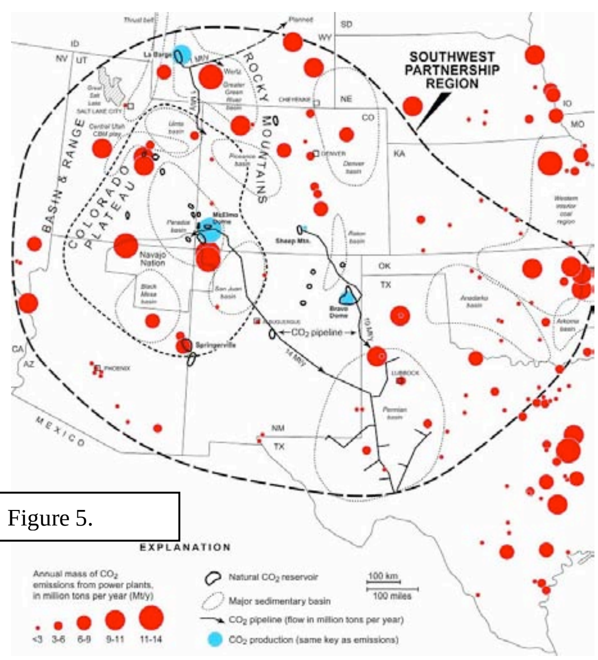


Figure 5.

how public perceptions of CO_2 sequestration (in communities near pilot projects) have changed during the pilot project.

2. CHARACTERIZATION OF REGION AND EVALUATION OF OPPORTUNITIES

The SWP region includes all of Arizona, Colorado, Kansas, New Mexico, Oklahoma, and Utah, roughly one-third of Texas, and significant portions of southern Wyoming and eastern Nevada (Figure 5). The SWP comprises a large, diverse group of expert organizations and individuals specializing in carbon sequestration science and engineering, and public policy and outreach.

Southwest CO_2 Sources: The region is energy-rich and possesses one of the largest population and energy-production growth rates in the nation. Two major CO_2 pipeline networks transport more than 30 million tons/year of natural, subsurface CO_2 from southern Colorado and northern New Mexico to petroleum fields in the Permian Basin, where it is used for enhanced oil recovery. The 10 largest coal-fired power plants in the region produce about 140 million tons of CO_2/year, with roughly 50% of that coming from fossil fuel combustion. Other point sources include natural gas processing plants, refineries, and ammonia/fertilizer, ethylene and ethanol, and cement plants. More than 40 databases were integrated into the main SWP database.

Sequestration Sinks and Aggregate GHG Storage Potential: The *geologic sinks* data were collected in modified GASIS databases, one for each state. Only hydrocarbon fields with 2003 cumulative productions that exceeded 1 million barrels of oil or 10 billion cubic feet of gas were considered large enough for further analyses. Colorado's data are typical of the detail available for each state, and thus we summarize Colorado's GHG sink potential, for sake of example of our Phase I regional characterization and the basis for continued Phase 2 characterization activities.

Although CO_2 sink potential is widely distributed across Colorado, data collection focused on seven primary study areas. These areas were chosen on the basis of maximum diversity in potential sequestration options that were within 50 miles of a power plant. The estimated CO_2 sequestration capacity of the seven study areas exceeds 150 billion tons, providing the potential for several hundred years of carbon storage based on 1999 emission levels (Table 3).

Of the 223 oil and gas fields in the Colorado database, 122 are located within 30 miles of a large, coal-burning power plant and are deep enough to maintain CO_2 at supercritical conditions. The preliminary forecast of CO_2 capacity for oil and gas reservoirs in the seven study areas is 443 million tons with more than 80% of that capacity contained in the Denver, Ignacio, and Rangely study areas. This was determined by converting all liquid production to thousand cubic feet gas equivalent at surface conditions (Mscf), combining this volume with gas production, and applying a conversion factor of 17.15 Mscf per ton CO_2. These CO_2 capacity calculations are conservative due to underestimation of water production.

Table 3. Estimated Carbon Sequestration Capacity for Colorado
(in Million Short Tons)

1999 Emissions		Geologic			Mineralization		Total Capacity
		Oil & Gas	**CBM**	**Saline Aquifers**	**Silicates**	**Produced Waters**	
Canon City	12	0	0	22,300	2,200		24,500
Craig	10	9	0	9,300	30,000	0.001	39,309
Denver	7	183	0	22,600		<0.001	22,783
Fort Morgan	5	16	0	8,700		<0.001	8,716
Ignacio	29	93	838	15,800		0.009	16,731
Palisade	1	56	8	22,800	200	<0.001	23,064
Rangely	4	86	1	19,300		0.015	19,387
Total	***68***	***443***	***847***	***120,800***	***32,400***	***0.026***	***154,490***

One of the most promising sequestration options is in coal beds at depths greater than 2,000 ft. The preliminary forecast of CO_2 sequestration capacity for coalbed methane reservoirs in Colorado is 847 million tons with nearly all of that capacity associated with the Fruitland coal play in the Ignacio study area. This estimate of capacity was made by assuming that four CO_2 molecules would replace one methane molecule in the coal matrix. The process is far more complicated and requires a reservoir simulator to be calculated accurately. This CO_2 capacity calculation is conservatively low due to the absence of significant coalbed methane production in emerging basins in the state.

ECBM: The first CO_2-enhanced coal bed methane (ECBM) production occurred in the New Mexico portion of the San Juan Basin (SJB) in 1995. At Burlington's Allison Unit more than 100,000 tons of CO_2 were injected over a three-year period to enhance production of coalbed methane. The CO_2 is now sequestered in the coal at depths in excess of 3,000 ft. Critical factors for sequestration include coal seam continuity, cleat permeability, coal shrinkage/swelling, gas adsorption/desorption, and seal integrity. The SJB is one of the top ranked basins in the world for CO_2 coalbed sequestration because it has: 1) advantageous geology and high methane content; 2) abundant anthropogenic CO_2 from nearby power plants, 3) low capital and operating costs; 4) well developed natural gas and CO_2 pipeline systems; and 4) local companies, e.g., Burlington, with CBM and ECBM expertise. Selection of potential coal bed methane CO_2 sequestration sites in the SJB is difficult without the detailed CBM knowledge and reservoir studies because: 1) the coal seams are discontinuous; 2) all coalbed methane production from the Fruitland Formation in the SJB is now reported as coming from a single pool (= gas field) by the New Mexico Oil and Gas Commission, making it difficult to know how much methane has been produced from a single reservoir. We thus propose a SJB ECBM pilot test for Phase 2 validation testing.

Terrestrial sequestration: Terrestrial carbon capacity in the region is limited by low average annual precipitation and yearly variability in precipitation. Even in systems managed for carbon storage, wet years followed by a series of dry years may result in a net carbon flux from the system. There is limited opportunity to increase carbon storage on rangelands because most areas are at a relatively stable equilibrium given land use history and management. Much of the desert grassland and shrubland areas with less than 12 inches of annual precipitation is subject to loss of cover and exposure to wind and water erosion. Retaining soil carbon levels in these ecosystems will require active restoration practices that are risky and unreliable given the current technologies.

CO_2 mineralization engineering: mineralization, the process by which CO_2 is bound in a solid, is an integral component of regional CO_2 storage options. Above-ground mineralization using cations extracted from either produced waters (e.g., brines) or mined ores (e.g., silicates) offers two potential roles for engineered long-term storage. Although no workable process currently exists for these options, ongoing research in both areas is encouraging. Phase I regional analyses of mineralization opportunities suggest these approaches are not economic at this time.

Plans for Continued Characterization of Region: The SWP continues to refine GHG *sequestration capacity data* on a state-by-state basis. Our approach accounts for both <u>economic tradeoffs</u> and <u>value-added benefits</u>. We have developed a regional model that characterizes CO_2 sources, the geologic sinks, and the costs associated with sequestration options. Sources are characterized by annual CO_2 emissions, power plant efficiency, age of plant, and location. Sink characterization includes location, depth, volume, injectivity, sequestration capacities, and risk of leaks (based on geologic parameters). Cost equations for CO_2 separation, collection, transport, and injection based on emissions volumes have been developed based on information collected from relevant literature, and verified by members of the Physical Infrastructure and Sources Committee. These equations have been used to develop prototype cost algorithms for the regional integrated assessment model, and will be evaluated for the test area. These models have been vetted in workshops and web conferences to increase understanding by external parties, and to get input on desired interfaces – what elements of the model are accessible by users to explore different "what if" questions about sequestration alternatives.

The SWP proposes for Phase 2 to continue its *regional characterization* and *data collection* efforts on a state-by-state basis. These data are added to our GIS database by the Utah Automated Geographical Reference Center. These, in turn, are fed into the NATCARB database. For example, during Phase 1, Colorado focused on the seven key areas. During Phase 2, Colorado will add more detail to sinks throughout the entire state. New Mexico has refined the search engine in the GASIS Database to find fields that meet or exceed ten key criteria for CO_2 sequestration. They have also refined a procedure for estimating CO_2 sequestration capacity based on produced fluids. Those capacity numbers are now part of its database and can be searched by the new search engine. A procedure manual and spreadsheet for calculating these capacities is in draft form and will be circulated throughout the SWP shortly.

Value-Added Benefits and How Phase 1 Led to Phase 2 Field Pilot Options: Based on Phase 1 activities, the SWP is proposing three geologic pilot tests and two terrestrial pilots from an original regional list of 12, which included high potential projects in Wyoming, Arizona, Utah, New Mexico, Oklahoma, Texas, and Kansas. The SWP used an integrated assessment approach for ranking potential pilot tests, factoring in storage capacity, risk assessment and mitigation potential, costs and economic tradeoffs, proximity to sources, and other factors. The chosen pilots described in the previous section of the proposal provide distinct *value-added benefits*, including of enhanced methane production and enhanced oil production. An environmental value-added benefit is associated with cleanup of ECBM-produced brines and application of the desalinated water for a terrestrial pilot test consisting of re-vegetation of nearby riparian areas. A less obvious value-added benefit of the ECBM pilot is that the pilot test site is located wholly within a BLM Area of Critical Environmental Concern (ACEC), meaning that we will have to satisfy stringent environmental regulations in order to sequester CO_2. The best practices that are learned at the San Juan ECBM pilot could become the model for environmentally-friendly sequestration guidelines in future projects.

3. PROJECT PLAN AND APPROACH

A. OBJECTIVES

The Southwest Regional Partnership on Carbon Sequestration proposes to carry out five field pilot tests to validate the most promising sequestration technologies and infrastructure concepts, including three geologic pilot tests and two terrestrial pilot programs. This field-testing will demonstrate efficacy of proposed sequestration technologies to reduce or offset greenhouse gas emissions in the region. Risk mitigation, optimization of MMV protocols, and effective outreach and communication are additional critical goals of these field validation tests.

B. SCOPE OF WORK

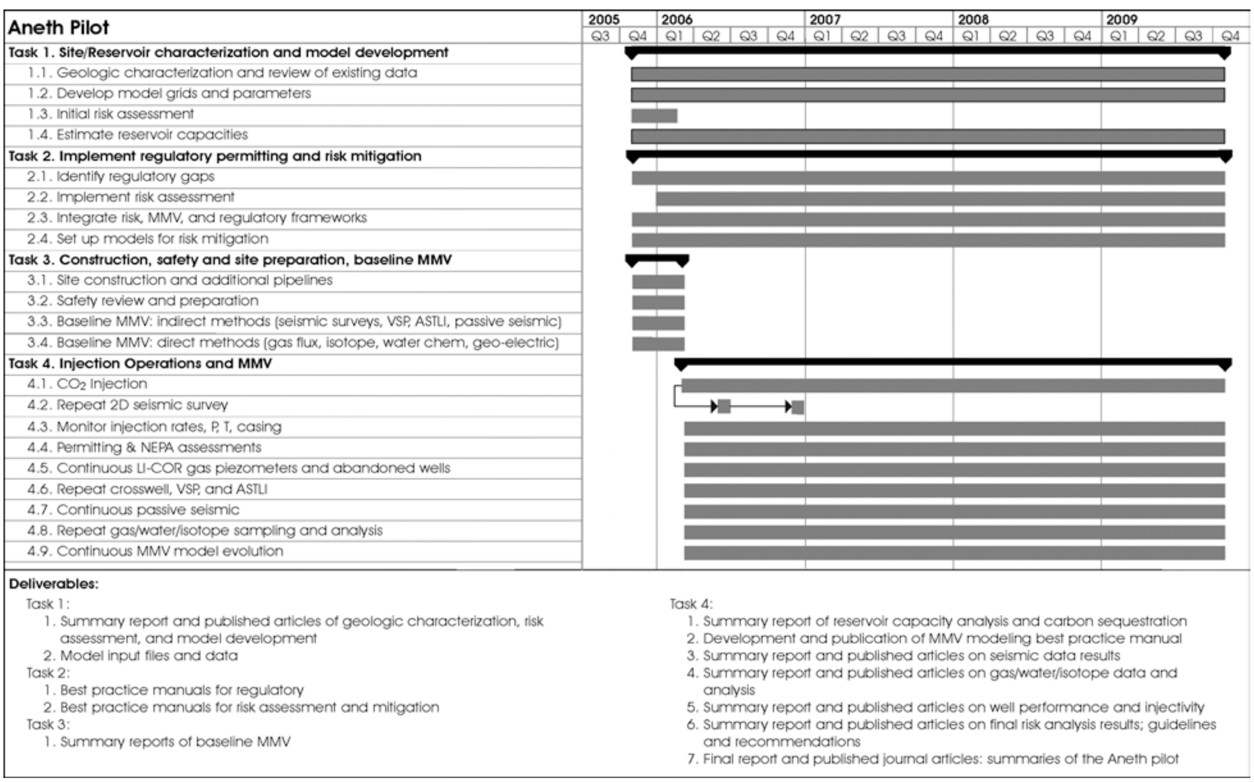
The Southwest Partnership proposes a truly regional approach for its technology validation program, including geologic pilot tests located in Utah, New Mexico, Texas, and a region-wide terrestrial analysis. Each geologic sequestration test will include injection of a minimum of ~75,000 tons/year to ~150,000 tons/year CO_2, with a minimum injection duration of one year.

C. TASKS TO BE PERFORMED AND DELIVERABLES

The SWP will carry out six major tasks, including five proposed carbon sequestration field validation pilot tests. A sixth major task is the extensive Outreach and Education program necessary for effective communication with the public, regulators, and other stakeholders. The suite of pilot tests will be conducted over four years' time, and the individual tasks and subtasks associated with each pilot will overlap to some degree. Additionally, scheduling of pilots was made to meet the business plans or needs of field operators. Thus, while the proposed SWP program will have two distinct budget phases, its technical phases will be relatively continuous. The SWP program is extremely large with dozens of tasks and deliverables, because of the number and breadth of the six major projects. Thus, for brevity we will use Gantt charts to summarize each of these major projects.

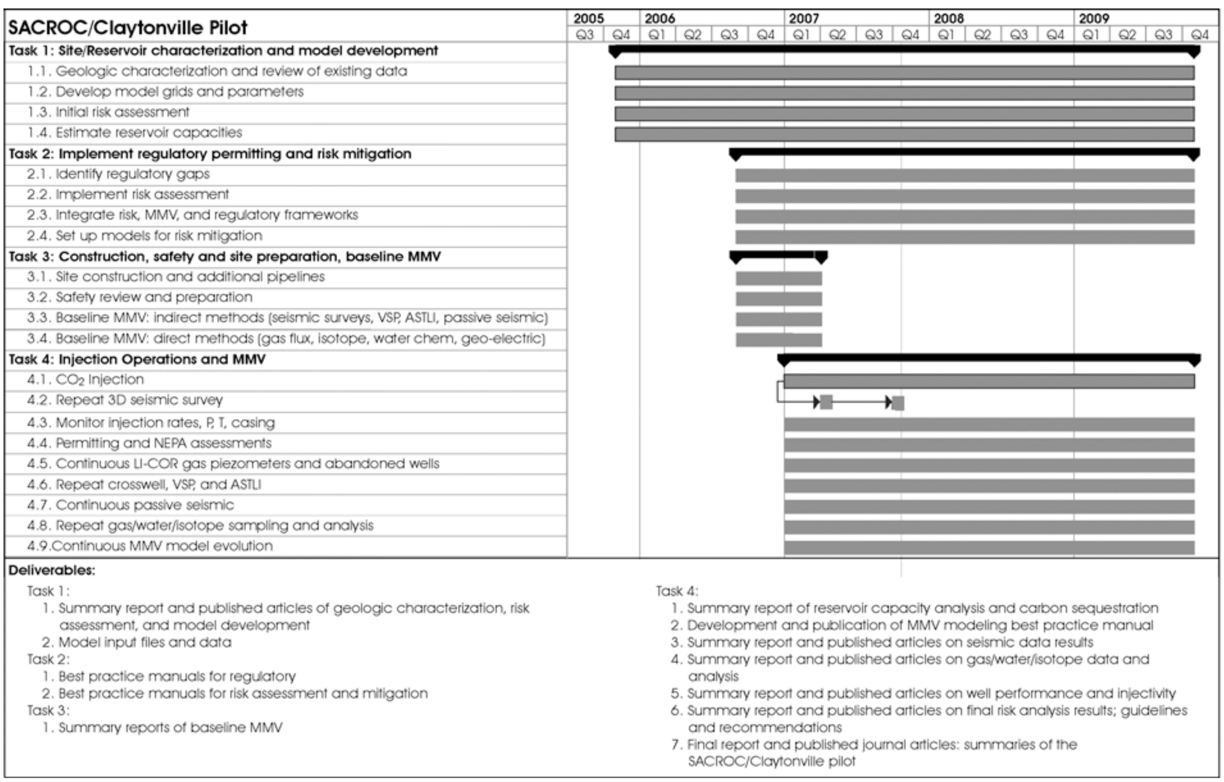
Major Task 1: Aneth EOR / Deep Saline Pilot Test

Our first pilot test will be a combined EOR – Deep Saline sequestration pilot injection test, to be conducted in the Aneth Field near Bluff, Utah. The operators of the field, Resolute Natural Resources Company and the Navajo Nation Oil and Gas Company, will work with the SWP and inject up to 150,000 tons per year for 3.5 years. The SWP will conduct extensive MMV studies, including a suite of direct techniques (direct CO_2 flux measurements) and indirect techniques (e.g., seismic methods). MMV design will depend on baseline MMV measurements and detailed reservoir models based on extensive geological characterization. Tasks, subtasks, and associated deliverables are detailed in the Gantt chart below. The pilot will begin in November, 2005, and conclude in November, 2009. The overall project goals are to validate sequestration technologies, including MMV and risk mitigation approaches, and to identify regulatory gaps. The tasks listed below tackle these objectives explicitly.



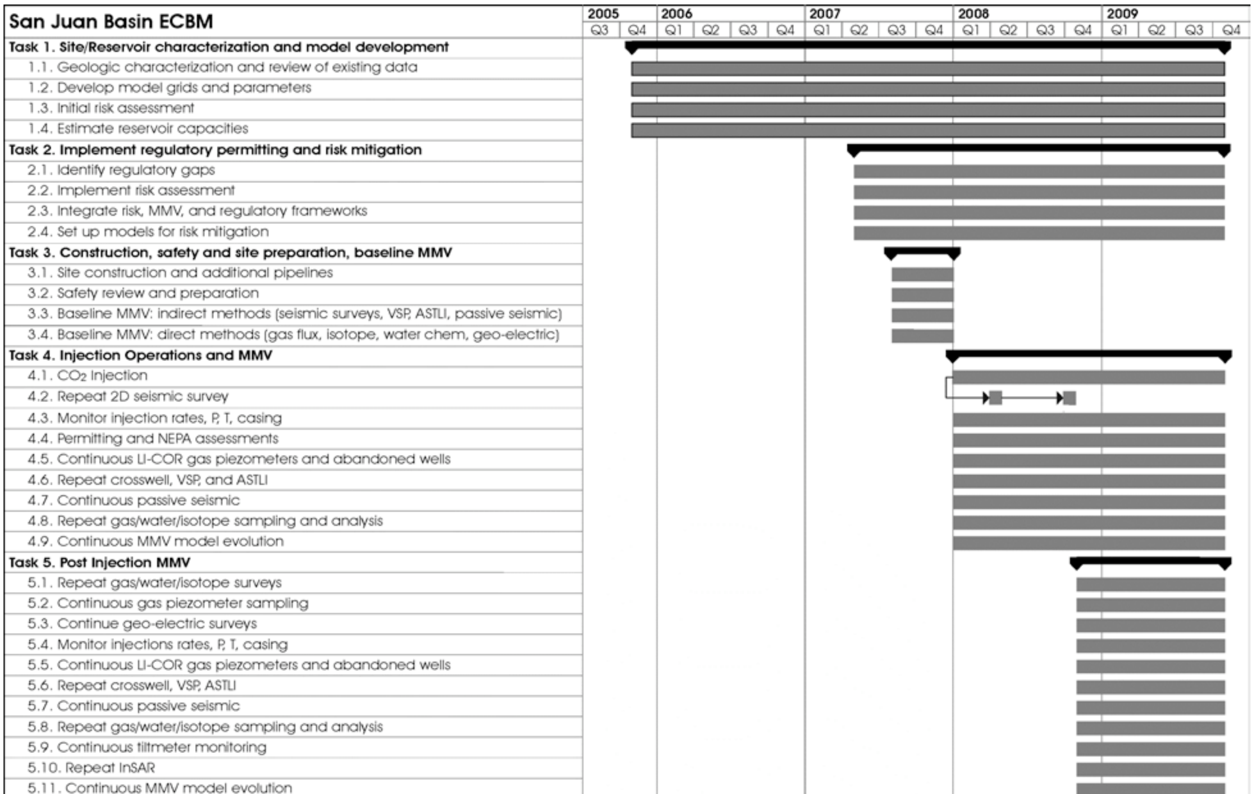
Major Task 2: SACROC - Claytonville EOR - CO_2 Sequestration Pilot Test

The second SWP geologic field pilot is the SACROC-Claytonville pilot test, in which we will evaluate enhanced oil recovery efficiency with concomitant CO_2 storage efficacy. The pilot is scheduled to begin in January, 2007 and will continue until project end, November of 2009. The details of tasks and deliverables for these projects are listed in the following Gantt chart. MMV design will depend on baseline MMV measurements and detailed reservoir models already begun by SWP partners Texas BEG and ARI. The geology of Aneth and the SACROC-Claytonville fields are slightly similar (carbonate reservoirs), but their depth ranges are different and offer very different hydrodynamic settings. A particular goal of MMV for the SACROC-Claytonville pilots, similarly, is to examine 3-D seismic efficacy and compare these seismic results to 2-D seismic efficacy at the other two geologic pilot sites. Among the project's goals is to compare MMV approaches and efficacy for a diversity of settings. General project goals are to validate sequestration technologies and employ risk mitigation approaches.



Major Task 3: San Juan Basin Enhanced Coalbed Methane – CO_2 Sequestration Pilot Test

The third SWP geologic field pilot is the San Juan ECBM pilot test, in which we will evaluate coalbed methane production efficiency with concomitant CO_2 storage efficacy. Pilot CO_2 injection is scheduled to begin around January, 2008, and continue for one year. Plans include injection of ~75,000 tons CO_2 during that year. Burlington will carry out this project exclusively for the SWP, including drilling an injection well for the pilot. This pilot, like the others planned, is intended to test a suite of MMV approaches tailored for its unique geology (coalbeds) and value-added benefit (methane production). Additional objectives include detailed risk assessment and mitigation plans, and to identify regulatory gaps for ECBM and CO_2 sequestration. Tasks and deliverables address these objectives explicitly:



Deliverables:

Task 1:
1. Summary report and published articles of geologic characterization, risk assessment, and model development
2. Model input files and data

Task 2:
1. Best practice manuals for regulatory
2. Best practice manuals for risk assessment and mitigation

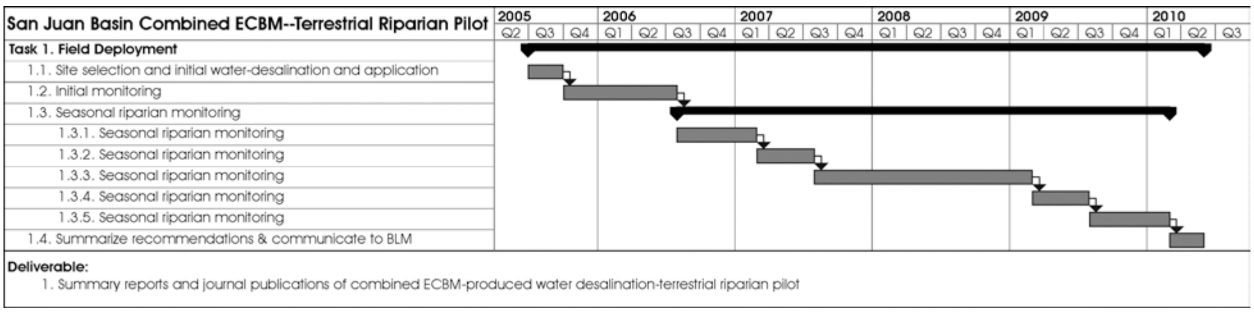
Task 3:
1. Summary reports of baseline MMV

Task 4:
1. Summary report of reservoir capacity analysis and carbon sequestration
2. Development and publication of MMV modeling best practice manual
3. Summary report and published articles on seismic data results
4. Summary report and published articles on gas/water/isotope data and analysis
5. Summary report and published articles on well performance and injectivity
6. Summary report and published articles on final risk analysis results; guidelines and recommendations
7. Final report and published journal articles: summaries of the San Juan Basin ECBM pilot

Task 5:
1. Summary of post injection data
2. Summary of final risk analysis results; guidelines and recommendations
3. Summary of the Aneth pilot operations, results, and analyses
4. Final report and published journal articles: summaries of the San Juan Basin ECBM pilot operations, results, and analyses

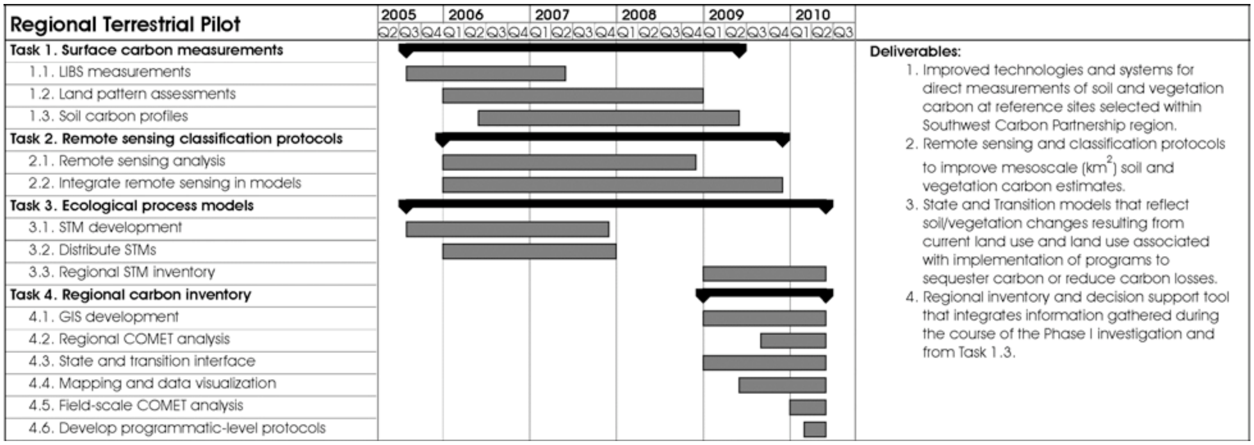
Major Task 4: San Juan Basin Terrestrial Sequestration Pilot

An additional pilot test planned for the San Juan basin is a local terrestrial sequestration pilot test. We propose a riparian area restoration project tied to the ECBM pilot test. Specifically, produced water from the San Juan basin will be desalinated and applied to a riparian area and CO_2 sequestration monitored and evaluated. While the ECBM pilot injection will begin in January, 2008, the terrestrial pilot will begin at the start of the Phase 2 program. Initial testing will involve produced water from other SJB wells, but will ultimately involve the production wells of the ECBM pilot. The overall project goals are to validate sequestration technologies, including MMV and risk mitigation approaches, and to identify regulatory gaps. The tasks listed below tackle these objectives explicitly.



Major Task 5: Regional Terrestrial Pilot

The SWP will continue its terrestrial analyses from the Phase 1 project, and will leverage results of that initial analysis for a comprehensive regional pilot. Goals for this pilot include improved technologies and systems for direct measurements of soil and vegetation carbon, remote sensing and classification protocols to improve mesoscale (km^2) soil and vegetation carbon estimates, state and transition models that reflect soil/vegetation changes resulting from current land use and land use associated with implementation of programs to sequester carbon or reduce carbon losses, and finally a regional inventory and decision support tool that integrates information gathered during the course of the Phase I project. The tasks and deliverables summarized below address these goals.



Major Task 6: Outreach and Education Plans

The SWP plans to implement a comprehensive outreach and education plan, designed to maximize awareness of sequestration opportunities in the southwest and provide stakeholders information about proposed deployment efforts and possible future efforts. All outreach tasks will begin at the start of the Phase 2 project and run continuously till the end of Phase 2, as depicted in the Gantt chart. The SWP will comply with NEPA and regulatory permitting public involvement requirements as appropriate. The SWP has developed an action plan for all pilots describing the effort required to inform and educate the public.

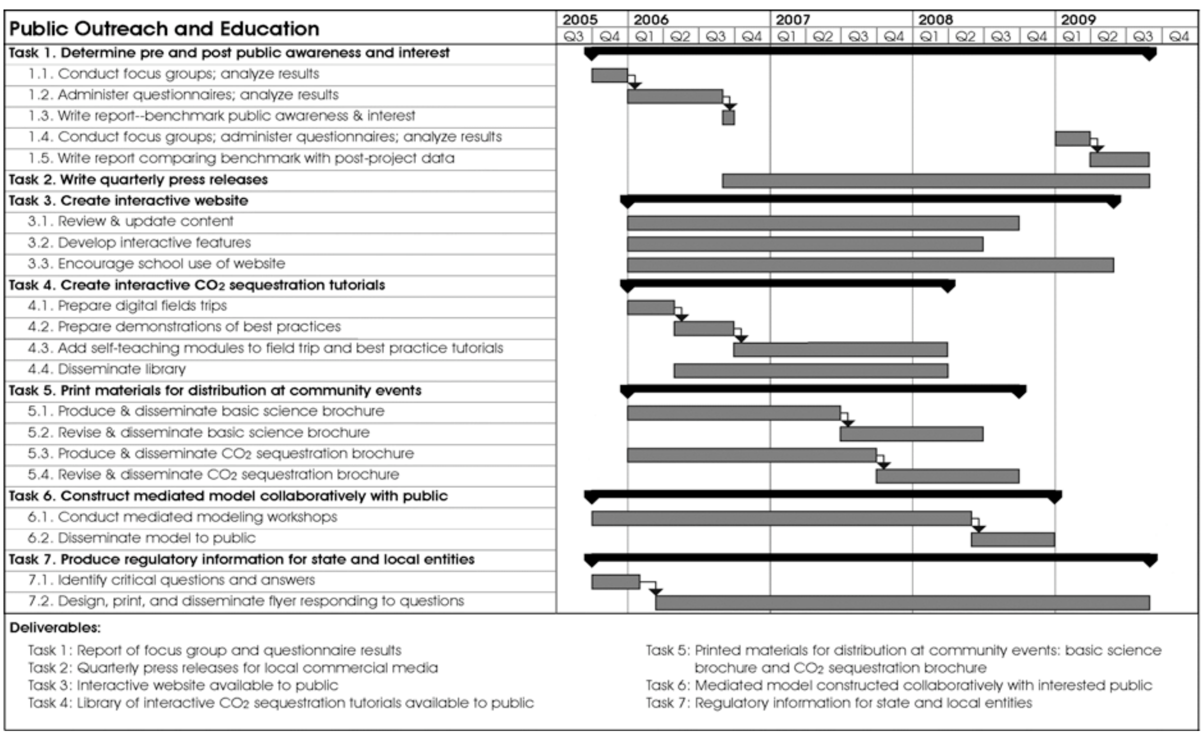


Table 1. Estimated labor hours and categories for each pilot project task.

Pilot	*Aneth*				*SJB-ECBM*				*SJB-Terrestrial*				*SACROC/Claytonville*			
Task	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4
PI/Project Manager	231	231	231	231	231	231	231	231	231	231	231	231	231	231	231	231
Eng. & Eco.*	622	622	622	622	1448	1448	1448	1448	589	589	589	589	1497	1497	1497	1497
Technician	179	179	179	179	335	335	335	335	179	179	179	179	833	833	833	833
Scientific	3913	3913	3913	3913	4500	4500	4500	4500	2780	2780	2780	2780	3972	3972	3972	3972
Clerical	0	0	0	0	83	83	83	83	0	0	0	0	87	87	87	87

Pilot	*Regional Terrestrial*				*Outreach & Education*					
Task	1	2	3	4	1	2	3	4	5	6
PI/Project Manager	231	231	231	231	154	154	154	154	154	154
Eng. & Eco.*	662	662	662	662	0	0	0	0	0	0
Technician	1539	1539	1539	1539	0	0	0	0	0	0
Scientific	4690	4690	4690	4690	0	0	0	0	0	0
Clerical	0	0	0	0	0	0	0	0	0	0
Outreach specialist	0	0	0	0	587	587	587	587	587	587

*Economists and some engineers are working on economic aspects.

Cost-share Contributions to Phase 2

Colorado Geol. Survey	$35,046	In Kind
ARI	$144,300	Software
Utah Geol. Survey	$107,500	In Kind
Gas Technology Institute	$111,449	In Kind
Resolute Natural Resources	$289,030	In Kind
Texas A&M University	$264,461	In Kind
University of Utah	$100,769	In Kind
The CRUX	$43,072	In Kind
Texas BEG	$250,000	In Kind
Steve Hook	$45,000	In Kind
Western Governors Association	$30,000	In Kind
Burlington Resources	$447,500	In Kind
Kinder Morgan CO2	$889,240	In Kind
Pinnacle	$84,000	In Kind
Los Alamos National Lab	$0	NONE
Sandia National Lab	$305,000	In Kind
NMIMT	$448,658	Cash

Table 2. Cumulative proposed travel for the entire duration of the Phase 2 Project.

Organization	*NMIMT*	*Sandia*	*LANL*	*ARI*	*AZU*	*BREDEHOEFT*	*CRUX*
Purpose	DC/ RM/PM	DC/ RM/PM	DC/ RM/PM	DC/ RM/PM	DC/ RM/PM	DC/ RM/PM	RM/PM
No. trips	137	35	60	15	2	12	37
Origin	Socorro, NM	ABQ	Los Alamos, NM	HOU	Tempe, AZ	Sausalito, CA	College Station, TX
Destination	FIELD/ABQ, WDC, HOU, WVA ,SLC, OK	FIELD/ABQ/WDC, HOU, WVA	FIELD/ABQ/WDC, HOU, WVA	FIELD/ABQ/WDC, WVA	FIELD/ABQ/WDC, HOU, WVA	FIELD/ABQ/WDC, HOU, WVA	ABQ/WDC, HOU, WVA
Duration	2-3 days	2 days	2 days	2 days	2 days	2 days	2 days
Personnel	2	2	1	1	1	1	1
Organization	*CGS*	*UGS*	*GTI*	*TAMU*	*BEG*	*WGA*	
Purpose	DC/ RM/PM	DC/ RM/PM	RM/PM	DC/ RM/PM	DC/ RM/PM	RM/PM	
No. trips	19	40	13	12	54	26	
Origin	Denver CO	SLC	Des Plaines, IL	College Station, TX	Austin TX	Denver, CO	
Destination	FIELD/ABQ/WDC, HOU, WVA	FIELD/ABQ/WDC, HOU, WVA	ABQ/WDC, HOU, WVA	FIELD/ABQ/WDC, HOU, WVA	FIELD/ABQ/WDC, HOU, WVA	ABQ/WDC, HOU, WVA	
Duration	2 days	2 days	2 days	2 days	2 days	2 days	
Personnel	1	1	1	1	1	1	

Key: DC = collection; RM = review meetings; PM = professional meetings; FIELD = field locations for pilot sites; ABQ = Albuquerque, NM; HOU = Houston, TX; MWV = Morgantown, WV; WDC = Washington, DC; SLC = Salt Lake City, UT; OK = Oklahoma City, OK

<u>Management Tools and Inter-Partnership Technical Working Group Participation</u>

Standard management tools will be used to coordinate and manage the project, by key personnel described in the following section. Technical communication and inter-partnership communication will continue with Partnership technical working groups organized in Phase 1.

4. REGIONAL PARTNERSHIP COMPOSITION, TECHNICAL, AND MANAGEMENT

<u>Credentials, Capabilities, and Experience of the Organizations Involved</u>

The Southwest Regional Partnership on Carbon Sequestration (SWP) comprises a diverse group of expert organizations specializing in carbon sequestration science and engineering, as well as economics, public policy and outreach. These partner organizations are drawn from: 1) industry, 2) State governmental agencies and universities, 3) U.S. Federal government entities, and 4) other specialized partners like the Western Governors Association. All Partner organizations in the SWP played key roles in the Phase I program, and thus a wealth of experience is ready for the Phase 2 field validation testing program. A new priority for Partnership success in Phase 2 is strong participation by industry partners. Industry assistance and collaboration is critical for the proposed field validation and verification testing of sequestration technologies. Key industry partners in the proposed Phase 2 validation testing include Kinder Morgan CO_2 L.P. (KinderMorgan), Burlington Resources, Inc., Resolute Natural Resources Company, and the Navajo Oil and Gas Company, all of whom are operators of proposed field pilot test sites. Also paramount to Phase 2 success is continued collaboration on the part of power companies such as Public Service Co. of New Mexico (PNM), Pacificorp, Intermountain Power Agency, Tucson Electric Power, and Oklahoma Gas & Electric, all of whom have agreed to continue as Phase 2 SWP partners.

Credentials, Capabilities, Experience and Availability of Key Personnel

The Partnership will retain most of its key personnel from Phase 1 activities for the proposed Phase 2 pilots. All key personnel are amply prepared for Phase 2 validation testing by their active roles in the Phase I SWP program. Additional management personnel added for the Phase 2 tasks, the five pilot projects proposed, are key managers and points-of-contact for project site operators. These include **Mike Hirl** of KinderMorgan – SACROC-Claytonville pilot, **Steve Malkewicz** of Resolute – Aneth pilot, **Wilson Groen** of the Navajo Nation Oil and Gas Company – Aneth pilot, **Jim Schlabaugh** of Burlington – San Juan basin ECBM pilot, **Joel Brown**, U.S. Department of Agriculture – Regional terrestrial pilot, and **Joe Hewett**, U.S. Bureau of Land Management – San Juan terrestial pilot. All proposed project personnel available to the degree indicated for the 48-month duration of the project, assuming that the project begins approximately November 1, 2005. Details of the affiliations, credentials, capabilities and experience of key personnel are outlined in the resumes provided in attached file “resumes.doc.”

Project Organization, Structure and Diversity of Abilities

The project is organized within a set of nested and interacting management units that integrates the technical and geographic breadth of the project team. Project vision and overall technical management will be handled by an Executive Steering Committee (ESC) that comprises representatives drawn from each principal Partner. The ESC will also work with the National Energy Technology Lab. (NETL), the

Western Governor's Association and all regional State geological surveys to ensure continuity across State boundaries as the Partnership performs its pilot testing and continued regional characterization.

Similar to Phase 1 operations, core working groups will form, one for each of the five proposed pilot tests, and these working groups will meet frequently. The ESC will meet at least three times per year.

Prior Experience in Project Management

While overall technical management will be addressed by the ESC, day-to-day project management will be handled by the New Mexico Institute of Mining and Technology. Project Manager and PI **Dr. Brian McPherson** has several years experience in research management and is currently PI for the Southwest Regional Partnership on Carbon Sequestration, Phase I, and has managed two other large CO_2 sequestration projects. Utah Co-PI **Dr. Rick Allis** is Director of the Utah Geological Survey, just concluded serving as co-Principal Investigator of a DOE CO_2 sequestration project in the partnership region, and has considerable experience in project management with large teams. Leader of the GIS/Database initiative, **Dr. Dennis Goreham**, manages one of the most recognized GIS centers in the nation (UT AGRC) and Co-chairs the Western Governor's Association Geographic Information Council. Other key management personnel from the Partnership include co-PI **Karen Deike** of the Western Governors' Association, Assistant Project Manager for Field Operations **Dick Benson,** co-PI **Dave Borns** of Sandia National Lab, co-PI **Mark Holtz** of the Texas BEG, co-PI **Bob Siegfried** of GTI, and co-PI **Tarla Peterson** of the University of Utah. Resumes are attached in the file "resumes.doc."

Facilities, Equipment and Materials

The SWP has some of the facilities and equipment necessary for carrying out the required Phase 2 tasks. Otherwise, we have budgeted for all necessary field equipment and vendors required to carry out the proposed pilots and MMV activities. For databases, the Utah Automated Geographic Reference Center (AGRC) will continue to host the Southwest Region's databases. Outreach will be facilitated using the existing outreach and education mechanisms in place via Phase 1 activities, with outreach support offered by Western Governors' Association.